VNI West Project Assessment Conclusions Report Volume 1: Identifying the preferred option for VNI West

May 2023

Regulatory Investment Test for Transmission

Important notice

Purpose

This Project Assessment Conclusions Report has been prepared to meet the requirements of clauses 5.16A.4(i) – (l) of the National Electricity Rules to the extent applicable having regard to the orders issued by the Victorian Minister for Energy and Resources under the *National Electricity (Victoria) Act 2005* (NEVA) pursuant to section 16Y of the NEVA on 20 February 2023 and 27 May 2023. This Project Assessment Conclusions Report has also been prepared pursuant to AEMO's functions under clause 4.4 of the NEVA Order of 27 May 2023.

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Locations

Descriptions and visual representations of geographic locations in this document are indicative only. Locations will be determined after the conclusion of the RIT-T process, as required during detailed design, route assessment, planning and community engagement phase.

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AEMO and Transgrid acknowledge the many First Nations that host Australia's electricity grids and pay respect to Elders past, present and emerging. We respect the Indigenous history of the lands in which we currently and plan to operate, being conscious of the landscape-scale impacts of the energy transition. We wish to emphasise the importance of early and continued engagement, working closely with Traditional Owners, as the grid seeks to expand.

Executive summary

The Victoria – New South Wales Interconnector West (VNI West) project, by its nature, covers the interconnection between Victoria and New South Wales. The associated regulatory investment test for transmission (RIT-T) and this Project Assessment Conclusions Report (PACR) provide analysis on the combined investment case as first proposed in the 2018 *Integrated System Plan* (ISP). This report also has regard to the Victorian Minister for Energy and Resources' *National Electricity (Victoria) Act 2005* (NEVA) Orders issued in February 2023 and May 2023. The New South Wales aspects of the project are not subject to the NEVA Orders, and while in the early stages of development, are already responding to the feedback provided during early engagement on the broader VNI West project.

This PACR finds that the preferred option is a 500 kilovolt (kV) double-circuit overhead transmission line between Victoria and New South Wales, connecting Western Renewables Link (WRL) (at Bulgana) with EnergyConnect (at Dinawan) via a new terminal station near Kerang, and crossing the Murray River north of Kerang – 'Option 5A'.

The preferred Option 5A is a variant identified through responses to the additional Consultation Report published in February 2023 ('Additional Consultation Report'). Option 5A is electrically similar to Option 5, but with higher hosting limits for renewable generation, and covering a different area of interest in the north of Victoria and the south of New South Wales. It crosses the Murray River north of Kerang, whereas Option 5, the proposed preferred option in the Additional Consultation Report, crosses the Murray River near Echuca.

Option 5A was recommended by AEMO Victorian Planning (AVP) to the Victorian Minister for Energy and Resources as it is considered most likely to facilitate and expedite delivery, in that:

- The net benefits from the economic modelling under the Australian Energy Regulator's (AER's) Cost Benefit Analysis (CBA) Guidelines for both options evaluated in this PACR are very close (within 1%).
- Councils have indicated there is broader social licence for VNI West crossing the Murray River north of Kerang, and therefore more likelihood of timely implementation.
- The multi-criteria analysis (MCA) used to broadly identify potential environmental, social and engineering constraints that may impact timely project delivery shows that both options perform similarly and are superior to the alternatives considered in the Additional Consultation Report.
- Option 5A presents fewer environmental constraints and avoids intercepting the Patho Plains, an area of significant grassland habitat known to support the endangered Plains-wanderer.
- Option 5A avoids passing near Ghow Swamp, a place of national cultural significance.
- Option 5A is expected to harness more renewable generation in Victorian renewable energy zones (REZs) than Option 5.

The Minister has accepted this recommendation. Accordingly, the May 2023 NEVA Order specifies that the preferred option, to the extent it relates to the Declared Shared Network (DSN), must connect to WRL at Bulgana, via a new terminal station near Kerang, and cross the Murray River proximately north of Kerang (Wamba Wamba Country). Following this May 2023 NEVA Order, for an option to be credible under the RIT-T and this PACR, it must assume this Victorian configuration and the New South Wales components must be viable with that Victorian configuration. On that basis, Option 5A is the preferred option.

The power system in eastern Australia is undergoing fundamental, rapid and complex change. The integration of renewable generation and adoption of new technologies continues to shift the characteristics of electricity supply and is essential to meet Australia's commitments to emissions reductions and achieve net zero by 2050.

The forecast closure of ageing coal-fired generators in Victoria and New South Wales presents a significant challenge to the reliable supply of electricity. Targeted investment in transmission infrastructure is critical to adapt to these changes and harness Australia's rich renewable energy resources in a cost-effective manner and maintain downward pressure on electricity prices.

VNI West is a proposed second transmission link between Victoria and New South Wales that will harness clean, low-cost electricity from REZs in both states and improve the reliability and security of electricity supply as ageing coal-fired power stations are retired.

Under its declared network functions – including for Victorian transmission planning – set out in the National Electricity Law (NEL), AVP is responsible for planning, contracting and directing augmentation on the Victorian electricity transmission DSN. AusNet Services (AusNet) owns and operates much of that network, and has been contracted to build, own and operate WRL, a new double-circuit high-voltage transmission line between Bulgana and Sydenham currently being progressed through the environmental and planning approvals process. Transgrid operates and manages the high voltage electricity transmission network in New South Wales and the Australian Capital Territory (ACT) and is the Jurisdictional Planning Body for New South Wales.

In July 2022, AVP and Transgrid published and commenced consultation on the Project Assessment Draft Report (PADR), the second of three reports in the prescribed RIT-T process that covers the entire VNI West project. The PADR identified 'VNI West (via Kerang)'[1] as the proposed preferred option, connecting WRL (at the proposed terminal station north of Ballarat) with EnergyConnect (at Dinawan) via new stations near Bendigo and near Kerang.

One of the key issues identified through the PADR submissions and early engagement was the southern connection point into WRL and its compatibility with land use between Ballarat and Bendigo. In response, AVP and Transgrid embarked on investigation of alternate VNI West options, still running via a terminal station near Kerang, but with connection to the WRL west of the previously proposed terminal station north of Ballarat.

WRL is a new double-circuit high-voltage transmission line between Bulgana and Sydenham currently being progressed through the environmental and planning approvals process by AusNet.

These two transformative transmission projects are critical to meet the Victorian Government's renewable energy targets by increasing transmission network capacity for existing and new renewable generation in western Victoria.

Consultation on a revised option that connected WRL (at Bulgana) with EnergyConnect (at Dinawan) via a new terminal station near Kerang

On 20 February 2023, the Victorian Minister for Energy and Resources used powers under the *National Electricity (Victoria) Act 2005* (NEVA) to issue an order pursuant to section 16Y of the NEVA (February 2023 NEVA Order). The February 2023 NEVA Order confers upon AVP functions which include the assessment of alternate options to the preferred options, as described in the VNI West PADR and the WRL PACR, to expedite the development and delivery of both projects[2].

[1] Referred to as 'Option 1' in the Additional Consultation Report published February 2023.

[2] The VNI West and WRL Specified Augmentations are described in clause 3 of the May 2023 NEVA Order.

Consistent with the February 2023 NEVA Order, AVP, in consultation with Transgrid, considered factors relevant to the expedited development and delivery of VNI West, including social and environmental impacts raised by stakeholders which could impact expedition and delivery of VNI West.

Following the February 2023 NEVA Order, AVP and Transgrid published an Additional Consultation Report on the outcomes of the alternate options assessment and accompanying material (including a standalone report summarising and responding to PADR submissions). The Additional Consultation Report had regard to the February 2023 NEVA Order and represented an additional step to the formal RIT-T process, over and above the minimum consultation requirements prescribed under the RIT-T process.

The Additional Consultation Report assessed seven options in total. These options included consideration of various connection points with WRL further west than the PADR proposed preferred option's connection north of Ballarat, to avoid land use concerns between Bendigo and Ballarat that had been identified by stakeholders. AVP had regard to its functions under the NEVA Order in assessing and ranking these options.

The Additional Consultation Report identified Option 5, connecting to WRL (at Bulgana) with EnergyConnect (at Dinawan) via a new terminal station near Kerang, as the new proposed preferred option. Key reasons provided were that Option 5:

- Ranked effectively equal highest on a purely net benefits basis, delivering $1.3 billion net market benefits for consumers.
- Was less sensitive to potential cost increases or discount rate rises than the other options.
- Performed the best across all objectives in the MCA, intersecting significantly fewer protected areas, and significantly less native vegetation, critical habitat and land with higher agricultural potential, than all other options, and scoring equal best in relation to separation from buildings.
- Avoided the Bendigo to Ballarat corridor that submitters to the PADR suggested was problematic.
- Performed better than all other options in sensitivity analysis where it was assumed the Victorian Government's offshore wind commitments are legislated.

AVP and Transgrid consulted with a broad range of stakeholders, Traditional Owners, local government and community members over a six-week period to seek feedback on Option 5. Following this engagement and consideration of the feedback received, AVP consulted with VicGrid, a division of the Victorian Department of Energy, Environment and Climate Action, on the draft outcomes of the alternate options analysis and the PACR, as required under the February 2023 NEVA Order, and provided a draft of this PACR to the Victorian Minister for Energy and Resources on 3 May 2023 to inform the May 2023 NEVA Order, prior to this PACR being published.

In accordance with AEMO findings on the options based on the February NEVA Order, the May 2023 NEVA Order specifies that the preferred option, to the extent it relates to the declared transmission system must connect to WRL at Bulgana, via a new terminal station near Kerang and cross the Murray River proximately north of Kerang (Wamba Wamba Country). Following this May 2023 NEVA Order, for an option to be credible under the RIT-T and this PACR, it must assume the Victorian configuration specified in the order. On that basis, Option 5A is the preferred option for the Victorian and New South Wales components, as it is the only credible option where the New South Wales component is viable with that Victorian configuration required by order.

In preparing the PACR, Option 5 was assessed as a credible option. However, following the May 2023 NEVA Order, Option 5 is no longer a credible option as it is based on a different Victorian configuration to that required under the NEVA Order. References to Option 5 as a credible option in the remainder of this document are, following the May 2023 NEVA Order, no longer applicable.

This PACR Volume 1 reports on the estimated net market benefits of Option 5A and Option 5, including under sensitivity analysis, and provides further detail on Option 5A as the preferred option, as required under the RIT-T and having regard to the NEVA Orders.

PACR Volume 2: *Summary of submissions and responses to Additional Consultation Report* outlines the stakeholder engagement to date and summarises the Additional Consultation Report feedback and AVP and Transgrid's joint responses.

Stakeholder feedback on the Additional Consultation Report

A range of stakeholder information sessions and meetings were held to support the Additional Consultation Report engagement process. These sessions involved a broad range of interested parties including consumer representatives, manufacturers, developers, financiers, generators, retailers, government departments, local government areas (LGAs), community members, and network service providers (NSPs). AVP and Transgrid are grateful for the feedback received and for the open and ongoing dialogue with stakeholders and communities that has informed this PACR.

Feedback was sought on:

- The outcomes of the assessment undertaken in the Additional Consultation Report;
- The feasibility of Option 5; and
- Whether the MCA had captured the salient environmental, social and engineering factors, including those which may impact on the timely development of the project.

In total, over 500 submissions were received, with the majority of these submissions from concerned landholders and community members. Submissions covered a range of topics, including the following key themes:

- Level of support for Option 5
- Concerns with the MCA and area of interest
- Technical feasibility of Option 5
- Concerns that renewable generation development is limited
- Land use, health and safety, and fire fighting concerns
- Underestimation of costs on Victorian side
- Querying the project need and benefits
- Concerns with engagement, transparency, and the RIT-T/NEVA process
- Preference for undergrounding

While a number of stakeholders supported the undertaking of an MCA to provide greater consideration to social, cultural and environmental factors which may influence timely project delivery, it was recognised that there are limitations in applying this approach at such an early stage when it is necessary to rely primarily on desktop analysis.

Some stakeholders, including local councils, identified the need to consider a modified area of interest to cross the Murray River north of Kerang, avoiding some environmentally and culturally sensitive regions within the area of interest for the proposed preferred option identified in the Additional Consultation Report (Option 5). Factors of concern raised included potential impacts on the critically endangered Plains-wanderer bird species, culturally sensitive areas of national significance such as Ghow Swamp, tourism and recreation activities around Echuca and Moama, agriculture (particularly irrigated dairy districts), and community impacts in both Victoria and New South Wales. Critically, these local councils welcomed VNI West traversing their LGAs instead, provided it also supported renewable generation development in the area. This evolution of the route is also expected to reduce impediments to timely delivery.

Key themes raised in the Additional Consultation Report submissions, and feedback received subsequently, along with AVP and Transgrid's responses to the feedback, have been summarised in Volume 2 of this PACR. One lengthy submission from the Victorian Energy Policy Centre (VEPC) raised concern about the overall need for the VNI West project. Many of the assertions made in the submission are based on incorrect premises regarding the detailed engineering and economic models on which the RIT-T is founded, along with many other inconsistencies that are contrary to both government policy and numerous independent economic analyses regarding development of the power system as part of the transition to net zero emissions. A response to the VEPC submission is also provided in Volume 2 of this PACR.

Responding to key feedback

Three of the key changes that have been incorporated into this PACR in response to Additional Consultation Report submissions relate to:

- Exploring a variant of Option 5 that is electrically similar, but with a different Murray River crossing point and higher hosting limits for renewable generation in the Murray River REZ (V2) – Option 5A.
- Exploring opportunities for VNI West (either option) to harness more renewable generation.
- Updating cost estimates, particularly on the Victorian side, to reflect latest market and labour trends as identified in AEMO's 2023 Transmission Cost Database, and the Victorian Government's recently announced additional landholder payments[3].

In addition, the impact on net market benefits if power flow controllers prove not to be technically feasible for Option 5, or if a more westerly route around Kerang is needed under Option 5A, have been considered through sensitivity analysis.

Individual landholders and community members have provided detailed and valuable information that will be of great assistance to narrow the identified area of interest to a corridor during the next phase of engagement.

Consultation with potentially impacted landholders will intensify, commensurate with the next phase of detailed planning which includes narrowing of the potential corridor. For those landholders within the corridor who may host the infrastructure, a landholder liaison will be assigned to better understand how the land is used today, how impacts on that land use can be minimised both during construction and in the long term, and to initiate discussions on appropriate compensation.

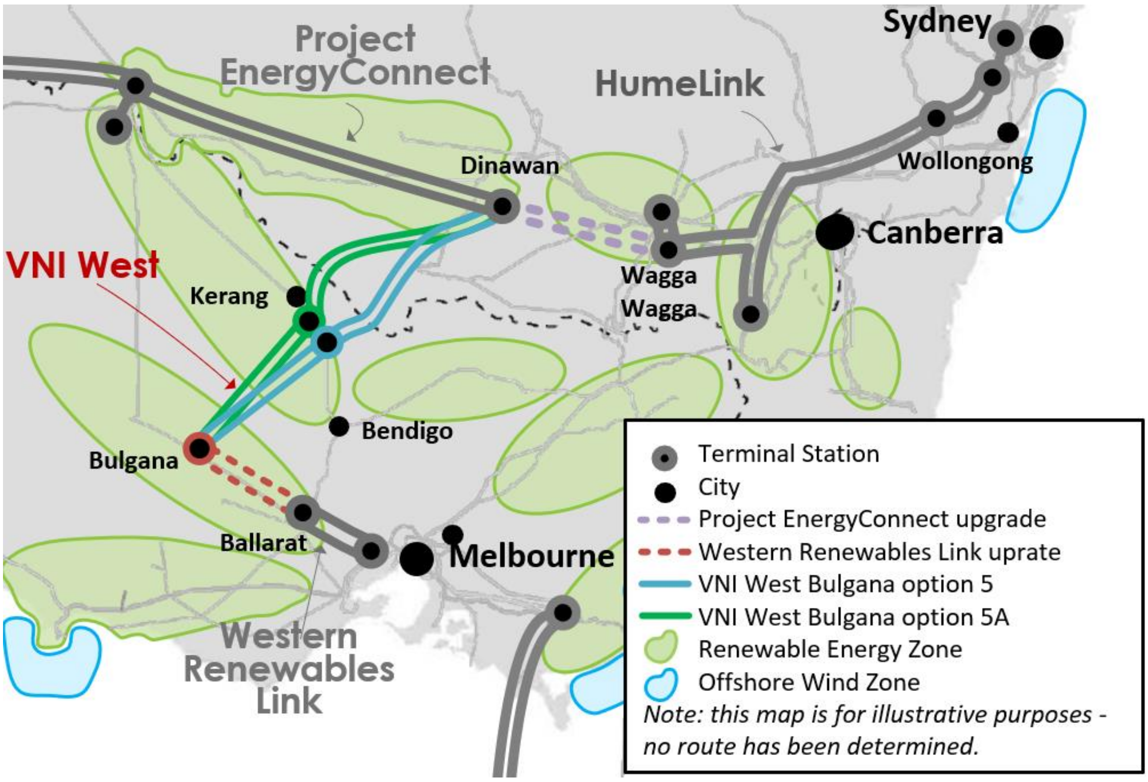
Two options have been assessed in this PACR, both of which have been developed in response to stakeholder feedback

This PACR assesses two options – one option developed in response to stakeholder feedback on the PADR (Option 5), and one option developed in response to stakeholder feedback on the Additional Consultation Report (Option 5A).

[3] See https://www.premier.vic.gov.au/sites/default/files/2023-02/230224-Landholder-Payments-For-A-Farier-Renwables-Transition.pdf.

Option 5 was assessed in the Additional Consultation Report and reflects the top-ranked option coming out of that process (on both a net market benefits basis and under the MCA). Option 5A is a variant of Option 5, which crosses the border north of Kerang. Option 5, on the other hand, crossed the Murray River near Echuca. River crossings between these two options are not feasible due to the RAMSAR wetlands on both sides of the border. The two credible options are shown in Figure 1.

Figure 1 Credible options assessed in this PACR



Both options assessed in this PACR:

- Involve a 500 kV double-circuit transmission line for VNI West.
- Originate at Dinawan substation, north of Jerilderie in New South Wales, with connection to EnergyConnect.
- Include a new terminal station near Kerang, in Victoria, with a connection to the existing 220 kV line between Kerang and Bendigo.
- Terminate at a new terminal station near Bulgana, in Victoria, with connection to WRL.
- Result in construction of WRL at 500 kV from Sydenham to Bulgana and remove the need for a new terminal station north of Ballarat[4].

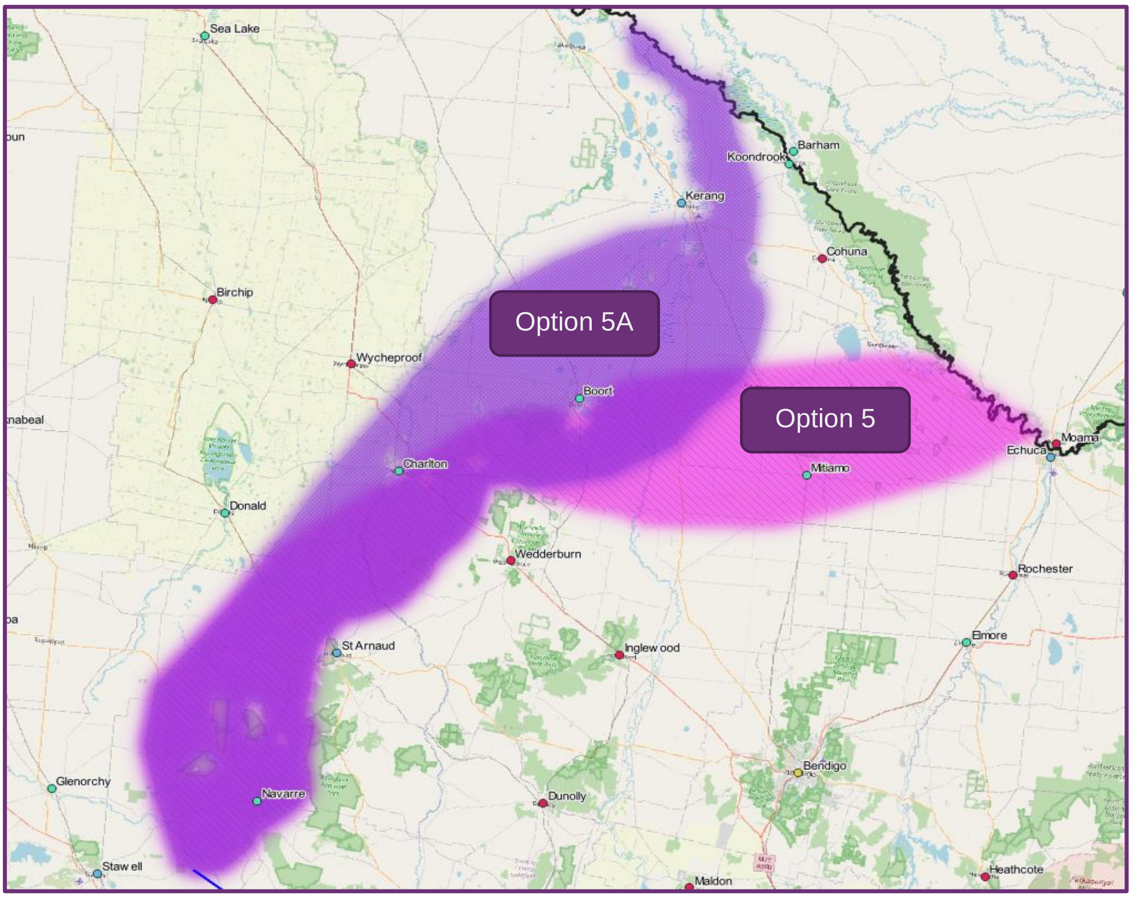
The differences in the options relate to the area of interest near the border between Victoria and New South Wales, and can be summarised as:

[4] While the associated costs of these works are considered in the assessment of options for the VNI West PACR, the uprating of the line section to 500 kV between Ballarat and Bulgana, and change to the location of the current proposed terminal station north of Ballarat to Bulgana, and associated works, is an element of the scope for delivery of the WRL project.

- **Option 5 (near Echuca)** – connects from Dinawan, via a new terminal station near Kerang, directly to WRL at a new terminal station near Bulgana (Wotjobaluk Country), crossing the Murray River near Echuca (Yorta Yorta Country).
- **Option 5A (north of Kerang)** – connects from Dinawan, via a new terminal station near Kerang, directly to WRL at a new terminal station near Bulgana (Wotjobaluk Country), crossing the Murray River north of Kerang (Wamba Wamba Country).

Figure 2 shows the two areas of interest on the Victorian side, ranging approximately 10-50 kilometres wide. Further detailed planning and assessment is required to narrow this corridor as quickly as possible to provide communities with certainty as soon as is practical.

Figure 2 Victorian areas of interest for credible options assessed in this PACR



Options 1 and 3A from the Additional Consultation Report (and the VNI West PADR/2022 ISP in the case of Option 1) have not been progressed due to scoring lower than Option 5 across the range of objectives assessed in that report, taking the February 2023 NEVA Order into account. While there was some support in submissions for Option 1 and Option 3 (the options without any 500 kV uprate of WRL), it was primarily from councils and developers in the north of Victoria concerned that Option 5, connecting to Bulgana, limited the opportunities for renewable generation investment in the Murray River REZ. The councils were concerned that without these development opportunities, social licence in their shires would be lost. There was also one submission in support of Option 3A, similarly due to it harnessing more renewable generation. The REZ limits are discussed further below. No information received during the Additional Consultation Report process had the ability to sufficiently improve the performance of Options 1, 3 or 3A such that any would outperform Option 5. Therefore, these options have not been taken forward in the PACR, and the focus has instead been on addressing concerns raised around Option 5 during the Additional Consultation Report process.

The technical characteristics of the credible options are summarised in Table 1. Specifically, this table shows the indicative impact on transfer capability (in both directions) and the REZ transmission limit (by affected REZ) for each option, based on AVP and Transgrid's power system analysis assessing both thermal and stability limits, as well as the estimated capital costs. The table also shows the technical characteristics for the two sensitivities involving wholesale market modelling.

Table 1 Summary of the credible options assessed

Option	Indicative impact on transfer capability		Indicative impact on REZ transmission limit		Capital cost* $m 2020-21
	VIC to NSW	NSW to VIC	Individually	Total	
Option 5 (near Echuca)	+1,960 megawatts (MW)	+1,710 MW	V2 – Murray River: +1,075 MW** V3 – Western Vic (WRL timing): +1,460 MW*** V3 – Western Vic (VNI West timing): +200 MW N5 – South West NSW: +900 MW	+3,635 MW	3,406
Option 5A (north of Kerang)	+1,935 MW	+1,669 MW	V2 – Murray River: +1,580 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +200 MW N5 – South West NSW: +900 MW	+4,140 MW	3,499
Sensitivities					
Option 5A (westerly sensitivity)	+1,910 MW	+1,650 MW	V2 – Murray River: +1,460 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +0 MW N5 – South West NSW: +900 MW	+3,820 MW	3,499
Option 5 (without series compensation)	+1,750 MW	+1,500 MW	V2 – Murray River: +800 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +0 MW N5 – South West NSW: +900 MW	+3,160 MW	3,331

* While the capital costs are shown at an aggregate level in this table, in the body of this report they have been broken out by key cost category and state for each option (early works, substation works, line works, power flow controllers, property/land access/easements and biodiversity offset costs).
** Since the Additional Consultation Report, further refinements of the power system model have identified a slightly higher V2 REZ limit of 1,075 MW (versus 850 MW in the Additional Consultation Report).
*** For all options and sensitivities, the V3 REZ transmission limit (WRL timing) is inclusive of the 600 MW limit increase associated with the current WRL scope.

The REZ transmission limits represent the maximum generation that can be dispatched at any point in time within a REZ; the additional generation development can exceed these limits because variable renewable generation such as wind and solar does not always operate at full capacity.

The REZ transmission limits presented allow for a mix of renewable generation in the Murray River and Western Victoria REZs. Depending on the generation type, there will be diversity in both geographic location as well as technology that will allow for generation from both REZs. Note that both the Murray River and Western Victoria REZs are limited by different elements of the existing parallel 220 kV network. Therefore, no one REZ can fully utilise the capacity of VNI West; renewable generation will be required in both REZs to optimally utilise VNI West capacity.

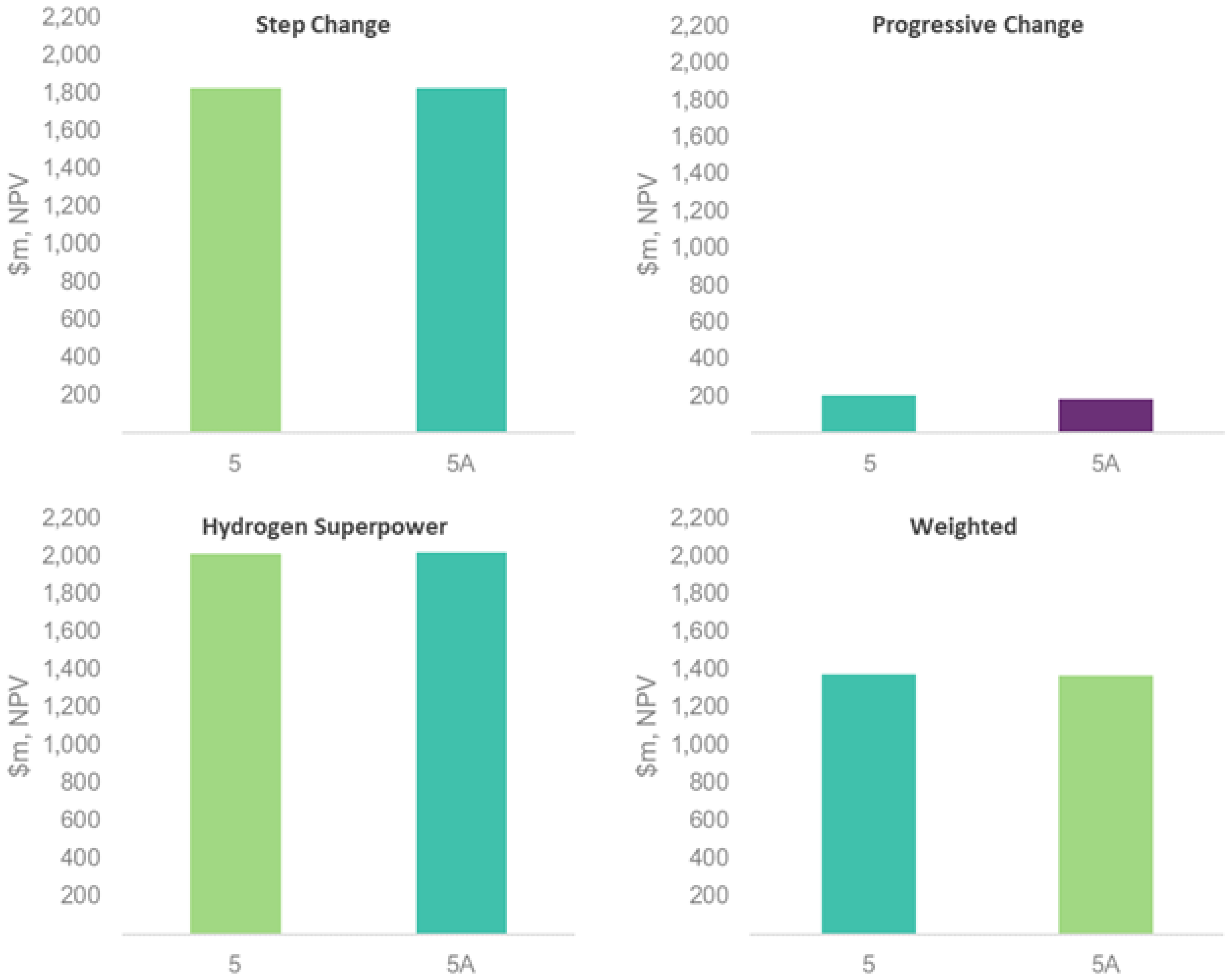
Further, Option 5A does provide higher REZ transmission limits for renewable generation development in the Murray River REZ than Option 5, although at a slightly higher cost given the longer line length required on the

New South Wales side for this option to cross the Murray River north of Kerang. The net market benefit assessment determined whether or not this alternate option better met the identified need for the RIT-T, which is to facilitate the efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales[5].

The net present value (NPV) assessment finds that Option 5A delivers $1.4 billion net market benefits for consumers

On a scenario-weighted net market benefit basis,[6] Option 5 and Option 5A are found to be ranked effectively equally, as shown in Figure 3. Option 5 (near Echuca) is expected to deliver net benefits of approximately $1,374 million NPV, while Option 5A (north of Kerang) is found to have net benefits of approximately $1,371 million NPV (0.2% less than Option 5).

Figure 3 Net benefits of each option assessed



Note: the **dark green** bar in each figure above indicates the option that has the highest estimated net benefits for that scenario, while the **light green** bars indicate the option is found to have net benefits that are within 5% of the top-ranked option, otherwise the option is shown in **purple**.

[5] AEMO, 2022 ISP, June 2022, p. 74, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf.

[6] The actionable ISP framework requires RIT-T assessments to use ISP parameters, including the scenarios and their weights. AEMO specifies in the 2022 ISP that the *Step Change* scenario should be given a 52% weight, the *Progressive Change* scenario should be given a 30% weight, and the *Hydrogen Superpower* scenario should be given an 18% weight in the RIT-T assessment.

Across all scenarios, avoided generation and storage costs are forecast to be the main driver of the estimated benefits, followed by fuel cost savings and REZ transmission expansion cost savings.

The market modelling forecasts that Murray River REZ (V2), Western Victoria REZ (V3), and South-West New South Wales REZ (N5), have considerably more renewable capacity built, compared to the ‘do nothing’ base case, in all three scenarios modelled. Specifically, with Option 5A in place, upwards of 3.4 gigawatts (GW) of renewable generation capacity is projected to be built across Murray River REZ and Western Victoria REZ in Victoria by 2050, in addition to the renewable generation already forecast to be harnessed by WRL. The South-West New South Wales REZ is also projected to build more solar and wind capacity, particularly under the *Step Change* and *Progressive Change* scenarios.

Transgrid engaged EY to undertake wholesale market modelling to assess the gross market benefits expected to arise under each of the credible options and scenarios. Assumptions and input data sources were independently selected in accordance with the CBA Guidelines by both Transgrid and AVP as joint RIT-T proponents. The wholesale market modelling methodology applied to assess gross market benefits in this PACR is the same as that presented in the Additional Consultation Report and is similar to the approach used in the 2022 ISP. The assessment of costs and calculation of net economic benefits and preferred option was conducted by AVP and Transgrid using the forecast gross market benefits and other inputs.

The robustness of the net benefit rankings and size of the benefits has been assessed by way of sensitivity and boundary testing in this report, varying key assumptions raised by stakeholders as having potential to materially change the outcomes of the cost benefit analysis. The purpose of the sensitivity analysis is to help identify whether variations in assumptions, if realised, could increase the risk of over- or under-investment for consumers and therefore serve as signposts for closer monitoring.

The key findings from this additional testing can be summarised as follows:

- From a net market benefits perspective, Option 5 performs slightly more favourably than Option 5A under the offshore wind sensitivity, if capital costs were to increase, or if applying a higher discount rate. This is due to its slightly lower cost, and lower REZ transmission limits when compared to Option 5A. However, Option 5A continues to deliver significant benefits for consumers under these sensitivities, and the selection of Option 5A reflects the Victorian Government’s commitment to support development of renewable generation in these REZs, as noted in the reasons for the February 2023 NEVA Order.
- Under all sensitivities tested where the net market benefits of the options reduce, they are still expected to generate significant cost savings for consumers. In the core *Step Change* scenario, the net market benefit is approximately $1.83 billion. Under the sensitivities to the *Step Change* scenario:
  - Assuming it is legislated, the Victorian Government’s offshore wind policy reduces the expected net benefits of Option 5 and Option 5A to $959 million and $913 million, respectively.
  - If adding power flow controllers to the Kerang to Bulgana segment of the line proves to be technically infeasible, the expected net benefits of Option 5 are $1,729 million (a reduction of approximately $98 million relative to core *Step Change* outcomes), and similar reductions are assumed to apply for Option 5A.
  - If a more westerly route around Kerang is taken, requiring connection to the existing 220 kV lines between Kerang and Wemen, the expected net benefits of Option 5A are $1,718 million (a reduction of approximately $109 million).

Multi-criteria analysis and the additional consultation undertaken following the PADR has informed the recommendation to the Victorian Minister and the second NEVA Order

AVP, in conjunction with external consultants AECOM, developed a detailed MCA methodology to further assess the options on the Victorian side and help determine which option is most likely to facilitate timely delivery. The MCA methodology has been designed to focus on social and environmental impacts in Victoria, in addition to technical and cost-benefit considerations, recognising the importance of these factors in building social licence which in turn should assist to facilitate and expedite development, delivery, construction and energisation. The importance of building social licence has also been recently recognised by the Australian Energy Market Commission (AEMC)[7].

The MCA methodology involves a series of systematic steps, including:

- Identifying constraints and opportunities.
- Identifying indicative alignments in Victoria to allow the analysis to be undertaken.
- Developing and implementing a project-specific framework.
- Undertaking the analysis and scenario/ sensitivity testing.

Six objectives, containing a total of 18 criteria, were considered in this MCA methodology and each option was scored on each criteria using a rating from one (being most favourable) to five (being least favourable). Each criterion was then weighted, based on expert judgement and relevant experience preparing submissions for planning and environment approvals, and a weighted score was determined to rank the options.

Based on the MCA and weighted scoring, Option 5 was found to be the highest ranked option in the Additional Consultation Report. However, as already discussed, a key concern raised in stakeholder feedback on the Additional Consultation Report was the proposed Victoria/New South Wales border crossing area of interest.

The investigation of Option 5A as a variant of Option 5 was made possible due to further studies undertaken by Transgrid determining that it would be viable on the New South Wales side to go to Dinawan from this alternative crossing area north of Kerang, while remaining outside declared National Park areas and RAMSAR wetlands.

Both Option 5 and 5A have been analysed in a revised MCA summarised in Table 2. The results indicate that for the Victorian side of the project, both options rank closely on all criteria assessed, and perform better than all other options previously assessed in the Additional Consultation Report.

Option 5A harnesses the most renewable generation and therefore ranks the same as Option 5 on net benefits criteria, despite the slightly longer line length and associated cost. Option 5A also performs better than Option 5 environmentally, consistent with feedback received in submissions, with the least area of native vegetation being intersected. Option 5A scored slightly less favourably in terms of cultural (higher area of potential cultural sensitivity intersected) and social (larger number of buildings within 300 metres and number of land parcels intersected), although critical field work is needed to validate this assessment.

The differences in scoring between Option 5 and Option 5A are not considered material given the lack of granularity in the MCA undertaken at this early stage. Relying on desktop analysis to differentiate between areas of interest in relatively close proximity can be challenging without the benefit of field surveys and further

[7] For example, as part of the 'Transmission Planning and Investment' review, the AEMC noted the importance of these factors in the delivery of transmission investments and considers that there is an opportunity for the AER to provide guidance on how they can be assessed (including potential studies and analysis that transmission network service providers (TNSPs) could undertake). See AEMC, *Transmission Planning and Investment – Stage 2*, Final Report, 27 October 2022, pp. 29-30.

community engagement. The feedback from stakeholders therefore supplements this assessment. This feedback included concerns raised regarding the potential impacts of the Option 5 area of interest on the critically endangered Plains-wanderer bird species, culturally sensitive areas such as Ghow Swamp, ecotourism and recreation activities and agriculture, along with some frustration that the area of interest bypassed communities wanting the infrastructure to support renewable generation development in their shire.

Table 2 Results of the VNI West MCA for Victoria

MCA Analysis Results			
Options		**Option 5** to Bulgana (Echuca crossing)	**Option 5A** to Bulgana (north Kerang crossing)
MCA Objective	**Weighting (%)**	WEIGHTED SCORING	
Benefits (net)	70%	1.41	1.41
Environmental	5%	0.08	0.06
Cultural	5%	0.10	0.12
Social	10%	0.21	0.26
Land use	5%	0.06	0.06
Engineering	5%	0.16	0.16
Total	*100%*		
Weighted Score (max is 5)		**2.01**	**2.06**
Rank		**1**	**2**

Note: the criteria measures were given a score of 1 to 5, in line with their associated rating system where the lower the score the more preferred or higher ranked that measure would be. Therefore, once the scores for all criteria are combined, the more favourable options will have a lower total score.

The results of the MCA, as well as the additional consultation undertaken since the PADR and consultation with VicGrid, informed the AVP recommendation to the Victorian Minister for Energy and Resources regarding Option 5A being preferred. This recommendation culminated in the May 2023 NEVA Order.

While the MCA only focuses on Victoria, it is noted that Transgrid has identified numerous challenges associated with the Option 5 area of interest within New South Wales through early social, agricultural and environmental constraints analysis and engagement with regional stakeholders. These challenges include the need to traverse large areas of productive irrigated cropping land, environmental impacts at the Murray River and significant impacts to regional tourism and development around Moama. On the other hand, Option 5A would traverse fewer productive irrigated cropping properties, traveling instead through larger broad acre farming properties, and avoid more highly populated areas. While these factors have not been taken into account in deciding on the preferred option for the RIT-T assessment of the New South Wales component, these factors are also likely to support more timely project delivery.

The February and May 2023 NEVA Orders relates only to the Victorian side of VNI West and as such community and stakeholder engagement in New South Wales is still in the very early stages. Transgrid will continue to work with a newly established Regional Reference Group, Traditional Owners and local councils to gather local insights and feedback and develop a less impactful corridor supporting the preferred river crossing in Option 5A.

Conclusion of this RIT-T process

The preferred VNI West option is a 500 kV double-circuit overhead transmission line between Victoria and New South Wales, connecting WRL (at Bulgana) with EnergyConnect (at Dinawan) via a new terminal station near Kerang, and crossing the Murray River north of Kerang – 'Option 5A'.

Specifically, Option 5A:

- Delivers approximately $1.4 billion of net market benefits in NPV terms over the assessment period. On a scenario-weighted basis, there is found to be a 0.2% difference in net benefits between Option 5 and Option 5A.
- Is expected to harness the most renewable generation in the Murray River REZ in Victoria, while also increasing the hosting capacity in Western Victorian and South West New South Wales REZs.
- Ranks best (or joint best with Option 5) from an environmental, land-use and engineering perspective, consistent with stakeholder feedback received in submissions.
- Avoids passing near Ghow Swamp, a place of national cultural significance.
- Has broader social licence, based on stakeholder submissions, due to traversing more of the Murray River REZ and crossing the river north of Kerang.
- Is the only credible option where the New South Wales component is viable with that Victorian configuration required by the May 2023 NEVA Order.

While not factored into the RIT-T assessment, on the New South Wales side Option 5A also avoids prime irrigation land and the Moama tourism hub that may have been impacted by the original Murray River crossing at Echuca.

Further information and next steps

Early works have already commenced in both Victoria (by Transmission Company Victoria, a wholly owned subsidiary of AEMO) and in New South Wales (by Transgrid). Both Transmission Company Victoria and Transgrid are targeting first spring surveys in 2023 to assist in accelerating delivery, as requested by both state and federal governments. Spring surveys are ecological surveys undertaken on land along the proposed transmission corridor to determine which plant and animal species may be impacted by the proposed transmission line. While some surveys will occur year-round, the majority are undertaken in spring as this is the most active season for most plants and animals, making them easier to identify. All early works are expected to be complete by early 2026.

Transgrid will now seek a 'feedback loop' confirmation from AEMO (in its national planning role) in line with the actionable ISP framework ahead of lodging a Contingent Project Application (CPA) for investment in VNI West. Transgrid is intending to submit two CPAs to the AER in relation to the regulatory cost recovery for the New South Wales side of the project:

- The 'Initial CPA' will seek cost recovery for the Stage 1 early works, based on the preferred option.
- The 'Final CPA' will seek cost recovery for the Stage 2 implementation costs, including the construction costs of the project (this CPA will cover the bulk of the project cost).

Transgrid will need to seek further ‘feedback loop’ confirmation from AEMO prior to submitting the ‘Final CPA’ to confirm that the project is still part of the optimal development path in the latest ISP and delivers positive market benefits in the ‘most likely’ scenario.

The regulatory arrangements in Victoria do not require AVP to seek a ‘feedback loop’ confirmation from AEMO.

This report marks the end of the formal RIT-T consultation process under the National Electricity Rules (NER). Detailed engagement with affected communities and landholders will now commence. This ongoing engagement will include the following activities:

- Continuing regionally focused engagement with communities and stakeholders that will potentially host the infrastructure to understand inherent values, opportunities, and constraints as inputs to a corridor definition process.
- Establishing Stakeholder Reference Groups and continuing Regional Reference Groups, to allow stakeholders to collaborate with the project teams to further develop and refine the study corridor.
- Undertaking direct engagement with potentially affected landholders (most likely from June 2023), to identify the best route alignment and optimise the route based on localised property constraints.
- Engaging with landholders prior to commencing environmental field studies to assist in route refinement.
- Commencing discussions with affected landholders in relation to compensation.

In parallel, AusNet will continue engaging with landholders along the proposed WRL route to provide them with the latest available information and respond to their questions and concerns about the associated changes to WRL. In particular, with the uprating of the 220 kV section of WRL to 500 kV as specified in the May 2023 NEVA Order, AusNet has identified further investigations that will be required prior to submitting the Environment Effects Statement, including:

- Deviating the line where the proposed route for the 220 kV is too constrained to accommodate the 500 kV line due to a larger easement area being required; and
- Tower siting and positioning, as they are expected to be taller and have a larger base footprint.

Information about the process and upcoming stakeholder engagement activities going forward will be published on the VNI West dedicated webpages at www.transgrid.com.au/vniw and www.aemo.com.au/vni-west. Transmission Company Victoria and Transgrid will advise in more detail – through direct correspondence and broad regional communications programs – on how and when stakeholders, communities and landholders can input into the route selection and refinement process.

AEMO and Transgrid acknowledge the many First Nations that host Australia’s electricity grids and pay respect to Elders past, present and emerging. We respect the Indigenous history of the lands in which we currently and plan to operate, being conscious of the landscape-scale impacts of the energy transition. We wish to emphasise the importance of early and continued engagement, working closely with Traditional Owners, as the grid seeks to expand.

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1 Introduction

The Regulatory Investment Test for Transmission (RIT-T) is an economic cost benefit test used to assess and rank different network and non-network investment options that address an identified power system need.

This Project Assessment Conclusions Report (PACR) is the final step in the consultation process in relation to expanding the Victoria – New South Wales Interconnector West (VNI West) RIT-T, which was identified as an 'actionable ISP project' in the 2022 *Integrated System Plan* (ISP)[8].

This PACR follows the February 2023 additional Consultation Report and accompanying material that was released in response to feedback from stakeholders to further consider and consult on alternate options and to assess which option is most likely to facilitate timely delivery consistent with the terms of the February 2023 *National Electricity (Victoria) Act 2005* (NEVA) Order. This PACR also has regard to the May 2023 NEVA Order that specifies the preferred option to the extent that it relates to the declared transmission system (broadly the Victorian portion of the project).

1.1 Overview of RIT-T and NEVA process followed

The power system in eastern Australia is undergoing fundamental, rapid and complex change as it transitions to net zero emissions. The integration of renewable generation and adoption of new technologies continues to shift the geography and technical characteristics of electricity supply in Victoria and New South Wales. Concurrently, the forecast closure of ageing coal-fired generators in Victoria and New South Wales presents a significant challenge to supply reliability for the energy industry.

This transformation is being driven by the latest round of announced coal-fired generator closures[9] as well as state and federal government commitment to renewable energy and associated emissions reduction targets.

In response to this fundamental transition in the energy system, AEMO (in its role as national transmission planner) is required under the regulatory and planning framework to publish an ISP at least every two years. The ISP provides a roadmap for the National Electricity Market (NEM) to transition to net zero by 2050 and identifies network investments that AEMO considers to be key to successfully underpinning the energy market transition (the 'optimal development path'). The 'actionable ISP' regulatory framework requires the RIT-T to be applied to those projects that are the priority, actionable ISP projects, to progress in the near term.

[8] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[9] See https://www.agl.com.au/about-agl/how-we-source-energy/loy-yang-power-station#:~:text=AGL%20Loy%20Yang%20Power%20Station,significant%20decarbonisation%20initiatives%20in%20Australia.

The opportunity to increase interconnection between Victoria and New South Wales was included as part of the 2018 ISP (then referred to as SnowyLink[10]). VNI West was identified as an 'actionable ISP project' in the 2020 ISP[11] and this status continued in the 2022 ISP[12].

Targeted investment to increase the interconnection capacity between the two states will facilitate the efficient dispatch of new and existing generation and help maintain supply reliability in Victoria. This is expected to put downward pressure on energy costs by lowering overall power system investment and dispatch costs across the NEM. The investment will also provide interconnector diversity by creating multiple physical interconnector routes between Victoria and New South Wales with no geographic points in common. This interconnector diversity increases the resilience of the grid against extreme climate conditions and improves overall system security.

In December 2019, AEMO Victorian Planning (AVP) and Transgrid formally commenced this RIT-T through publishing a Project Specification Consultation Report (PSCR). This initial stage of the RIT-T process pre-dated the 'actionable ISP' framework that is now part of the regulatory framework. AVP and Transgrid subsequently opted to apply the actionable ISP framework to VNI West and a Project Assessment Draft Report (PADR) was published in July 2022, following publication of the 2022 ISP in June 2022. The PADR called for submissions by 9 September 2022.

Twenty-six submissions were received on the PADR[13]. All non-confidential submissions are available on the AEMO website[14]. Submissions included a broad range of feedback relating to the options assessed in the PADR, including questions relating to the modelling undertaken, concerns about social and environmental impacts of the proposed preferred option, and suggestions that additional options be considered in the PACR.

This feedback led to a refinement of the market modelling methodology, and the inclusion of five new options for assessment, in addition to the two considered in the PADR.

Additionally, on 20 February 2023, the Victorian Minister for Energy and Resources used powers under the *National Electricity (Victoria) Act 2005* (NEVA) to issue an order pursuant to section 16Y of the NEVA (February 2023 NEVA Order). The February 2023 NEVA Order conferred upon AVP functions which included the assessment of alternate options to the preferred options[15] which would expedite the development and delivery of VNI West (and the Western Renewables Link (WRL))[16] or otherwise better meet a crucial national electricity system need.

AVP considered social and environmental impacts raised by stakeholders as concerns which might impact expedition and delivery of VNI West in its analysis.

To provide a further opportunity for stakeholder engagement and consultation, in February 2023 AVP and Transgrid published an additional consultation report on potential alternate options (the 'Additional Consultation Report'), and accompanying material (including a standalone report summarising and responding to PADR submissions). The Additional Consultation Report had regard to the February 2023 NEVA Order and represented

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[10] AEMO, 2018 ISP, July 2018, pp. 8-9, 86-88 and 90-92, at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2018-integrated-system-plan-isp.

[11] AEMO, 2020 ISP Appendix 3. Network investments, July 2020, p. 14, at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

[12] AEMO, 2022 ISP, June 2022, p. 75.

[13] Including three verbal submissions made by organisations at the Energy Consumer Submission Forum.

[14] At https://aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission/stakeholder-consultation.

[15] As described in the VNI West PADR and the WRL PACR.

[16] The VNI West and WRL Specified Augmentations are described in clause 3 of the NEVA Order.

an additional step to the formal RIT-T process, following calls from stakeholders for further consultation on alternate options including the proposed location of the terminal station and connection between VNI West and WRL north of Ballarat. The Additional Consultation Report was released on 23 February 2023, with submissions requested by 5 April 2023. AVP and Transgrid conducted a broad series of stakeholder engagement sessions relating to the Additional Consultation Report.

AVP consulted with VicGrid, a division of the Victorian Department of Energy, Environment and Climate Action, on the draft outcomes of the alternate options analysis and the PACR, as required under the February 2023 NEVA Order, and provided a draft of this PACR to the Victorian Minister for Energy and Resources on 3 May 2023 to inform the second NEVA Order gazetted 27 May 2023 (May 2023 NEVA Order), prior to this PACR being published.

In accordance with AEMO findings on the options based on the February NEVA Order, the May 2023 NEVA Order specifies that the preferred option, to the extent it relates to the declared transmission system, must connect to WRL at Bulgana, via a new terminal station near Kerang, and cross the Murray River proximately north of Kerang (Wamba Wamba Country). Following this May 2023 NEVA Order, for an option to be credible under the RIT-T and this PACR, it must assume the Victorian configuration specified in the order.

On that basis, Option 5A is the preferred option for the Victorian and New South Wales components as it is the only credible option where the New South Wales component is viable with that Victorian configuration required by the May 2023 NEVA Order.

In preparing the PACR, Option 5 was assessed as a credible option. However, following the May 2023 NEVA Order, Option 5 is no longer a credible option, as it is based on a different Victorian configuration to that required under the NEVA Order. References to Option 5 as a credible option in the remainder of this document are, following the May 2023 NEVA Order, no longer applicable.

This PACR has been published in two volumes:

- Volume 1 (this volume) reports on the estimated net market benefits of the options analysed, including under sensitivity analysis, and provides further detail on the preferred option, as required under the RIT-T and having regard to the NEVA Orders.
- Volume 2: *Summary of submissions and responses to Additional Consultation Report* outlines the stakeholder engagement to date, and summarises the Additional Consultation Report feedback and AVP and Transgrid's joint responses.

1.2 Why was a NEVA Order made?

In March 2020, the Victorian Government amended the NEVA to provide powers to fast-track network investments to improve the reliability of Victoria's transmission system. A key purpose of these amendments was to accelerate priority transmission projects and network investments, which can be held up by the complex national regulatory regime under the National Electricity Law (NEL) and National Electricity Rules (NER).

Under section 16Y of the NEVA, the Victorian Minister for Energy and Resources may make orders to regulate a transmission project or modify or exclude regulatory requirements under the NEL and NER.

These powers can change AEMO's functions under the NEL and NER as Victorian Transmission System Planner.

A Ministerial Order under section 16Y of the NEVA can, for example, modify or disapply laws or rules under the national regulatory framework relating to:

- The RIT-T.
- Contestable procurement rules for transmission projects.

If appropriate, a NEVA Order may also specify an alternative test in place of the RIT-T.

The Minister's Statement of Reasons accompanying the February 2023 NEVA Order[17] highlighted the Victorian Government's commitment to "*accelerating VNI West to ensure a reliable, secure and affordable supply of electricity to all Victorians*". The Minister considered that taking steps to accelerate VNI West provided:

- Strategic protection against the risk of early coal retirement or unplanned outages, where sufficient replacement dispatchable capacity may not otherwise be available in the electricity system, by enabling earlier than anticipated access to replacement electricity supply and dispatchable capacity across the NEM, including through Snowy 2.0;
- Victorian generators, including future offshore wind generators, with earlier export opportunities into northern jurisdictions to support reliability and security of supply in other NEM states; and
- Opportunities to mitigate against gas supply scarcity and high electricity prices by enabling hosting capacity for low-cost renewables.

To support timely delivery of VNI West, and mitigate against delay risks, the NEVA Order:

- Provided for AVP (or subsidiary) to carry out its VNI West early works program for the Victorian component on VNI West, working towards undertaking first spring surveys in 2023.
- Allowed AVP to assess and consult on alternate VNI West options, including potential changes to where it connects to WRL, which could provide more certainty over timely project delivery.
- Removed the need under the NER to re-apply the VNI West RIT-T or WRL RIT-T due to a relevant material change in circumstances.

The scope of the February 2023 NEVA Order allowed for early development work in Victoria to continue while the RIT-T is progressing. The February 2023 NEVA Order:

- Still required AVP to prepare and publish a PACR for VNI West with Transgrid.
- Did not change obligations to follow future environmental and planning approval processes.
- Only impacted the Victorian portion of VNI West and had no impact on the New South Wales portion.

The February 2023 NEVA Order also required that AVP receive prior approval from the Victorian Minister for Energy and Resources, or that a further NEVA Order is made, before a construction agreement for VNI West is entered into, and included additional oversight mechanisms for the state.

The NEVA Order takes contestability out of the regulatory framework, but this does not necessarily mean the Minister will not make the build, own and operate phase a contestable process once early works have progressed sufficiently to reduce uncertainty in the pending tender process.

[17] See http://www.gazette.vic.gov.au/gazette/Gazettes2023/GG2023S267.

1.3 Role of this report

This PACR is the final consultation document in the RIT-T process for assessing options for increasing interconnection between Victoria and New South Wales.

This report, the PACR Volume 1:

- Identifies and confirms the market benefits expected from expanding interconnection capacity between Victoria and New South Wales.
- Describes the options that have been assessed under this RIT-T (as well as additional options considered but not progressed), which have been informed by the submissions received.
- Presents the results of the final net present value (NPV) analysis for each of the options assessed.
- Describes the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion.
- Presents the outcomes of the multi-criteria analysis (MCA) developed to assess and rank options against broader environmental, social and engineering criteria that may increase likelihood of timely project delivery.
- Identifies the overall preferred option of the RIT-T, that is, the option that is expected to maximise net market benefits in the long-term interest of consumers while having regard to AVP's functions under the NEVA Orders.

Overall, a key purpose of RIT-T framework is to provide interested stakeholders the opportunity to review the analysis and assumptions during the analysis and have certainty and confidence that the preferred option at the end of the process in the PACR has been robustly identified as optimal. As jurisdictional planners, AVP and Transgrid are responsible for undertaking the RIT-T, and the Australian Energy Regulator (AER) monitors and enforces compliance with the process.

AVP and Transgrid have published a separate volume (Volume 2) alongside this PACR that summarise points raised in submissions to the Additional Consultation Report, released in February 2023, and earlier PADR, as well as how this feedback has been addressed in the RIT-T analysis.

The Additional Consultation Report published by AVP and Transgrid in February 2023 contained a detailed description of a number of additional options considered in response to stakeholder submissions on the PADR. AVP and Transgrid also published a detailed summary of the points raised in submissions to the PADR, and how they have been considered in finalising this RIT-T, as well as a market modelling report which provided additional detail on the updated wholesale market modelling[18]. The material in these reports has not been included in this PACR, to avoid repetition.

1.4 Further information and next steps

This PACR represents the final stage in the RIT-T consultation process. Any party wishing to dispute the conclusions made in this PACR must give notice to the AER of the dispute in writing, setting out the grounds for the dispute, and at the same time, give a copy of the dispute notice to AVP and Transgrid. The closing date for this to occur for this PACR is 26 June 2023[19].

[18] See https://aemo.com.au/initiatives/major-programs/vni-west/reports-and-project-updates.

[19] NER 5.16B(c)

At the competition of the RIT-T process, the wider area of interest (with a width of between 10 kilometres and 50 kilometres) would be used as the starting point for further engagement and route identification and refinement. This will provide flexibility to select an alignment that can avoid issues and constraints that have been identified through ACR submissions and which are identified during future site investigations and stakeholder engagement.

As part of the future route determination process which follows the completion of the RIT-T, the area of interest would undergo more focused assessments, surveys and discussions with stakeholders and landowners to further investigate environmental, cultural and social constraints and opportunities. This will allow the refinement of this area of interest to an ‘investigation or study corridor’.

Following conclusion of the RIT-T process, Transgrid will seek ‘feedback loop’ confirmation from AEMO (as national planner) in line with the actionable ISP framework ahead of lodging a Contingent Project Application (CPA) for investment in VNI West. Transgrid intends to submit two CPAs to the AER in relation to the regulatory cost recovery for the project:

- The ‘Initial CPA’ will seek cost recovery for the Stage 1 early works, based on the preferred option.
- The ‘Final CPA’ will seek cost recovery for the Stage 2 implementation costs, including the construction costs of the project (this CPA will cover the bulk of the project cost).

Transgrid will need to seek further ‘feedback loop’ confirmation from AEMO prior to submitting the ‘Final CPA’ to confirm that the project is still part of the optimal development path in the latest ISP and delivers positive market benefits in the ‘most likely’ scenario.

The ISP feedback loop requires AEMO (in its national planning role) to confirm that the preferred option from the RIT-T remains aligned with the optimal development path in the most recent ISP. This process will ensure that the investment is confirmed as being consistent with the optimal development path in the latest ISP, taking into account any updated information available.

While the RIT-T is a technical and economic cost benefit test focused on delivering net market benefits, AVP and Transgrid acknowledge the important environmental, land use, safety, amenity, social, cultural and community matters raised by stakeholders through this RIT-T consultation process (and note that these factors were considered at a high level for the Victorian components of the project as part of the Additional Consultation Report released in February 2023, with further information provided in response).

Matters raised in submissions that are not able to be addressed in the RIT-T process have been collated and will be given due consideration as part of the corridor selection and project planning and environmental approvals processes. This will avoid and minimise project impacts while ensuring the project continues to deliver market benefits in the long-term interest of electricity consumers. Where it is not possible to avoid project impacts, compensation will be offered.

The general approach to engagement in 2023 will focus on a methodology that narrows a broad project study area into a proposed route. This will include:

- Continuing regionally focused engagement with communities and stakeholders that will potentially host the infrastructure to understand inherent values, opportunities, and constraints as inputs to a corridor definition process.
- Establishing Stakeholder Reference Groups and continuing Regional Reference Groups, to allow stakeholders to collaborate with the project teams to further develop and refine the study corridor.

- Undertaking direct engagement with potentially affected landholders (most likely from June 2023), through dedicated landholder liaison, to identify the best route alignment and optimise the route based on localised property constraints.
- Engaging with landholders prior to commencing environmental field studies to assist in route refinement.
- Commencing discussions with affected landholders in relation to compensation.

In parallel, AusNet Services (AusNet) will continue engaging with landholders along the proposed WRL route to provide them with the latest available information and respond to their questions and concerns about the associated changes to WRL. In particular, with the uprating of the 220 kV section of WRL to 500 kV as specified in the May 2023 NEVA Order, AusNet has identified further investigations that will be required prior to submitting the Environment Effects Statement including:

- Deviating the line where the proposed route for the 220 kV is too constrained to accommodate the 500 kV line due to a larger easement area being required; and
- Tower siting and positioning, as they are expected to be taller and have a larger base footprint.

Information about the process and upcoming stakeholder engagement activities going forward will be published on the VNI West dedicated webpages at www.transgrid.com.au/vniww and www.aemo.com.au/vni-west. Transmission Company Victoria and Transgrid will advise in more detail – through direct correspondence and a broad regional communications program – on how and when stakeholders, communities and landholders can input into the route selection and refinement process.

Further details in relation to this project can be obtained from VNIWestRITT@aemo.com.au.

Activities not related to the RIT-T but necessary to progress assessment of the project to achieve approval are also being undertaken, including preparing for the detailed planning and environmental assessment processes required in both New South Wales and Victoria.

1.5 Supporting materials

Supporting materials that may be of interest are included in Table 3.

Table 3 Supporting materials

Source	Website address and link
Transmission Company Victoria (TCV)	https://transmissionvictoria.com.au/
Market modelling results – PACR	https://aemo.com.au/initiatives/major-programs/vni-west/reports-and-project-updates
Additional Consultation Report	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/vni-west-consultation-report---options-assessment.pdf?la=en
Market modelling for the Additional Consultation Report	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/victoria-to-nsw-interconnector-west-vni-west--market-modelling-report-for-additional-options.pdf?la=en
VNI West PADR Submissions	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/vni-west-padr-submissions.pdf?la=en
Electricity Transmission Lines – Bushfire Management and Community Safety (ESV)	https://www.esv.vic.gov.au/about-us/publications/electricity-transmission-lines-bushfire-management-and-community-safety

Source	Website address and link
Electric Safety (Electric Line Clearance) Regulations 2020	https://www.esv.vic.gov.au/industry-guidance/electrical/line-clearance/legislation-policies-and-areas
Easement and compensation guidelines (AusNet)	https://www.westernrenewableslink.com.au/assets/resources/Landholder-Guide-Option-for-Easement-process-and-compensation-March-2023.pdf
Landowner Guide (AusNet)	https://www.westernrenewableslink.com.au/assets/resources/Landholder-guide-Land-access-easements-and-compensation-June-2022.pdf
Easement guidelines (Transgrid)	https://www.transgrid.com.au/media/3tkdd5lr/easement-guidelines.pdf
Farming and transmission (AEMO)	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/useful-links/fast-facts---farming-and-transmission.pdf?la=en
Essential Services Commission Statement of Expectations for land access	https://www.esc.vic.gov.au/electricity-and-gas/inquiries-studies-and-reviews/electricity-transmission-company-land-access-statement-expectations
Better Practice Landholder and Community Engagement Guide (The Energy Charter)	https://www.theenergycharter.com.au/wp-content/uploads/2021/09/Better-Practice-Landholder-and-Community-Engagement-Guide-Final-September-2021.pdf
Better Practice Social Licence Guideline (The Energy Charter)	https://www.theenergycharter.com.au/wp-content/uploads/2023/05/The-Energy-Charter_Better-Practice-Social-Licence_2023_GUIDELINE.pdf
Community Engagement Guidelines for Building Powerlines (Clean Energy Council)	https://www.cleanenergycouncil.org.au/advocacy-initiatives/community-engagement/community-engagement-guidelines-for-building-powerlines-for-renewable-energy-developments
Energy Networks Australia	https://www.energynetworks.com.au/electric-and-magnetic-fields/
Australian Radiation Protection and Nuclear Safety Agency	https://www.arpansa.gov.au/
World Health Organisation	https://www.who.int/health-topics/electromagnetic-fields#tab=tab_1
Victorian Transmission Investment Framework consultation paper	https://engage.vic.gov.au/victorian-transmission-investment-framework
Project Specification Consultation Report	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/vni-west_rit-t_pscr.pdf?la=en
Project Assessment Draft Report	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/vni-west-project-assessment-draft-report.pdf?la=en
February 2023 NEVA Order	http://www.gazette.vic.gov.au/gazette/Gazettes2023/GG2023S060.pdf
May 2023 NEVA Order	http://www.gazette.vic.gov.au/gazette/Gazettes2023/GG2023S267.pdf
Australian Energy Regulator's Cost Benefit Analysis Guidelines	https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf
Guidance note: Regulation of actionable ISP projects (AER)	https://www.aer.gov.au/system/files/AER%20-%20Final%20Guidance%20note%20-%20Regulation%20of%20actionable%20_ISP%20projects%20-%20March%202021%20-%20FINAL%20FOR%20PUBLICATION%2812129318.1%29.pdf
HumeLink Undergrounding Study	https://www.transgrid.com.au/media/y0mpqzvw/humelink-project-underground-report-august-2022-final.pdf
AusNet Undergrounding Study	https://www.westernrenewableslink.com.au/assets/resources/Underground-construction-summary-November-2021.pdf
AEMO 2023 Transmission Cost Database	https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation
Webinar recording and Q&A and deep dive Q&A	https://aemo.com.au/initiatives/major-programs/vni-west/project-resources/additional-consultation-report-resources

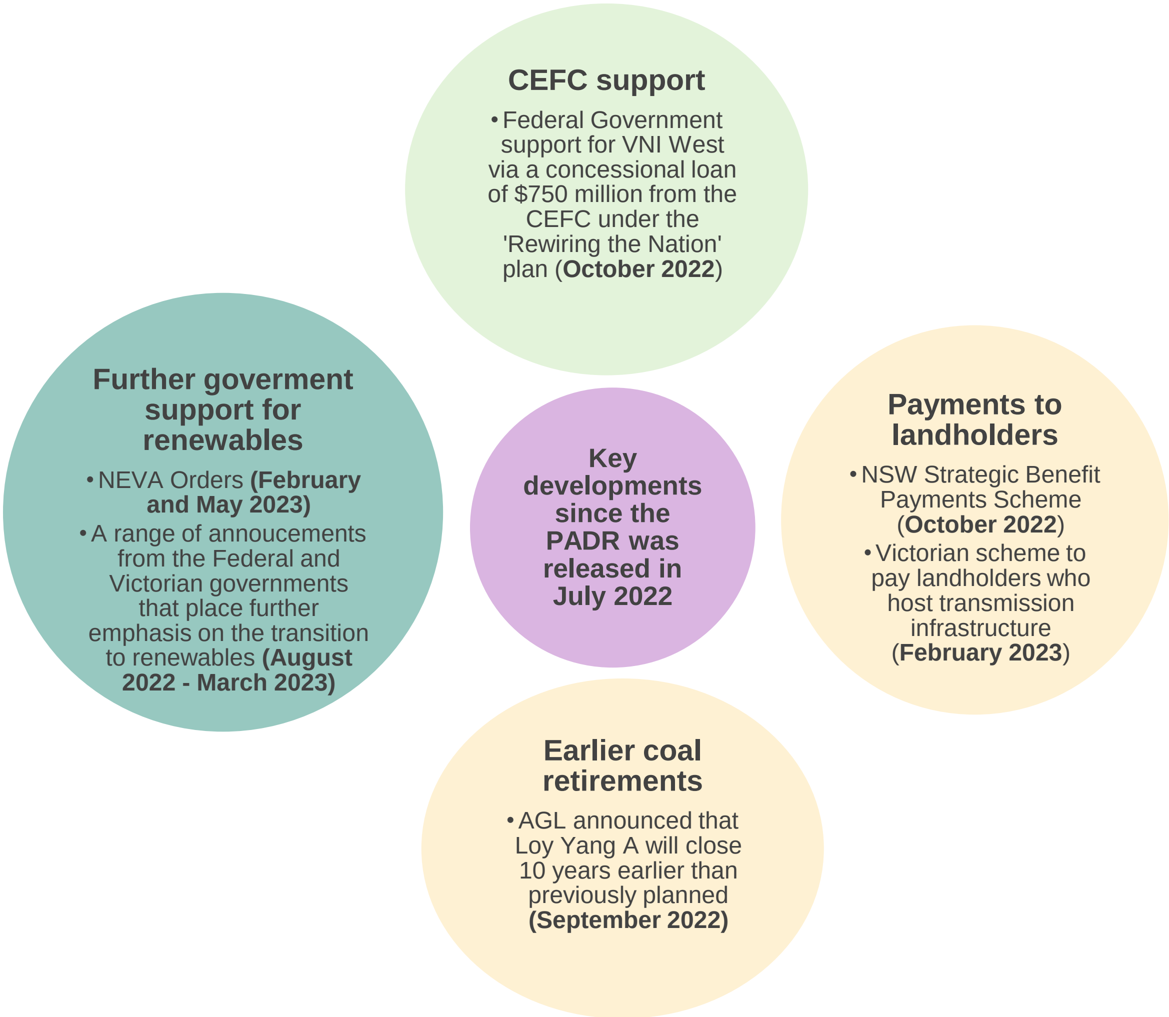
2 Key developments since the PADR

There have been several key external developments since the PADR was released in July 2022. The assessment in this PACR (and the earlier Additional Consultation Report) builds on the assessment in the PADR to reflect these developments where relevant, together with addressing points raised in submissions.

2.1 Key developments external to the RIT-T since the release of the PADR

There have been several key developments outside of this specific RIT-T process since the PADR was released. Each of these key developments is outlined below.

Figure 4 Key developments external to the RIT-T since the release of the PADR



2.2 Government support for VNI West

In October 2022, the Federal and Victorian governments announced that the Clean Energy Finance Corporation (CEFC) will provide a concessional loan of $750 million for VNI West. This funding forms part of the first announcement under the Federal Government's wider 'Rewiring the Nation' plan, outlined in Section 2.3 below. The concessional financing was announced to ensure VNI West is accelerated from the timeframes outlined in the 2022 ISP (the announcement states it is being provided to ensure a 2028 completion)[20]. Details on how this concessional financing will be rolled out in Victoria are yet to be provided, and no assumptions have been made in this PACR.

On 21 December 2022, the Federal Government and the New South Wales Government announced a $7.8 billion deal to connect New South Wales' renewable energy zones (REZs) and connect Snowy 2.0 to the grid. The deal will back eight critical transmission and REZ projects, including VNI West, and is jointly funded by Rewiring the Nation ($4.7 billion) and the New South Wales Transmission Acceleration Facility ($3.1 billion)[21].

This support for VNI West follows earlier Federal Government support announced for the New South Wales portion of the early works required and the commitment to enhancing the Dinawan to Wagga Wagga portion of EnergyConnect. This portion is to be constructed at a larger capacity than originally planned to lower the overall costs of delivering VNI West and minimise the disruption to landholders and the environment in the area[22].

AVP and Transgrid note that the February 2023 NEVA Order enables AVP to commence early works now, working towards undertaking first spring surveys in 2023 (which is a year earlier than expected at the time of the PADR). The reasons for expediting delivery of VNI West are articulated in the Minister's statement of reasons accompanying the February 2023 NEVA Order and summarised in Section 1.2.

Both AVP and Transgrid are actively progressing opportunities to deliver the project by 2028, so the benefits can be delivered to the national network sooner. Achievement of all delivery dates is subject to obtaining the necessary planning and environmental approvals, assembling land and easements, detailed design, and extensive community and landholder engagement, which is expected to take about three years to complete.

2.3 Further support from governments for the transition to renewables

There has been significant government support for the transition to renewables in the NEM in recent years and VNI West is expected to play a key role in this transition. Specifically, the driver for the credible options considered in this PACR is to help facilitate the reliable and secure transition away from coal-fired generation to renewable generation and meet government commitments to renewable energy and emissions reductions targets, while keeping costs to consumers as low as possible.

The identified need for this RIT-T includes facilitating the efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales[23].

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[20] Prime Minister, *Rewiring the Nation to supercharge Victorian Renewables - Media Release*, 19 October 2022.

[21] Minister for Climate Change and Energy, *Joint media release: Landmark Rewiring the Nation deal to fast-track clean energy jobs and security in New South Wales*, 21 December 2022.

[22] These earlier developments were outlined in Sections 2.5 and 2.6 of the PADR, respectively.

[23] AEMO, 2022 ISP, June 2022, p. 74, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf.

There have been several government announcements since the PADR that place further emphasis on this transition. Each of these developments is outlined below. Consistency with government emissions and renewables policies was a key theme raised in submissions to the PADR and Additional Consultation Report.

Due to the timing of these government announcements, they are not reflected in the 2022 ISP assumptions and so have also not been explicitly modelled as part of this PACR. However, AVP and Transgrid have assessed the consistency of the modelled outcomes with these policies, where relevant, as reported on below.

National Energy Transformation Partnership

The August 2022 Energy Ministers' Meeting saw Energy Ministers agree the vision, principles and key initial priority areas for a new National Energy Transformation Partnership (the Partnership), which represents a reset of relations across governments and the first fully integrated national energy and emissions agreement[24].

In October 2022, the Federal Government announced a commitment of $157.9 million to support the implementation of the Partnership as part of the 2022-23 Budget[25], which was supported by Energy Ministers as part of the October 2022 Energy Ministers' Meeting[26].

The Partnership's first action is to fast track an emissions objective into the national energy objective (NEO), ensuring that developments to deliver net zero are undertaken in the long-term interest of consumers[27]. The February 2023 Energy Ministers' Meeting saw Energy Ministers note progress towards this and commit to a near-term timeline for agreement of the final Bill in the second quarter of 2023[28].

The Partnership will identify and declare transmission of national significance, including the actionable ISP projects in the ISP (such as VNI West), accelerate the timely delivery of these projects, and ensure better community consultation. The Partnership will also develop integrated energy infrastructure and regional planning scenarios spanning electricity and gas networks, electrification pathways and new industry possibilities[29].

The December 2022 Energy Ministers' Meeting saw Energy Ministers announce a new Commonwealth revenue underwriting scheme (the 'Commonwealth Capacity Investment Scheme') under the Partnership. The scheme is intended to be operational in the second half of 2023 and will be limited to zero emissions dispatchable generation and storage technologies (and will complement and work with existing state and territory schemes to help deliver the national energy transformation)[30].

The *Climate Change Act 2022* (Cth)

In September 2022, the Federal Government passed the *Climate Change Act 2022* (Cth) that includes an emissions reduction target for Australia of 43% below 2005 levels by 2030 and net zero emissions by 2050[31]. The *Climate Change Act 2022* (Cth) empowers the Climate Change Authority to provide the Federal Government with independent and expert advice, while agencies including the Australian Renewable Energy Agency (ARENA), the

[24] Energy Ministers', *Meeting Communique*, 12 August 2022, p. 2.

[25] Federal Government, *Budget October 2022-23, Budget Strategy and Outlook - Budget Paper No. 1*, 25 October 2022, p. 15, at https://budget.gov.au/2022-23-october/content/bp1/download/bp1_2022-23.pdf

[26] Energy Ministers', *Meeting Communique*, 28 October 2022, p. 2.

[27] Energy Ministers', *Meeting Communique*, 12 August 2022, p. 2.

[28] Energy Ministers', *Meeting Communique*, 24 February 2023, p. 2.

[29] Energy Ministers', *Meeting Communique*, 12 August 2022, p. 2.

[30] Energy Ministers', Meeting Communique, 8 December 2022, pp. 1-2.

[31] *Climate Change Act 2022* (Cth) s 10(1).

CEFC, Infrastructure Australia and the Northern Australia Infrastructure Facility will embed amended targets in their objectives and functions[32].

While these new targets have not been explicitly modelled in the NPV net benefit results presented in this PACR to preserve alignment with the 2022 ISP, the observed wholesale market modelling outcomes are consistent with them. For example, the market modelling undertaken for this PACR finds that NEM-wide emissions are forecast to be 77% below 2005 levels in 2030-31 and 97% below 2005 levels by the end of the assessment period (2049-50) for Option 5A under the *Step Change* scenario.

On 27 March 2023, the Federal Energy Minister and Greens leader announced a key change to the Safeguard Mechanism[33]. Specifically, it was announced that facilities that produce over 100,000 tonnes of greenhouse gases annually will need to keep their net emissions below a hard cap or ceiling, which will not be able to exceed current levels and will decrease over time (previously the cap increased going forward). The finalisation of the Safeguard Mechanism was stated to be a key milestone in achieving Australia's 43% emissions reduction target by 2030[34].

Rewiring the Nation

The Federal Government's $20 billion 'Rewiring the Nation' plan, as part of its wider 'Powering Australia' initiative, is aimed at modernising Australia's electricity networks in line with the ISP through providing low cost financing to the industry[35]. The CEFC is leading the financial aspects of the program and, as part of the Federal 2022-23 Budget, it was announced that the CEFC was to receive $8.6 billion for 'Rewiring the Nation' projects[36].

In October 2022, the first announcement under the 'Rewiring the Nation' plan was made, stating that the Federal and Victorian governments had signed an agreement setting out:[37]

- $1.5 billion of concessional financing from 'Rewiring the Nation' available for REZ projects in Victoria, including offshore wind projects.
- A commitment to coordinate Victorian and Federal regulatory processes to support the rapid development of the Victorian offshore wind industry.
- A concessional loan of $750 million for VNI West to ensure it is completed by 2028 (as outlined in Section 2.2 above).

The announcement also noted that the Federal, Victorian and Tasmanian governments have entered agreements stipulating that each government will contribute equally to a total of 20% of project equity to deliver Marinus Link[38]. This government support provides further certainty that Marinus Link will proceed in line with the AEMO ISP optimal development path.

[32] Prime Minister, Minister for Climate Change and Energy, *Media Release*, 8 September 2022, at https://www.pm.gov.au/media/australia-legislates-emissions-reduction-targets.

[33] The Safeguard Mechanism requires Australia's largest greenhouse gas emitters to keep their net emissions below an emissions limit (a baseline). See https://www.dcceew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism.

[34] See https://minister.dcceew.gov.au/bowen/media-releases/safeguard-mechanism-one-step-closer-parliamentary-passage and https://greens.org.au/news/media-release/greens-secure-hit-coal-and-gas-safeguard-deal.

[35] Australian Labor Party, Powering Australia, 2021, p. 22, at https://keystone-alp.s3-ap-southeast-2.amazonaws.com/prod/61a9693a3f3c53001f975017-PoweringAustralia.pdf.

[36] CEFC, *Budget signals major funding boost for CEFC as part of Rewiring the Nation program*, 27 October 2022, at https://www.cefc.com.au/media/media-release/budget-signals-major-funding-boost-for-cefc-as-part-of-rewiring-the-nation-program/.

[37] Prime Minister, *Media Release*, 19 October 2022, at https://www.pm.gov.au/media/rewiring-nation-supercharge-victorian-renewables#:~:text=Rewiring%20the%20Nation%2C%20through%20the,equity%20to%20deliver%20Marinus%20Link.

[38] Prime Minister, *Media Release*, 19 October 2022, at https://www.pm.gov.au/media/rewiring-nation-supercharge-victorian-renewables#:~:text=Rewiring%20the%20Nation%2C%20through%20the,equity%20to%20deliver%20Marinus%20Link .

In December 2022, a second announcement under the ‘Rewiring the Nation’ plan was made, stating that the Federal and New South Wales governments had signed a $7.8 billion funding deal[39] to unlock eight critical transmission and REZ projects:

- Sydney Ring – Hunter Transmission Project.
- Central-West Orana REZ.
- New England REZ.
- HumeLink.
- VNI West.
- Hunter-Central Coast REZ, including offshore wind opportunities.
- Sydney Ring – Southern Sydney Ring.
- South-west REZ.

Developments in Victoria

The Victorian Government has made several announcements regarding the transition to renewables since the PADR was released, outside of those noted above in combination with other governments. These include:

- **Renewable energy storage targets** – in September 2022, the Victorian Government introduced energy storage targets that call for 2.6 GW of renewable energy storage by 2030 and 6.3 GW by 2035 (and announced a $157 million package to support these targets)[40]. In addition, it was announced that an investment of $119 million from the $540 million REZ Fund[41] will be made in a 125 megawatts (MW) big battery and grid forming inverter in the Murray River REZ (between Bendigo and Red Cliffs).
- **Development of offshore wind targets** – the Victorian Government issued an Offshore Wind Policy Directions Paper in March 2022[42] that set targets of 2 GW of offshore wind generation by 2032, 4 GW of offshore wind by 2035, and 9 GW of offshore wind by 2040[43]. In its Implementation Statement 1, released in October 2022, the Victorian Government stated that VicGrid will lead a coordinated approach to the development of transmission[44] and that it will establish a new entity (Offshore Wind Energy Victoria) to support the successful establishment of the offshore wind sector[45]. The Victorian Government has released two Implementation Statements to date (October 2022 and March 2023) outlining the development of the offshore wind sector[46], including that $76 million has been allocated to assist with achieving the offshore wind targets[47].

[39] Prime Minister, *Media Release*, 22 December 2022, at https://www.pm.gov.au/media/landmark-rewiring-nation-deal-fast-track-clean-energy-jobs-and-security-nhttps://www.pm.gov.au/media/landmark-rewiring-nation-deal-fast-track-clean-energy-jobs-and-security-nsw.

[40] Premier, *Media Release*, 27 September 2022, p. 1, at https://www.premier.vic.gov.au/australias-biggest-renewable-energy-storage-targets. .

[41] See https://www.energy.vic.gov.au/renewable-energy/transmission-and-grid-upgrades.

[42] Victoria State Government, Offshore Wind Policy Directions Paper, March 2022, at https://www.energy.vic.gov.au/__data/assets/pdf_file/0029/580619/Offshore-Wind-Policy-Directions-Paper.pdf.

[43] Victoria State Government, Offshore Wind Policy Directions Paper, March 2022, p. 10.

[44] Victoria State Government, Implementation Statement 1, October 2022, p. 11, at https://www.energy.vic.gov.au/__data/assets/pdf_file/0030/603399/The-Victorian-Offshore-Wind-Implementation-Statement-1.pdf.

[45] Victoria State Government, Implementation Statement 1, October 2022, p. 27.

[46] See https://www.energy.vic.gov.au/renewable-energy/offshore-wind-energy.

[47] Victorian Labour, Boosting Wind Power and Renewables Jobs, 21 October 2022, at https://static1.squarespace.com/static/5b46af5a55b02cea2a648e93/t/6351ca723c8f470b5b73aee5/1666304627944/BOOSTING+WIND+POWER+AND+RENEWABLE+JOBS.pdf.

- **Renewable energy target and Victorian Government involvement in new renewable energy projects** – on 20 October 2022, the Victorian Government announced that it will bring forward Victoria's renewable energy target to 95% by 2035 and will revive the State Electrical Commission to build new renewable energy projects. The announced plan would see an initial investment of $1 billion to deliver 4.5 GW of renewable generation capacity[48]. The government also committed to include an emissions reduction target of 75-80% by 2035 and net zero emissions by 2045 (five years ahead of the government's previous commitments).
- **The Victorian Transmission Investment Framework (VTIF)** – the Victorian Government is currently considering a new framework for planning and developing transmission infrastructure to ensure delivery of REZs. The framework comprises of five key elements: 1) a new planning process for transmission and REZ development; 2) introducing new access arrangements that support investment; 3) basing transmission and REZ developments on early, inclusive and ongoing community engagement; 4) introducing benefit sharing arrangements that enable better outcomes for local communities; and 5) identifying clear roles and responsibilities for VicGrid[49]. The Victorian Government issued a consultation paper in July 2022 on the VTIF for public consultation and VicGrid published submissions and summary reports in late 2022[50].

The Victorian renewable energy storage targets and increased renewable energy target have not been explicitly modelled as part of this PACR, because they do not currently meet committed policy criteria under the NER. However, AVP and Transgrid note that the modelling undertaken is considered consistent with these targets for the *Step Change* and *Hydrogen Superpower* scenario and finds that for Option 5A, under the *Step Change* scenario, there is:

- 3.4 GW of renewable energy storage (including small-scale and large-scale) in Victoria by 2030 (compared to the 2.6 GW target) and 6.2 GW by 2035 (compared to the 6.3 GW target).
- 98% renewable energy by 2035 (compared to the 95% target).
- An emissions reduction of 99% by 2035 (compared to the target of 75% to 80%) and 98% by 2045 (compared to the target of net zero emissions).

The 125 MW big battery and grid forming inverter in the Murray River REZ has also not been explicitly modelled as part of this PACR since it was not included in the 2022 ISP assumptions.

The Victorian Government's Offshore Wind Policy does not currently meet the criteria under the NER necessary to be treated as a 'committed policy' (and is therefore not included in the core scenarios for the PACR cost benefit analysis). Notwithstanding, AVP and Transgrid have investigated a sensitivity as part of this report that assumes significant Victorian offshore wind development going forward. This has been investigated in light of increased government support for Victorian offshore wind, including 'Rewiring the Nation' funding and the Victorian Government's offshore wind targets set out in its Offshore Wind Policy Directions Paper[51], as well as the various points raised by stakeholders in response to the PADR and Additional Consultation Report regarding these developments.

[48] Victorian Labour, Putting power bank in the hands of Victorians, 20 October 2022, at https://static1.squarespace.com/static/5b46af5a55b02cea2a648e93/t/635081cc456e953e2dee5108/1666220494096/PUTTING+POWER+BACK+IN+THE+HANDS+OF+VICTORIANS+-+Copy.pdf.

[49] Victorian State Government, Victorian Transmission Investment Framework Preliminary Design Consultation Paper, July 2022, p. 6, at https://engage.vic.gov.au/victorian-transmission-investment-framework.

[50] See https://engage.vic.gov.au/victorian-transmission-investment-framework.

[51] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.

This sensitivity forecasts that both Option 5 and Option 5A continue to deliver significantly positive net benefits with offshore wind targets imposed (see Section 6.4.1).

The VTIF is not an explicit input to the RIT-T analysis (nor the 2022 ISP) due to it not being a firm instrument at that stage. The VTIF is a potential new framework for how transmission infrastructure is to be planned and developed but is currently only at the consultation stage[52].

Developments in New South Wales

The New South Wales Government, through the Energy Corporation of New South Wales (EnergyCo)[53], is currently procuring a new network battery – the 'Waratah Super Battery' (to be located at the site of the previous Lake Munmorah Power Station) – dedicated to supporting the electricity transmission grid and ensuring New South Wales continues to have reliable energy supply following the anticipated closure of the Eraring Power Station. The battery will provide up to 700 MW/1,400 megawatt hours (MWh) of capacity and operate as part of a System Integrity Protection Scheme[54,55.] The New South Wales Minister for Energy has appointed Transgrid as the Network Operator for the project and has directed Transgrid to carry out the Waratah Super Battery project as a Priority Transmission Infrastructure Project[56].

On 4 October 2022, the first tender under the New South Wales Electricity Infrastructure Roadmap was launched, which is designed to build at least 12 GW of renewable energy and 2 GW of long duration storage by 2030[57]. On 1 May 2023, AEMO Services announced the outcome of this tender process, procuring a total of 1,395 MW of capacity over three renewable generation projects and one long-duration storage lithium-ion battery project with a continuous discharge capacity of at least eight hours. These projects are expected to be delivered by 2025-26. The second tender, seeking the equivalent of 380 MW of firming infrastructure, opened on 3 April 2023 and closed 18 May 2023[58]. In addition, EnergyCo continues to plan and progress the first five REZs for New South Wales (in the Central-West Orana, New England, South-West, Hunter-Central Coast and Illawarra regions). This provides further certainty that these developments will proceed in line with the AEMO ISP optimal development path.

The modelling forecasts the outcomes of Option 5 and Option 5A under the *Step Change* scenario as follows.

- New South Wales is forecast to build around 1.5 GW of large-scale storage and 2.5 GW of pumped hydro by 2030-31.
- Renewable energy's share is forecast to be approximately 81% of New South Wales generation by 2030-31. Particularly, large-scale wind and solar generation is forecast to be around 47 terawatt hours (TWh) in New South Wales in 2030-31.

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[52] The State of Victoria Department of Environment, Land, Water and Planning, *Victorian Transmission Investment Framework Preliminary Design Consultation Paper*, July 2022. See https://engage.vic.gov.au/victorian-transmission-investment-framework.

[53] The Energy Corporation of New South Wales (EnergyCo) is a statutory authority established under the *Energy and Utilities Administration Act 1987* and is responsible for leading the delivery of REZ as part of the New South Wales Government's Electricity Infrastructure Roadmap.

[54] The physical size of the of Battery Energy Storage System (BESS) is anticipated to be 850 MW/1,680 MWh, with 700 MW/1,400 MWh available for the System Integrity Protection Scheme function.

[55] Minister for Energy, *Media Release*, 14 October 2022, at https://www.energyco.nsw.gov.au/sites/default/files/2022-10/Matt Kean med rel - Waratah Super Battery powers up at Munmorah.pdf.

[56] See https://www.energyco.nsw.gov.au/projects/waratah-super-battery and https://www.energyco.nsw.gov.au/waratah-super-battery-munmorah-site.

[57] See https://www.nsw.gov.au/media-releases/electricity-infrastructure-roadmap-tenders-open.

[58] See https://aemoservices.com.au/tenders.

Developments in Queensland

In July 2022, the Queensland Government announced $145 million to establish three Queensland Renewable Energy Zones (QREZs) in southern, central and northern Queensland[59]. Following this, in late September 2022, the Queensland Government announced an 'Energy and Jobs' plan[60] that includes the creation of a 'SuperGrid' involving four key large scale infrastructure areas –1) renewable investments, 2) storage, firming and dispatchable capacity, 3) major network transmission and system strength, and 4) clean energy hubs.

In September 2022, the Queensland Government released an Infrastructure Blueprint that outlines the indicative retirement schedule for Queensland's publicly owned coal-fired power stations under the plan[61]. Noting that the final schedule is to be confirmed with individual generators, the Infrastructure Blueprint includes a three phased approach, with:

- Stanwell, Callide B, Tarong and Tarong North gradually shifting to seasonal operation or synchronous condenser conversion for one or more units ('Phase 1') from 2026-27 – for Kogan Creek, this occurs later (2034-35).
- No units currently reaching 'Phase 2', which would see further conversion of units to seasonal operation once the first long duration pumped hydro energy storage (PHES) is online.
- Callide B being the first generator to reach 'Phase 3'[62] (2028-29) – Stanwell and Tarong and Tarong North reaching 'Phase 3' in 2032-33 and 2033-34, respectively, while Kogan Creek is the last to reach Phase 3 (after 2034-35).

The above announcements have not been explicitly modelled as part of this PACR, because they do not currently meet committed policy criteria under the NER. The Queensland coal-fired generator retirement dates assumed in the wholesale market modelling for this PACR (which have been sourced from the 2022 ISP) align closely with the dates outlined in the Infrastructure Blueprint (above) in the *Step Change* scenario. However, the 2022 ISP dates indicate a few years delay in some coal capacity retirement in the late 2030s.

The SuperGrid is aiming to attract $62 billion of industry-wide capital investment[63] and meet the longstanding Queensland Renewable Energy Target (QRET) of having 50% renewable generation by 2030, which will contribute to meeting the Queensland Governments 30% economy-wide emissions reduction target on 2005 levels by 2030[64]. The investment in renewables and an additional $4 billion[65] commitment to energy transformation will contribute to meeting two new Queensland renewable energy targets – 70% by 2032 and 80%

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[59] Queensland Government, Queensland's COVID-19 Economic Recovery Plan – Budget update, June 2021, p. 19, at https://s3.treasury.qld.gov.au/files/Budget_2021-22_Covid_Economic_Recovery_Plan.pdf.

[60] Queensland Government, Queensland Energy and Jobs Plan, September 2022, p. 6, at https://www.epw.qld.gov.au/__data/assets/pdf_file/0029/32987/queensland-energy-and-jobs-plan.pdf and Queensland Government, Queensland SuperGrid Infrastructure Blueprint, September 2022, pp. 4 and 5, at https://www.epw.qld.gov.au/__data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf.

[61] Queensland Government, Queensland SuperGrid Infrastructure Blueprint – Optimal infrastructure pathway for the Queensland Energy and Jobs Plan, September 2022, p. 48.

[62] Phase 3 is defined as further conversion of units to seasonal operation and reversible conversion to synchronous condensers, as well as ongoing operation as clean energy hub including potential on site storage, dispatchable capacity, hydrogen development, and operations and maintenance bases for publicly owned large-scale renewable energy.

[63] See https://www.statedevelopment.qld.gov.au/industry/manufacturing-queenslands-super-grid-in-queensland#:~:text=The%20Queensland%20Energy%20and%20Jobs,across%20public%20and%20private%20sectors.

[64] See https://www.des.qld.gov.au/climateaction/emissions-targets.

[65] See https://www.epw.qld.gov.au/__data/assets/pdf_file/0018/33507/energy-factsheet-december-2022.pdf.

by 2035[66]. The wholesale market modelling undertaken for this PACR forecasts that both of these targets are met under both options, as well as the base case:

- Renewable energy share in Queensland is forecast to be 71% by 2030-31 and 84% by 2035-36.
- Emissions are forecast to reduce by around 62% and 79% reduction from the 2005 level by 2030-31 and 2035-36 respectively.

Announced payments for landholders in New South Wales and Victoria

In October 2022, the New South Wales Government announced that landholders who host new significant transmission infrastructure will be eligible for payments under the new Strategic Benefits Payment Scheme[67]. Specifically, the payments:

- Will apply to a range of projects delivered under the *Electricity Infrastructure Investment Act 2020* (NSW) (EII Act), such as REZ network infrastructure projects and priority transmission infrastructure projects, as well as actionable projects identified in the ISP (such as VNI West).
- Are to be set at $200,000 (in real 2022 dollars) per kilometre of transmission line hosted and are to be paid in annual instalments over 20 years and treated as operating expenditure (opex) for the purposes of cost recovery by the network service provider (NSP).
- Begin once the applicable project is energised.
- Are to be indexed to inflation annually.
- Are separate, and in addition to, any compensation that is paid to landowners for transmission easements on their land in accordance with the *Land Acquisition (Just Terms Compensation) Act 1991* (NSW).

In February 2023, the Victorian Government announced a similar scheme for Victorian landholders. The scheme includes payments for a typical area of new transmission easement at a standard rate of $8,000 per year per kilometre of transmission hosted for 25 years (with the first payments under the new arrangements stated to go to landholders who host transmission easements along the selected VNI West and WRL transmission corridors)[68]. While these operating costs were not included in the Additional Consultation Report net market benefit assessment due to the timing of the announcement, they have been reflected in the assessment in this PACR[69].

2.4 How the RIT-T analysis has been updated since the PADR

AVP and Transgrid have updated the RIT-T analysis since the PADR to make several general refinements in line with this stage of the RIT-T process, as well as to directly respond to points raised in submissions to the PADR and Additional Consultation Report and reflect external developments (where relevant).

[66] See https://www.des.qld.gov.au/climateaction.

[67] New South Wales Government, *Strategic Benefit Payments Scheme – for private landowners hosting major new transmission infrastructure projects in New South Wales*, October 2022.

[68] See: https://www.premier.vic.gov.au/landholder-payments-fairer-renewables-transition. While it is not clear at this stage whether the $8,000 payments are to be inflated each year (that is, kept constant in real terms), it has been assumed that they are for the purposes of this PACR. This is considered a conservative estimate and is consistent with how the New South Wales scheme is to operate.

[69] In doing so, it is assumed that Option 5 involves 205 km for VNI West, while Option 5A involves 206 km. Further, 95% of these line lengths are assumed to be on private land.

Updates that were already reflected in the NPV analysis presented in the Additional Consultation Report are outlined in Appendix A8. The remainder of this section focuses on further updates that have been implemented since the Additional Consultation Report and in response to stakeholder submissions.

2.5 Option costs have been updated to reflect the announced payments for landholders

The landholder payments recently announced by the New South Wales and Victorian governments have been reflected in the costs of the options in this PACR through the inclusion of additional opex line items.

The New South Wales payments were reflected in the analysis presented in the February 2023 Additional Consultation Report, however the estimated km length underpinning these payments has been updated marginally for this PACR. The Victorian payments were not included given the timing of the announcement from the Victorian Government.

For the purposes of the estimation of the payment amount, 85% of the total line length in New South Wales is assumed to be on private land and 95% of the total line length in Victoria is conservatively assumed to be on private land for the purposes of calculating these payments. The line lengths for each option are shown in Table 6 in Section 3.3.

2.6 Victorian costs have been revised

Submissions to the PADR and Additional Consultation Report raised a number of concerns regarding the completeness and accuracy of the costs included in the cost benefit analysis and requested further information on the methodologies adopted (see PACR Volume 2 for a summary of points raised).

Based on this consultation feedback, updated costing input information received since the Additional Consultation Report, and also the recently updated 2023 Transmission Cost Database (TCD), the cost estimate for the Victorian Option 5 has further been revised for this PACR. The same updated input information has been used to estimate Option 5A costs.

The revisions to the Victorian estimates for the PACR include:

- **Revision of the Victorian 500 kV transmission line costs to reflect new market costing information**. As pointed out in the feedback, Victorian line costs appeared lower than New South Wales costs. While this is partially due to differences in allocations to the cost categories, some costs were identified as requiring escalation due to recent changes in market factors such as material and labour price inflation. The Victorian line costs have been updated with reference to analysis undertaken as part of a concurrent update to the AEMO TCD, as well as recent transmission network service provider (TNSP) per kilometre rates for similar lines. Specifically, the Victorian line bottom-up cost estimates have been escalated based on the trends identified in AEMO's 2023 TCD update for the current market line capital costs, with the costs for easement compensation and biodiversity offsets estimated separately (all discounted back to June 2021 real dollars[70]). This update only applies to the VNI West lines component, because the WRL line estimates are based on TNSP estimates.

[70] All costs in this PACR are reported in June 2021 real dollars.

- **Changes to known and unknown risk allowances** based on the levers available in the 2023 TCD, replacing the earlier $300 million overall contingency allowance that was previously included in the PACR and Additional Consultation Report on a percentage of total cost basis. The TCD contingency allowances for known and unknown risk (as described in Section 3.3.1) are able to better reflect the level of project complexity and risk identified from the MCA and consultation process.
- **Additional allowances for accessing land for survey purposes have been included** in response to recent changes in the payment structure for access agreements used by other organisations (such as AusNet).
- **Biodiversity offset allowances have been re-estimated** based on the areas of interest for each option identified through the MCA process.
- **The Victorian landholder payments have been reflected** (as outlined in Section 2.5) in the operating expenses.
- **Operating expenses have been updated to reflect latest advice on easement tax.** In response to submissions received on the Additional Consultation Report, further advice was obtained on the approach to calculating total taxable value of easements within Victoria with the estimated easement tax updated to reflect the advice.

2.7 Refined impact on the Murray River (V2) REZ

Since the Additional Consultation Report, further refinements of the power system model have identified a slightly higher Murray River (V2) REZ limit of 1,075 MW (compared to 850 MW in the Additional Consultation Report) for Option 5. These same power system model refinements have been applied to determine the REZ transmission limits for Option 5A. This has been reflected in the wholesale market modelling undertaken for this PACR.

3 Two options have been assessed

This PACR assesses two options – Option 5, which was developed in response to stakeholder feedback on the PADR, and a variant of this, Option 5A, developed in response to stakeholder feedback on the Additional Consultation Report.

Option 5 was the proposed preferred option in the Additional Consultation Report, with an area of interest crossing the Murray River near Echuca (Yorta Yorta country). Option 5A is a variant of Option 5 which crosses the Murray River north of Kerang (Wamba Wamba country). Both connect EnergyConnect (at Dinawan) to WRL (at Bulgana) via a terminal station near Kerang.

AVP and Transgrid have identified a variant of Option 5 involving a routed corridor north of Kerang, crossing the Murray River on Wamba Wamba Country (Option 5A). One of the primary drivers for this further north-western corridor investigation since the Additional Consultation Report was to take into account the Murray River Group of Councils' concerns raised around the potential impacts of the Option 5 area of interest on the endangered Plains-wanderer bird species, culturally sensitive areas of national significance (such as Ghow Swamp), tourism and recreation activities around Echuca, agriculture, and community impacts in Victoria. Critically, these same stakeholders suggested an alternate northern Murray River crossing that, in their view, currently has broader social license and would help alleviate many of these environmental, land-use and cultural concerns, ultimately improving likelihood of timely project delivery.

At the same time, Transgrid identified that a northern river crossing could be possible, provided the corridor through this area allowed for a route which remains outside of declared National Park areas in New South Wales. Recent consultation with New South Wales National Parks and Wildlife Service (NPWS) confirmed that the proposed development would need to address key risks outlined in the NPWS 2020 publication "*Developments adjacent to National Parks and Wildlife Service Lands – Guidelines for consent and planning authorities*"). In consideration of these NPWS guidelines, Transgrid believes that these risks can be appropriately addressed in the New South Wales planning process, through the preparation of an Environmental Impact Statement and subsequent management plans.

AVP and Transgrid will continue to engage with stakeholders including the Murray River Group of Councils on an appropriate crossing for the Murray River.

Further, while these factors were not taken into account for the RIT-T assessment of the New South Wales component, a northern river crossing would help minimise the degree to which the corridor would traverse productive irrigated cropping properties on the New South Wales side, travelling instead through larger broad acre farming properties.

Both Option 5 and Option 5A have been assessed in this PACR. They:

- Involve a 500 kV double-circuit transmission line for VNI West.
- Originate at Dinawan substation, north of Jerilderie in New South Wales, with connection to EnergyConnect.

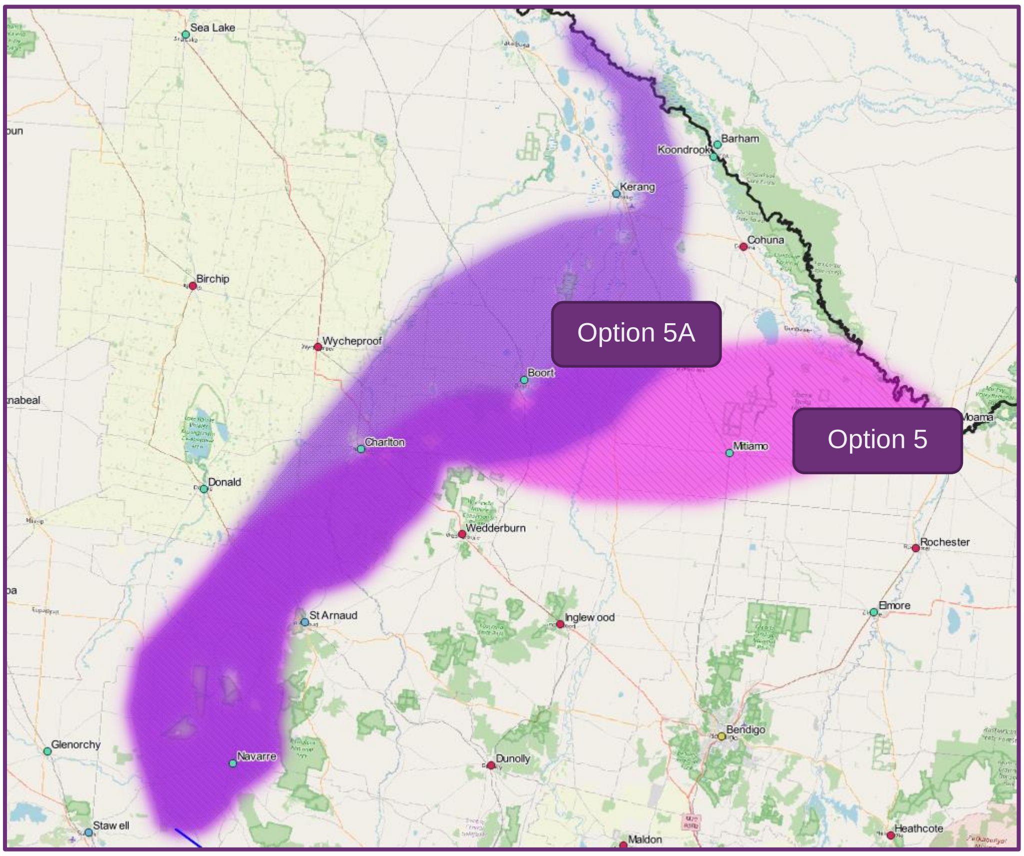
- Include a new terminal station near Kerang, in Victoria, with a connection to the existing 220 kV network between Kerang and Bendigo.
- Terminate at a new terminal station near Bulgana, in Victoria, with connection to WRL.
- Result in construction of WRL at 500 kV from Sydenham to Bulgana and remove the need for a new terminal station north of Ballarat[71].

The differences in the options primarily relate to the area of interest near the border between Victoria and New South Wales, and can be summarised as:

- **Option 5 (near Echuca)** – connects from Dinawan, via a new terminal station near Kerang, directly to WRL at a new terminal station near Bulgana (Wotjobaluk Country), crossing the Murray River near Echuca (Yorta Yorta Country).
- **Option 5A (north of Kerang)** – connects from Dinawan, via a new terminal station near Kerang, directly to WRL at a new terminal station near Bulgana (Wotjobaluk Country), crossing the Murray River north of Kerang (Wamba Wamba Country).

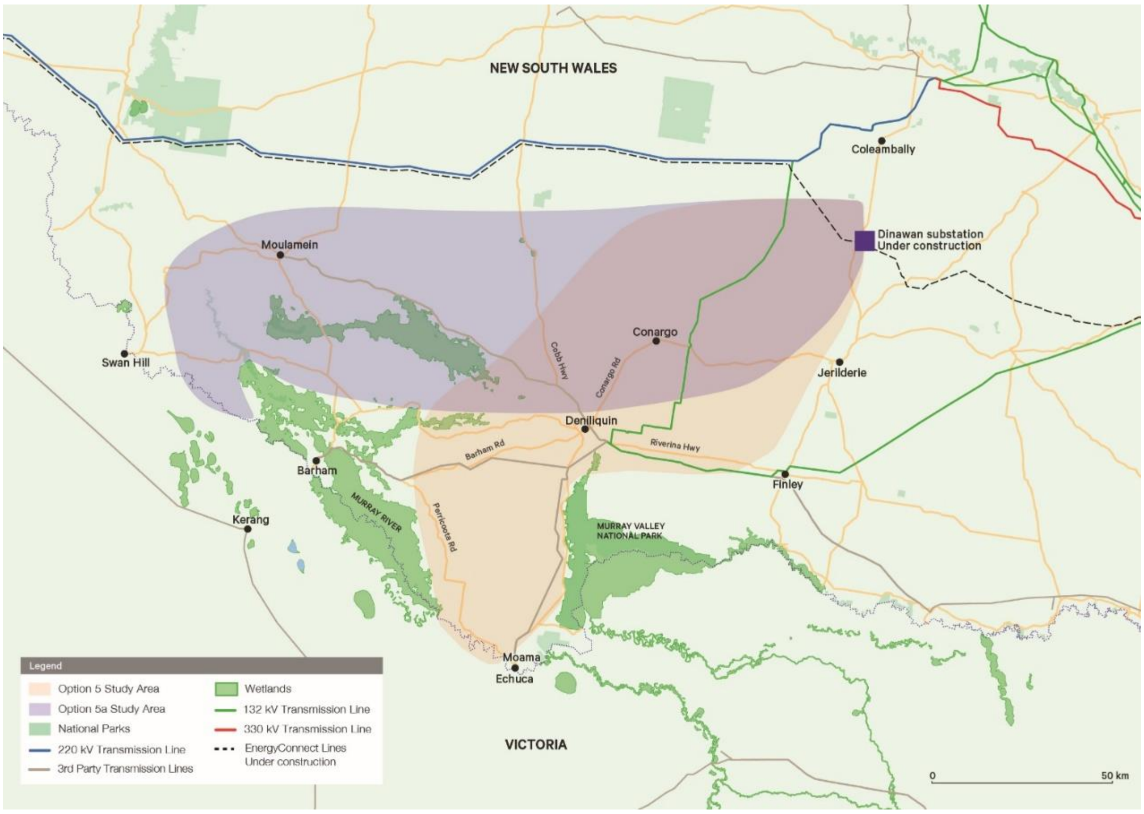
The two options are shown in Figure 5 and Figure 6 for Victoria and New South Wales respectively. All areas of interest shown are high-level schematic illustrations only, and specific line routes have not yet been determined. Further detail in relation to each option is provided in Appendix A2.

Figure 5 The two option variants assessed – Victorian view



[71] While the associated costs of these works are considered in the assessment of options for the VNI West PACR, the uprating of the line section to 500 kV between Ballarat and Bulgana and change to the location of the current proposed Terminal Station north of Ballarat to Bulgana, and associated works, is an element of the scope for delivery of the WRL project.

Figure 6 The two option variants assessed – New South Wales view



River crossings between these two options are not feasible due to the RAMSAR wetlands on both sides of the border.

Options 1, 2, 3, 3A and 4 from the Additional Consultation Report (and VNI West PADR/2022 ISP in the case of Option 1) have not been progressed, due to them scoring lower than Option 5 across the range of objectives assessed (including net market benefits) to lower risk of delays in development and delivery having regard to the NEVA Orders. Option 5A performs similarly to Option 5 and therefore is reasonably expected to also outperform the other options.

Submissions to the Additional Consultation Report noted support for the move away from Mount Prospect and the Bendigo to Ballarat corridor as outlined in Option 1 due to the social and environmental constraints present. While there was some support in submissions for Options 1 and 3 (the options without any 500 kV uprate of WRL), it was primarily from councils and developers in the north of Victoria concerned that Option 5, connecting to Bulgana, limited the opportunities for renewable generation investment in the Murray River REZ. The councils were concerned that without these development opportunities, social license in their shires would be lost. AVP and Transgrid consider that the updated assessment of REZ transmission limits for Option 5 and the introduction of Option 5A, which not only addresses some of the environmental and social concerns raised but is also capable of harnessing more renewable generation in the Murray River REZ than Option 5, responds to this feedback. There was also one submission in support of Option 3A, similarly due to it harnessing more renewable generation, however it did not perform as well as Option 5 under the MCA in the Additional Consultation Report.

There was no further information received during the Additional Consultation Report process that had the ability to fundamentally change the scoring to the extent that Options 1, 3 and 3A would perform better than Option 5. For these reasons, Options 5 and 5A have been progressed, while all other credible options from the Additional Consultation Report have not.

Options to underground the lines were raised in submissions to the PADR (and the PSCR) and were suggested by stakeholders and communities as possible solutions that could help minimise social and environmental impacts associated with the project. Under the regulatory requirement to develop the most prudent and efficient option that will maximise benefits to energy consumers, and minimise risk of over-investment, full undergrounding is considered a cost-prohibitive solution to respond to community and stakeholder concerns, while still meeting the identified need. It would also take much longer to deliver. While AVP and Transgrid may consider partial undergrounding in exceptional circumstances, we are committed to working closely with community and stakeholder groups during route selection to consider more cost-effective solutions, such as route diversion, screening, and line tower design, that can help manage social and environmental impacts[72]. Further assessment on the merits and challenges of undergrounding the lines is presented in Appendix A4.

All options are assumed to have a staged delivery, with staged Contingent Project Applications (for the New South Wales components), which aligns with the 2022 ISP. The first stage, early works, is expected to be completed no later than 2026.

Table 4 below summarises the assumed timing for key components of the options assessed in this report. For the purpose of this PACR, VNI West is assumed to be delivered in accordance with the ISP scenario-dependent timing. For example, the 500 kV double-circuit line from Sydenham to Bulgana (a change of scope for WRL) is assumed to be delivered by 2027, and the 500 kV double-circuit line from Dinawan to Bulgana via a terminal station near Kerang is assumed to be delivered by 2031 (under the *Step Change* scenario).

Table 4 Assumed timing for all options

Scenario	Stage 1 (early works)	Stage 2 (WRL components)	Stage 2 (VNI West components, based on ISP timing for each scenario)
Step Change	Now until 2025-26	July 2027	July 2031
Progressive Change		July 2027	July 2038
Hydrogen Superpower		July 2027	July 2030

Under both VNI West options considered, delivery of WRL is assumed to be delayed from its original 2026 completion date to 2027. The assumed one-year delay is based on the assumption that any change in the scope would lead to schedule delays, but that continuing with the existing scope (with a terminal station north of Ballarat) may also be subject to schedule delays. This means that in the base case, with no VNI West option, the WRL project has also been assumed to be delayed, with practical completion in 2027.

While these are the delivery dates assumed for this PACR, it is noted that any concessional financing under the Rewiring the Nation plan, outlined in Section 2.3, will be provided to support an accelerated timeframe with completion in 2028. To help facilitate this acceleration, Transmission Company Victoria (a wholly owned subsidiary of AEMO) has commenced early works for the Victorian portion of the project, as enabled by the February 2023 NEVA Order. Transgrid is similarly progressing early works for the New South Wales portion having received earlier support for this from the Federal Government. Both organisations are targeting first spring surveys in 2023.

[72] AVP and Transgrid responded to this, and other points raised in submissions, in the VNI West PADR Submissions report, released in February 2023, at https://aemo.com.au/initiatives/major-programs/vni-west/stakeholder-consultation.

3.1 Two new sensitivities have been considered

Two new sensitivities have been identified since the Additional Consultation Report that have slightly different power system impacts:

- A variant of Option 5A that runs further west of Kerang.
- A variant of Option 5 that tests the effect of removing the series compensation on the Kerang to Bulgana section.

These sensitivities have been undertaken to understand the impacts on net market benefits if, through further detailed technical design and land planning and environment activities undertaken in the next stages of project development, changes to the area of interest are required, or technical aspects need to be modified.

Option 5A – westerly sensitivity

The Option 5A – westerly sensitivity differs from Option 5 and 5A in that it has its connection to the existing 220 kV network on the west side of Kerang, that is, on the Kerang–Wemen line. While not geographically distant from the network connection of Option 5A on the Kerang–Bendigo line, this results in a different electrical configuration that results in less Murray River REZ (V2) capacity. Although not included in the modelling for this sensitivity, this variant is also considered to present more power system complexity than Option 5A and may require additional compensation equipment or network upgrades to optimise the Murray River (V2) REZ capacity for both existing and future generators.

For these reasons, this variant on Option 5A has not been considered as an option in this PACR, but may still need to be considered in future if necessary during the detailed route selection process to minimise land, social, planning and environmental impacts. It has therefore been included as a sensitivity to understand the impacts on net market benefits.

The results of this sensitivity are shown in Section 6.4.2.

Option 5 sensitivity – no series compensation

Both Option 5 and Option 5A connect to WRL at its westerly point, Bulgana, and have a long overall path length between Bulgana and Kerang, and therefore high impedance. As a result, the existing 330 kV VNI and 220 kV western Victorian networks reach limits before the 500 kV VNI West is fully utilised. This results in lower interconnector transfer capability on these VNI West options than options previously considered that connect to WRL further east, via an additional new terminal station near Bendigo[73]. To address this, both options include series compensation on the Kerang to Bulgana section of VNI West to reduce the impedance of VNI West and thereby improve network load sharing between the existing network and the proposed 500 kV network.

Stakeholders requested more information about the technical feasibility of utilising series compensation to increase the capacity of Option 5 (which can be extended to Option 5A).

[73] The laws of physics determine network load sharing based on the impedance (opposition to electrical flow) of parallel networks. If lines in parallel are at capacity, more flow can be 'forced' to flow down alternate lines that are not fully utilised by manipulating, such as through series compensation or power flow controllers, the actual or apparent network impedance of selected flow paths.

An additional sensitivity on Option 5 has been added to the PACR to test the robustness of the analysis should the series compensation be removed from scope prior to implementation. It is assumed that the same relative change to net benefits and interconnector transfer and REZ limits can be extended to Option 5A.

To assess the technical feasibility of the proposed series compensation at its currently proposed location, sub-synchronous resonance screening studies have been completed. Initial studies completed to date indicate there is a very low risk of issues with resonance with both existing and future generators due to the mesh-like network of the Western Victorian transmission grid. This topology of the network, once VNI West is completed, means that there is a very low chance (after multiple, concurrent contingency events have occurred) that generators would be connected in a radial configuration relative to the series compensation, which is the configuration of highest concern for resonance issues.

For future generation connections, Type 3 or synchronous generators connecting close to the series compensation are expected to be the most at risk of any impact from the compensation capacitors, however it is expected that with detailed design and planning/verification studies completed, the risks can be mitigated. There are relatively simple mitigations that can be put in place to limit resonance issues, should they be encountered in further studies. In addition to this, alternate compensation options to series capacitors will also be investigated as part of the detailed technical design in the next stage of the project, should the series capacitors be deemed infeasible or potentially need to be removed in the future.

The results of this sensitivity are shown in Section 6.4.3.

3.2 Technical characteristics of the options assessed

The technical characteristics of the credible options are summarised in Table 5 below.

Specifically, Table 5 shows the indicative impact on interconnector transfer capability (in both directions) and the REZ transmission limit[74] (by affected REZ) for each option, and the assessed sensitivities, based on AVP and Transgrid's power system analysis considering thermal, and voltage and transient stability limits.

All options and sensitivities involve substantial increases in interconnector transfer capability between Victoria and New South Wales, and are ultimately comparable to a large, multi-unit, baseload power station in the NEM[75].

[74] REZ transmission limits represent the maximum generation that can be dispatched at any point in time within a REZ; the additional generation development can exceed these limits as variable renewable energy (VRE) generation does not always operate at full capacity.

[75] For example, Loy Yang A has a nameplate capacity of 2,225 MW.

Table 5 Summary of the credible options assessed – transfer capacities and REZ limits

Option	Indicative impact on transfer capability		Indicative impact on REZ transmission limit		Capital cost* $m 2020-21
	VIC to NSW	NSW to VIC	Individually	Total	
Option 5 (near Echuca)	+1,960 MW	+1,710 MW	V2 – Murray River: +1,075 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +200 MW N5 – South West NSW: +900 MW	+3,635 MW	3,406
Option 5A (north of Kerang)	+1,935 MW	+1,669 MW	V2 – Murray River: +1,580 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +200 MW N5 – South West NSW: +900 MW	+4,140 MW	3,499
Sensitivities					
Option 5A (westerly sensitivity)	+1,910 MW	+1,650 MW	V2 – Murray River: +1,460 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +0 MW N5 – South West NSW: +900 MW	+3,820 MW	3,499
Option 5 (without series compensation)	+1,750 MW	+1,500 MW	V2 – Murray River: +800 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +0 MW N5 – South West NSW: +900 MW	+3,160 MW	3,331

* While the capital costs are shown at an aggregate level in this table, they have been broken out by key cost category and state for each option in Section 3.3 of this report; that is, early works, substation works, line works, power flow controllers, property/land access/easements and biodiversity offset costs.

Improvements to REZ transmission limits

Unlike previous options considered, none of the options or sensitivities decouple Waubra Terminal Station from the existing 220 kV network, as there is no 500 kV terminal station proposed near Waubra/Lexton. Further power system analysis was undertaken to determine if improvements could be made to REZ transmission limits by decoupling Waubra Wind Farm from the existing 220 kV network and establishing a new 500 kV terminal station near Waubra/Lexton. In this analysis, no net increase in Western Victoria REZ (V3) hosting capacity was observed as any generation transferred onto the 500 kV network introduced a new network constraint that offset the benefits of removing it from the existing 220 kV network. Similarly, moving the Waubra Wind Farm connection was found to introduce other constraints that prevented an increase in the Western Victoria REZ (V3) limits over what is achieved in the current options.

Both options utilise series compensation on the Bulgana–Kerang 500 kV lines to optimise network load sharing between the existing 220 kV network and the new 500 kV lines and maximise REZ transmission limits, particularly Murray River V2 REZ capacity. This solution manages heavier loading on the Kerang–Bendigo 220 kV line, which is as a result of the options not having a connection to Bendigo, coupled with future load growth projections.

Since the Additional Consultation Report, further refinements of the power system model have also identified a slightly higher Option 5 Murray River REZ (V2) limit of 1,075 MW (versus 850 MW in the Additional Consultation Report), which has been reflected in the market modelling in this PACR, and in Table 5 above.

As mentioned in the Additional Consultation Report, and as suggested in some of the consultation feedback, additional modifications to the existing network have been identified as potential lower-cost investments for further investigation in future to harness more renewable generation in western Victoria and increase supply to the Bendigo area, if and when needed. These lower-cost minor modifications could include improvements like incorporating dynamic line ratings into the REZ transmission limit modelling, 220 kV power flow control, or control schemes to improve contingency response under higher power transfer levels. Additional modifications include thermal uprate of existing line segments and replacement of end-of-life lines with higher-rated double-circuit lines.

Network congestion in the Bendigo area will continue to be monitored

As mentioned above, with the preferred options not having a connection via Bendigo, heavier loading on the Kerang–Bendigo 220 kV line is observed. This heavier loading takes into consideration forecasts for future Bendigo area load growth, as per the *Victorian Annual Planning Report*[76], which assesses electricity supply to the Bendigo area over the next 10 years. AVP will continue to monitor electricity demand growth in the Bendigo area as part of normal electricity supply planning practices. AVP will also continue to liaise with the local council to understand local developments which need to be considered for electricity supply arrangements to the area.

3.3 Estimated costs of the options

3.3.1 Capital costs

This section details cost estimates and how they have been derived.

Table 6 shows the expected capital cost for each option by key component (in both Victoria and New South Wales)[77]. The methodology used to develop the estimates is summarised in further detail in Appendix A5, and as supplemented by the additional refinements outlined in this section.

Points to note from Table 6 include:

- EnergyConnect enhanced costs are the incremental line build costs associated with construction of the portion of the line between Dinawan and near Wagga Wagga at 500 kV rather than 330 kV.
- The additional costs associated with changing WRL scope are included in the Stage 2 costs figures below, however the WRL additional subtotal has also been presented separately for clarity.
- Both options include allowance for both power flow controllers and series compensation components (although these have been excluded from the Kerang to Bulgana segment of the line for the Option 5 sensitivity).
- The Victorian capital costs of the options have been further revised since the Additional Consultation Report released in February 2023, as outlined in Section 2.6.

[76] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/victorian-planning/victorian-annual-planning-report.

[77] All costs and benefits in this report are presented in FY2020-21 dollars, unless otherwise stated.

Table 6 Summary of the credible options assessed in this report – capital costs, $m in FY2020-21 dollars

Cost component	Option 5 (to Bulgana)		Option 5A (to Bulgana, east of Kerang)	
	NSW	VIC	NSW	VIC
Stage 1 – Early works				
Early works – Property/access/ easements	66	69	72	69
Early works – other	50	60	50	60
EnergyConnect enhanced	182	-	182	-
Stage 2 – Implementation				
Substation/ terminal station works	354	415	354	415
Line works	751	1,034	831	1,034
Power flow controllers / series compensation	183	164	183	164
Biodiversity offset costs	66	12	73	12
Total (by state)	1,651	1,755	1,744	1,755
Total (all states)	3,406		3,499	
WRL – Incremental costs for alternate options (included in the totals above but separately itemised here as well for transparency)				
Included cost		315		315
WRL uprate length		104 km		104 km
Other relevant assumptions				
Approximate line length [A]	184 km	205 km	203 km	206 km
Project EnergyConnect uprate length	174 km	-	174 km	-
Quantity substations/ terminal stations [B]	-	1	-	1

A. Approximate line length is the indicative total length (in kilometres) of lines between EnergyConnect (at Dinawan) and the connection point to WRL. As a route has not yet been determined, line length has been taken as the centre of the area of interest.
B. Quantity substations/ terminal stations is the quantity of terminal stations along the VNI West project and excludes the Dinawan and WRL connection point terminal stations.
C. WRL included uprate costs include costs across all cost components, not just line works. Refer to the single line diagrams in Appendix A2 for scope details.

The cost estimates presented in the VNI West PADR, the Additional Consultation Report and this PACR have been undertaken on a jurisdictional basis, with AVP responsible for the estimates of the part of the options located in Victoria and Transgrid responsible for the estimates of the part of the options located in New South Wales. Cross-checks have been conducted as part of this process to ensure consistency.

Both AVP and Transgrid have estimated the following six different categories of cost for each option:

- Early works.
- Substation works.
- Line works.
- Costs of modular power flow controllers.
- Property/land access/easements.
- Biodiversity offset costs.

The level of granularity in the revised cost estimates is considered consistent with that in AEMO's 2023 TCD[78] that has been updated in preparation for the 2024 ISP. The update includes expert cost estimation advice, which has been informed by recent transmission project tendering outcomes in the NEM.

Further, to assess the new variant/sensitivities added since the Additional Consultation Report, AVP and Transgrid have produced new cost estimates for each option for the PACR. These cost estimates have been developed using the methodology outlined in Appendix A5 of this report.

Western Renewables Link costs

The Victorian component costs include the direct costs of modifying the WRL project so that all costs associated with modifying WRL to connect VNI West at Bulgana are captured in the cost benefit analysis undertaken through this VNI West RIT-T; that is, any additional costs, over the estimated cost for the WRL project as currently scoped, are attributed to the VNI West option, as these costs will only be incurred if the option is developed. These additional costs are a result of WRL scope modifications that would be required for relocation and reconfiguration of the proposed terminal station north of Ballarat to Bulgana.

The detailed description of each option in Appendix A2 also outlines the specific modifications required to WRL's current scope to achieve each option. These have been reflected in the specified augmentation schedule of the May 2023 NEVA Order.

Any impact on the WRL current Environment Effects Statement (EES) process is now being assessed by AusNet. In particular, with the uprating of the 220 kV section of WRL to 500 kV as specified in the May 2023 NEVA Order, AusNet has identified further investigations that will be required prior to submitting the EES, including:

- Deviating the line where the proposed route for the 220 kV is too constrained to accommodate the 500 kV line due to a larger easement area being required; and
- Tower siting and positioning, as they are expected to be taller and have a larger base footprint.

If any modifications are required as a result of the EES process, the impact of these modifications will be assessed to determine if any consequential changes to VNI West would be required.

Estimate accuracy and contingency

The cost estimates are considered to an accuracy of ±30%[79], including for the WRL scope change costs, which AVP and Transgrid consider to be 'Class 4' estimates[80] under the AACE International classification. This accuracy level has been selected with consideration to the AACE classification guidelines for the level of design definition completed to date, the intended usage of the estimate, the estimate preparation method, the cost estimate source information, and cost item granularity used to develop the aggregate estimates.

AVP and Transgrid consider the cost estimates used in the PACR to be at a higher level of accuracy than estimates wholly developed using AEMO's 2023 TCD cost estimating tool, since they reflect additional detailed costing undertaken by AVP and Transgrid in the context of this project[81].

[78] See AEMO, 2023 Transmission Expansion Options Report Consultation, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

[79] Accuracy bands have been derived statistically, such that 80% of project estimates should fall within these limits. It is therefore expected that, across a large sample of projects, approximately 20% of them will fall outside of these bands.

[80] AEMO, 2021 *Transmission Cost Report,* August 2021, p. 12.

[81] Additional detail on the 'class' of capital cost estimates, and why it is considered appropriate, can be found in Section 2.2.2 of the Additional Consultation Report.

AVP and Transgrid note that the level of accuracy is consistent with current industry practice for this stage of the investment process[82]. The level of cost accuracy for the investments will be further refined and developed as the project progresses. As outlined in Section 1.4, as part of the CPA process, Transgrid will seek a 'feedback loop' confirmation from AEMO in line with the actionable ISP framework ahead of lodging a CPA for investment in VNI West. Transgrid intends to submit two CPAs to the AER in relation to the regulatory cost recovery for the project.

Cost estimates include an allowance for known and unknown risks that will or could arise during the further development and execution of this project, including:

- Known risks – where risks are identified but the ultimate value of the risk is not known:
  - Land access / easements / compulsory acquisition.
  - Cultural heritage.
  - Environmental offset risks (biodiversity).
  - Waste disposal/contamination.
  - Geotechnical makeup along the route (ground conditions for footings).
  - Outage restrictions.
  - Weather delays.
  - Project complexity.
- Unknown risks – where the risk has not been identified but industry experience indicates these could occur:
  - Productivity and labour cost.
  - Plant procurement cost.
  - Project overheads.
  - Scope and technology.

A specific route for the preferred option will only be confirmed following completion of the RIT-T. An extensive range of factors may affect the project cost, including (but not limited to) environmental factors affecting line route, biodiversity considerations, land acquisition or easement cost, construction cost implications arising from route dynamics, currency fluctuations and construction contractor costs in the proposed construction period. It is expected through completion of early works that greater certainty on risk will be obtained through stakeholder engagement, site investigations and design development. As such, the capital costs specified will be subject to further refinement.

3.3.2 Operating costs

Annual routine operating and maintenance costs are assumed to be 1% of capital costs for transmission assets, including early works, substation works, lines works and modular power flow controllers (but excluding land-related costs and biodiversity offset costs). In addition, Victorian land taxes for both the terminal station properties and transmission line easements have been estimated for each of the options and included as operating expenditure.

[82] The 2021 AEMO *Transmission Cost Report* states that future ISP projects typically have costs estimated to be 'Class 5B or 5a', while the PADR and PACR are typically at 'Class 4 or Class 3'. See AEMO, 2021 *Transmission Cost Report*, August 2021, pp. 12 and 13.

In response to a query raised during the March 2023 deep dive sessions, AVP and Transgrid note that the 1% of capital cost value is consistent with that used in the 2021 *Inputs, Assumptions and Scenarios Report* (IASR) (this is the latest final IASR released by AEMO). During consultation on the 2021 IASR, stakeholders questioned the appropriateness of this value and, in response, AEMO reviewed recent revenue determinations, contingent project applications and RIT-Ts, and concluded that 1% was reasonable for ISP purposes, because the cost of major projects in the ISP are dominated by transmission lines rather than substations. It is also noted that the AER will review and approve network expenditure from one revenue period to the next, so only efficient and prudent project costs are expected to be passed through to consumers[83].

As outlined in Section 2.5, the operating costs also now include the landholder payments announced by both New South Wales and Victorian governments.

[83] AEMO, 2021 *IASR Consultation Summary Report*, July 2021, p. 88.

4 Ensuring the robustness of the analysis

The two options have been assessed across three scenarios, consistent with the recommendations of the 2022 ISP. The scenarios and assumptions feeding into the scenarios are sourced directly from those used in the 2022 ISP. Under the actionable ISP framework, the ISP directs the use of specific scenarios (and their weightings) for each RIT-T.

These scenarios reflect different assumptions about future market development, the pace of the energy transition and other uncertain but potentially material factors that are expected to affect the relative market benefits of the options being considered. The different scenarios investigated test the robustness of the RIT-T credible options to different assumptions about how the energy sector may develop in the future.

4.1 The assessment considers three 'reasonable scenarios'

The RIT-T is focused on identifying the top ranked credible option that maximises expected net benefits. However, uncertainty exists around aspects such as how quickly the energy transformation will occur, the scale of future distributed energy resource uptake, and the level of demand growth as other sectors electrify or consider use of alternate zero-emission fuels.

To deal with this uncertainty, the actionable ISP framework requires AEMO to direct the use of specific scenarios for each RIT-T. The costs and market benefits for each credible option are estimated across these scenarios and then weighted based on the likelihood-based weightings identified in the ISP for each scenario to determine a weighted ('expected') net benefit[84]. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

Option 5 and Option 5A have been assessed under three scenarios as part of this PACR assessment, which align with the three scenarios recommended for the VNI West RIT-T in the 2022 ISP. Table 7 below summarises the specific key variables that influence the net benefits of the options under each of the three scenarios considered.

Table 7 PACR modelled scenario's key drivers input parameters

Key drivers input parameters	*Step Change*	*Progressive Change*	*Hydrogen Superpower*
Underlying consumption	2021 *Electricity Statement of Opportunities* (ESOO) (2022 ISP) – *Step Change*	2021 ESOO (2022 ISP) – *Progressive Change*	2021 ESOO (2022 ISP) – *Hydrogen Superpower*
Committed and anticipated generation	ISP 2022		
New entrant capital cost for wind, solar single axis tracking (SAT),	2021 Inputs and Assumptions Workbook – *Step Change*	2021 Inputs and Assumptions Workbook – *Progressive Change*	2021 Inputs and Assumptions Workbook – *Hydrogen Superpower*

[84] AER, *Cost Benefit Analysis Guidelines*, August 2020, p. 53.

Key drivers input parameters	*Step Change*	*Progressive Change*	*Hydrogen Superpower*
open-cycle gas turbine (OCGT), PHES, large-scale batteries and hydrogen turbines			
Retirements of coal-fired power stations	2022 ISP *Step Change* outcomes	2022 ISP *Progressive Change* outcomes, updated to reflect more recently announced closure date of 2035 for Loy Yang coal-fired power stations.	2022 ISP *Hydrogen Superpower* outcomes
Gas fuel cost	2021 Inputs and Assumptions Workbook – *Step Change*: Lewis Grey Advisory 2020, Step Change	2021 Inputs and Assumptions Workbook – *Progressive Change*: Lewis Grey Advisory 2020, Central	2021 Inputs and Assumptions Workbook – *Hydrogen Superpower*: Lewis Grey Advisory 2020, Step Change
Coal fuel cost	2021 Inputs and Assumptions Workbook – *Step Change*: Wood Mackenzie, Step Change	2021 Inputs and Assumptions Workbook – *Progressive Change*: Wood Mackenzie, Central	2021 Inputs and Assumptions Workbook – *Hydrogen Superpower*: Wood Mackenzie, Step Change
NEM carbon budget to achieve 2050 emissions levels*	2021 Inputs and Assumptions Workbook – *Step Change*: 891 Mt CO2-e 2023-24 to 2050–51.	2021 Inputs and Assumptions Workbook – *Progressive Change*: 932 Mt CO2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook – *Hydrogen Superpower*: 453 Mt CO2-e 2023-24 to 2050-51
Victoria Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030 VRET2 including 600 MW of renewable capacity by 2025		
Queensland Renewable Energy Target (QRET)	50% by 2030		
Tasmanian Renewable Energy Target (TRET)	2021 Inputs and Assumptions Workbook: 200% renewable generation by 2040		
New South Wales Electricity Infrastructure Roadmap	2021 Inputs and Assumptions Workbook: 12 GW New South Wales Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the 2022 ISP 2GW of long duration storage (8 hrs or more) by 2029-30		
Queensland – New South Wales Interconnector Upgrade (QNI Minor)	2022 ISP – commissioned by July 2022		
Victoria – New South Wales Interconnector Upgrade (VNI Minor)	2022 ISP – commissioned by December 2022		
Victorian SIPS	2022 ISP – 300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021		
EnergyConnect	2022 ISP – commissioned by July 2026		
Western Renewables Link	1 July 2027		
HumeLink**	2022 ISP – *Step Change*: commissioned by July 2028	2022 ISP – *Progressive Change*: commissioned by July 2035	2022 ISP – *Hydrogen Superpower*: commissioned by July 2027
New-England REZ Transmission	2022 ISP – *Step Change*: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	2022 ISP – *Progressive Change*: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	2022 ISP – *Hydrogen Superpower*: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031, and stage 3 by July 2042
Marinus Link	2022 ISP –first cable commissioned by July 2029 and second cable by July 2031		
QNI Connect	2022 ISP – *Step Change*: commissioned by July 2032	2022 ISP – *Progressive Change*: commissioned by July 2036	2022 ISP – *Hydrogen Superpower*: commissioned by July 2029 and stage 2 to be commissioned by July 2030

Key drivers input parameters	*Step Change*	*Progressive Change*	*Hydrogen Superpower*
VNI West	2022 ISP – *Step Change*: commissioned by July 2031	2022 ISP – *Progressive Change*: commissioned by July 2038	2022 ISP – *Hydrogen Superpower*: commissioned by July 2030
Snowy 2.0	2021 Inputs and Assumptions Workbook – commissioned by December 2026		

* Market modelling for the PACR applies emissions for 2023-24 to 2029-30, 2030-31 to 2039-40 and the last decade of modelling, as carbon budget constraints using the 2022 ISP outcomes.
** This RIT-T modelled HumeLink as commissioned according to the ISP scenario timings, which are ahead of the VNI West timings across all scenarios.

4.2 Weighting the reasonable scenarios

AEMO specified in the 2022 ISP that the scenario weightings in Table 8 should be applied in the VNI West RIT-T[85]. While these weightings have been applied to weight the estimated market benefits and identify the preferred option across scenarios, AVP and Transgrid have also carefully considered the results in each scenario in Section 6 and Appendix A9 to better understand how differences in the future 'states of the world' can impact the benefits of the options.

Table 8 Scenario probability weightings

Scenario	2022 ISP probability weighting
Step Change	52%
Progressive Change	30%
Hydrogen Superpower	18%

4.3 Sensitivity analysis

In addition to the scenario analysis, AVP and Transgrid have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing. The range of factors tested as part of the sensitivity analysis in this PACR are:

- Interaction with the Victorian Government's offshore wind policy, should it become a 'committed policy' that satisfies the criteria set out in the NER.
- A variant of Option 5A that runs further west of Kerang.
- Effect of removing the series compensation on the Kerang to Bulgana section.
- Changes in the capital costs and operating costs of the credible options.
- Alternative commercial discount rate assumptions.

The results of the sensitivity tests are discussed in Section 6.3.

AVP and Transgrid have also estimated the 'threshold value' for key variables beyond which the outcome of the analysis would change. As there are inter-dependencies between many of these variables, the threshold values are indicative only and assume all else being equal.

[85] AEMO, 2022 ISP, June 2022, p. 75. AEMO has not included the *Slow Change* scenario because it carries a low likelihood (4%) and the optimal timing is similar to the *Progressive Change* scenario.

5 Estimating gross market benefits

Seven classes of gross market benefit under the AER Cost Benefit Analysis (CBA) Guidelines are considered material for this RIT-T and have been estimated as part of the PACR assessment. Wholesale market modelling has been used to estimate these classes of market benefits.

5.1 Classes of market benefit considered

The key benefits expected from increasing transfer capacity between New South Wales and Victoria and harnessing more renewable generation in REZs are driven by anticipated changes in wholesale market outcomes going forward as Australia transitions to net zero by 2050.

Under NER 5.15A.3(b)(4), when applying the RIT-T to an actionable ISP project, the RIT-T proponent must quantify all classes of market benefits identified in the relevant ISP and may also consider other classes of market benefits in accordance with the CBA Guidelines.

A RIT-T proponent has discretion when considering whether to quantify a market benefit class set out in the CBA Guidelines that AEMO did not include in the ISP. In applying its discretion, the RIT-T proponent should consider whether:

- Doing so is likely to materially affect the outcome of the CBA; and
- The associated computational burden of including it is not expected to be disproportionate to the potential benefits.

The classes of market benefit included in the 2022 ISP were:

- Generator and storage capital deferral.
- Fixed operating and maintenance (FOM) cost savings.
- Fuel cost savings.
- Variable operating and maintenance (VOM) cost savings.
- Unserved energy (USE) + demand side participation (DSP) reductions.

These are all considered in this RIT-T.

The specific classes of market benefit under the CBA Guidelines that have been modelled as part of this PACR are:

- 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)
- Changes in fuel consumption in the NEM arising through different patterns of generation dispatch.
- Differences in REZ transmission costs.
- Changes in involuntary load curtailment.

- Changes in voluntary load curtailment.
- Changes in network losses.
- Option value (to the extent it is calculated through the scenario-specific differences in project timing).

For each scenario described in Section 4.1, the CBA Guidelines require classes 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 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 (for example, that is required to connect REZs).

Transgrid engaged EY to undertake wholesale market modelling to assess the gross market benefits expected to arise under each of the credible options and scenarios. While EY took instruction from Transgrid as its client, assumptions and input data sources were independently selected in accordance with the CBA guidelines by both Transgrid and AVP as joint RIT-T proponents. The wholesale market modelling methodology applied to assess gross market benefits in this PACR is the same as that presented in the Additional Consultation Report and is similar to the approach used in the 2022 ISP. The methodology is outlined briefly in Appendix A7. The market modelling report accompanying the Additional Consultation Report provides additional detail on these modelling studies, as well as the key modelling assumptions and approach adopted more generally[86]. Input assumptions for the PACR modelling are the same as those described in the Additional Consultation Report market modelling report except for changes to the input assumptions listed in Table 5 (in Section 3 of this report). This report should be read in conjunction with that report to understand the full context of input assumptions and methodology for the assessment of gross market benefits. The assessment of costs and calculation of net economic benefits and preferred option was conducted by AVP and Transgrid using the forecast gross market benefits and other inputs.

One key difference between the ISP and this RIT-T assessment is the choice of counterfactual used to assess the market benefits of each option. The counterfactual 'base case' in the ISP is one without any new transmission development, whereas in this RIT-T assessment, other major transmission projects identified in the ISP optimal development path are assumed to be developed in all 'states of the world', including the counterfactual.

5.1.1 Changes in costs for other parties in the NEM

This class of market benefit is expected where credible options result in different investment patterns of generators and large-scale storage across the NEM, compared to the base case. This class of benefit combines the following 2022 ISP benefit classes: generator and storage capital deferral, FOM cost savings, and VOM cost savings.

In particular, the market modelling forecasts that there are large amounts of avoided new generation and storage investment compared to the base case. As shown in Section 6 and Appendix A9, these avoided or deferred costs associated with generation and storage are the most material class of market benefit estimated for both options across the three scenarios. While this class of market benefits captures all avoided or deferred capital costs, as well as operating and maintenance costs (both variable and fixed), the market modelling finds that it is made up primarily of avoided or deferred capital costs.

[86] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/victoria-to-nsw-interconnector-west-vni-west--market-modelling-report-for-additional-options.pdf?la=en.

5.1.2 Changes in fuel consumption in the NEM

This class of market benefit is expected where credible options result in different patterns of generation and storage dispatch across the NEM, compared to the base case.

In particular, expanding transfer capacity and harnessing more renewable generation from diverse sources enables demand centres to be supplied by lower cost generation than can be expected if no upgrade is undertaken. For example, while gas-fired generation in Victoria still plays a crucial role in firming and providing essential power system services to maintain grid security and stability over the outlook period, the market modelling forecasts that new renewable generation avoids the need for relatively high-cost gas-fired generation in Victoria to operate as frequently. As outlined in Section 6 and Appendix A9, this is the second largest class of benefit estimated for both options across the three scenarios.

5.1.3 Differences in REZ transmission costs

This benefit class relates to the costs of intra-regional transmission investment associated with the development of REZs that could be avoided if a credible option is pursued.

AEMO has identified a number of candidate REZs in various NEM jurisdictions as part of the ISP and has included allowances for transmission augmentations that it considers would be required to develop those REZs. Option 5 and Option 5A allow development of some of these REZs (South West New South Wales REZ (N5), Murray River REZ (V2) and Western Victoria REZ (V3)), without the need for additional intra-regional transmission investment (or less of it), leading to expected REZ transmission cost savings.

5.1.4 Changes in involuntary load curtailment

Increasing the transfer capacity between New South Wales and Victoria allows existing generation and storage in each state to be utilised more efficiently to meet demand. It is also expected to provide greater access to renewable generation and the deep storage of Snowy 2.0 which, in combination with development in other REZs, is forecast to meet demand throughout the year at lowest cost to consumers, once ageing coal plant retires.

This market benefit involves quantifying the impact of changes in involuntary load shedding associated with the implementation of each credible option via the time-sequential integrated resource planner (TSIRP). Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided USE for each option. AVP and Transgrid have adopted the AER's most recent assumptions for the VCR for the purposes of this assessment, as in the 2021 IASR.

This class of market benefit is forecast to be relatively small within the market modelling as new generation and storage capacity is built in all future states of the world, including the base case, if required to meet demand and a reserve margin used as a proxy for the reliability standard. There is therefore no material difference in the expected quantity of involuntary load shedding between each option and the base case, under each of the scenarios. Many of the reliability benefits of VNI West are therefore reflected through capital deferral, with less investment in dispatchable capacity required to maintain reliability in an efficient manner.

5.1.5 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load once wholesale prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances.

Where the implementation of a credible option affects wholesale price outcomes, and in particular results in wholesale prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.

This class of market benefit is also forecast to be relatively low in the market modelling for this RIT-T, reflecting that the level of voluntary load curtailment currently present in the NEM is not significant.

5.1.6 Changes in network losses

The TSIRP market modelling has taken into account the change in network losses (on hourly basis) that may be expected to occur as a result of the implementation of each of the credible options, compared with the level of network losses which would occur in the base case, for each scenario.

The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits associated with avoided fuel costs and changes to voluntary and involuntary load shedding.

The reduction in network losses between the base case and the two options is not considered material for this PACR, since any effect on losses will come primarily from the VNI West component itself (which features in both options).

5.1.7 Option value

The modelling in this PACR estimates the option value associated with VNI West as part of the scenario analysis, which is in line with the AER's CBA Guidelines[87]. Specifically, while the timing of Stage 1 is the same across the scenarios, the timing for Stage 2 differs depending on scenario (as outlined in Table 4), which captures the option value associated with the second stage[88] as identified in the 2022 ISP.

AVP and Transgrid do not consider VNI West to exhibit additional flexibility outside of the Stage 1/Stage 2 flexibility, so do not consider there to be any additional option value associated with VNI West, and so also do not consider additional, detailed real options analysis to be warranted.

5.2 Classes of market benefit not considered material

The NER require that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific class (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option[89].

The PSCR outlined how all categories of market benefit identified in the RIT-T have the potential to be material with the exception of changes in ancillary services costs, competition benefits, and the negative of any penalty payable for not meeting the renewable energy target. AVP and Transgrid have not changed the PSCR view regarding the immateriality of these potential sources of market benefit.

[87] AER, *Cost Benefit Analysis Guidelines*, August 2020, pp. 37-42.

[88] While this RIT-T assessment did not separately quantify the option value associated with the second stage, the 2022 ISP assessment showed that staging VNI West delivers an additional $40 million of net market benefits over proceeding now with VNI West without any staging.

[89] NER 5.16.1(c)(6).

5.3 Applying ISP parameters

Under the actionable ISP framework, the ISP identifies the major transmission investments (including enhanced interconnection) and development opportunities (generation, storage and DER) that are key to underpinning the energy transition (the 'optimal development path') and makes key network and non-network projects 'actionable' by triggering a requirement on the relevant jurisdictional planners to apply the RIT-T. As part of this framework, the AER has published CBA Guidelines to make the ISP actionable that seek to minimise duplication between the ISP and RIT-Ts.

In doing so, several changes to the RIT-T process have been introduced, including guidance as to how the RIT-T proponent must apply the ISP parameter.

NER 5.10.2 defines ISP parameters as meaning, for an ISP project:

- The inputs, assumptions and scenarios set out in the most recent IASR;
- The other ISP projects associated with the optimal development path (where ISP projects include actionable ISP projects, future ISP projects and ISP development opportunities); and
- Any weightings specified as relevant to that project.

In accordance with the CBA Guidelines, unless there is a demonstrable reason not to, the RIT-T proponent is required to:

- Adopt the scenarios that AEMO has specified as relevant to that RIT-T application, and the inputs and assumptions from the most recent IASR.
- Adopt the likelihood weightings to apply to the scenarios, as specified in the most recent ISP.
- Include other actionable ISP projects in all states of the world (including the base case).
- Treat non-actionable ISP projects (that is, future ISP projects and ISP development opportunities) as modelled projects that can vary by scenario or state of the world as per the ISP.

Section 4.3.6 of the CBA Guidelines provides further clarification that the inclusion of modelled projects in a given state of the world will be determined using appropriate market development modelling and that, for completeness, where the RIT-T proponent adopts the market modelling from the ISP, ISP projects that are not actionable ISP projects (that is, future ISP projects and ISP development opportunities) will usually be modelled projects.

For the purpose of this RIT-T analysis, AVP and Transgrid have adopted the scenarios and likelihood weightings from the 2022 ISP (see Section 4) and have included all other actionable ISP projects in all states of the world (including the base case), in accordance with the CBA Guidelines.

Some future ISP projects are also adopted in relevant scenarios in the base case and VNI West options, namely Queensland – New South Wales Interconnector (QNI) Connect and New England REZ Extension being infrastructure needed to enable the 8 GW of renewable generation capacity in this zone (a minimum objective set under the *NSW Electricity Infrastructure Investment Act 2020)*. It was necessary to model these future ISP projects explicitly to ensure an appropriate representation of the Central New South Wales (NCEN) and Northern New South Wales (NNS) sub-regions in market modelling. These projects are the same in each scenario's base case and with the VNI West options.

All other future ISP projects and all ISP development opportunities have been treated as modelled projects that have been re-optimised through EY's market modelling; that is, the market modelling results from the 2022 ISP have not been adopted. AVP and Transgrid consider that there are two demonstrable reasons for not including these ISP parameters:

- As discussed above, capital deferral benefits account for the vast majority of market benefits of VNI West. The inclusion of VNI West changes the pattern of generation and storage development across the NEM. Different VNI West options also harness different levels of renewable generation along the VNI West pathway. Had the ISP development opportunities been taken from the 2022 ISP and not reoptimised under different states of the world, or different VNI West options, changes to patterns of generation development (and therefore changes in capital deferral) attributed to differences in the credible options considered would not have been identified. This would have made it very difficult to assess which option maximises benefits for consumers.
- The base case for the RIT-T (based on a 'take one out at a time' approach[90] with other actionable ISP projects included) is very different to the base case for the ISP (where only 'business as usual' transmission investment can occur), and therefore the appropriate generation (and storage) development for the RIT-T base case does not exist in the most recent ISP.

5.4 Cost benefit analysis parameters used

The CBA Guidelines requires the discount rate used in the NPV analysis to be the commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. A central discount rate of 5.50% (real, pre-tax) has been used in the NPV analysis, consistent with the RIT-T requirements and the 2021 IASR. The cost benefit analysis has included sensitivity testing with a lower bound discount rate of 2.30% equal to the latest AER Final Decision for a TNSP's regulatory proposal at the time of preparing this PACR[91], and an upper bound discount rate of 7.50% (consistent with the upper bound in the latest final IASR). AVP and Transgrid note that the upper bound is above the revised central discount rate estimate of 7% presented in the Draft 2023 IASR[92].

The Long-term Investment Planning model adopts the same commercial discount rates as used in the NPV discounting calculation in the cost benefit analysis[93]. This is consistent with the approach taken in the 2022 ISP.

[90] See Section 4.3.6 of AER's CBA Guidelines for an explanation of this approach.

[91] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM as of the date of this analysis. See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powerlink-determination-2022%E2%80%9327/final-decision.

[92] AEMO, *Draft 2023 Inputs, Assumptions and Scenarios Report,* December 2022, p. 110.

[93] Except in the discount rate sensitivities; see Section 6.4.5.

6 Net market benefits

The net market benefit assessment finds that the two options assessed in this PACR are effectively jointly top ranked on a purely NPV basis and deliver approximately $1.4 billion in net benefits in present value terms under the RIT-T.

This chapter summarises the net market benefit assessment outcomes for the *Step Change* scenario – the most likely scenario from the 2022 ISP – and the outcomes weighted across all three scenarios (*Step Change*, *Progressive Change* and *Hydrogen Superpower*) according to the weights prescribed in the 2022 ISP. The specific outcomes for the *Progressive Change* and *Hydrogen Superpower* scenarios are in Appendix A9.

Forecast gross market benefits have increased relative to the Additional Consultation Report in all scenarios, due to the increases in REZ hosting limits identified through further refinement of the power system modelling, as requested by some stakeholders (for example, AusNet, Murray River Group of Councils, and the Wimmera Development Association). The net market benefits, however, have decreased slightly, due to the increase in costs, particularly on the Victorian side.

All costs and benefits in this report are presented in June 2021 real dollars, unless otherwise stated, consistent with the PADR and the Additional Consultation Report.

Forecast generation and capacity outlooks and gross market benefit outcomes are based on market modelling conducted by EY in accordance with the CBA Guidelines for each of the credible options and scenarios selected by Transgrid and AVP. While EY took instruction from Transgrid as its client, assumptions and input data sources were independently selected in accordance with the CBA Guidelines by both Transgrid and AVP as joint RIT-T proponents. This is described further in Appendix A7 and the market modelling report accompanying the Additional Consultation Report. This report should be read in conjunction with those reports to understand the full context of input assumptions and methodology for the assessment of gross market benefits. The assessment of costs and calculation of net economic benefits and preferred option was conducted by AVP and Transgrid using the forecast gross market benefits and other inputs.

6.1 *Step Change* scenario

The *Step Change* scenario is summarised by AEMO as 'rapid consumer-led transformation of the energy sector and coordinated economy-wide action'. The *Step Change* scenario moves quickly initially to fulfilling Australia's net zero policy commitments and, rather than building momentum over time (as in the *Progressive Change* scenario), sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM. By 2050, this scenario assumes that most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion vehicles has all but ceased.

Under these assumptions, Option 5 and Option 5A are found to be ranked equally. Option 5A is expected to deliver net benefits of approximately $1,827 million. Option 5 is also found to have net benefits of approximately $1,827 million (0.02% less than Option 5A).

Option 5A has the greatest indicative impact on REZ transmission limits of the two options (+4,140 MW compared to +3,635 MW for Option 5). Option 5A has marginally lower transfer capability from Victoria to New South Wales (+1,935 MW) than Option 5 (+1,960 MW) (see Section 3.2).

Both Option 5 and Option 5A are forecast to have a similar trend in gross market benefits and underlying changes in generation and capacity outlook relative to the base case. The discussion and figures in this section are mainly focused on Option 5A. Outcomes for Option 5 are similar to those presented in the Additional Consultation Report.

Figure 7 presents the estimated net benefits for each option under the *Step Change* scenario.

Figure 7 Summary of estimated net benefits under the *Step Change* scenario

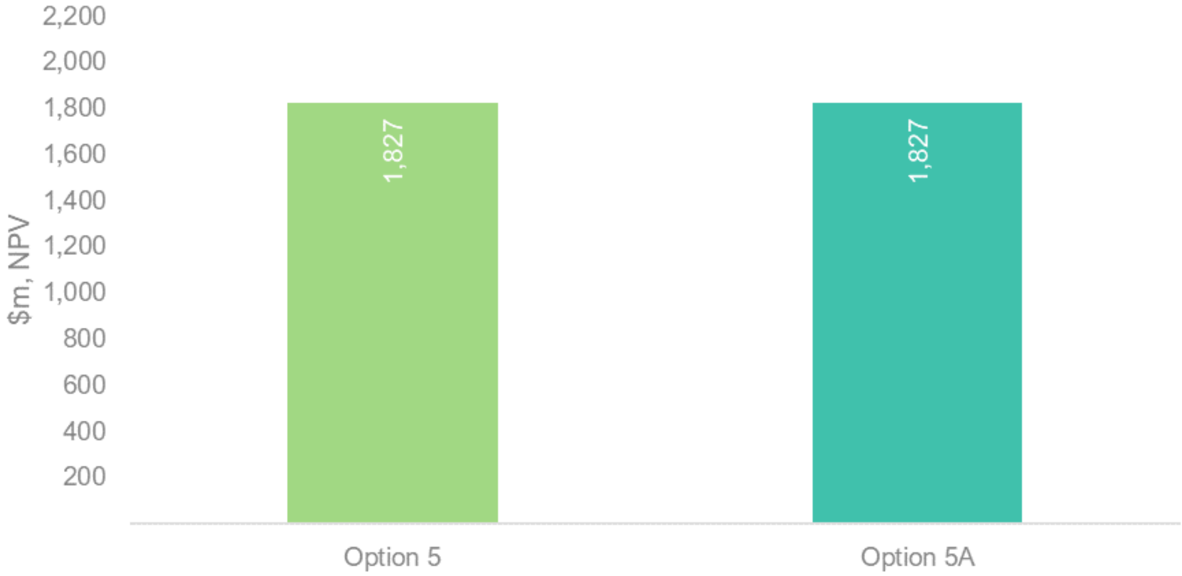
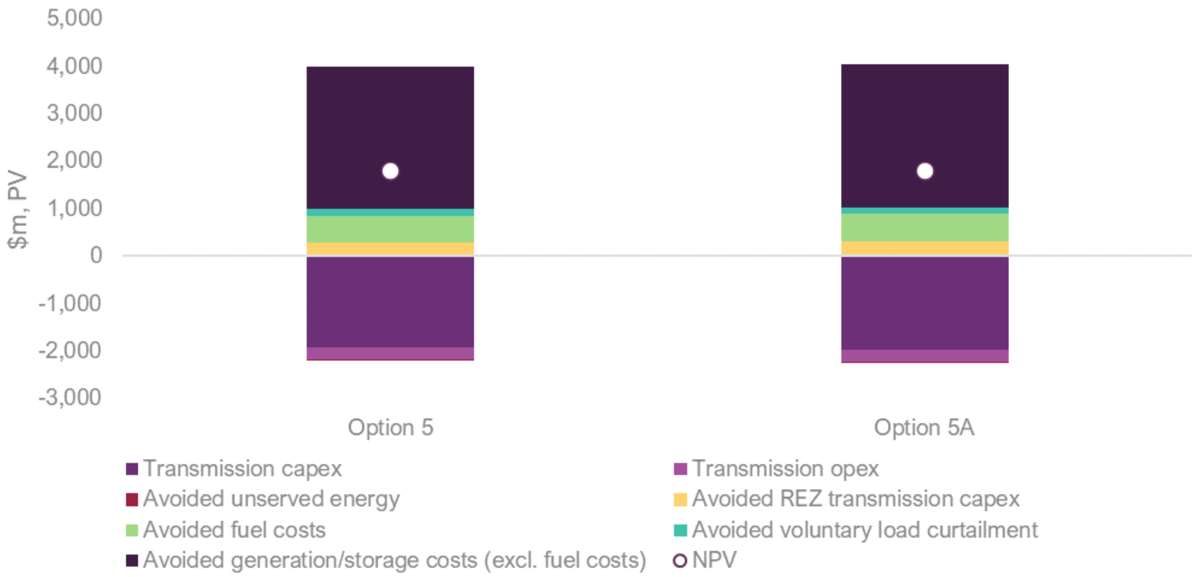


Figure 8 shows the composition of estimated net benefits for each option under the *Step Change* scenario.

Figure 8 Breakdown of estimated net benefits under the *Step Change* scenario



The key findings from the assessment of each option under this scenario are:

- Avoided/deferred generation and storage costs and avoided fuel costs are estimated to be the primary sources of benefit for both options (Table 9).
- Avoided/deferred generation and storage costs are estimated to comprise approximately 75% and 74% of the estimated gross benefits of Option 5 and Option 5A, respectively.
- Avoided fuel costs are estimated to comprise approximately 15% and 14% of the estimated gross benefits of Option 5 and Option 5A, respectively.
- Avoided/deferred generation and storage costs (the darkest sections of each bar in Figure 8) are primarily driven by deferred/avoided investment in solar and wind, large-scale storage (mostly pumped hydro energy storage), and gas, that is otherwise needed in Victoria to maintain reliability once brown coal retires[94]. There are also forecast savings from avoided/deferred generation and storage costs in other regions, except New South Wales, as discussed below. A breakdown of forecast avoided/deferred generation and storage costs by technology is shown in Table 10.
  - After commissioning, both options are expected to enable increased resource sharing between Victoria and the other mainland regions that alters the distribution of investment in renewables and generally reduces the need for gas capacity for energy and reserve in the NEM.
  - With both options, while there is still significant capacity investment in all regions, some investment that had been needed in Victoria is no longer required, and other, more efficient investment in solar and storage is located in New South Wales and shared with Victoria when needed, noting that Victoria now also has greater access to Snowy 2.0’s deep storage. Improved interconnection and unlocked REZs with VNI West Option 5A are also generally forecast to reduce the need for investment in other NEM regions.
  - Overall, the amount of forecast capacity investment is also estimated to be lower with both options while delivering more variable renewable generation than the base case, due to improved access to higher capacity factor REZs and reduced forecast spill. Across the NEM, both options are forecast to reduce solar and wind spill relative to the base case. However, the interaction of several factors affects the amount of spill in each REZ and region – these factors are the change in distribution of renewable investment, the change in ratio of wind to solar investment in each REZ, and the direct effect of additional transmission access to some REZs in Victoria and New South Wales associated with VNI West options.
  - From the mid to late 2030s, both options are forecast to avoid gas generation build in Victoria that would otherwise be needed for firming, due to the increased transfer limits between Victoria and New South Wales enabling more generation to be imported to Victoria to meet demand during times of low renewable generation, and providing Victoria with greater access to Snowy 2.0’s deep storage.
  - Option 5A unlocks more transmission network capacity for the Murray River REZ (V2), resulting in more solar investment in that REZ than Option 5.
- Avoided fuel costs (the light green sections of each bar in Figure 8) arise primarily from avoided gas generation in Victoria after VNI West is commissioned.

[94] The presence of gas generation in the base case is not considered to be inconsistent with the Victorian Government’s Gas Substitution Roadmap, as electrification of the gas sector is assumed in the demand forecasts and most of this additional demand is supplied by renewable generation. Without stronger interconnection with New South Wales, a moderate level of gas generation is still required in Victoria to firm these renewables, but greenhouse gas emissions continue to decline to net zero by 2050.

- While gas generation plays a firming role after coal closures, with VNI West some of the residual gas generation, which is required in the base case, is forecast to be replaced by increased wind, solar and storage generation in all mainland NEM regions. The majority of the forecast increased wind and solar generation comes from New South Wales, and from less renewable spill in Victoria.
- Gas still plays a critical role as coal-fired generation retires, as a complement to battery and pumped hydro generation in periods of peak demand, and during long 'dark and still' weather periods. It will also provide essential power system services to maintain grid security and stability.

- REZ transmission cost savings (the yellow sections of each bar in Figure 8) are driven by VNI West allowing builds in REZs with increased transmission capacity such as Murray River (V2) and Western Victoria (V3) to replace/defer REZ transmission expansion in REZs such as Central North Victoria (V6) and South West Victoria (V4).

Table 9 Breakdown of forecast gross market benefits by benefit class under the *Step Change* scenario

	Avoided generation and storage costs (excl. fuel)	Avoided fuel costs	Avoided REZ transmission capital expenditure (capex)	Avoided load curtailment
Option 5	75%	15%	7%	3%
Option 5A	74%	14%	8%	4%

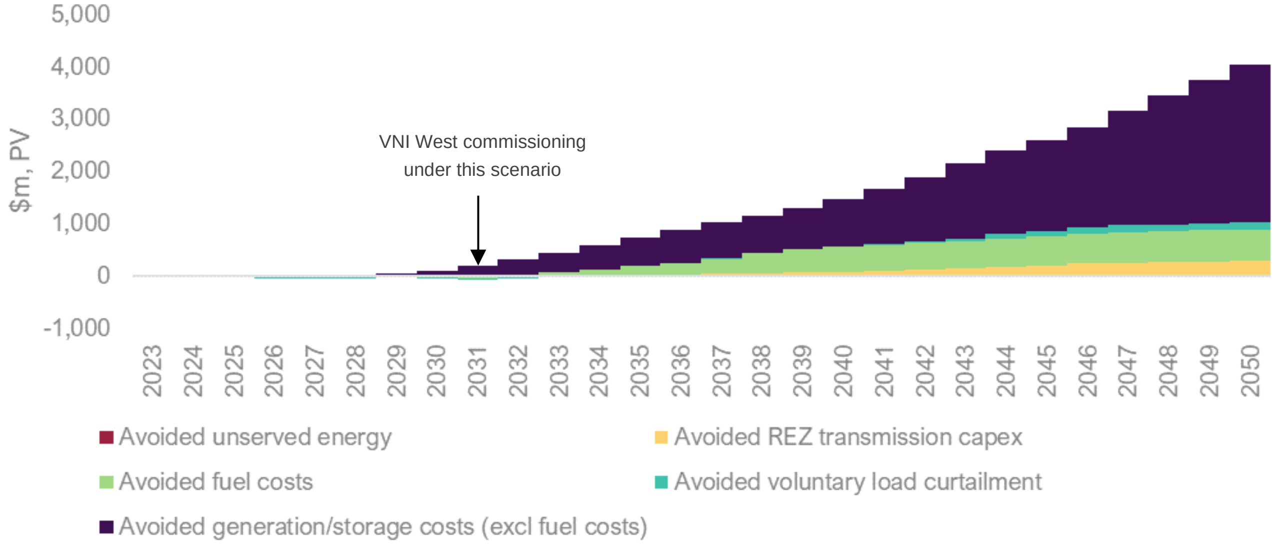
Table 10 Breakdown of forecast avoided/deferred generation and storage costs by technology as a percentage of total forecast gross market benefits under the *Step Change* scenario

	Avoided generation and storage costs (excl. fuel)		Avoided fuel costs	
	Option 5	Option 5A	Option 5	Option 5A
Coal	0%	0%	-2%	-2%
Gas	4%	4%	16%	16%
Wind	33%	34%	0%	0%
Solar	14%	13%	0%	0%
Pumped hydro	22%	21%	0%	0%
Grid-scale battery storage	4%	3%	0%	0%
% of total forecast gross benefits	75%	74%	15%	14%

Figure 9 below presents the estimated cumulative expected gross benefits for Option 5A for each year of the assessment period under the *Step Change* scenario[95]. It shows that benefits from avoided/deferred generation and storage costs, as well as benefits from avoided fuel consumption, mainly accrue from commissioning of the main components of VNI West in 2031-32. REZ transmission cost savings are forecast to be relatively high for Option 5A (and mainly accrued in the 2040s).

[95] This figure and all figures of this type in this report only present the annual breakdown of estimated gross benefits for Option 5A. The separately released spreadsheet presents an annual breakdown of costs and benefits for both options. Since this figure shows the cumulative gross benefits in present value terms, the height of the bar in the last year equates to the gross benefits for Option 5A shown in Figure 8 above. This applies to all figures of this type in this document.

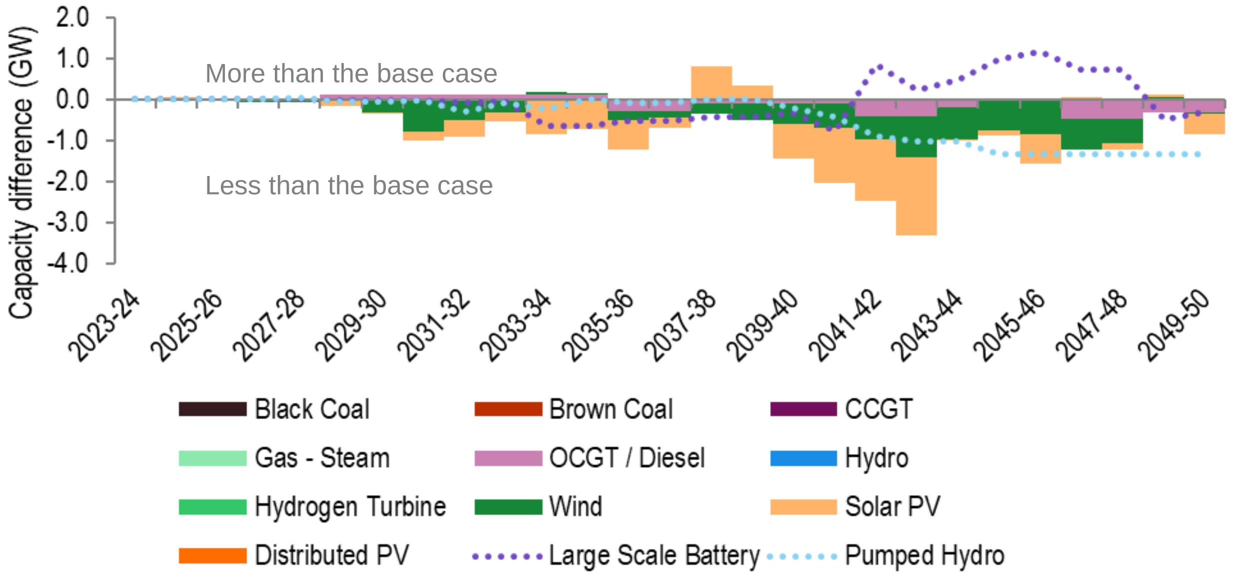
Figure 9 Breakdown of cumulative gross benefits for Option 5A under the *Step Change* scenario



The pattern of forecast market benefits is the same for Option 5 and so it has not been shown here. The data for Option 5 can be found in the accompanying NPV workbooks released alongside this PACR.

Figure 10 summarises the forecast difference in generation and storage capacity for Option 5A (in GW), compared to the base case[96]. These capacity differences are driving the benefit associated with avoided or deferred generation and storage costs, which dominates all other benefits combined.

Figure 10 Difference in cumulative capacity build with Option 5A, compared to the base case, under the *Step Change* scenario



Distributed PV: distributed photovoltaics.

Option 5A is forecast to generally avoid pumped hydro energy storage investment and to a lesser extent gas capacity in the NEM, and defer battery storage investment. This option is also forecast to result in deferring some

[96] For the avoidance of doubt, all figures of this type in the PACR are showing the differences in cumulative capacity *across the NEM*, compared to the base case.

wind and solar capacity investment. Less capital investment is forecast since Option 5A enables greater existing and future NEM generation diversity and more efficient utilisation of Snowy 2.0, although with similar capacity factors to the base case.

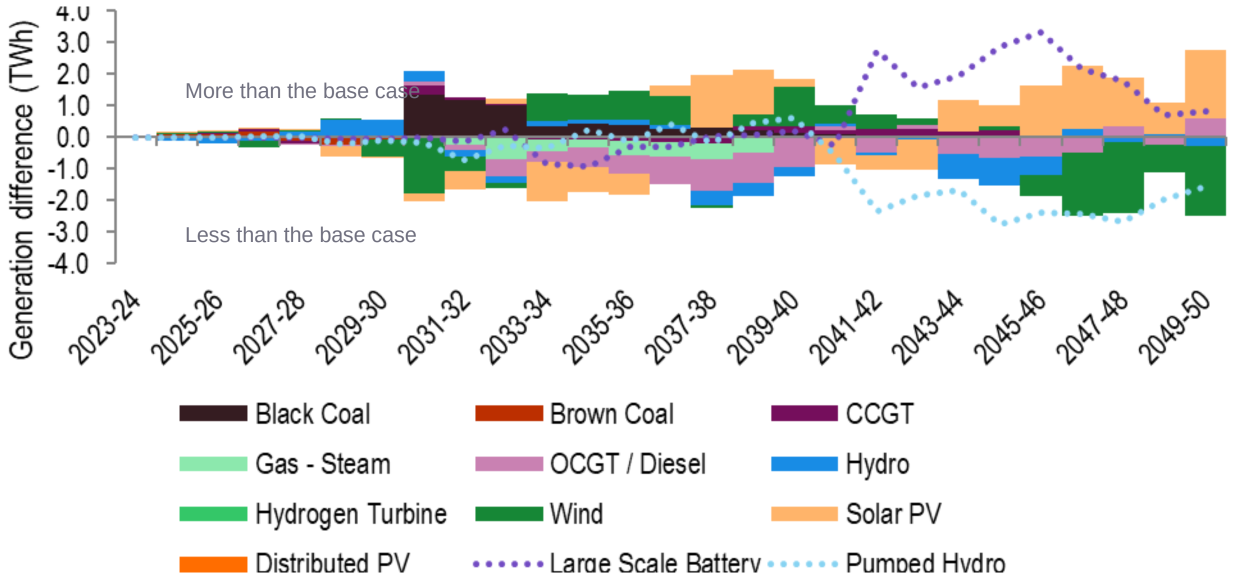
There is relatively more renewable and storage investment required in all regions except New South Wales in the base case. Some of this investment can be avoided or deferred with Option 5A in place. On the other hand, Option 5A enables some more solar, storage and in later years wind investment in New South Wales. Overall, the amount of forecast capacity investment is lower due to improved access to higher capacity factor REZs, the ability to share resources across the NEM, and overall reduced forecast spill relative to the base case. Across the NEM, Option 5A is forecast to reduce wind and solar spill by 3% and wind spill volume by 7% relative to the base case.

A system with Option 5A is forecast to generally build more wind and in later years more solar in Western Victoria REZ (V3), while more solar is forecast to be built in Murray River REZ (V2). South West New South Wales REZ (N5) is generally expected to see more solar and to a smaller extent wind built in later years, with Option 5A in place. In addition, with the improved access to a diversity of resources provided by this option, more investment in higher quality REZs such as Central West Orana (N3) and Darling Downs (Q8) is forecast.

On the other hand, Option 5A is forecast to reduce the capacity otherwise forecast in the remaining Victorian REZs, particularly Ovens Murray (V1) and Gippsland offshore (O3), as well as other regions REZs such as Wagga Wagga (N6), and some Queensland and Tasmanian REZs.

Figure 11 summarises the difference in generation and storage output modelled for Option 5A (in TWh), compared to the base case. These generation differences are driving the avoided fuel cost benefit. The reduction in open-cycle gas turbine (OCGT)/diesel utilisation underlying this fuel cost saving is clearly evident.

Figure 11 Difference in output with Option 5A, compared to the base case, under the *Step Change* scenario



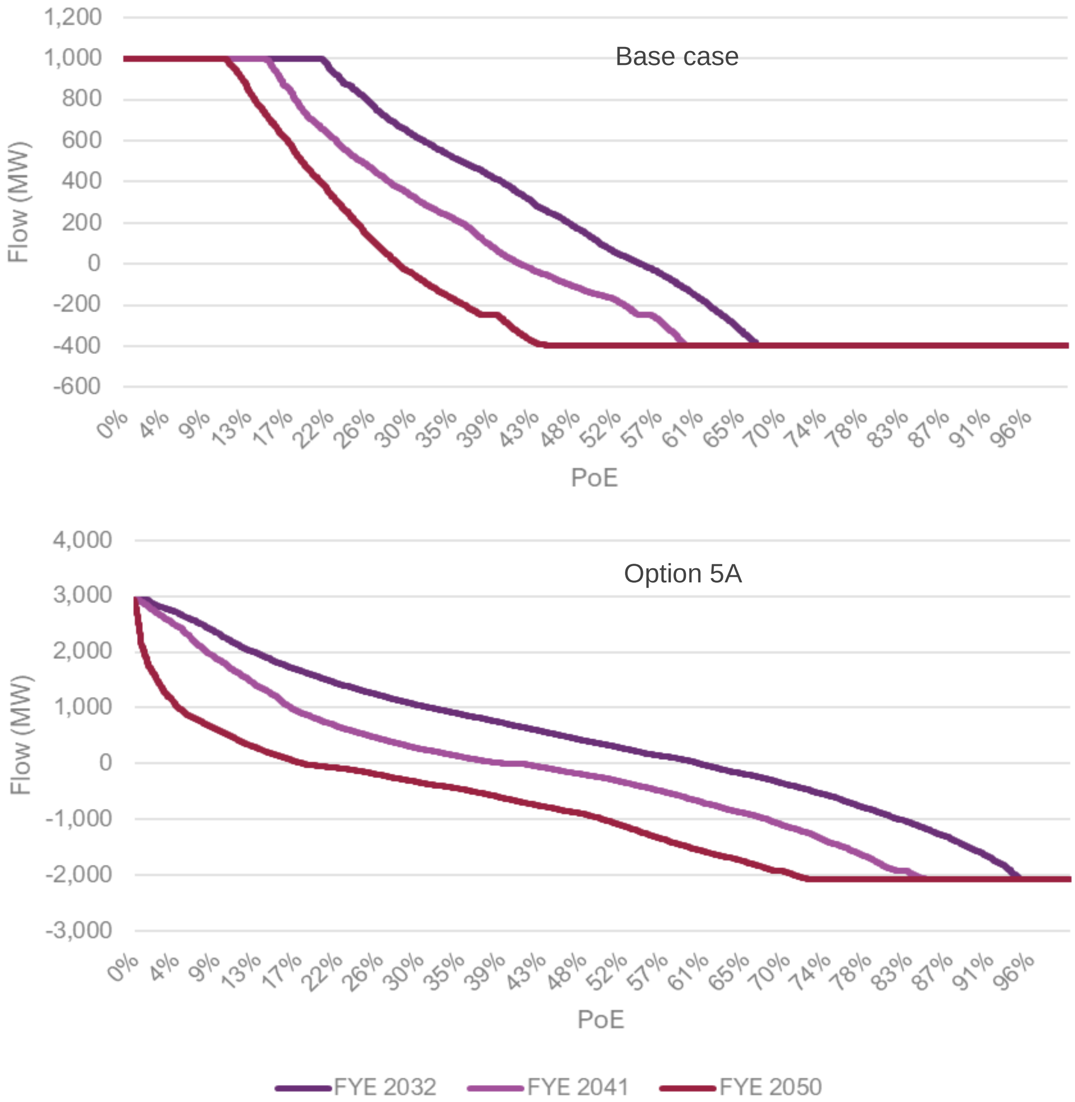
Generally, peaking gas generation is the cheapest option in Victoria in the base case to supply peak demand during times of low renewable generation and meet the reserve requirement in this region in the absence of brown coal and relatively lower interconnection to the rest of the mainland. While gas generation is forecast in the base case and to a smaller extent in VNI West options, the NEM renewable energy share in the final year of the study is expected to be around 98% and the carbon budget constraint is forecast to be met in the base case and with

VNI West. In the *Step Change* scenario, the carbon budget is 886 metric tons of carbon dioxide equivalent (Mt CO2-e) cumulative emissions from 2023-24 to 2049-50 (defined by the ISP for the global temperature increase of ~1.8ºC by 2100).

In general, with Option 5A in place, some gas generation is replaced with increased wind and solar generation due to increased access to high quality REZs and increased ability to share resources across regions. With Option 5A in place, compared to the base case there is generally less spill expected for wind and solar as a result of better utilisation of existing and new entrant resources. Wind generation is expected to compete with hydro generation, particularly in Tasmania, and as hydro has higher running costs compared to wind, this results in more hydro spill relative to the base case.

Figure 12 shows annual duration curves for VNI in the base case and under Option 5A. As VNI West is not commissioned in the base case, the flow is limited to 1,000 MW in the export direction, and 400 MW in the import direction. In 2031-32, VNI is at the import limit approximately 35% of the time, and at the export limit approximately 20% of the time. From the 2030s through to 2050, the VNI flow trends towards importing more, with the import limit being reached approximately 55% of the time in 2049-50.

Figure 12 Flow duration curve – base case (top) and Option 5A (bottom)

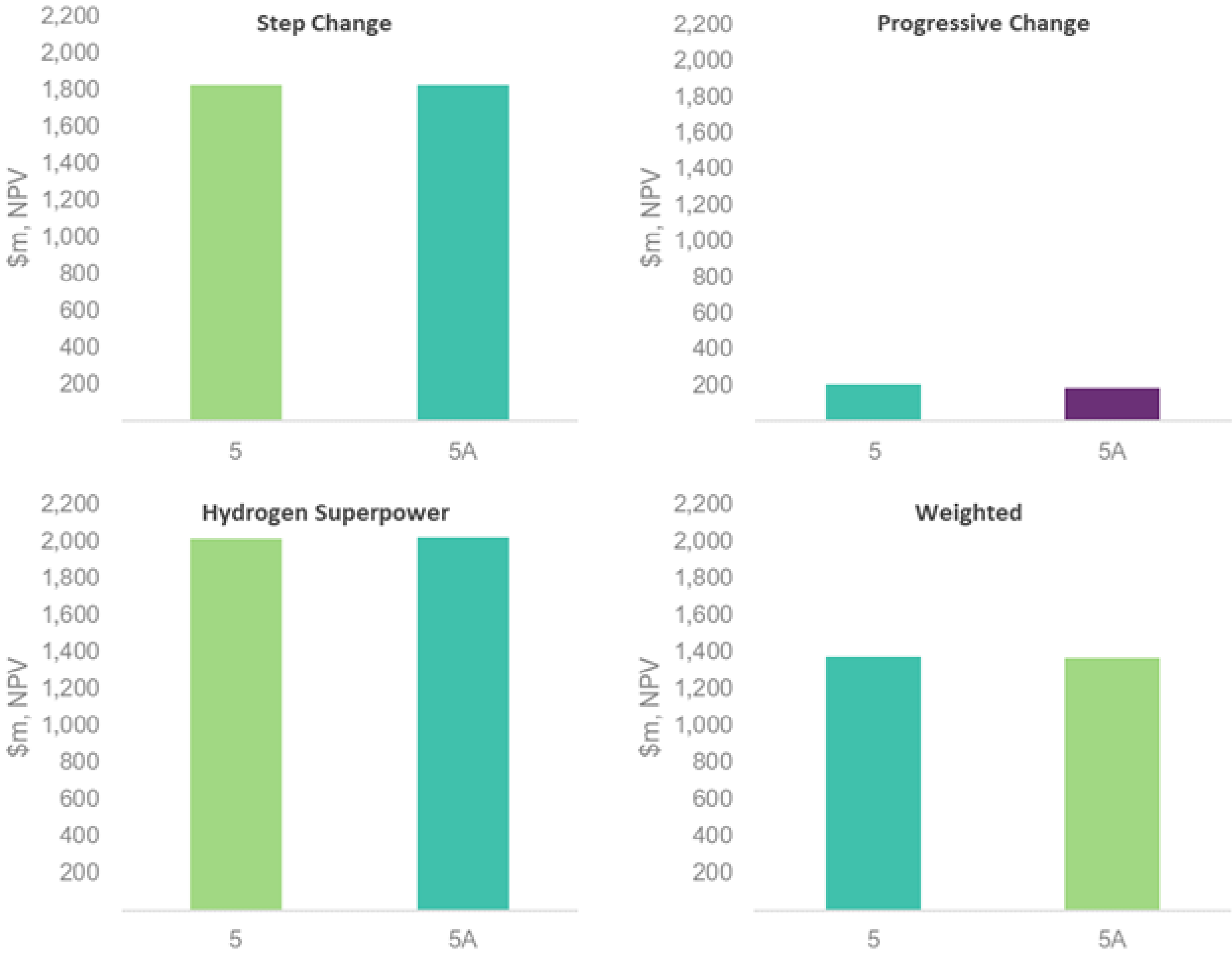


In the base case (Figure 12 top), VNI is expected to become increasingly importing as the limited onshore resources in Victoria become fully utilised, so that Victoria is expected to rely more on imports from other NEM regions (such as New South Wales) to meet growing demand. Figure 12 (bottom) shows the full range of how the upgraded interconnector is expected to be utilised, and congestion on the interconnector is expected to be relieved compared to the base case. As observed for the base case, the VNI (including VNI West) is expected to be heavily utilised throughout the planning horizon, importing more generation into Victoria in the later years of the study, for the same reasons as mentioned above for the base case, although is constrained on import far less.

6.2 Scenario-weighted results

On a scenario-weighted basis,[97] Option 5 and Option 5A are found to be ranked effectively equally. Option 5 is expected to deliver net benefits of approximately $1,374 million, while Option 5A is found to have net benefits of approximately $1,371 million (0.2% less than Option 5). Figure 13 presents the estimated net benefits for each option on a scenario-weighted basis, as well as under each scenario modelled.

Figure 13 Summary of estimated net benefits on a scenario weighted basis



Note: the **dark green** bar in each figure above indicates the option that has the highest estimated net benefits for that scenario, while the **light green** bars indicate the option is found to have net benefits that are within 5% of the top-ranked option, otherwise the option is shown in **purple**.

[97] The actionable ISP framework requires RIT-T assessments to use ISP parameters, including the scenarios and their weights. AEMO specified in the 2022 ISP that the *Step Change* scenario should be given a 52% weight, the *Progressive Change* scenario should be given a 30% weight and the *Hydrogen Superpower* scenario should be given an 18% weight in the RIT-T assessment.

Figure 13 shows that the two options are effectively equally ranked from a net market benefits perspective under the *Step Change* and *Hydrogen Superpower* scenarios. As Option 5 harnesses less renewable generation, it performs slightly better in the *Progressive Change* scenario (where the transition to net zero emissions is slightly slower), whereas Option 5A performs slightly better in the *Hydrogen Superpower* scenario (where the transition occurs rapidly). Please refer to Appendix A9 for a discussion of the results under the *Progressive Change* and *Hydrogen Superpower* scenarios.

6.3 Payback period

Table 11 below shows the year that the cumulative benefits in present value terms of the two options are expected to exceed the *full costs* in present value terms (without subtracting the terminal value). This demonstrates that payback is reached before the end of the assessment period for all scenarios, as well as on a weighted basis, except for in the *Progressive Change* scenario; that is, the costs (including operating and maintenance (opex) to the dates below) are expected to have been fully paid back before the end of the assessment period. This reduces the relevance of any benefits beyond the end of the assessment period, since the investment has already delivered more benefits than it has cost well before then.

Table 11 Payback periods for Option 5 and Option 5A (including opex until the payback year)

Scenario	Option 5	Option 5A
Step Change	2045	2046
Progressive Change	>2050	>2050
Hydrogen Superpower	2041	2042
Weighted	2046	2047

Moreover, if the full opex over the life of the investments is included (that is, not just the annual opex until the payback year), the same conclusions hold but with one year longer payback periods for Option 5 across all scenarios and for Option 5A in the *Hydrogen Superpower* scenario. This is shown in Table 12 below.

Table 12 Payback periods for Option 5 and Option 5A (including lifetime opex)

Scenario	Option 5	Option 5A
Step Change	2046	2046
Progressive Change	>2050	>2050
Hydrogen Superpower	2042	2043
Weighted	2047	2047

AVP and Transgrid acknowledge that future benefit streams beyond the end of the assessment period are necessarily highly uncertain (especially avoided fuel costs, given the energy transition occurring). However, some benefit categories will endure beyond the end of the assessment period, including for avoided investment costs, as these relate to the avoided annual costs from the time the investment is avoided over the period of that asset's life. An indicative assessment undertaken as part of preparing the Additional Consultation Report suggests that these benefits are expected to be significant beyond the end of the assessment period.

6.4 Sensitivity analysis

In addition to the scenario analysis above, AVP and Transgrid have considered the robustness of the outcome of the cost benefit analysis through undertaking a number of sensitivity tests. These tests all relate to the weighted net benefits, unless stated otherwise.

The range of factors tested as part of the sensitivity analysis in this report were:

- Interaction with the Victorian Government's offshore wind policy, should it become a 'committed policy' that satisfies the criteria set out in the NER.
- A variant of Option 5A that runs further west of Kerang.
- Effect of removing the series compensation on the Kerang to Bulgana line section.
- Changes in the capital costs and operating costs of the credible options.
- Alternative commercial discount rate assumptions.

These sensitivity tests are discussed in the sections below.

6.4.1 Interaction with the Victorian Government's offshore wind policy

The Victorian Government's Offshore Wind Policy does not currently meet the criteria under the NER necessary to be treated as a 'committed policy' and is therefore not included in the core scenarios for this cost benefit analysis. However, in light of increased government support for Victorian offshore wind, including Rewiring the Nation funding and the Victorian Government's offshore wind targets set out in its Offshore Wind Policy Directions Paper[98], as well as the various points raised in submissions to the PADR regarding these developments, AVP and Transgrid have investigated a sensitivity that assumes significant Victorian offshore wind development going forward.

Specifically, this sensitivity assumed 9 GW of offshore wind in Victoria by 2040-41, increasing linearly from 2028-29, in both the base case and VNI West options, commensurate with levels of development anticipated if the Victorian Government's offshore wind policy is legislated.

Figure 14 presents the net benefits of Option 5 and Option 5A under the *Step Change* scenario with the Victorian Government's offshore wind policy assumed to be a committed policy, compared to the net benefits under the core *Step Change* scenario results (discussed in Section 6.1).

Both Option 5 and Option 5A are forecast to continue to deliver significantly positive net benefits under this sensitivity with offshore wind targets imposed, although the net benefits are smaller than the core results. There remains value in harnessing wind and solar in Western Victoria REZ (V3) and Murray River REZ (V2) to provide renewable resource diversity, and the increase in interconnector transfer capability provides greater opportunities for offshore wind generation to export into the northern regions.

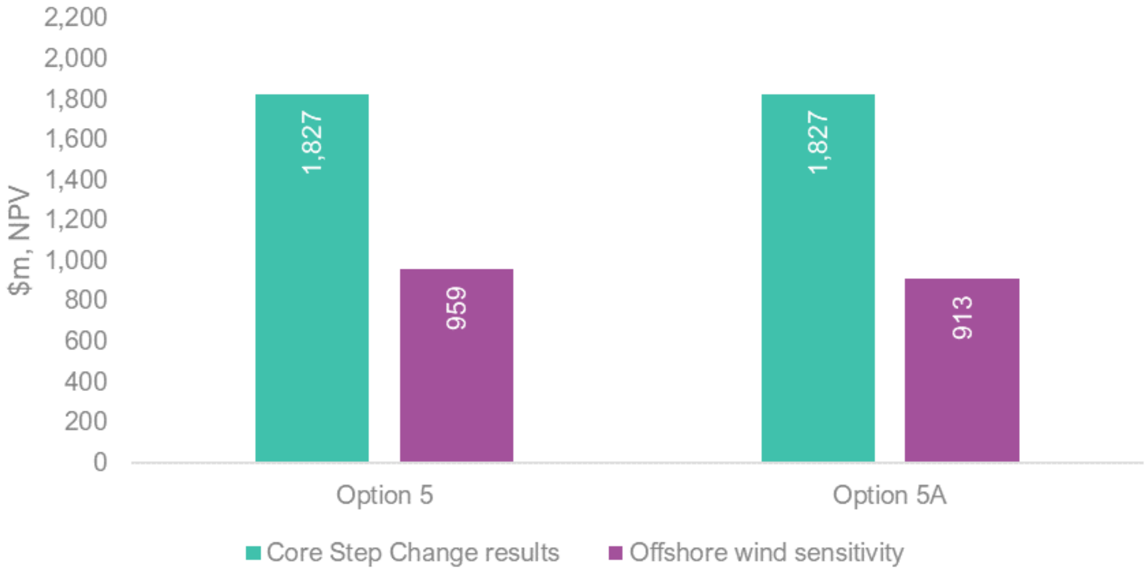
Forecast capital expenditure (capex) and FOM cost savings, fuel cost savings and REZ expansion savings are all reduced for both options in this sensitivity compared to the core results where offshore wind is not forced in. The reduction in benefits in the offshore wind sensitivity can be attributed to more closely aligned Victorian capacity outlooks in the base and with VNI West cases. This reduces the opportunity for VNI West to produce savings by altering investment and dispatch in Victoria.

[98] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.

In particular:

- Developing offshore wind capacity at scale in Victoria reduces the amount of additional new wind, solar and storage investment that is needed in the NEM in the base case.
- With less additional new capacity installed in the base case, there are fewer opportunities for VNI West to enable capital to be more efficiently allocated and shared across the NEM.
- Including offshore wind is forecast to result in less gas use in the base case, which results in less opportunity for fuel cost savings with VNI West in place.

Figure 14 Estimated net benefits of Option 5 and Option 5A in the *Step Change* scenario with the Victorian Government's offshore wind policy



6.4.2 A variant of Option 5A that runs further west of Kerang

AVP and Transgrid investigated a sensitivity to test the robustness of the analysis should a more westerly route around Kerang be required for Option 5A. The analysis found that a more westerly route around Kerang with connection into the 220 kV lines between Kerang and Wemen delivers up to $109 million lower estimated net benefits than Option 5A under the *Step Change* scenario, as shown in Figure 15 below.

The main driver of this reduction in net market benefit is the lower REZ transmission capability in the Murray River REZ (V2) – 1,460 MW compared to 1,580 MW for Option 5A.

Figure 15 Estimated net benefits of Option 5A and Option 5A (western sensitivity) in the *Step Change* scenario

6.4.3 Removing the assumed series compensation on the Kerang to Bulgana line section

AVP and Transgrid investigated a sensitivity to test the robustness of the analysis should the series compensation on the Kerang to Bulgana line section be removed from scope prior to implementation.

The analysis found that the estimated net market benefits of Option 5 are expected to reduce by approximately $98 million (but still be significantly positive) under the *Step Change* scenario if series compensation is found to not be technically feasible following ongoing detailed studies, as shown in Figure 16 below.

Figure 16 Estimated net benefits of Option 5 with and without series compensation assumed in the *Step Change* scenario

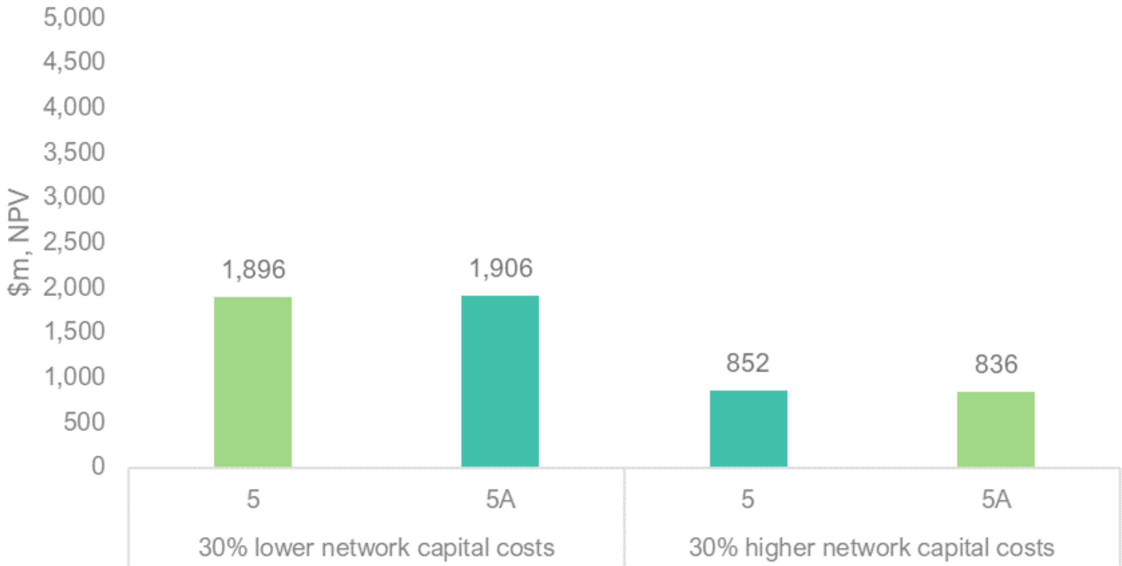
While this sensitivity has been investigated on Option 5, it is assumed that the same relative change to net benefits and interconnector transfer and REZ limits can be extended to Option 5A (so the same conclusion is expected to hold).

6.4.4 Changes in the network capital costs and opex costs of the credible options

The capital cost estimates are considered to be at an accuracy of ±30%, which AVP and Transgrid consider to be 'Class 4' estimates[99] (see Section 3.3.1). AVP and Transgrid consider the cost estimates used in the PACR to be at a higher level of accuracy than estimates developed using the AEMO Transmission Cost Database's cost estimating tool, since they reflect additional detailed costing undertaken by AVP and Transgrid in the context of this project.

Figure 17 shows the results under both 30% lower and 30% higher assumed network capital costs. Higher assumed capital costs favour Option 5, while lower costs favour Option 5A.

Figure 17 Estimated weighted net benefits with 30% lower and higher network capital costs



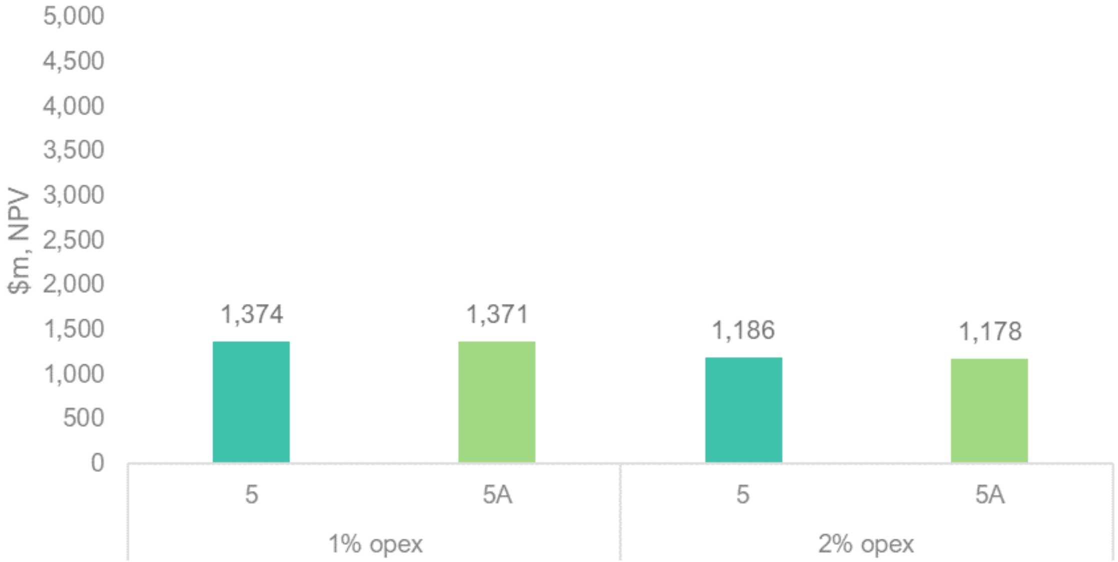
Extending these sensitivity tests to investigate key boundary values finds that the central estimates of network capital costs would need to increase by around 77% for Option 5A to have negative net benefits, or 79% for Option 5 to have negative net benefits. This is considered unlikely given the cost estimates have been estimated at a +/-30% level of accuracy at this stage.

Each of the above capital cost sensitivities also implicitly varies the assumed level of annual opex (since it is assumed to be 1% of the underlying capital costs). AVP and Transgrid consider that opex of 1% of the underlying capital costs is reflective of the actual costs that would be incurred in maintaining 500 kV transmission lines and towers.

However, a standalone sensitivity has also been investigated that assumes annual opex at 2% of capital costs in response to a concern raised in a PADR submission and reiterated in submission to the Additional Consultation Report. This sensitivity has been undertaken on the core scenario-weighted results (those presented in Section 6.2) and does not change the key conclusions of the analysis. Option 5 and Option 5A remain jointly top-ranked and are expected to deliver positive net benefits (on a weighted basis), as shown in Figure 18 below.

[99] AEMO, 2021 *Transmission Cost Report,* August 2021, p. 12.

Figure 18 Estimated weighted net benefits with opex assumed at 2% of capex



6.4.5 Alternative commercial discount rate assumptions (in calculating the costs)

The robustness of the calculated net benefits to variations in discount rates has been tested using:

- A lower bound discount rate of 2.30% (equal to the latest AER Final Decision for a TNSP's regulatory proposal at the time of preparing this report[100]).
- An upper bound discount rate of 7.50% (consistent with the upper bound in the latest final IASR).

Figure 19 below shows the results under both these assumed discount rates. A higher assumed discount rate slightly favours Option 5, while a lower assumed discount rate slightly favours Option 5A. Note that only the discount rate used to determine the NPV was changed in this sensitivity. Market modelling and the outcomes from it remain based on a discount rate of 5.5%.

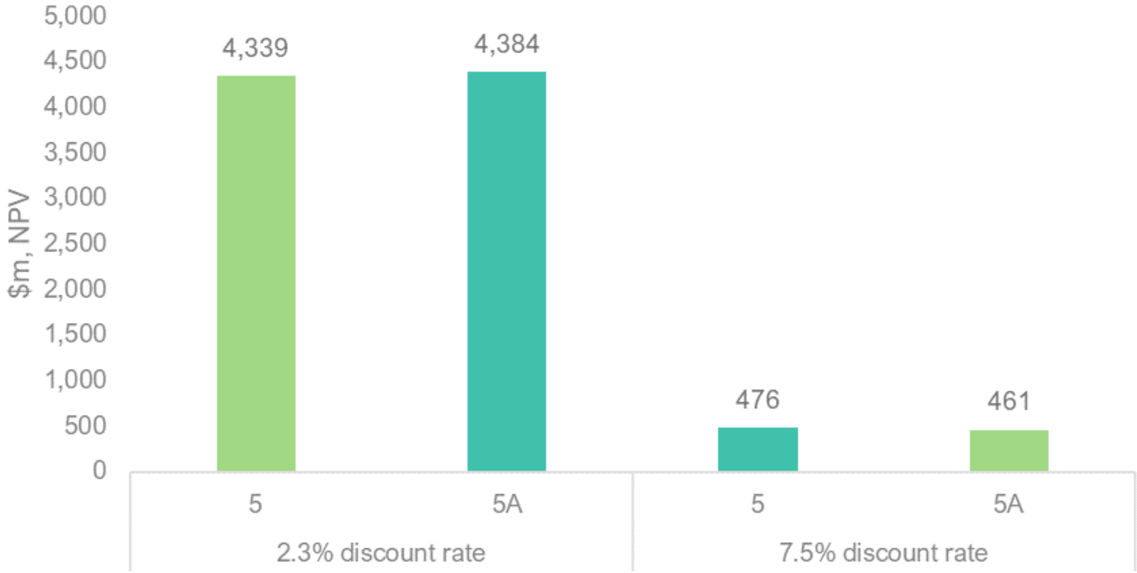
Extending these sensitivity tests to investigate key boundary values finds that the discount rate would need to be greater than 9.2% for Option 5A to have negative net benefits, or 9.3% for Option 5 to have negative net benefits (however, AVP and Transgrid consider discount rates this high unlikely at this current point in time and note that they are greater than both the 2022 ISP central rate of 5.50% and the Draft 2023 IASR central rate of 7%, as well as the draft 2023 IASR upper bound of 9%).

AVP and Transgrid acknowledge that since the assumptions for the 2022 ISP were developed, discount rates have increased as a result of strong inflationary pressures with an associated sharp increase in the risk-free rate (government long-term bond yields) and a higher debt premium. To reflect these changing market dynamics, AEMO in its Draft 2023 IASR has revised the central discount rate estimate to 7%, with an upper bound of 9% and a lower bound of 4%[101].

[100] This is equal to weighted average cost of capital (WACC) (pre-tax, real) in the latest final decision for a transmission business in the NEM as of the date of this analysis. See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powerlink-determination-2022%E2%80%9327/final-decision.

[101] AEMO, *Draft 2023 Inputs, Assumptions and Scenarios Report,* December 2022, p. 110.

Figure 19 Estimated weighted net benefits with lower and higher assumed discount rates



For this RIT-T, AVP and Transgrid must adopt the 2022 ISP Parameters unless there is a demonstrable reason why an addition, omission or variation to the ISP parameters is necessary. The AER CBA Guidelines require that 'demonstrable reasons' for departing from ISP parameters be limited to where there has been a material change that AEMO would, but is yet to, reflect in a subsequent IASR, ISP or ISP update.

While is it clear that AEMO intends to incorporate higher discount rates in the next ISP, AVP and Transgrid do not consider that this would materially change the outcomes of this RIT-T, because the sensitivity analysis above indicates that both options would continue to yield positive net benefits even if the discount rate were to reach the upper bound of the rates proposed in the Draft 2023 IASR.

7 Multi-criteria assessment for NEVA Order

AVP, in conjunction with external consultants AECOM, developed an MCA Framework to further assess and rank the options consistent with the functions conferred by the February 2023 NEVA Order.

The MCA methodology (for Victoria) considers environment, cultural heritage, land use and engineering aspects, in addition to net economic benefits, and enables ranking of the options according to their performance against each criterion. This approach has been developed to better incorporate a wider range of criteria and risks in decision-making to facilitate delivery of VNI West, having regard to the February 2023 NEVA Order.

The MCA has been updated as part of this PACR, to assess and compare Option 5A with Option 5. It shows that both options rank closely on all criteria assessed and perform better than all other options previously looked at in the Additional Consultation Report. Option 5A performs better than Option 5 environmentally. Option 5A scored slightly less favourably on cultural and social criteria, although critical field work is needed to validate this assessment.

New South Wales is not subject to any NEVA Order, and as such Transgrid will undertake MCA on the New South Wales side of the project as part of its ongoing early consultation and engagement to inform corridor refinement with communities and landowners.

AVP, in conjunction with external consultants AECOM, developed a high-level MCA methodology for Victoria to further assess the options and help determine which option is most likely to facilitate timely delivery, consistent with the functions conferred by the February 2023 NEVA Order[102]. The Additional Consultation Paper presented the detailed background to the MCA assessment, which is summarised below[103]. This high-level MCA is not a substitute for more detailed analysis that will be conducted shortly after concluding this RIT-T to inform corridor refinement in both states.

[102] See http://www.gazette.vic.gov.au/gazette/Gazettes2023/GG2023S267.

[103] See the Additional Consultation Paper for a full description of the MCA methodology adopted.

7.1 Methodology

The Victorian suitability analysis outlined and undertaken during the Additional Consultation Report process has been applied to Option 5A. The ratings for Option 5 remain the same as in the Additional Consultation Report, with only the net benefits score being updated to reflect the latest analysis.

The MCA methodology has been designed to focus on social and environmental impacts in Victoria, in addition to technical and cost-benefit considerations, recognising the importance of these factors in building social licence which in turn should assist to facilitate and expedite development, delivery, construction and energisation. The importance of building social licence has also been recently recognised by the Australian Energy Market Commission (AEMC)[104].

The overall aim of the MCA process is to have a well-designed, documented MCA which allows for the ranking of network options which otherwise provide effectively the same net benefits. The process included:

- Identification of constraints and opportunities – appropriate data and information was gathered from publicly available sources, private data, and stakeholder discussions, and reviewing lessons learnt from previous and current projects. This information was analysed and categorised in terms of constraint complexity and mapped, generating a suitability heat map.
- Identification of indicative alignments – this suitability map facilitated the inclusion of biophysical elements and socio-cultural conditions of the landscape in the identification of indicative 100-metre alignments for each option within a refined *broad geographical area* or 'area of interest'.
- Development and implementation of a project-specific framework – the framework included project-specific systematic steps (setting objectives, developing criteria, formulating measures and determining weightings and scoring approach).

The framework consisted of six objectives, containing a total of 18 criteria, with each option scored on each criteria using a rating from 1 (being most favourable) to 5 (being least favourable). Each criterion was then weighted, based on expert judgement and relevant experience preparing submissions for planning and environment approvals, and a weighted score was determined to rank the options. At a high level, these objectives can be summarised as follows:

- **Net economic benefits** – maximising the net benefits for consumers (consistent with the RIT-T framework and provided the highest weighting accordingly).
- **Environment** – avoiding or minimising impacts on the natural environment (rated based on the number of hectares of protected areas such as RAMSAR Wetlands and National Parks, area of native vegetation, area of critical habitat and the number of waterways intersected by each indicative alignment).
- **Cultural heritage** – avoiding and minimising impacts on Aboriginal and non-Aboriginal cultural heritage (rated based on the area of non-Aboriginal cultural heritage items or conservation areas and the area of potential Aboriginal cultural heritage sensitivity intersected by each indicative alignment).

[104] For example, as part of the 'Transmission Planning and Investment' review, the AEMC noted the importance of these factors in the delivery of transmission investments and considers that there is an opportunity for the AER to provide guidance on how they can be assessed (including potential studies and analysis that transmission network service providers (TNSPs) could undertake). See AEMC, *Transmission Planning and Investment – Stage 2*, Final Report, 27 October 2022, pp. 29-30.

- **Social** – avoiding and minimising impacts on local communities (rated based on the area of residential zone land and significant landscape overlay area intersected by each indicative alignment and the number of buildings within 300 metres of the centre-line of each indicative alignment).
- **Land use** – avoiding or minimising impacts on existing and future land use, such as agriculture and forestry (rated based on the number of land parcels bisected where the smaller portion is greater than 20% of the total parcel size, area of high agricultural potential land, area of forestry tenure land and resource tenure land intersected by each indicative alignment).
- **Engineering** – minimising engineering complexities during construction and operation as well as impacts on existing infrastructure (rated based on consideration of the topography, area of land subject to inundation or area within a bushfire overlay, and the number of existing infrastructure crossings intersected by each indicative alignment).

It is acknowledged that only the high-level 'areas of cultural sensitivity' dataset was included in the MCA, and further understanding of the Aboriginal cultural heritage and cultural values within the area of interest is required through consultation with Traditional Owners and appointment of a cultural heritage practitioner. AVP and Transgrid recognise that, when determining the connections between people and place in a holistic way, it is vital to combine ethnohistorical research with On Country visits, in an effort to collaboratively identify and understand the tangible and intangible Aboriginal cultural values of the land on which the project is proposed to take place. AVP and Transgrid recognise the importance of continuing to develop an understanding of the potential impact of the project on both tangible and intangible cultural heritage during route refinement. This will be done via additional research and ongoing consultation with Traditional Owners of the land on which the project is proposed to take place, as well as undertaking a formal Cultural Heritage Management Plan (CHMP) process with each impacted Traditional Owner group.

It is similarly acknowledged that the land use assessment has been based on a study revised in 2000, which predicted inherent production potential based on identifying and assessing characteristics of the land that are likely to be limited to agricultural or horticultural production. The assessment is qualitative and provides a ranking of production potential. Given that this prediction is of the inherent potential for plant biomass production, the impact of land management practices that improve production such as fertilisers, lime, gypsum or irrigation is not included. It is therefore indicative only, and no substitute for field work and in-depth discussions with landholders and communities in the next phase of the project.

7.2 MCA outcomes in the Additional Consultation Report

Based on the MCA and weighted scoring, Option 5 was found to be the highest ranked option in the Additional Consultation Report due to the specific strengths of the option across all objectives; that is, estimated net economic benefits, environment, cultural, land-use and social objectives. It was found to rank first, or equal first, across all six objectives considered. It did have some engineering complexity to be worked through, but these technical challenges were considered manageable.

There was no further information received during the Additional Consultation Report process that was foreseen to have the ability to fundamentally change the scoring, to an extent where the other options would perform better than Option 5. Therefore, the other options have not been taken forward into the revised MCA.

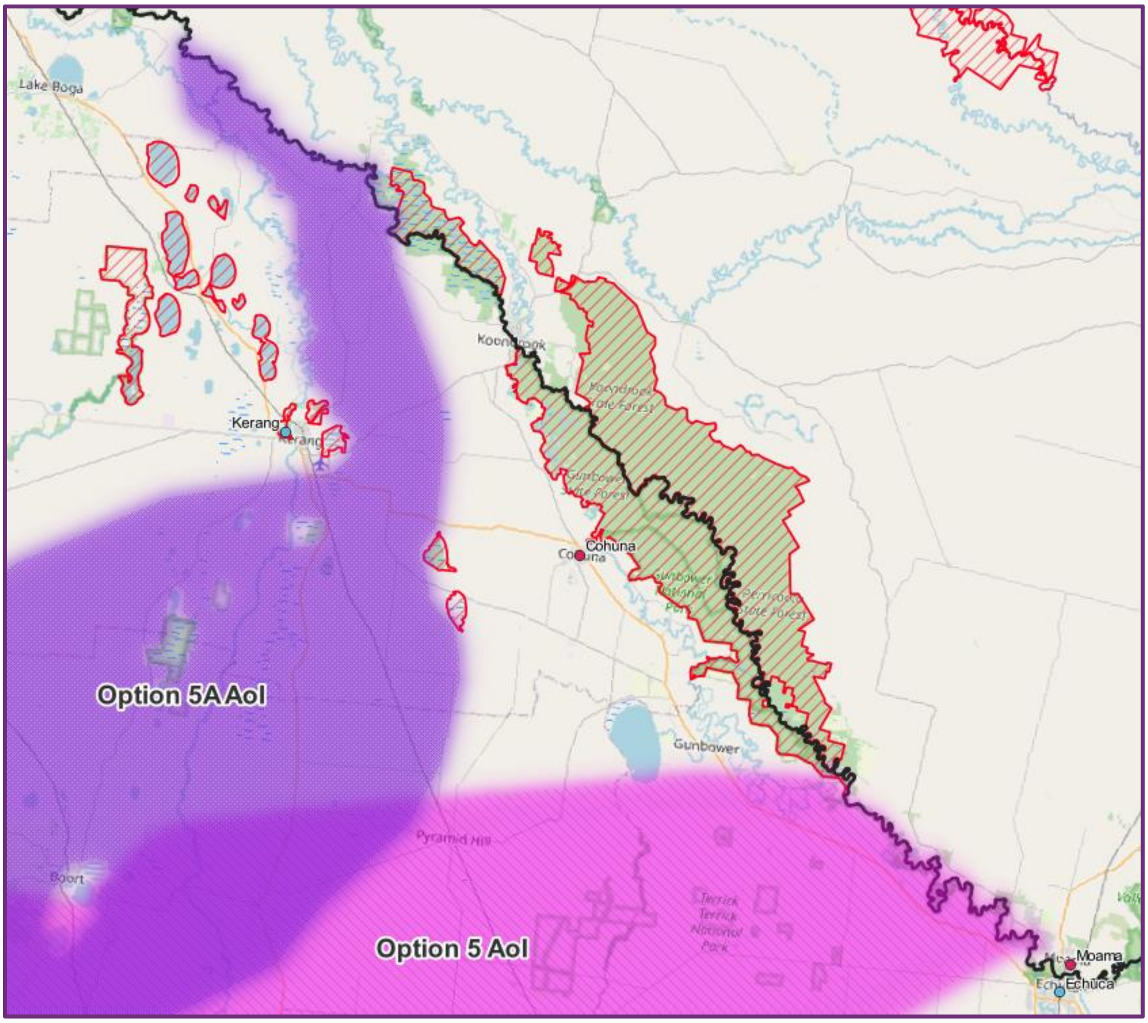
Section 4 of the Additional Consultation Report provides additional detail on the MCA methodology and outcomes.

7.3 Consideration of Additional Consultation Report submissions

As already discussed, a key concern raised in stakeholder feedback on the Additional Consultation Report was the proposed Victoria/New South Wales border crossing area of interest. Factors including potential impacts on the critically endangered Plains-wanderer bird species, culturally sensitive areas of national significance (such as Ghow Swamp), ecotourism and recreation activities, agriculture, and community impacts were raised as concerns which could impede timely delivery.

This has resulted in the development of an Option 5A (north of Kerang) which investigated an alternative border crossing area north of Kerang, west of the known RAMSAR wetlands on both sides of the border (see Figure 20). The investigation of this option was made possible due to further studies undertaken by Transgrid determining a potential to go to Dinawan from this alternative crossing area.

Figure 20 Alternative crossing area north of Kerang in relation to RAMSAR Wetlands (red hashed)



7.4 MCA results for options considered in this PACR

The MCA has been updated as part of this PACR to reflect the latest NPV results for Option 5 and 5A (see Table 13).

Table 13 Revised results of the VNI West MCA for the credible options assessed in this PACR

MCA Analysis Results			
Options		**Option 5** to Bulgana (Echuca crossing)	**Option 5A** to Bulgana (north Kerang crossing)
MCA Objective	**Weighting (%)**	WEIGHTED SCORING	
Benefits (net)	70%	1.41	1.41
Environmental	5%	0.08	0.06
Cultural	5%	0.10	0.12
Social	10%	0.21	0.26
Land use	5%	0.06	0.06
Engineering	5%	0.16	0.16
Total	*100%*		
Weighted Score (max is 5)		**2.01**	**2.06**
Rank		**1**	**2**

Note: the criteria measures were given a score of 1 to 5, in line with their associated rating system, where the lower the score the more preferred or higher ranked that measure would be. Therefore, once the scores for all criteria are combined, the more favourable option will have a lower total score.

The results indicate that both options rank closely on all criteria assessed, and as such, perform better than all other options previously looked at in the Additional Consultation Report.

Option 5A is expected to harness the most renewable generation and therefore ranks the same as Option 5 on net benefits criteria, despite the slightly longer line length and associated cost.

Option 5A also performs better than Option 5 environmentally, consistent with feedback received in submissions, with the least area of native vegetation, including highly ecologically significant communities (Environmental Protection and Biodiversity Conservation (EPBC) listed threatened Ecological Communities and state endangered Ecological Vegetation Classes), being intersected.

Additional stakeholder feedback received during consultation indicates that Option 5 would also have more of an impact on ecotourism and the critically endangered Plains-wanderer (and its associated habitat) in the Echuca and Terrick Terrick regions.

Option 5A scored slightly less favourably in terms of cultural (higher area of potential cultural sensitivity intersected), although it does avoid passing by Ghow Swamp, a place of national cultural significance, and social (larger number of buildings within 300 metres and number of land parcels intersected), although critical field work is needed to validate this assessment. The social rating was the key driver of the slightly poorer weighted score.

The differences in scoring between Option 5 and Option 5A are not considered material given the lack of granularity in the MCA undertaken at this early stage. Relying on desktop analysis to differentiate between areas of interest in relatively close proximity can be challenging without the benefit of field surveys and further community engagement. The feedback from stakeholders therefore supplements this assessment when having regard for the NEVA Orders.

The results of the MCA, as well as the additional consultation undertaken since the PADR and consultation with VicGrid, has informed the AVP recommendation to the Victorian Minister for Energy and Resources on 3 May 2023 regarding Option 5A being preferred, prior to this PACR being published. This recommendation culminated in the May 2023 NEVA Order.

7.5 Community sentiment

Several submissions indicated a greater level of social license could be achieved if VNI West considered an alternative river crossing north of Kerang, rather than the crossing proposed for Option 5 in the Additional Consultation Report (between Gunbower and Echuca). Murray River Group of Councils and its member councils noted in submissions that the proposed crossing point between Gunbower and Echuca was inappropriate due to social, cultural and environmental constraints which were not adequately addressed in the MCA.

Murray River Group of Councils noted they have been working to develop social license for renewable generation projects since 2017, including working to develop a community understanding that transmission projects would be required to unlock renewable generation projects in the Murray River REZ.

> *'Since the inception of VNI-West, the Kerang route (originally option VNI-7) had been indicated, and understood by Council, proponents, and communities, as running from north of Ballarat, via the west of Bendigo (to a new terminal station) and then northwards to a new terminal station near Kerang and on to cross the river north of Kerang.*
>
> *This route broadly follows the existing transmission line easement and was, in our view, broadly understood by the community. There was a level of social licence for this due to the understanding that it would unlock needed transmission capacity in the system allowing for increased investment in renewable energy generation in the region.' – Murray River Group of Councils Submission*

AVP and Transgrid greatly appreciate feedback provided by Murray River Group of Councils and its member councils and have reconsidered the river crossing point to avoid the Gunbower to Echuca area and instead investigated a river crossing north of Kerang. AVP and Transgrid look forward to working closely with Murray River Group of Councils members to develop social license in the area to generate support for the preferred option 5A.

8 Benefits from VNI West preferred option and interaction with other major projects

The driver for the credible options considered over the course of this RIT-T is to help facilitate the reliable and secure transition away from coal-fired generation to renewable generation while keeping costs to consumers as low as possible.

The NEVA Order made in February 2023 introduced an additional driver, which was to accelerate VNI West delivery to the extent possible to provide strategic protection against the risk of early coal retirement or unplanned outages and to mitigate against gas supply scarcity.

Based on the net market benefits and MCA assessment presented in this PACR, Option 5A is the preferred option that is considered most likely to maximise benefits to consumers while also facilitating the delivery of the augmentation and meeting the crucial electricity system needs of Victoria as required under the NEVA Order assessment criteria.

This preferred option delivers approximately $1.4 billion in expected net market benefits to consumers and producers of electricity and supports the energy market transition through:

- Efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in ageing generator reliability – including mitigation of the risk that existing plants close earlier than expected.
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales through improved network capacity and access to demand centres.
- Enabling more efficient resource sharing between NEM regions.

These sources of market benefit were included as the 'identified need' for VNI West in the 2022 ISP[105]. The modelling of market benefits reflects all government policies regarding renewables consistently with the 2022 ISP and all estimated benefits are *in addition* to those expected from other major projects in the NEM (such as WRL, EnergyConnect, HumeLink and Snowy 2.0).

8.1 Benefits from expanding interconnection between regions and harnessing more renewable generation

The modelling in this PACR (and in the earlier Additional Consultation Report) shows that, in the absence of investment under this RIT-T, significant alternative additional investment by market participants would be needed

[105] AEMO, 2022 ISP, June 2022, p. 74.

over the modelling outlook period to continue to meet demand, as existing dispatchable generation (and, in particular, brown coal generation) in Victoria retires. Although wholesale prices have not been assessed, the wholesale cost increases resulting from this additional investment by market participants alone would exceed the cost of VNI West. It also shows that the proposed investment facilitates the development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales and, overall, enables more efficient resource sharing between NEM regions.

The preferred option unlocks significant transmission transfer capacity for the Murray River REZ (V2) and Western Victoria REZ (V3) and the wholesale market modelling forecasts that these REZs, in addition to the South-West New South Wales REZ (N5), have considerably more renewable capacity built, compared to the 'do nothing' base case, in all three scenarios modelled. Specifically, by 2050, with the preferred option in place:

- The Murray River REZ is projected to build substantially higher solar capacity (between 2.3 GW and 2.9 GW in total across the three scenarios).
- The Western Victoria REZ is projected to build a greater quantity of wind capacity (between 1.1 GW and 1.3 GW in total across the three scenarios).
- The South-West New South Wales (SWNSW) REZ is projected to build more solar and wind capacity, particularly under the *Step Change* and *Progressive Change* scenarios.

The additional renewable capacity build in the REZs mentioned above, compared to the base case, is higher than the increase in REZ transmission limits facilitated by VNI West (shown in Section 3.2). This is because not all the generation will be operating at full capacity all of the time, and the modelling strikes a balance between generation curtailment and efficient utilisation of REZ transmission capacity. In addition, existing renewable retirements in the REZs unlocks more transmission capacity for the relevant REZs.

In addition, the wholesale market modelling found that the output from existing generators in both the Murray River and Western Victoria REZs is greater with VNI West on account of the transmission transfer capacity unlocked for these REZs. This means consumers can get access to more renewable generation that would otherwise be "spilled".

Overall, the preferred option, as assessed by AVP and Transgrid, is found to support the development of additional renewable generation in the Western Victoria, Murray River and Southern New South Wales REZs, as the NEM transitions to low-emission generation technologies. Opening up additional transmission capacity in areas of the NEM for renewable generation investment facilitates access to high quality renewable resources. When combined with stronger interconnection between regions with diverse load profiles, the amount of wind and solar investment to achieve the same levels of renewable energy output decreases.

In the context of the RIT-T assessment, the preferred option is expected to primarily deliver the following classes of market benefit[106]:

- Reduced generation and storage investment costs, resulting from more efficient investment (74% of the gross market benefits in *Step Change* scenario).
- Reductions in total dispatch costs, by enabling lower cost renewable generation to displace higher cost fossil fuel generation (14% of the gross market benefits in *Step Change* scenario).

[106] While the RIT-T prescribes 10 different classes of market benefit that must be considered in a RIT-T assessment, AVP and Transgrid find that VNI West is expected to primarily deliver these three classes of market benefit. Additional detail on each class of market benefit can be found in the AER's CBA Guidelines.

- Avoided/lower intra-regional transmission investment associated with the development of REZs (8% of the gross market benefits in *Step Change* scenario).

Section 5.1 discusses each of the specific classes of market benefit under the RIT-T that have been estimated as part of the PACR assessment. Section 6.1 discusses in more detail the additional development and dispatch of renewable generation facilitated under the *Step Change* scenario, as well as what it displaces/defers compared to the 'do nothing' base case.

8.2 Minor benefits accrue ahead of commissioning

As outlined in Section 2.9.1 of the February 2023 report summarising PADR submissions, the wholesale market modelling assumes perfect foresight (consistent with the ISP), which means that parties may make changes to their investment and operating decisions in anticipation of VNI West being commissioned, including deferring investment in renewable generation and storage. In the modelling, the observed impacts prior to commissioning represented wholesale market entities (current and prospective generators and storage) changing their investment and operational decisions in anticipation of the new interconnector being commissioned.

However, AVP and Transgrid note that the model outcomes show that only minor market benefits accrue prior to commissioning of the main VNI West transmission lines spanning the Victoria – New South Wales border. Although the headline commissioning date for VNI West is 1 July 2031 in the *Step Change* scenario, there are several differences in input assumptions between the VNI West options and scenario base cases that occur earlier than this date. For example, all options consider an upgrade to the WRL from 1 July 2027, which helps relieve the existing generation congestion in the area as well as further unlocking capacity for new renewable investment in this REZ. In addition, the VNI West options include the EnergyConnect enhanced investment from 1 July 2026 which impacts the transfer limit of the SWNSW to Wagga area and also the transmission capacity of SWNSW REZ (N5).

8.3 The assessment considers all costs of generation and storage as well as transmission

The approach used in the modelling includes all the relevant costs for both the option cases and the base case. Each case has its own cost to supply demand while maintaining constraints such as emissions reduction and renewable energy targets. This includes costs of operating new and existing capacity and the capital and operating cost of new investments (generation, storage and REZ transmission). The difference between the costs of the base case and an option case (excluding the direct cost of the option itself) is the gross market benefits of that option and, after considering the direct cost of the option, the net benefits are calculated.

This approach is consistent with the CBA Guidelines and ensures that the analysis takes account of all capital and operating costs for new and existing generation and storage, as well as transmission, under both the base case and option cases.

8.4 Interaction with the Western Renewables Link

WRL is a proposed 190 km overhead high-voltage electricity transmission line that will carry renewable energy from Bulgana in western Victoria to Sydenham in Melbourne's north-west. The project is critical infrastructure required to unlock the renewable energy potential of western Victoria as a key REZ and will help deliver clean and affordable energy to Victorians.

The WRL project has completed the RIT-T process and has progressed through the contestable appointment of AusNet Services in December 2019 as the developer of the new infrastructure. AusNet Services will build, own, operate and maintain the new infrastructure[107]. AusNet Services is currently preparing the Environment Effects Statement.

The 2022 ISP considers the WRL as an 'anticipated' project (with a delivery date of July 2026) and includes it in its optimal development path[108]. The WRL (in its current scope) has therefore been assumed in both the base case and all option cases as part of this RIT-T, consistent with the actionable ISP framework and the AER's CBA Guidelines[109]. Changes to WRL scope, as required for both Option 5 and Option 5A, are only applied in the options cases.

In light of submissions to the PADR, a sensitivity analysis was undertaken as part of the Additional Consultation Report which addressed concerns raised that the net market benefits of WRL and VNI West combined have not been adequately assessed. Specifically, it constructed an alternative base case for this sensitivity that excluded not only the VNI West investment but also the WRL project. That is, the base case for this sensitivity considers a state of the world where neither VNI West nor WRL go ahead, while the option cases assume that both go ahead. This sensitivity found that VNI West and WRL combined are expected to deliver substantial net market benefits (in the order of $1.9 billion for Option 3A and Option 5 assessed at the time), compared to a base case where neither go ahead.

A key principle underlying the RIT-T and the modelling undertaken is to identify the *incremental* benefits (and costs) arising from each option relative to the base case. As outlined above, WRL is assumed in both the base case and the VNI West cases, so the modelling only calculates the *incremental* benefits (and costs) for VNI West *over and above* those accruing from WRL. As a result, there is no double-counting of benefits across WRL and VNI West. Nonetheless, the cost benefit analysis of the two projects combined, undertaken as a sensitivity in the Additional Consultation Report, was intended to allay concerns stakeholders may have that benefits have been double-counted.

The incremental cost impact due to modification of WRL has been included as a direct cost attributable to both Option 5 and Option 5A. Specifically, the options involve relocating the WRL terminal station from north of Ballarat to Bulgana and uprating portions of the transmission line from 220 kV to 500 kV, and the incremental cost of this has been reflected in the assessment of the two options.

[107] See https://www.westernrenewableslink.com.au/about/.

[108] AEMO, 2022 ISP, June 2022, p. 66.

[109] AER, *Cost Benefit Analysis Guidelines*, August 2020, pp. 62-63.

8.5 Interaction with other major projects in the NEM

EnergyConnect and HumeLink are assumed to be commissioned between three and 12 years before the main components of VNI West across the scenarios investigated. Delays to these projects would likely still result in their commissioning prior to VNI West. The impact of any delays to these two projects on the benefits of VNI West is considered to be minimal. EnergyConnect and HumeLink are expected to be commissioned significantly ahead of VNI West, so any realistic delays are not expected to result in them being commissioned after VNI West.

Avoided/deferred capital investment is the major source of market benefits for VNI West. Investors would already have reflected the expectation of investments in EnergyConnect and HumeLink into their plans based on the currently expected commissioning dates, and would be unlikely to alter their investment decisions in light of any delay. In other words, the avoided/deferred investment benefits associated with VNI West would not be materially affected by any delay in either EnergyConnect or HumeLink.

Fuel cost savings are only forecast to accrue after commissioning of VNI West, so delays to EnergyConnect or HumeLink are not expected to materially affect this source of benefits either. AVP and Transgrid have therefore not included a sensitivity in relation to any such delay as part of the NPV analysis.

As noted above in Section 8.4 in relation to WRL, as well as in Section 5.2, the RIT-T modelling includes other major network projects that are included in the 2022 ISP optimal development path in both the counterfactual base case (without VNI West) and the option cases. This means that only the *incremental* costs and benefits of the VNI West options are captured in the modelling and there is no double-counting of the expected benefits between VNI West and other major projects in the NEM. None of the benefits of the other major network projects, relative to a base case where they are not assumed, have been captured as part of this RIT-T.

The assessment estimates the impact of the connection of EnergyConnect and VNI West at Dinawan on the expected benefits for VNI West (which was not estimated as part of the PADR). Specifically, the costs and benefits of this re-routing (and expanded capacity) for EnergyConnect have now explicitly been modelled as part of the assessment, in both the Additional Consultation Report and this PACR.

9 Conclusion

AVP and Transgrid have identified Option 5A (with a river crossing north of Kerang) as the preferred option for VNI West. It is estimated to deliver $1.4 billion in net market benefits in NPV terms to consumers over the assessment period and is most likely to facilitate and expedite delivery in the assessment required under the NEVA Order.

This option has been recommended for the following reasons:

- On a scenario weighted basis,[110] Option 5 and Option 5A are found to be ranked effectively equally as the two top ranked options. Option 5 is expected to deliver estimated net benefits of approximately $1,374 million, while Option 5A is estimated to have net benefits of approximately $1,371 million (0.2% less than Option 5).
- Option 5A continues to deliver significant forecast benefits to consumers under the sensitivity assessments undertaken, including the offshore wind sensitivity
- Option 5A crosses the river north of Kerang, which was independently identified as a preferred crossing point by councils wanting to attract investment into the area.
- Option 5A has the potential to harness more renewable generation in the Murray River REZ than Option 5, which provides greater opportunity for diversity of supply, and helps maintain social licence in Gannawarra.
- Option 5A presents fewer environmental constraints than Option 5 and avoids intercepting the Patho Plains – an area of significant grassland habitat known to support the endangered Plains-wanderer.
- Option 5A avoids passing near Ghow Swamp, a place of national cultural significance.
- Option 5A avoids the Bendigo to Ballarat corridor that many submitters to the PADR suggested is problematic.

This conclusion has been supported by the February 2023 NEVA Order that enabled a high-level MCA methodology to be developed and applied to assist with determining the preferred option on the Victorian side. In particular, in deciding on the preferred option, the MCA has enabled social, environmental and cultural considerations to be weighed up, in addition to technical and cost-benefit considerations, recognising the importance of these factors in building social licence which in turn should assist to facilitate and expedite development, delivery, construction and energisation.

In accordance with AVP findings on the options based on the February NEVA Order, the May 2023 NEVA Order specifies that the preferred option, to the extent it relates to the declared transmission system, must connect to WRL at Bulgana, via a new terminal station near Kerang, and cross the Murray River proximately north of Kerang (Wamba Wamba Country). Once this order is made, for an option to be credible under the RIT-T and this PACR, it must assume the Victorian configuration specified in the May 2023 NEVA Order.

On that basis, Option 5A is the preferred option for the Victorian and New South Wales components, as it is the only credible option where the New South Wales component is viable with that Victorian configuration required by the May 2023 NEVA Order.

[110] The actionable ISP framework requires RIT-T assessments to use ISP parameters, including the scenarios and their weights. AEMO specified in the 2022 ISP that the *Step Change* scenario should be given a 52% weight, the *Progressive Change* scenario should be given a 30% weight, and the *Hydrogen Superpower* scenario should be given an 18% weight in the RIT-T assessment.

In preparing the PACR, Option 5 was assessed as a credible option. However, following the May 2023 NEVA Order, Option 5 is no longer a credible option, because it is based on a different Victorian configuration to that required under the NEVA Order.

The estimated capital cost of Option 5A is approximately $3,499 million (June 2021 real dollars), which is comprised of $1,755 million in Victoria and $1,744 million in New South Wales.

Annual routine operating and maintenance costs are assumed to be 1% of capital costs for transmission assets, including early works, substation works, lines works and modular power flow controllers (but excluding land related costs and biodiversity offset costs, since these are one-off and do not require ongoing operating costs). Victorian land taxes for both the terminal station properties and transmission line easements have also been included as operating costs, as have payments to landholders in New South Wales and Victoria.

Technically, VNI West Option 5A comprises of the following augmentations:

- A new 500 kV double-circuit overhead line from Bulgana to near Kerang to locality of Dinawan, including series compensation on the line near Kerang.
- Construction of the Dinawan to near Wagga Wagga line as a double-circuit 500 kV line, rather than a double-circuit 330 kV line and later uprate from 330 kV to 500 kV operation (including new 500 kV bays and a transformer station near Wagga Wagga).
- Establish Dinawan 500 kV switchyard with two 500/330 kV 1,500 megavolt amperes (MVA) transformers.
- Establish new terminal station near Kerang with two 500/220 kV 1,000 MVA transformers.
- 220 kV connections from the new terminal station near Kerang to the existing 220 kV lines near Kerang.
- Modular power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang and 220 kV lines between Dederang and Thomastown following certain contingencies.
- 500 kV line shunt reactors at both ends of the three following 500 kV circuits: (i) Bulgana – near Kerang, (ii) near Kerang – Dinawan and (iii) Dinawan – near Wagga Wagga.
- Up to +/- 400 megavolt amperes reactive (MVAr) dynamic reactive compensation at the new 220 kV terminal station near Kerang.
- Relocation and modification of WRL terminal station from north of Ballarat to Bulgana. This includes a 500 kV switchyard with two 500/220 kV transformers at the existing Bulgana terminal station.
- Two new 500 kV bays and line exits with a total of two 500 kV line shunt reactors at the Bulgana Terminal Station have been included in the VNI West costs (with the remainder of the terminal station assumed part of the WRL scope).
- Construction of the WRL spur line to Bulgana as a double-circuit 500 kV line, rather than a double-circuit 220 kV line.
- Approximately 100 MVAr 500 kV switched bus connected reactor at Sydenham.

In addition, series compensation or additional power flow controllers would be installed along the Kerang to Bulgana section to reduce impedance on the new 500 kV network and thereby improve network load sharing with, and manage network loading on, the existing 330 kV Victoria – New South Wales Interconnector and the existing 220 kV western Victoria network between Bendigo and Kerang, in the absence of a new terminal station and connection near Bendigo. Work is ongoing to confirm the technical feasibility of this solution.

Early works have already commenced in both Victoria (by Transmission Company Victoria, a wholly owned subsidiary of AEMO) and in New South Wales (by Transgrid). Both Transmission Company Victoria and Transgrid are targeting first spring surveys in 2023 to assist in accelerating delivery as requested by both the state and federal governments. Spring surveys refer to the ecological surveys that are undertaken on land along the proposed transmission route to determine which plant and animal species may be impacted by the proposed transmission line. While some surveys will occur year-round, the majority are undertaken in spring as this is the most active season for most plants and animals, making them easier to identify. All early works are expected to be complete by early 2026.

Option 5A is considered viable in terms of effective connection to New South Wales, however detailed MCA will be undertaken prior to further route refinement in New South Wales and further detailed MCA for Victoria. In Victoria, route refinement may include further consideration of the Option 5A westerly sensitivity if environmental or cultural constraints emerge in the current area of interest near Kerang. However, this westerly route is not currently being progressed, as the sensitivity does not perform as well as Option 5A from a net market benefits, renewable generation development, or power system performance perspective.

In terms of New South Wales, Transgrid will now seek a 'feedback loop' confirmation from AEMO (in its national planning role) in line with the actionable ISP framework ahead of lodging a CPA for investment in VNI West. Transgrid is intending to submit two CPAs to the AER in relation to the regulatory cost recovery for the project:

- The 'Initial CPA' will seek cost recovery for the Stage 1 early works, based on the preferred option.
- The 'Final CPA' will seek cost recovery for the Stage 2 implementation costs, including the construction costs of the project (this CPA will cover the bulk of the project cost).

Transgrid will need to seek further 'feedback loop' confirmation from AEMO prior to submitting the 'Final CPA' to confirm that the project is still part of the optimal development path in the latest ISP and delivers positive market benefits in the 'most likely' scenario.

The regulatory arrangements in Victoria do not require AVP to seek a 'feedback loop' confirmation from AEMO for the Victorian section of the project.

This report marks the end of the formal RIT-T consultation process under the NER. Detailed engagement with potentially impacted communities and landholders will now commence. This ongoing engagement will include the following activities:

- Continuing regionally focused engagement with communities and stakeholders who may potentially host the infrastructure to understand inherent values, opportunities, and constraints as inputs to a corridor definition process.
- Establishing Stakeholder Reference Groups and continuing Regional Reference Groups, to ensure stakeholders can continue to collaborate with the project teams to further develop and refine the study corridor.
- Undertaking direct engagement with potentially affected landholders (most likely from June 2023), to identify the best route alignment and optimise the route based on localised property constraints.
- Commencing discussions with affected landholders in relation to compensation.
- Engaging with landholders prior to commencing environmental field studies.

In parallel, AusNet will continue engaging with landholders along the proposed WRL route to provide them with the latest available information and respond to their questions and concerns about the associated changes to

WRL. In particular, with the uprating of the 220 kV section of WRL to 500 kV as specified in the May 2023 NEVA Order, AusNet has identified further investigations that will be required prior to submitting the EES, including:

- Deviating the line where the proposed route for the 220 kV is too constrained to accommodate the 500 kV line due to a larger easement area being required; and
- Tower siting and positioning, as they are expected to be taller and have a larger base footprint.

Information about the process and upcoming stakeholder engagement activities going forward will be published on the VNI West dedicated webpages at www.transgrid.com.au/vni-west and www.aemo.com.au/vni-west. Transmission Company Victoria and Transgrid will advise in more detail – through direct correspondence and broad regional communications programs – on how and when stakeholders, communities and landholders can input into the route selection and refinement process.

A1. Checklist of compliance clauses

This section sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clause 5.16A.4(d) of the National Electricity Rules version 199 and Table 14 of the CBA Guidelines.

Table 14 Checklist of compliance clauses

NER clause	Summary of requirements	Relevant section(s) in PACR
5.16A.4(d)	The project assessment conclusions report must include:	-
	(1) include the matters required by the Cost Benefit Assessment Guidelines;	Table 15
	(2) adopt the identified need set out in the Integrated System Plan (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	Section 3
	(3) describe each credible option assessed	Section 3 and Appendix A2
	(4) include a quantification of the costs, including a breakdown of operating and capital expenditure for each credible option	Section 3.3
	(5) assess market benefits with and without each credible option and provide accompanying explanatory statements regarding the results	Section 6 and Appendix A9
	(6) if the RIT-T proponent has varied the ISP parameters, provide demonstrable reasons in accordance with 5.15A.3(b)(7)(iv)	NA
	(7) identify the proposed preferred option that the RIT-T proponent proposes to adopt	Section 9
	(8) for the proposed preferred option identified under subparagraph (7), the RIT-T proponent must provide: (i) details of the technical characteristics; and (ii) the estimated construction timetable and commissioning date.	Section 3.2
5.16A.4(v)	(2) a summary of, and the RIT-T proponents' response to, submissions received, if any, from interested parties sought	Volume 2: PACR. The report released in February 2023 on the PADR submissions also includes a detailed summary of all points raised in those submissions.

Table 15 List of binding elements on RIT-T proponents in the CBA Guidelines

Binding elements	Provision	Classification	Relevant section(s) in PACR
1	RIT-T proponents are required to provide the AER with a compliance report when applying the RIT-T to an actionable ISP project, which must be submitted no later than 20 business days after the publication of the project assessment conclusions report	Requirement	Appendix A1
2	In its compliance reports, RIT-T proponents are required to identify where they: • have complied with applicable requirements; • have had regard to applicable considerations (including the reasons for the weight they have attached to each consideration); and • have resolved key issues raised by the AER through the issues register.	Requirement	Appendix A1
3	RIT-T proponents are required to identify breaches of the CBA guidelines, if any, in their compliance reports and provide an explanation for the breach.	Requirement	Appendix A1. AVP and Transgrid consider there are no breaches of the CBA Guidelines.
4	If a compliance report contains confidential information, RIT-T proponents are required to provide another nonconfidential version of the report in a form suitable for publication.	Requirement	Compliance report does not contain confidential information
5	When a RIT-T proponent is considering whether to	Consideration	Section 3

Binding elements	Provision	Classification	Relevant section(s) in PACR
	include new credible options that AEMO did not consider in the ISP, it must have regard to the guidance in Section 4.3.1 of the CBA Guidelines on what constitutes a credible option when justifying its decision. When identifying new credible options, the RIT-T proponent must consider all options it could reasonably classify as credible options, taking into account factors that the RIT–T proponent reasonably considers it should take into account. In considering what it should take into account, the RIT–T proponent must have regard to the following: • if the identified need in the ISP entails meeting a service standard, the degree of flexibility offered by that service standard; • the advantages of constructing credible options with option value; and • the benefits of constructing new credible options to meet the identified need in the ISP over broadly similar timeframes to the ISP candidate option and non-network options identified in the ISP.		
6	The base case is required to be where the RIT-T proponent does not implement a credible option to meet the identified need, but rather continues its business as usual activities, including for where reliability corrective action is driving the identified need.	Requirement	Section 5
7	'Demonstrable reasons' for departing from ISP parameters are required to be limited to where there has been a material change that AEMO would, but is yet to reflect in, a subsequent IASR, ISP or an ISP update. For example, this might include a material change in circumstances, such as where the AER has published updated VCR values that AEMO is yet to incorporate in the IASR. Where a material change is not a change in circumstances or facts (for example, a change in the RIT-T proponent's understanding or assessment of the facts, rather than a change in the facts themselves), the RIT–T proponent might choose to attain written confirmation of the change from AEMO.	Requirement	Section 5.3
8	If the modelling period is shorter than the life of the credible option, the RIT-T proponent is required to incorporate the operating and maintenance costs (if any) for the remaining years of the credible option into the terminal value.	Requirement	Appendix A6
9	When valuing the costs of compliance, there may be cases where a RIT-T proponent can lawfully pay a financial amount rather than undertake some other action for compliance. In such cases, the RIT-T proponent must consider whether the financial amount is smaller than the costs of undertaking some other action before determining whether it should treat the financial amount as part of that credible option's costs.	Consideration	N/A – options considered in the PACR do not involve cost of compliance payments of a financial amount in place of some other action for compliance.
10	For any RIT-T application where AEMO has not specified which scenario/s or weightings to apply, the RIT-T proponent must consider the AER's guidance on estimating probability-based weightings as set out in the previous RIT-T application guidelines that applied to all RIT-T projects.	Consideration	AEMO ISP scenario weightings adopted
11	RIT-T proponents must consider performing sensitivity testing by varying one or multiple inputs/assumptions. In considering whether or how to perform sensitivity testing, the RIT-T proponent must have regard to any relevant risks identified in stakeholder submissions, and whether sensitivity testing would build on the analysis already undertaken in the ISP and be proportionate and relevant to the RIT-T assessment.	Consideration	Section 6.4
12	The RIT-T proponent must consider using the ISP modelling period (also known as the planning horizon) of 20+ years as the default when assessing credible options to meet identified needs arising out of the ISP. If the expected profile of the market benefits and costs of the ISP candidate option are longer than the modelling period used in the ISP, the RIT-T proponent must	Consideration	Appendix A8.7

Binding elements	Provision	Classification	Relevant section(s) in PACR
	consider whether it might be valuable to adopt a longer modelling period, whilst also considering the need for alignment with the ISP. For relatively incremental ISP candidate options, the RIT-T proponent must consider whether a shorter period would reduce the computational burden without compromising the quality of the CBA or undermining alignment with the ISP.		
13	Where the modelling period is shorter than the expected life of a credible option, the RIT-T proponent is required to include any relevant and material terminal values in its discounted cash flow analysis. The RIT-T proponent is required to explain and justify the assumptions underpinning its approach to calculating the terminal value, which represents the credible option's expected cost and benefits over the remaining years of its economic life.	Requirement	Appendix A6
14	For the purposes of clause 5.16A.5(b) of the NER, the relevant cost is the cost for the particular stage. However, AEMO also must have regard to the full cost of the project in providing its written confirmation, under clause 5.16A.5(b) of the NER, that the status of the actionable ISP project remains unchanged.	Consideration	N/A
15	The RIT–T proponent must consider describing in each RIT–T report how it has engaged with consumers, as well as other stakeholders; and sought to address any relevant concerns identified as a result of that engagement. The RIT-T proponent must consider undertaking early engagement with consumers, non-network businesses and other key stakeholders to the extent that doing so complements rather than duplicates or hinders AEMO's engagement work in developing the ISP. The RIT-T proponent also must have regard to how it can adopt best practice consumer engagement in line with our 'consumer engagement guideline for network service providers'.	Consideration	PACR Volume 2
16	The RIT–T proponent is required to provide transparent, user-friendly data to stakeholders, to the extent this protects commercially sensitive information and is not already provided by the ISP.	Requirement	Section 6 and modelling outcomes accompanying the PACR
17	In providing transparent, user-friendly data to stakeholders, the RIT-T proponent must have regard to how it can present information in line with stakeholder preferences.	Consideration	Section 6 and modelling results accompanying the PACR
18	The Draft Report is required to include, if applicable: • Demonstrable reasons for adopting different modelling techniques to what AEMO used in the ISP. • An explanation as to why any non-network options proposed in response to new actionable ISP projects in the final ISP are not credible options.	Requirement	N/A
19	When publishing the Conclusions Report, RIT-T proponents are required to: • Publish, in addition to a summary of submissions, any submissions received in response to the Draft Report, unless marked confidential. • Date the Conclusions Report to inform potential disputing parties of the timeframes for lodging a dispute notice with the AER.	Requirement	All non-confidential submissions have been published online. Section 1.4 sets out the timeframes for lodging a dispute.
20	If a RIT-T proponent receives any confidential submissions on its Draft Report, it must consider working with submitting parties to make a redacted or nonconfidential version public.	Consideration	All submitters received confirmation of the confidentiality status of their submission and submission publication process, with an invitation for further discussion at their discretion. We will continue to work with submitters to explore whether redacted or non-confidential versions of submissions are able to published, in which case we will do that as soon as practicable.

A2. Additional detail on the options

This appendix provides additional information on the two options assessed in this PACR.

A2.1 Elements common to both options

The options presented in this PACR are largely similar technically, with the primary differences being in their areas of interest, as described below. Technically both options comprise the following augmentations:

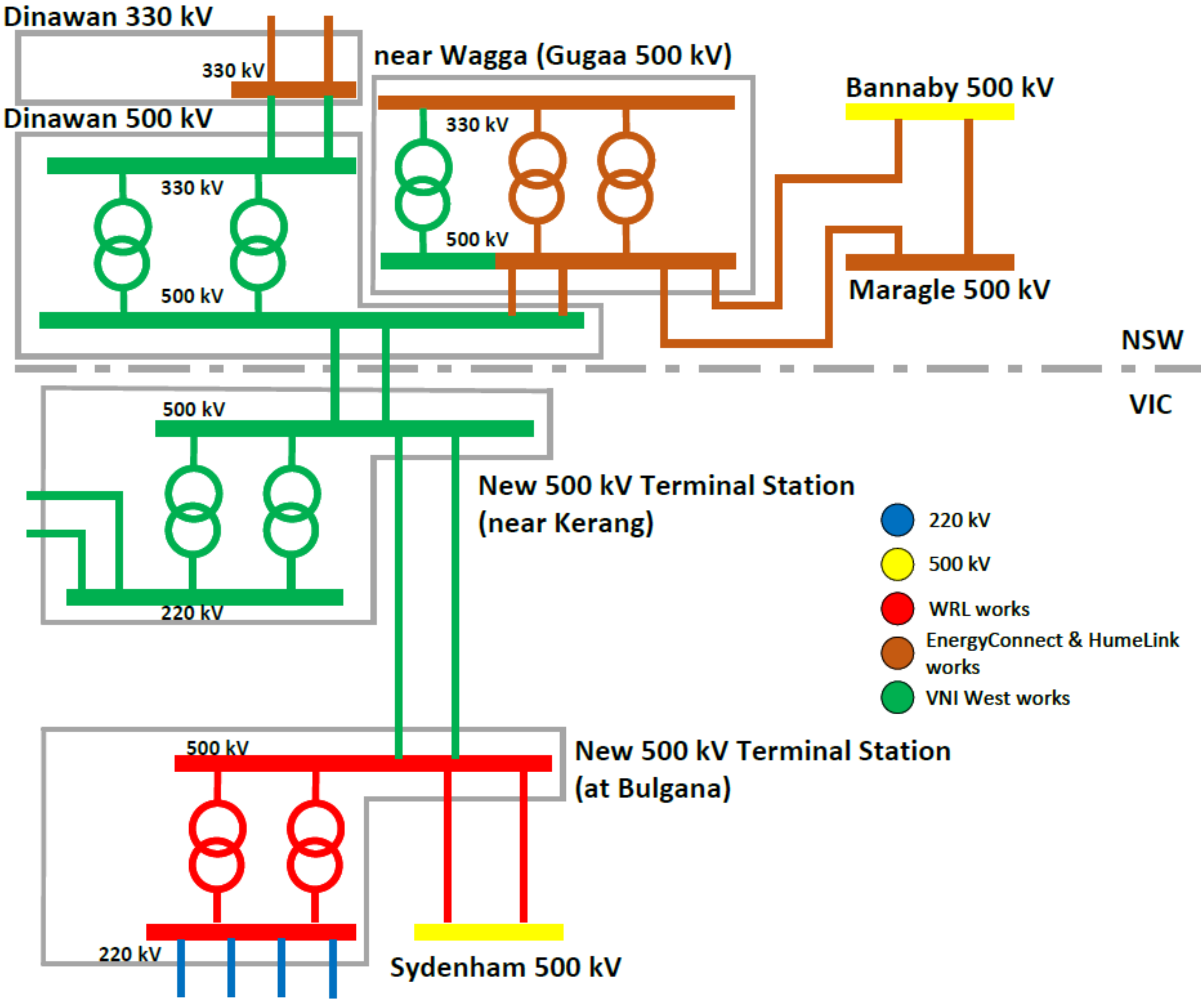
- A new 500 kV double-circuit overhead line from Bulgana to near Kerang to locality of Dinawan, including series compensation on the line near Kerang.
- Construction of the Dinawan to near Wagga Wagga line as a double-circuit 500 kV line, rather than a double-circuit 330 kV line and later uprate from 330 kV to 500 kV operation (including new 500 kV bays and a transformer station near Wagga Wagga).
- Establish Dinawan 500 kV switchyard with two 500/330 kV 1,500 MVA transformers.
- Establish new terminal station near Kerang with two 500/220 kV 1,000 MVA transformers.
- 220 kV connections from the new terminal station near Kerang to the existing 220 kV lines near Kerang.
- Modular power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang and 220 kV lines between Dederang and Thomastown following certain contingencies.
- 500 kV line shunt reactors at both ends of the three following 500 kV circuits: (i) Bulgana – near Kerang, (ii) near Kerang – Dinawan and (iii) Dinawan – near Wagga Wagga.
- Up to +/- 400 MVAr dynamic reactive compensation at the new 220 kV terminal station near Kerang.
- Relocation and modification of WRL terminal station from north of Ballarat to Bulgana. This includes a 500 kV switchyard with two 500/220 kV transformers at the existing Bulgana terminal station.
- Two new 500 kV bays and line exits with a total of two 500 kV line shunt reactors at the Bulgana terminal station have been included in the VNI West costs (with the remainder of the terminal station assumed part of the WRL scope).
- Construction of the WRL spur line to Bulgana as a double-circuit 500 kV line, rather than a double-circuit 220 kV line.
- Approximately 100 MVAr 500 kV switched bus connected reactor at Sydenham.

In addition, series compensation or additional power flow controllers would be installed along the Kerang to Bulgana section to reduce impedance on the new 500 kV network. This improves network load sharing with, and manages network loading on, the existing 330 kV Victoria – New South Wales Interconnector and the existing 220 kV western Victoria network between Bendigo and Kerang, in the absence of a new terminal station and connection near Bendigo.

Under both options, WRL will be constructed at 500 kV from Bulgana to Sydenham; that is, the current project scope would be modified and the entire line would be uprated from 220 kV to 500 kV from north of Ballarat to Bulgana. The proposed terminal station north of Ballarat would be relocated to Bulgana.

VNI West wholly relies on WRL to connect to the Melbourne 500 kV grid, utilising the proposed 500 kV WRL transmission line from Bulgana to Sydenham. The cost of uprating from Bulgana to north of Ballarat from 220 kV to 500 kV, relocation of the proposed terminal station north of Ballarat, and modifications to the Bulgana Terminal Station to accommodate the 500 kV spur uprate, and associated works, have been considered as part of the cost of this option.

Figure 21 Single-line diagram for Option 5 and Option 5A



Construction, including detailed design, construction and 12 months of inter-network testing, is expected to take five years (excluding time for early works), with commissioning depending on the scenario modelled. Construction and commissioning of the WRL spur to Bulgana at 500 kV rather than 220 kV is assumed to be completed by 2027.

Achievement of all delivery dates is subject to obtaining the necessary planning and environmental approvals, assembling land and easements, detailed design, and extensive community and landholder engagement, which is expected to take about three years to complete. This is a year earlier than expected in the PADR, because the February 2023 NEVA Order enables AEMO to commence early works now, working towards undertaking first spring surveys in 2023.

A2.2 Inclusion of series compensation

While series compensation, in the form of series line capacitors, has been modelled in the options analysis, the precise series compensation or power flow solution will be determined during detailed design. Consideration of the precise solution will include further assessment of the engineering technical complexities and advantages of various potential solutions. In particular, AVP and Transgrid are aware of the risk that sub-synchronous control interactions with synchronous machines and doubly fed induction generators can arise in systems with series capacitors and this will be studied in detail.

Initial sub-synchronous resonance screening studies have been completed to confirm the feasibility of installing the series compensation at its currently proposed location. Studies completed to date indicate there is a very low risk of issues with resonance with both existing and future generators due to the mesh-like network of the Western Victorian transmission grid. Network series resonance conditions were observed at some generating plant located in the vicinity of the series compensation. These resonance conditions were at very low frequencies (<20 hertz (Hz)) and are unlikely to cause sub-synchronous oscillations (SSO). However, under some contingencies there are cases where some of the plant provides negative damping and these conditions will need to be reviewed with further, more-detailed electromagnetic transient (EMT) modelling. In relation to sub-synchronous torsional interaction (SSTI), due to the very low resonance frequency SSTI is not expected to occur.

For future generation connections, Type 3 or synchronous generators connecting close to the series compensation are expected to be the most at risk of any impact from the capacitors, however it is expected that with detailed design and planning/verification studies completed, the risks can be mitigated.

To further support the practicality of installing series compensation, the existing VNI has had series capacitors successfully in service for decades.

AVP and Transgrid welcome any insights from industry regarding potential alternative solutions to better share power flow between the existing and newly proposed parallel networks.

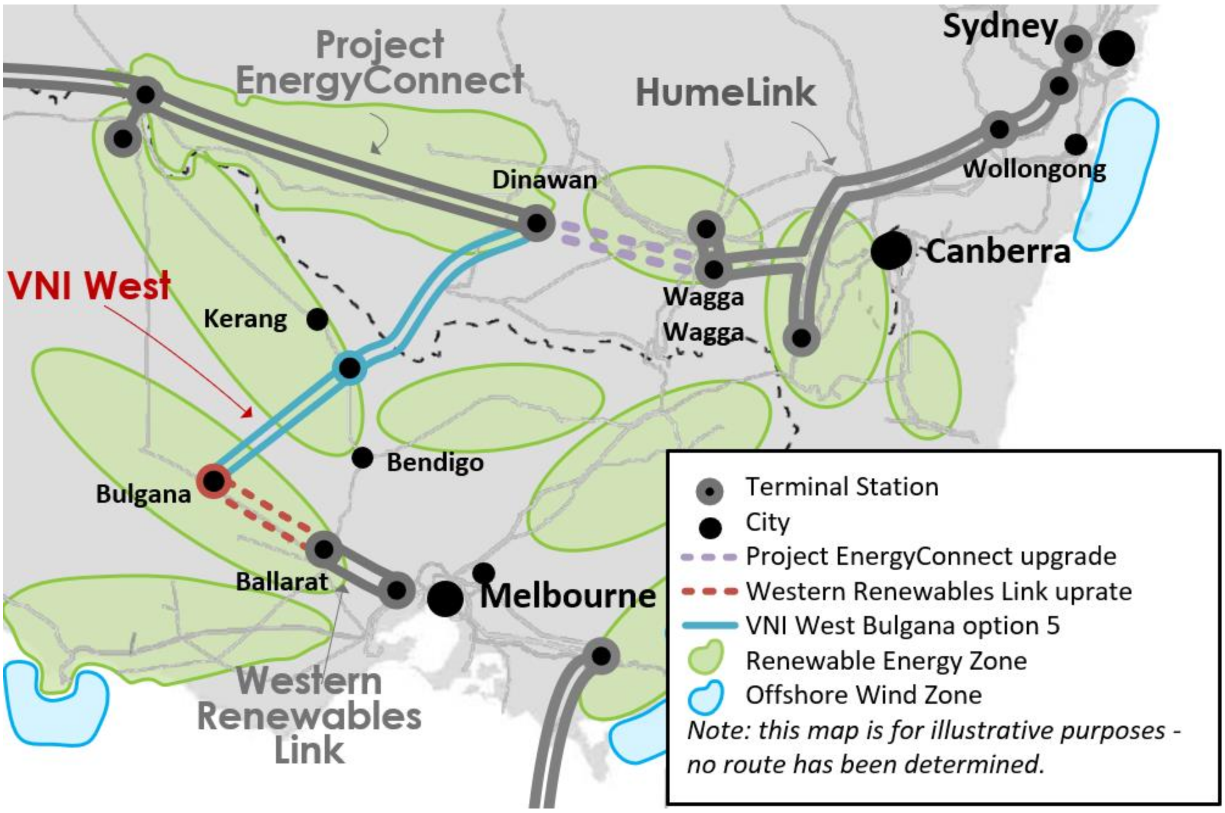
If, due to technical complexities, the project is progressed without series compensation on the 500 kV lines, or if they are required to be decommissioned in the future, the import and export transfer capability is marginally reduced. A sensitivity for Option 5 without series compensation has also been studied in Section 6.4.3 to understand the impact to the net market benefits, with the relative changes to capability expected to be equally applicable to Option 5A.

A2.3 Option 5 (near Echuca)

Option 5 (near Echuca) is the proposed preferred option that was presented in the Additional Consultation Report, following consultation on the PADR. It involves a new high-capacity 500 kV overhead double-circuit transmission line to connect WRL (at Bulgana) with EnergyConnect (at Dinawan) via new terminal stations at Bulgana and near Kerang. This option crosses the Murray River near Echuca (Yorta Yorta Country) and connects to the existing 220 kV network between Kerang and Bendigo.

Figure 22 below provides a plan view for Option 5, noting the lines represent network connections schematically, not a line route.

Figure 22 Schematic plan view of Option 5



Modelling indicates that this option will result in additional transfer capability of approximately 1,960 MW from Victoria to New South Wales and 1,710 MW from New South Wales to Victoria.

It is also estimated that Option 5 will increase the transmission limit at the following REZs by:

- 1,075 MW in the Murray River REZ (V2).
- 1,460 MW in the Western Victoria REZ (V3) from the WRL uprate.
- 200 MW in the Western Victoria REZ (V3) from VNI West.
- 900 MW in the South West New South Wales REZ (N5).

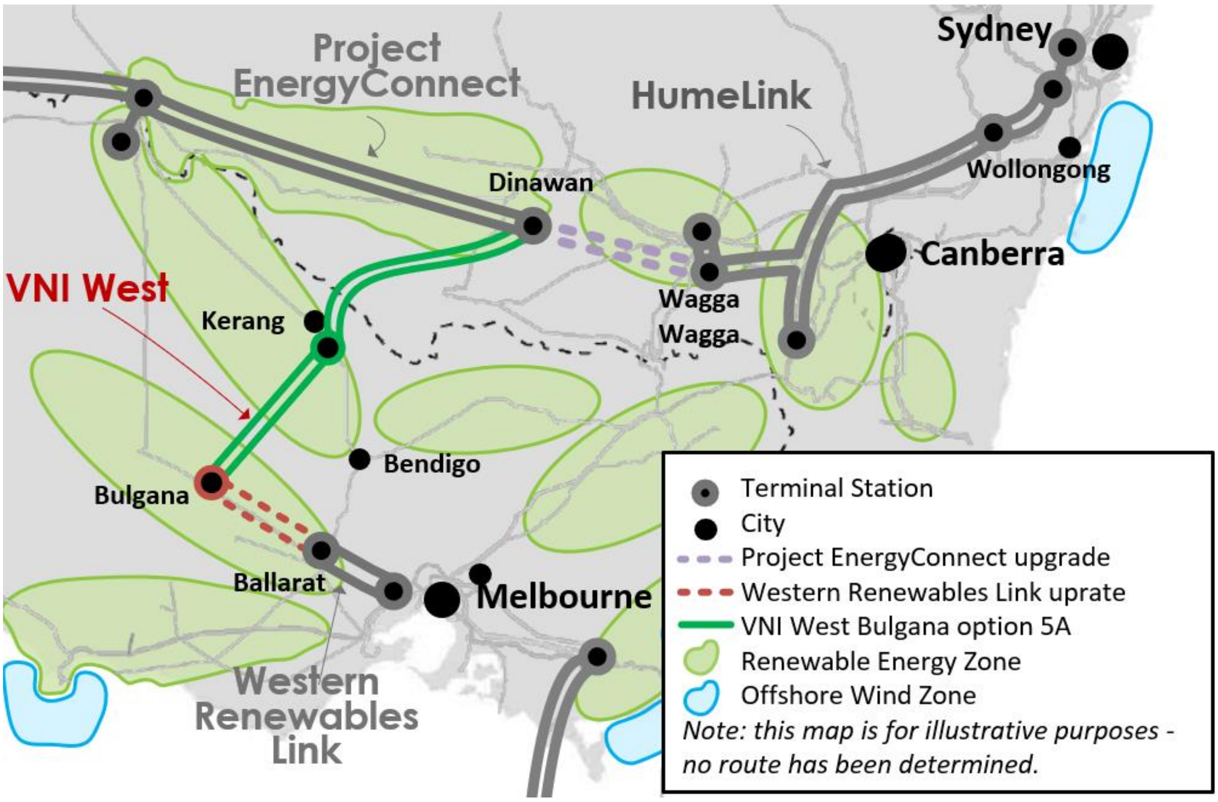
The estimated capital cost of this option is approximately $3,406 million, which is comprised of $1,755 million in Victoria and $1,651 million in New South Wales.

A2.4 Option 5A (east of Kerang)

Option 5A is a new corridor variant of Option 5 that has been identified in response to feedback received on the Additional Consultation Report. It involves a new high-capacity 500 kV overhead double-circuit transmission line to connect WRL (at Bulgana) with EnergyConnect (at Dinawan) via new terminal stations at Bulgana and near Kerang. This option crosses the Murray River north of Kerang (Wamba Wamba Country), and connects to the existing 220 kV network between Kerang and Bendigo.

Figure 23 below provides a plan view and a single-line diagram for Option 5A, noting the lines represent network connections schematically, not a line route.

Figure 23 Schematic plan view of Option 5A



Modelling indicates that this option will result in additional transfer capability of approximately 1,935 MW from Victoria to New South Wales and 1,669 MW from New South Wales to Victoria.

It is also estimated that Option 5A will increase the transmission limit at the following REZs by:

- 1,580 MW in the Murray River REZ (V2).
- 1,460 MW in the Western Victoria REZ (V3) from the WRL uprate.
- 0 MW in the Western Victoria REZ (V3) from VNI West.
- 900 MW in the South West New South Wales REZ (N5).

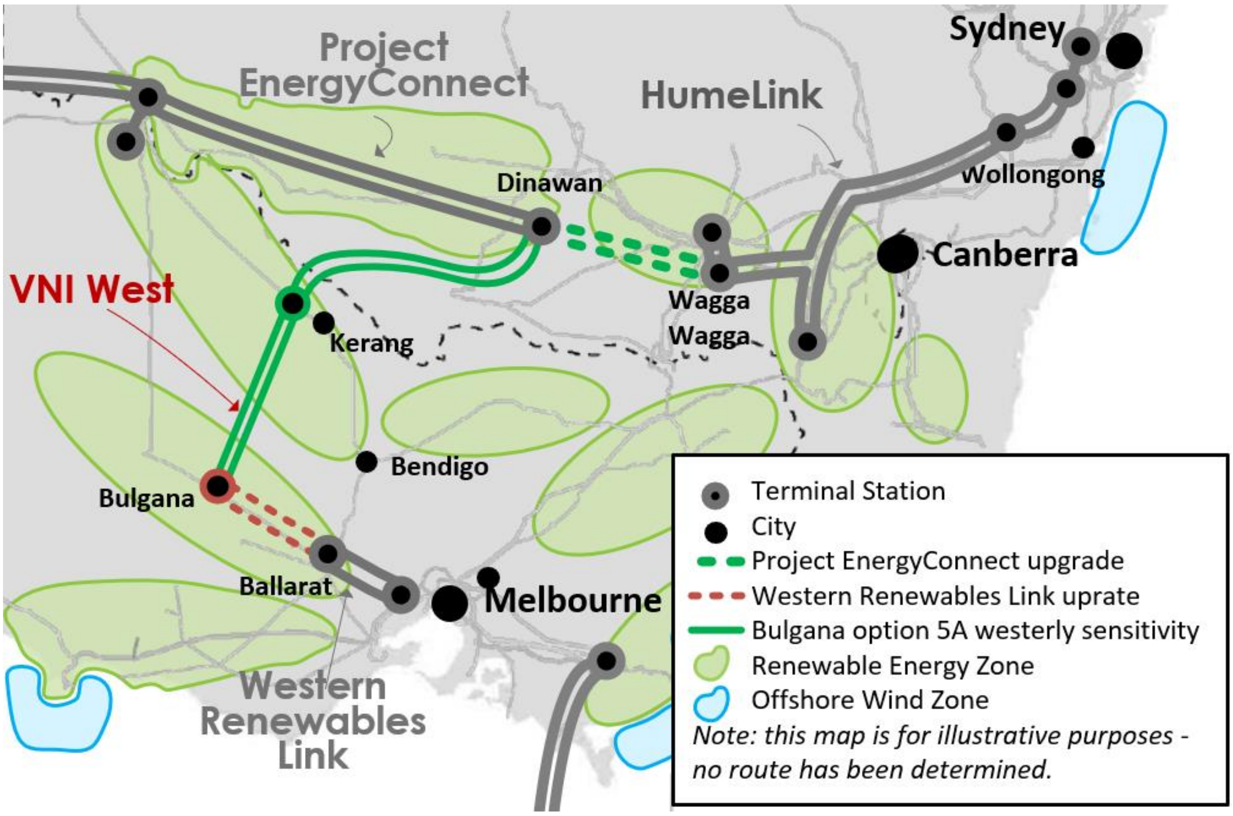
The estimated capital cost of this option is approximately $3,499 million, which is comprised of $1,755 million in Victoria and $1,744 million in New South Wales.

A2.5 Option 5A westerly sensitivity (west of Kerang)

The Option 5A westerly sensitivity is a corridor variant of Option 5A that routes west of Kerang. It involves a new high-capacity 500 kV overhead double-circuit transmission line to connect WRL (at Bulgana) with EnergyConnect (at Dinawan) via new terminal stations at Bulgana and near Kerang. This option crosses the Murray River near Echuca (Wamba Wamba Country), and connects to the existing 220 kV network further west between Kerang and Wemen.

Figure 24 below provides a plan view and a single-line diagram for the Option 5A westerly sensitivity, noting the lines represent network connections schematically, not a line route.

Figure 24 Schematic plan view of Option 5A westerly sensitivity



Modelling indicates that this option will result in additional transfer capability of approximately 1,910 MW from Victoria to New South Wales and 1,650 MW from New South Wales to Victoria.

It is also estimated that this option will increase the transmission limit at the following REZs by:

- 1,460 MW in the Murray River REZ (V2).
- 1,460 MW in the Western Victoria REZ (V3) from the WRL uprate.
- 0 MW in the Western Victoria REZ (V3) from VNI West.
- 900 MW in the South West New South Wales REZ (N5).

The estimated capital cost of this option is approximately $3,499 million, which is comprised of $1,755 million in Victoria and $1,744 million in New South Wales.

A3. Alternative options considered over the course of this RIT-T

Although this PACR is focused on the assessment of two options, both developed in response to submissions, a significant number of additional options have been considered at various stages over the course of this RIT-T, and the associated ISP assessment(s). These include:

- Options considered in the Additional Consultation Report.
- Options proposed in submissions to the PADR.
- Options proposed in submissions to the PSCR.
- Variations of VNI West.
- Options discounted in the 2020 ISP.
- Options discounted in the 2022 ISP.
- Options from the PSCR.

Table 16 below summarises each of these options and why they have not been included as part of the assessment in this report.

Table 16 Alternative options considered but not progressed

Option	Overview	Reason(s) it has not been progressed
Options considered in the Additional Consultation Report		
Option 1 (to north of Ballarat)	As per the PADR – connects from Dinawan, via the new terminal station near Kerang, to WRL at the proposed terminal station north of Ballarat, and routes via Bendigo.	Option 1 was found to be ranked significantly behind Option 5 in the Additional Consultation Report in terms of both the NPV assessment and the MCA assessment.
Option 1A (to north of Ballarat with spur uprate to 500 kV)	The same as Option 1 but with an additional spur involving uprate of WRL from the proposed terminal station north of Ballarat to Bulgana from 220 kV to 500 kV following the same WRL route for much of the length except for a slight variation around Waubra.	While Option 1A was found to be ranked within 5% of Option 3A and Option 5 on a weighted basis in the Additional Consultation Report, it was also found to present greater social licence challenges associated with a line through the Bendigo to Ballarat area that stakeholders suggested was particularly problematic. It is therefore considered inferior to Option 3A and Option 5 and so its consideration has been discontinued. Option 1A was also found to be inferior in terms of net market benefits to Option 1 under the *Progressive Change* and *Hydrogen Superpower* scenarios.
Option 2 (to north of Ballarat plus non-network)	The same as Option 1 but with a virtual transmission line (VTL) involving batteries at South Morang and Sydney West commissioned in 2026-27.	Option 2 was found to be the lowest ranked option in the Additional Consultation Report, and the additional cost of the VTL components is not outweighed by the additional expected market benefits (shown by Option 2 having lower net benefits than Option 1 in all three scenarios).
Option 3 (to Waubra/Lexton)	Connects from Dinawan, via the new terminal station near Kerang, to WRL at a new terminal station in the Waubra/Lexton area (Djaara Country), and routes via Bendigo. This option requires relocation of the WRL proposed terminal station north of Ballarat to near Waubra/Lexton and uprate of the proposed WRL transmission line from north of Ballarat to Waubra/Lexton from 220 kV to 500 kV.	The analysis in the Additional Consultation Report found that uprating WRL to 500 kV through to Bulgana is always net beneficial; that is, Option 3A is always ranked above Option 3. Further, Option 3 did not rank above Option 3A in the MCA assessment.

Option	Overview	Reason(s) it has not been progressed
Option 3A (to Waubra/Lexton with spur uprate to 500 kV)	Same as Option 3 but with the additional spur involving uprate of WRL from the proposed terminal station in Waubra/Lexton (Djaara Country) to Bulgana (Wotjobaluk Country) from 220 kV to 500 kV following the same WRL route for much of the length except for a slight variation around Waubra.	While Option 3A was found to have effectively the same level of estimated net benefit as Option 5 in the Additional Consultation Report, it ranked behind Option 5 under the MCA assessment. This finding was confirmed through stakeholder consultation where only two submissions suggested that Option 3A was favoured over Option 5
Option 4 (to Bulgana via Bendigo)	Connects from Dinawan, via the new terminal station near Kerang, to WRL at a new terminal station near Bulgana (Wotjobaluk Country), and routes via Bendigo. This option requires relocation of the WRL proposed terminal station from north of Ballarat to Bulgana (Wotjobaluk Country) and the uprate of the WRL transmission line from north of Ballarat to Bulgana from 220 kV to 500 kV.	Option 4 was found to be the worst performing purely interconnector option in the Additional Consultation Report (that is, excluding Option 2 which includes a non-network solution). This was the case under both the NPV assessment and the MCA assessment.
Options proposed in submissions to the PADR		
Underground high voltage direct current (HVDC)	Several submissions suggested undergrounding of HVDC cables should be considered for a number of reasons including reducing impact for access, environment, visual amenity, private properties, and heritage sites.	High voltage alternating current (HVAC) lines have significant benefits associated with connection of renewable generation compared to HVDC lines in terms of technical difficulty, scope of works at terminal stations and cost. The higher cost of connection associated with HVDC is more likely to undermine potential benefits of that generation. Undergrounding of HVDC adds another layer of costs and potential delays, which makes the option cost prohibitive and introduces more uncertainties around timing. The HumeLink Undergrounding Study, commissioned by a collaborative Steering Committee, showed the cost of undergrounding to be at least three times the cost of the project and that it would take a further five years to build.[A] AVP and Transgrid consider that the cost of undergrounding VNI West would also be orders of magnitude greater than using overhead lines, without adding commensurately to the expected market benefits, and would add significantly to the construction timetable. While full undergrounding is considered a cost prohibitive solution to balancing community and stakeholder expectations, while still meeting the identified need, AVP and Transgrid acknowledge the importance of considering partial undergrounding in exceptional circumstances and are committed to working closely with community and stakeholder groups to consider cost effective alternatives to undergrounding, such as route diversion, screening, and line tower design, that can help manage the broad and real social and environmental impacts.
Options proposed in submissions to the PSCR		
220 kV upgrades	Low-cost options in the 220 kV network.[B]	220 kV options were not recommended as part of the 2020 ISP or 2022 ISP. A larger augmentation is required, as a 220 kV upgrade option would not provide significant additional REZ hosting capacity, or interconnection transfer capability.
Option from a confidential submission	An alternative option was proposed in a confidential submission. The detail of the proposed option is not presented due to confidentiality obligations.	The option was not considered credible as it had a longer, less efficient topology that increased costs but did not provide a corresponding increase in benefits. It is therefore not considered commercially feasible. A response has been provided to the submitter.
Undergrounding	Underground either in whole or part of VNI West to reduce the impact on visual amenity.	The delivery of high-capacity high-voltage 500 kV underground lines would be unprecedented for the NEM, and unlikely to meet the 2022 ISP cost and time requirements (particularly, the timeframes under the *Step Change* and *Hydrogen Superpower* scenarios). Notwithstanding, undergrounding, either in whole or in part, was considered in response to submissions raising matters of social and environmental impacts, particularly as they relate to visual amenity. While full undergrounding is considered a cost prohibitive solution to balancing community and stakeholder expectations, while still meeting the identified need, AVP and Transgrid acknowledge the importance of considering partial undergrounding in exceptional circumstances and are committed to working closely with community and stakeholder groups to

Option	Overview	Reason(s) it has not been progressed
		consider cost effective alternatives to undergrounding, such as route diversion, screening, and line tower design, that can help manage the broad and real social and environmental impacts.
Variations to VNI West		
Connection via Donnybrook	A possible alternative starting point included in the 2020 ISP is through Donnybrook, instead of a new terminal station north of Ballarat.[C]	This alternative connection point was ruled out in the 2020 ISP. It has therefore no longer been considered in this RIT-T. Specifically, this alternative was considered but not progressed in the 2022 ISP due to the scope of EnergyConnect having changed since the publication of 2021 IASR where it now involves building double-circuit lines from Dinawan to Wagga Wagga at 500 kV and operating them initially at 330 kV. This reduced the cost estimate for the VNI West options assessed in the PADR (as cost of uprating EnergyConnect was included in VNI West, but the uprating avoided costs associated with building new parallel lines separate to EnergyConnect) and provided increased connection to the South West New South Wales, Murray River and Western Victorian REZ.[D] Consequently, this alternative via Donnybrook was considered less cost competitive without corresponding benefits and so was not progressed as an option in the 2020 ISP, the 2022 ISP or the PADR.
Staging of option capacity	The possibility of staging capacity for options by building to 500 kV and initially operating at 330 kV, or by stringing on only one side initially.	The possibility of staging capacity by building to 500 kV but initially operating at 330 kV, or by stringing only one side initially, was considered but not progressed as part of the PADR since the cost is nearly the same as for the credible options assessed. This is due to the easement requirements (and associated costs) remaining the same and, in the case of operating at 330 kV initially in Victoria, which has a 220 kV system, having to introduce new 220 kV/330 kV terminal stations. The staging of option capacity would also introduce uncertainty for generators and other parties seeking network connections as to the voltage that connection assets should be specified to.
Staging of VNI West by sections	The possibility of staging the section from a new terminal station north of Ballarat to Kerang first, with sections from Kerang to Dinawan and Wagga Wagga following after. This would allow for 1,000 MW of generation from the Murray River REZ (V2) to be harnessed first.	All options involving the uprate of WRL propose delivering the 500 kV uprate scope in line with WRL timing in 2027. Further staging or delaying the delivery of interconnection between Victoria and New South Wales is not beneficial as it delays the accrual of benefits.
Options discounted in the 2022 ISP [D]		
VNI 6	A double-circuit overhead 500 kV line from a terminal station north of Ballarat via a new terminal station near Shepparton to Wagga Wagga.[E] VNI 6 – Variant 1 involves new 500 kV transmission lines from a new terminal station north of Ballarat to Bendigo to Wagga	The VNI 6 option put forward in the PSCR and the 2020 ISP was ruled out in the 2022 ISP. It has therefore no longer been considered in this RIT-T. Specifically, this option was considered but not progressed in the 2022 ISP due to the scope of EnergyConnect having changed since the publication of the 2021 IASR, where it now involves building double-circuit lines from Dinawan to Wagga Wagga at 500 kV and operating them initially at 330 kV. This has reduced the cost estimate for the VNI West options assessed in the PADR (cost of uprating was part of VNI West, but the project avoided costs associated with building new parallel lines) and provides increased connection to the south-west New South Wales, Murray River and Western Victorian REZs.[D] Consequently, this VNI 6 alternative now has a similar cost to VNI West but lower market benefits due to unlocking less REZ hosting capacity compared to going via a new substation near Kerang and so was not progressed as an option in the 2022 ISP or the PADR. Additionally, as noted in Section 4.10 of the PADR, a number of submitters to the PSCR raised concerns with the VNI 6 topology running through high value agricultural farmland, including a high concentration of irrigation infrastructure investment and related agricultural production, which would likely impact timing and cost of construction as well as limiting development of new renewable generation in the area.
Options discounted in the 2020 ISP [F]		
VNI 3	Incremental network augmentation, which includes a series capacitor on the Wodonga–Dederang 330 kV line, a power flow controller on the Jindera–	AEMO, in its 2020 ISP, concluded that a larger augmentation is required, and that this option does not provide significant additional REZ hosting capacity.

Option	Overview	Reason(s) it has not been progressed
	Wodonga 330 kV line, an additional 330/220 kV transformer at Dederang, and additional reactive plant.	It was not reconsidered in the 2022 ISP.
VNI 4	Includes VNI Minor and a new 330 kV transmission line from Dederang to Yass via Jindera and Wagga Wagga.	AEMO, in its 2020 ISP, concluded that a larger augmentation is required, and that this option does not provide significant additional REZ hosting capacity. It was not reconsidered in the 2022 ISP.
VNI 5A **(Included in the PSCR)**	Strengthening the existing VNI corridor by establishing new 330 kV single-circuit transmission lines from South Morang to Dederang to Murray.	This option was discounted by the 2020 ISP analysis as it did not provide additional REZ hosting capacity and did not unlock the development, dispatch and sharing of renewable generation, especially in high quality REZs in northern and western Victoria and south-western New South Wales. It also does not offer interconnector diversity and therefore does not provide additional supply reliability or system resilience (particularly with respect to credible contingency events impacting both the existing line and option VNI 5A simultaneously) due to the shared route along the existing VNI corridor being vulnerable to bushfire.
VNI 9	VNI West going via either Kerang or Shepparton plus an extension from Bannaby to Sydney to remove network constraints between Bannaby, Marulan, Kangaroo Valley and the Sydney West/Sydney South area.	Extension considered in part of Reinforcing Sydney, Newcastle and Wollongong (another actionable ISP project).[G]
VNI 10	VNI Option 9 plus third 500 kV line from Wagga/Maragle to Bannaby. The third line can be a second circuit in a double-circuit tower configuration	The 2020 ISP considered this option to increase transfer from Snowy to Sydney but did not find that it formed part of the optimal development path. It also noted that this option provides no additional increase in transfer capability between New South Wales and Victoria (which is part of the identified need in this RIT-T), relative to VNI 7, but with a higher cost
VNI 11	This option considered a new 2,000 MW HVDC path which directly connects large Victorian demand centres in the greater Melbourne and Geelong area with the Snowy mountains area in New South Wales. Two new 1,000 MW HVDC transmission lines would connect from Sydenham Terminal Station or a new terminal station at Donnybrook to Wagga Terminal Station, with HVDC converter stations at both locations and an additional converter station in between to host renewable development.	While this option would improve the reliability outlook for Victoria and enable resource sharing between Victoria and New South Wales, it would be less flexible in facilitating the efficient development of future generation in areas with high quality renewable resources, and in providing an access point for this future generation to a high-capacity interconnector, as this would require the establishment of an AC-DC converter station at each connection location. The 2020 ISP stated that this option is more expensive than VNI West (via Kerang) when considering the need to host renewable development in nearby REZs [G] . This was reconfirmed in the 2022 ISP and therefore is not considered credible.
Other options from the PSCR		
Expansion A and Expansion B to accommodate REZs	Expansions were considered in the PSCR for VNI 6 (Expansion B) and VNI 7 (Expansion A) with new transmission lines to facilitate generation hosting capacity at Central North Victoria (V6) REZ and Murray River (V2) REZ respectively.	The VNI 6 option put forward in the PSCR and 2020 ISP was ruled out in the 2022 ISP, as outlined above. It has therefore no longer been considered in this RIT-T. Studies during the PADR revealed that VNI West already meets the required REZ hosting capacity without the need for an expansion. However, an expansion may be considered in the future to harness additional renewables.
VNI 8	This option was included in the VNI West PSCR as a lower cost 330 kV alternative to VNI West (via Kerang). It consisted of 330 kV double-circuit lines from a new terminal station north of Ballarat via Kerang and Darlington Point to Wagga, and avoiding Bendigo.	Due to the reduced transfer capability and REZ hosting capacity, this option delivered fewer net benefits compared to VNI 6 and VNI 7, and was therefore not progressed as a preferred candidate ISP option. It has therefore no longer been considered in this RIT-T. Moreover, AVP and Transgrid note that regardless of whether the line is built at 330 kV or 500 kV, switching stations are required and so 330 kV does not allow for material cost savings.

A. GHD, *Concept Design and Cost Estimate, HumeLink Project – Underground*, 22 August 2022.
B. ERM Power p 3.
C. AEMO, 2020 ISP Appendix 3. Network Investments, July 2020, p 66.
D. AEMO, Draft 2022 ISP, Appendix 5. Network investments, December 2021, p. 24.
E. The PSCR included two variations of this option that either bypass Shepparton (VNI 6-V1) or go via both Bendigo and Shepparton (VNI 6-V2). Specifically, VNI 6-V1 involved new 500 kV transmission lines from a new terminal station north of Ballarat – Bendigo – Wagga; VNI 6-V2 involved new 500 kV transmission lines from a new substation north of Ballarat – Bendigo – Shepparton – Wagga.
F. AEMO, 2020 ISP Appendix 3. Network Investments, July 2020, p 66. The majority of the options discussed and discounted in the 2020 ISP were not options that were included in the earlier PSCR, but have been included here for completeness.
G. AEMO, 2020 ISP Appendix 3. Network Investments, July 2020, p 66.

A4. Consideration of undergrounding transmission lines

Options to underground the lines were raised in submissions to the PSCR, the PADR and the Additional Consultation Report, and continue to be suggested by stakeholders and communities as a possible solution to minimising social and environmental impacts of the project. Delivery of high-capacity 500 kV underground lines, along the full length of the project, is not economically feasible based on current cost assumptions and has known technical challenges that need to be considered on a project- and route-specific basis. Some of the factors, which are discussed in more detail below, include:

- High voltage direct current (HVDC) (both overhead and underground options) not meeting the identified need of VNI West.
- Higher degree of technical difficulty and cost to connect renewable generation to HVDC.
- Underground high voltage alternating current (HVAC) having technical limitations
- Underground HVAC being significantly more expensive than HVAC overhead.
- Cable joints being required at regular intervals along the length of any underground sections.
- Differences in reliability and fault restoration.
- Limited supply of underground expertise.
- Shorter asset life expectancy of underground cables.
- Construction differences between overhead and underground installations.
- Operational differences between overhead and underground installations.
- Width of easements and impact of undergrounding to agricultural land.

While some of these factors vary between HVAC and HVDC technology, the cost and technical impediments to meeting the identified need through full undergrounding are significant and have resulted in the VNI West options assessed and presented in this PACR being based on overhead AC transmission technology.

Despite this, AVP and Transgrid acknowledge the importance of considering partial undergrounding in exceptional circumstances driven by significant technical, environmental and/or social factors. These factors are route-specific and can therefore only be investigated as part of the project's early works stage, following this PACR and the RIT-T process.

HVDC (both overhead and underground options) do not meet the VNI West identified need

Compared to HVAC, HVDC is used in more targeted applications such as point-to-point interconnection, as applied for Basslink, Murraylink and Marinus Link, or to connect individual inverter-based resources to an AC network, for example offshore wind. Since a key part of the identified need for VNI West is to facilitate efficient development of generation in areas with high quality renewable resources in Victoria and southern New South Wales, point-to-point HVDC is not a feasible option capable of meeting VNI West's identified need.

While HVDC underground cable is lower cost than HVAC on a per length of cable basis, it requires a converter station at each end of the cable, and at any connection point along the cable, to convert between DC and AC. The addition of converter stations, which can cost 2-3 times that of a high voltage AC terminal station and require land size similar to, and in addition to, the AC terminal station, typically make HVDC a more expensive option than HVAC in instances where multiple connections along the route are anticipated.

Higher degree of technical difficulty and cost to connect renewable generation to HVDC

HVAC lines have a significant benefit compared to HVDC lines in that, once a line is constructed, should a renewable proponent wish to connect at a location along the line, construction of a new connection point (substation) is technically straightforward.

For HVDC, including a new connection point requires more significant works at terminal stations that are both costly and more likely undermine any potential benefits obtained by using HVDC.

Underground HVAC has technical limitations

Underground HVAC cable lengths are limited by the laws of physics. Alternating current (HVAC) has higher power losses compared to direct current (HVDC) over long distances, which presents as a capacitative power loss in underground HVAC. To overcome these losses, additional reactive compensation is required at regular intervals on underground installations, typically every 30 km approximately. Not only does this severely limit the feasible installation length of HVAC, it adds to the project cost and also construction and environmental footprint, as the additional compensation equipment requires an installation space of approximately 200 metres x 200 metres.

This technical limitation is one of the primary reasons the longest 500kV HVAC installations in the world are around 30 to 40km in length.

Underground HVAC is significantly more expensive than HVAC overhead

AusNet prepared a preliminary cost estimate to underground the WRL project. This assessment indicated that the cost of underground construction on that project could be up to 16 times the cost of overhead construction for a comparative HVAC solution[111]. The HumeLink Undergrounding Study, commissioned by a collaborative Steering Committee, showed the cost of undergrounding to be at least three times the cost of the project and that it would take a further five years to build.

At a high level, and on a length per cable basis, the AEMO Transmission Cost Database indicates that undergrounding HVAC cables costs are approximately four to 20 times higher than overhead lines. Direct buried cables are at the lower end of this range, while tunnel installed cables are at the upper end. This price differential considers the cable only and does not consider the costs of constructing the transition stations, which are required at locations where the circuit transitions between underground and overhead. Each transition station is similar in size to a small transmission switching station, and typically costs approximately $105 million per station.

The cost of underground cable installation is highly dependent on the terrain and soil characteristics along the route. A complete in-depth study and characterisation of the subsurface and electrical environment is necessary to get an accurate cost estimate for undergrounding a specific section of transmission.

[111] AusNet, Western Renewables Link Underground construction summary, November 2021, p.16, at https://www.westernrenewableslink.com.au/assets/resources/Underground-construction-summary-November-2021.pdf.

Cable joints are required at regular intervals along the length of any underground sections

The high-capacity cables required to deliver equivalent capacity to the overhead circuits considered for VNI West would be very large, which limits the cable length that can be contained on a drum and transported, and hence require joints at regular intervals. Cable joints are installed in joint vaults which are large concrete boxes, with an approximate footprint of 60 square metres and 1.5 metre depth, buried along the underground construction route. In addition to splicing (joining) cables during construction, these vaults are also used for permanent access, maintenance, and repair of the cables.

The number of vaults required for an underground transmission line is dictated by the maximum length of cable that can be transported on a cable drum, the cable's allowable pulling tension, elevation changes along the route, and the sidewall pressure as the cable goes around bends.

For high-capacity 500 kV cable, as would be required for VNI West, it is expected that a minimum of three cables per phase would be required and would need to be spliced (joined) approximately every 500-1,000 metres. Therefore, three cable vaults would be required, adjacent to each other, every 500-1,000 metres along the entire length of any underground cable sections.

Differences in reliability and fault restoration

Overhead and underground lines are exposed to different types of outage and reliability risks. Unlike underground cables, overhead lines are exposed to weather-related outages, such as those caused by lightning strikes. However, the large number of cable joints required for underground high voltage cables increase the risk of failure. In the event of a cable fault, locating and repairing the fault can be challenging and time-consuming, and may take several weeks/months to repair. The duration of outages varies widely, depending on the circumstances of the failure, the availability of parts, and the skill level of the available repair personnel.

The typical outage of a 500 kV cable fault is estimated from 3-6 months and may involve the excavation of hundreds of metres of the cable depending on the type of fault and the extent of the damage. During this time, the circuit capacity will be significantly reduced.

In contrast, a fault or failure of an overhead line can usually be located almost immediately and repaired within hours or, at most, a day or two. In a worst-case scenario where a tower has failed, the majority of supply can be restored, even on temporary structures, within 3-5 days.

Limited supply of underground expertise

The expertise available that can install and repair underground cables gets more rare the higher the voltage. There are only a handful of personnel who have the cable expertise at 500 kV and most of these are tied to a cable supplier, further limiting availability. Further, there are currently no 500 kV underground cable installations anywhere in Australia, so the local technical expertise at this voltage is limited.

The duration of outages varies widely, depending on the circumstances of the failure and the availability of parts. However, they are almost always planned around the availability of suitably skilled repair personnel.

Additionally, the expertise required to manufacture underground cables is limited, which would delay the delivery of VNI West compared to an overhead technology.

Shorter asset life expectancy of underground cables

Underground transmission lines, especially at 500 kV, have higher life cycle costs than overhead transmission lines when combining construction repair and maintenance costs over the life of the line.

In addition, most cables are only supplied by the manufacturer with a maximum design life of 40 years. Overhead transmission lines, on the other hand, can have a design life of 80-100 years. This means that to match the life expectancy of an overhead line, a cable system will have to be replaced after 40 years, significantly increasing the ultimate cost of the solution. This is not factored into the capital cost comparison discussed above.

Construction differences between overhead and underground installations

Installation of an underground transmission cable generally involves the following sequence of events:

1. Clearing.
1. Trenching/blasting.
2. Laying of conduit.
3. Joint vault installation.
4. Backfilling.
5. Cable installation.
6. Site restoration.

The required continuous trench for the construction of underground lines causes greater soil disturbance than overhead lines, limiting the ability to avoid directly impacting environmental and culturally sensitive areas. Overhead line construction disturbs the soil mostly at the site of each transmission tower and can be micro-sited to avoid sensitive areas.

Operational differences between overhead and underground installations

Post-construction, trees and large shrubs would not be allowed within the easement of underground cables due to potential problems with roots. Certain vegetation and agricultural crops with shallow root systems may be allowed to return to the easement. However, these may need to be removed if the ground is required to be excavated for cable repairs. In terms of overhead lines, native vegetation can be retained within the easement up to a limited height.

Underground cables have improved visual and noise amenity as they are not visible after construction and have less impact on nearby property values and aesthetics. Overhead lines may have the potential to impact on visual amenity in sensitive locations.

Overhead lines, during certain climatic conditions, experience corona breakdown. This corona breakdown, which has a cracking sound, occurs when there is a temporary breakdown of the insulation of the air around the conductor. The noise associated with this corona breakdown can only be heard in close proximity to the overhead line. This effect does not occur in underground cable installations.

Underground cables are not exposed to bushfire events and do not hinder aerial firefighting activities. Overhead lines may be required to be deenergised before safe operation can occur by firefighting crews.

While land use activities such as grazing are permitted for both underground and overhead cables, location of structures are restricted within easements. When it comes to underground cables specifically, there is no restriction on irrigation methods or height of machinery as there would be with overhead. Although not restricted in terms of height, there is a restriction on weight of machinery when it comes to entering an underground easement.

These operational differences highlight why undergrounding decisions are very route-specific – in some circumstances it may impede existing land-use.

Width of easements

Underground lines generally require a narrower easement width of approximately 55 metres compared to an overhead line easement of 70 metres. However, the underground line easement width varies with HVAC and HVDC, as well as the required power transfer rating, so can be narrower or wider than this.

While less easement is required to be acquired for cable installations, the allowable vegetation within this easement is restricted to turf and native grasses, as the root systems of larger plants can damage the cable's backfill. As cropping has the potential to impact on the performance of the cable system, there is the potential for limitations on farming activity or livestock grazing.

A5. Cost estimating methodology

Additional work has been undertaken since the PADR and Additional Consultation Report to develop cost estimates for the new options.

The cost estimates presented in this report have been undertaken on a jurisdictional basis with AVP responsible for the estimates of the part of the options located in Victoria and Transgrid responsible for the estimates of the part of the options located in New South Wales. AusNet has provided cost estimates for the changes in WRL scope.

This appendix provides additional detail on the cost estimating methodologies applied by AVP and Transgrid for each of the key categories of cost.

A5.1 Cost estimating methodology for the Victorian components

The cost estimates were prepared on a desktop basis, utilising historical data available to AVP and where applicable, updated with current market costs and cross-checked against AEMO's latest version of the Transmission Cost Database. This section describes how each of the cost categories were estimated.

The cost estimates are considered to an accuracy of ±30%[112], including for the WRL scope change costs, which AVP and Transgrid consider to be 'Class 4' estimates[113] under the AACE International classification. This accuracy level has been selected with consideration to the AACE classification guidelines for the level of design definition completed to date, the intended usage of the estimate, the estimate preparation method, the cost estimate source information, and cost item granularity used to develop the aggregate estimates. AVP and Transgrid consider the cost estimates used in the PACR to be at a higher level of accuracy than estimates wholly developed using AEMO's 2023 Transmission Cost Database's cost estimating tool, since they reflect additional detailed costing undertaken by AVP and Transgrid in the context of this project.

Early works

AVP has estimated the cost of conducting early works as soon as possible to ensure the project can be delivered by July 2031 (the target commissioning date in the most likely ISP scenario). As defined in the ISP, and in more detail in the February 2023 NEVA Order, early works may include:

- Project initiation – scope, team mobilisation, service procurement.
- Stakeholder engagement – with local communities, landholders and other stakeholders.
- Land-use planning – identifying and obtaining all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection and easement acquisition.
- Detailed engineering design – transmission line, structure and substation design, detailed engineering design and planning.
- Cost estimation – finalisation, including quotes for primary and secondary plant.

[112] Accuracy bands have been derived statistically, such that 80% of project estimates should fall within these limits. It is therefore expected that, across a large sample of projects, approximately 20% of them will fall outside of these bands.

[113] AEMO, 2021 *Transmission Cost Report,* August 2021, p. 12.

Substations / terminal stations

Terminal station estimates were bottom-up estimates utilising typical terminal station layouts and indicative concept designs created for the various terminal stations. Unit prices used for this bottom-up estimate were based on historical data available to AVP and where applicable, updated with current market costs. These estimates include:

- Design and project management.
- Plant and equipment.
- Installation.
- Civils.
- Commissioning.

Specifically, as applicable to the option, allowance has been made to establish:

- A new 500/220 kV substation near Kerang, including two 1,000 MVA transformers and four 100 MVAr 500 kV line shunt reactors (size to be confirmed in detailed design). The new Kerang substation also includes 400 MVAr of dynamic reactive compensation on the 220 kV network.
- At the new terminal station planned to be built as part of WRL where VNI West will connect, allowance has been made to install two new 500 kV bays and line exits with a total of two 100 MVAr 500 kV line shunt reactors (size to be confirmed in detailed design).

Line works

Line cost estimations are highly dependent on site-specific matters including terrain, topology, geotechnical and soil conditions. Typical structure types, span lengths and construction methodologies have all been assumed in order to develop reasonable cost estimates. Line lengths have further been refined from the PADR estimates utilising a preliminary desktop approach of identifying and avoiding known technical, land, planning and environmental constraints through the MCA process.

The cost estimate for the new 500 kV transmission lines was based on a double-circuit tower line, with four conductors per phase per circuit. Allowance has also been made for optical ground wire (OPGW) and line surge arrestors.

Like the estimate for the terminal stations, the line estimate was a bottom-up estimate to generate a per-kilometre cost per line voltage level and includes:

- Materials.
- Construction work.
- Preliminaries and overheads.

This bottom-up estimate was then escalated to reflect new market costing information with reference to the concurrent update to the AEMO TCD, as well as recent TNSP per kilometre rates for similar lines. Specifically, the Victorian line costs have been based on the 2023 TCD update for line capital costs.

Power flow controllers / series compensation

The modular power flow controllers were estimated in two parts:

- The first part consists of the actual modular power flow controllers and was estimated based on market costs for the design, supply and installation of the modular power flow controllers.
- The second part consists of the terminal station works to interface the modular power flow controllers to the substations. The estimate for this work followed the same approach as for the substation estimates (outlined above). These estimates were bottom-up estimates utilising typical terminal station layouts and indicative concept designs created for the various terminal stations. Unit prices used for these bottom-up estimates were based on historical data available to AVP and, where applicable, updated with current market costs and site conditions and include the items listed for the substation estimates (outlined above).

This cost category also contains an allowance for series compensation that will be required on the Bulgana–Kerang section of the transmission line to reduce the reactance of the longer option length. The compensation equipment will be located at either the Bulgana or Kerang substations.

Property/land access/easements

Easement compensation

An assessment of the likely easement compensation costs has been undertaken with consideration to Section 41 of the *Land Acquisition and Compensation Act 1986* and the likely zoning, locality and parcel size. An estimate of ongoing land tax costs for easements located in Victoria has been included within this assessment.

Land acquisition

An estimate of land acquisition costs for new terminal stations near Kerang and the new WRL terminal station sites have been developed based on recent sales evidence for suitable sites at these locations. Rates for these locations are dependent on the zoning, locality, usability and parcel size.

An estimate of ongoing land tax costs for the terminal station sites has been included within this assessment.

No individual land or easement valuations can be completed at this stage of the project, as no route is determined.

Additional allowances for accessing land for survey purposes have been included in response to recent changes in the payment structure for access agreements used by other organisations.

Biodiversity offset costs

The biodiversity offset calculations required the determination of the extent of native vegetation that could potentially be impacted by an option[114]. This was achieved through running an indicative 'scenario test native vegetation removal' report using the Victorian Department of Environment, Energy and Climate Action's (formerly the Department of Environment, Land, Water and Planning) Environmental Systems Modelling Platform (EnSym).

The resultant offset requirements from the scenario test included:

- General Habitat Unit (GHU) offset requirements, measured as general habitat units for overall biodiversity impacts to native vegetation.

[114] The indicative option for biodiversity offsets is assumed to be Option 5 due to a density of vegetated areas, parks and reserves within the area of interest. Option 5A and the 5A westerly sensitivity share much of the same area of interest as Option 5, and due to the fact that a route has not yet been determined, the same biodiversity offset requirements/costs were assumed applicable to these options.

- Large Tree losses, estimated at five per hectare within vegetation classes comprising a tree canopy element.
- Species Habitat Unit (SHU) offset requirements, measured as species habitat units for impacts to rare or threatened species.

Significant impacts on EPBC listed vegetation communities and/or threatened flora or fauna that represent matters of national environmental significance are likely to trigger biodiversity offset requirements. Species listed under the *Environmental Protection and Biodiversity Conservation Act 1999* have been identified using the EnSym scenario results, which document the estimated proportion of modelled habitat impacted and potential impacts and estimated offset requirements.

The offset value identified for the worst-case proposed option was then converted to a per/kilometre rate. This per/kilometre rate was then multiplied by the area of interest approximate length for each option to estimate their offset costs.

These cost estimates were refined for the PACR, based on the indicative alignment identified for each option, by undertaking an EnSym scenario test for each of these to calculate the probable biodiversity offset costs.

Western Renewables Link

The cost estimates for any WRL scope changes have been derived from information provided by AusNet, and are considered by AusNet to also have an accuracy of +/- 30%. The methodology described above was used to estimate some of the scope changes the WRL project would incur that were not estimated by AusNet. The costs were estimated on an incremental basis, that is the incremental cost of the scope item over and above the current scope of the WRL project.

The changes to the WRL project scope and associated costs include:

- Uprating the transmission line between north of Ballarat and Bulgana from 220 kV to 500 kV , including costs for a wider easement. To estimate these costs, the per kilometre cost for the current 220 kV line was subtracted from the current market cost for the 500 kV line, while still accounting for known risks by means of an added 30% contingency. The higher voltage line will also require a wider easement, which will incur nominal additional costs that were obtained from independent valuer assessments of land values and compensation rates in the area.
- Relocation and reconfiguration of the proposed terminal station north of Ballarat to Bulgana. To estimate this cost, the cost of the current terminal station configuration was adjusted to account for scope items added or removed (for example, new bays or transformers, refer to Appendix A2 for further details) as required for the new terminal station configuration and operation. Costs were estimated bottom up based on terminal station footprint, land costs, and equipment supply and installation costs per the Substations and Property cost categories above.
- Additional approximately 100 MVAr 500 kV switched bus connected reactor at Sydenham.

The costs associated with change in scope of the WRL project were checked for accuracy by also estimating the total project cost utilising two methods for each of the options, from which an incremental cost was derived by subtracting the current estimated project cost. These two methods were:

- Bottom-up estimates of the entire project based on indicative concept designs created for the various options. Similar to above, unit prices used for this bottom-up estimate were based on historical data available to AVP.

- Using the Transmission Cost Database to produce high-level estimates for a few of the main options to confirm the bottom-up approach accuracy.

Known and unknown risks

The cost estimates include an allowance for known and unknown risks that will or could arise during the further development and execution of this project. The risk items included, and the settings applied for each, are:

- Known risks – where risks are identified but the ultimate value of the risk is not known:
  - Land access / easements / compulsory acquisition – high risk selected to include additional allowance.
  - Cultural heritage – BAU (business as usual); this setting assumes the risk can be mitigated through avoidance or elimination during the route selection process and prudent design.
  - Environmental offset risks (biodiversity) – BAU.
  - Waste disposal/contamination – BAU.
  - Geotechnical makeup along the route (ground conditions for footings) – BAU.
  - Outage restrictions – BAU.
  - Weather delays – BAU.
  - Project complexity – highly complex.
- Unknown risks – where the risk has not been identified but industry experience indicates these could occur. While the cost estimates are a Class 4, a Class 5A level of contingency (that is, higher) has been included in these below risk categories:
  - Productivity and labour cost.
  - Plant procurement cost.
  - Project overheads.
  - Scope and technology.

Landholder payments

The landholder payments recently announced by the Victorian Government have been reflected in the costs of the options in this PACR through the inclusion of additional opex line items.

For the purposes of the estimation of the payment amount, 95% of the total line length of the Victorian portion has been conservatively assumed to be on private land for the purposes of calculating these payments. The line lengths for each option are shown in Table 6 (in Section 3.3.1).

A5.2 Cost estimating methodology for the New South Wales components

The cost estimates were based on a desktop identification and analysis of the credible options with associated line work and substations.

The unit prices used for these estimates were based on historical data available to Transgrid and, where applicable, updated with current market costs.

A further desktop analysis of environmental, social and community, engineering and property constraint criteria was also used to inform the corresponding cost elements.

Transgrid estimated the costs of projects and programs using its estimating tool 'MTWO'[115]. The MTWO cost estimating database reflects actual outturn costs built up over more than 10 years from:

- Period order agreement rates and market pricing for plant and materials.
- Labour quantities from recently completed project.
- Construction tender and contract rates from recent projects.

The MTWO estimating database is reviewed annually to reflect the latest outturn costs and confirm that estimates are within their stated accuracy range and represent the most likely expected cost of delivery (P50 costs). As part of the annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.

All cost estimates in New South Wales have been developed at a high level (Class 4 estimate as defined by Association for the Advancement of Cost Engineering P50 probability of overrun -30% to +50%) based around the scope of work for the relevant option.

Early works

Transgrid has estimated the cost of conducting early works to ensure the project can be delivered by July 2031 (the target commissioning date in the most likely 2022 ISP scenario). As described in the 2022 ISP, early works may include:

- Project initiation – scope, team mobilisation, service procurement.
- Stakeholder engagement – with local communities, landholders and other stakeholders.
- Land-use planning – identify and obtain all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection and easement acquisition.
- Detailed engineering design – transmission line, structure and substation design, detailed engineering design and planning.
- Cost estimation – finalisation, including quotes for primary and secondary plant.
- Strategic network investment – an uplift to the delivered capacity of EnergyConnect between Dinawan and Wagga Wagga, as outlined below.

EnergyConnect enhanced works (incremental line build cost)

Following the Federal Government underwriting[116], Transgrid committed to construct approximately 160 km of EnergyConnect to a 500 kV specification instead of 330 kV. The relevant transmission line section runs between

[115] MTWO is a virtual-to-physical 5D BIM enterprise solution, designed to bring together all stakeholders and workflows on a single, cohesive platform. Built on a bespoke vertical cloud infrastructure supplied by Microsoft Azure, MTWO allows users to integrate and digitalise all project delivery processes in a complete end-to-end solution. More than 100 enterprise-wide modules are built into MTWO, with everything from 5D BIM virtualisation to scheduling, procurement, bidding and tendering on offer. RIB's iTWO cx project management software is also available as part of the MTWO solution.

[116] See https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw.

the proposed Dinawan Substation (south of Coleambally) and Wagga Wagga. The $181.5 million underwriting will enable a 500 kV double-circuit tower line constructed as part of the early works for VNI West.

The incremental cost permits the environmental assessment for, and the design and construction of, larger towers, additional conductors and associated line accessories.

Substations

Substation estimates were bottom-up estimates utilising typical substation layouts and indicative concept designs created for the various substations. Unit prices used for this bottom-up estimate were based on historical data available in Transgrid's MTWO estimating database. These estimates included:

- Design and project management.
- Plant and equipment.
- Installation.
- Civils.
- Commissioning.

Specifically, at Dinawan, a new 500 kV substation will be established including 2 x 1,500 MVA transformers and 4 x 150 MVAr 500 kV line shunt reactors. At the proposed Gugaa substation, allowance has been made to install 1 x 1,500 MVA transformer and 2 x 150 MVAr 500 kV line shunt reactors.

Line works

Line cost estimations are highly dependent on site-specific matters including terrain, topology, geotechnical and soil conditions. Typical structure types, span lengths and construction methodologies were all assumed to develop appropriate cost estimates. Line lengths were further refined from initial PSCR estimates utilising a preliminary desktop approach of identifying and avoiding known technical, land, planning and environmental constraints.

The line estimate was a bottom-up estimate and includes:

- Materials.
- Construction work.
- Preliminaries and overheads.

The cost estimate for the new transmission line was based upon a double-circuit tower line, with four conductors per phase per circuit. Allowance has also been made for OPGW and line surge arrestors.

Power flow controllers

Refer to the Victorian section above on how power flow controllers have been estimated.

Property/land access/easements

An estimate for land acquisition and easements cost was developed from recent similar projects in the region. A 70-metre width allowance was made for 500 kV transmission line easements. Property costs for the proposed Dinawan and Gugaa substations are covered by other ISP projects and no allowance has been made as part of the network option for this project.

No individual property valuations can be completed at this stage of the project, as no route is determined.

Biodiversity offset costs

A high level and indicative estimate of biodiversity offsets costs was prepared for the network option to approximate the potential scale of the biodiversity offset cost for the project. The approach taken to inform the indicative biodiversity cost estimate included identifying a nominal credit value and a nominal Threatened Ecological Communities (TECs) clearance area for threatened ecological communities.

The weighted average credit prices were taken from the New South Wales Department of Planning and Environment Spot Price Index. Furthermore, the Biodiversity Assessment Method Calculator (BAM-C) tool was used to identify the number of Ecosystem Credits and Species Credits that would be required for a nominal clearance area (access tracks and easements).

Strategic payments

In October 2022, the New South Wales Government announced that landowners who host new significant transmission infrastructure will be eligible for payments under the new Strategic Benefits Payment Scheme[117].

These payments have been reflected in the New South Wales operating costs of the options in this report through the inclusion of an additional opex line item. For the purposes of the estimation of the payment amount, the total line length of the New South Wales portion has been assumed to be 184 km, of which 85% is assumed to be on private land.

[117] New South Wales Government, *Strategic Benefit Payments Scheme – for private landowners hosting major new transmission infrastructure projects in New South Wales*, October 2022.

A6. Capital and operating terminal values

Table 17 below separately sets out the terminal values of capital and operating costs (in present value terms), as well as the adjusted net benefits that take into consideration both types of terminal values.

Capital cost terminal values are the undepreciated residual value of capital components of Option 5 and Option 5A.

Operating cost terminal values are the present value of remaining operating costs that will be incurred after the analysis period until the end of the life for each of the assets that make up each option. Operating cost terminal values also include land compensation payments for both New South Wales and Victoria[118], and land taxes for Victoria.

The adjusted net benefits in this appendix are calculated based on the inclusion of both the capital and operating cost terminal values.

Table 17 Capex and opex terminal values and adjusted net benefits

Capex and opex terminal values and adjusted net benefits, $m PV		Option 5	Option 5A
Step Change	Capex terminal value	435	448
	Opex terminal value	114	117
	Capex and opex terminal value	321	331
	Adjusted net benefits	1,712	1,710
Progressive Change	Capex terminal value	541	556
	Opex terminal value	123	126
	Capex and opex terminal value	418	430
	Adjusted net benefits	81	61
Hydrogen Superpower	Capex terminal value	420	433
	Opex terminal value	113	116
	Capex and opex terminal value	307	317
	Adjusted net benefits	1,903	1,909
Weighted adjusted net benefits		1,257	1,251

While the adjusted net benefits differ to the net benefits presented in Section 6 due to the inclusion of operating cost terminal values, the weighted adjusted net benefits show that the ranking of the options does not change and that Option 5 and Option 5A continue to be equivalent and top-ranked (within 0.5% of each other).

[118] New South Wales has land compensation payments over a period of 20 years, while Victoria has land compensation payments over a period of 25 years. A conservative assumption has been made that land compensation payments would continue until the end of VNI West asset life. Land compensation payments are assumed to start in the year of commissioning under each scenario.

A7. Wholesale market modelling methodology

Transgrid engaged EY to undertake wholesale market modelling to assess the gross market benefits expected to arise under each of the credible options and scenarios in accordance with the CBA guidelines. While EY took instruction from Transgrid as its client, assumptions and input data sources were selected in accordance with the CBA guidelines by both Transgrid and AVP as joint RIT-T proponents.

The wholesale market modelling methodology applied to assess gross market benefits in this PACR is the same as that presented in the Additional Consultation Report and is similar to the approach used in the 2022 ISP[119]. The market modelling report accompanying the Additional Consultation Report provides additional detail on these modelling studies, as well as the key modelling assumptions and approach adopted more generally.[120] Input assumptions for the PACR modelling are the same as those described in the Additional Consultation Report market modelling report except for changes to the input assumptions listed in Table 5. This report should be read in conjunction with that report to understand the full context of input assumptions and methodology. The assessment of costs and calculation of net economic benefits and preferred option was conducted by AVP and Transgrid using the forecast gross market benefits and other inputs.

EY applied a linear optimisation model that performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under each of the options. Specifically, EY undertook long-term investment planning to identify the least-cost generation, storage and unrelated transmission infrastructure development schedule, while meeting demand requirements, policy objectives, and technical generator and network performance limitations.

AVP and Transgrid have undertaken a detailed System Technical Assessment, which evaluates the power system behaviour and performance under the credible options and ensures market modelling outcomes are physically plausible, follow the operation of the NEM, and that the power system impacts of the credible options are appropriately represented. This assessment serves as an input to the wholesale market modelling EY has undertaken.

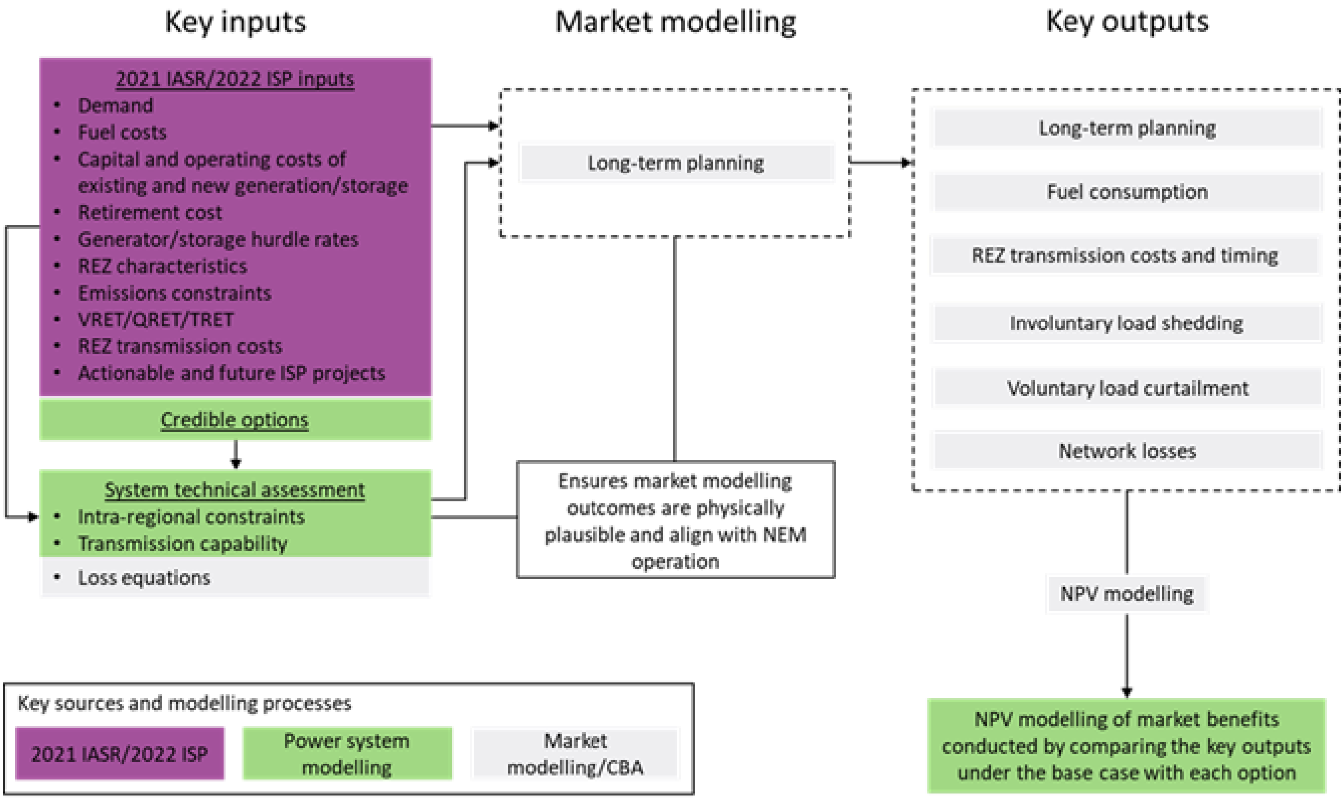
Similar studies are undertaken in developing the ISP.

Figure 25 illustrates the interactions between the key modelling studies and where the key assumptions have been sourced.

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

[120] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/vni-west-rit-t/victoria-to-nsw-interconnector-west-vni-west--market-modelling-report-for-additional-options.pdf?la=en.

Figure 25 Overview of the market modelling process and methodologies



A7.1 Long-term Investment Planning

The function of the Long-term Investment Planning is to develop generation, storage and REZ transmission infrastructure forecasts over the assessment period for each of the credible options and base cases.

This modelling determines the least-cost development schedule for each credible option and scenario drawing on the IASR assumptions used in the 2022 ISP regarding demand, supply, distributed energy resource uptake, network and other underlying assumptions such as carbon budget constraints over the assessment period.

The generation, storage and REZ transmission infrastructure development schedule resulting from the Long-term Investment Planning is determined such that:

- It economically meets hourly regional and system-wide demand while accounting for network losses.
- It builds sufficient generation and storage capacity to meet demand when economic, while considering potential generator forced outages. The cost of USE is balanced with the cost of new generation investment to supply any potential shortfall.
- Generators' technical specifications such as minimum stable loading and maximum capacity are observed.
- Notional interconnector flows do not breach technical limits and interconnector losses are accounted for.
- Hydro storage levels and battery storage state of charge do not breach maximum and minimum values and cyclic losses are accounted for.

- New generation capacity is connected to locations in the network where it is most economical from a whole of system cost.
- Scenario-specific NEM-wide emissions constraints are adhered to.
- NEM-wide and state-wide renewable energy targets are met.
- Generator maintenance outages are scheduled to represent planned generator outages.
- Energy-limited generators such as Tasmanian hydro-electric generators, the Snowy Hydro scheme and battery and pumped hydro storages are scheduled to minimise system costs.
- The overall system cost spanning the whole outlook period is optimised while adhering to constraints.

Rather than use the ISP development opportunities and future ISP projects relating to REZ development directly from the 2022 ISP, these infrastructure development forecasts are redetermined using market development modelling for each state of the world for consistency across the options assessed and the states of the world with and without the options in place. This is necessary to isolate the market outcome changes due to the options under assessment from any market outcomes changes due to differences in the modelling tools and approaches used in the ISP and this RIT-T.

Coal-fired generation is treated as dispatchable between its minimum load and its maximum load in the modelling. Coal-fired 'must run' generation is dispatched whenever available at least at its minimum load. No seasonal mothballing or two-shifting is assumed. Open-cycle gas turbines are assumed to operate with no minimum load; they start and are dispatched for a minimum of one hour whenever the cost of supply is at or above their short-run marginal cost.

The Long-term Investment Planning model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, plus a reserve level sufficient to allow for generation or transmission contingences which can occur at any time, regardless of the present dispatch conditions. This reserve level acts as a proxy for the reliability standard of no more than 0.002% expected USE in any region, in any given year.

Due to load diversity and sharing of reserve across the NEM, the reserve to be carried is minimised at times of peak, and provided from the lowest cost providers of reserve including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

Modelling of intra-regional constraints

The wholesale market simulations include a simplified representation of intra-regional constraints in addition to the inter-regional transfer limits.

Key intra-regional transmission constraints in New South Wales have been captured by splitting New South Wales into zones (Northern New South Wales – NNS, Central New South Wales – NCEN, Canberra – CAN and South West New South Wales – SWNSW), and explicitly modelling intra-regional connectors across boundaries or cut-sets between these zones. Bi-directional flow limits and dynamic loss equations were formulated for each intra-regional connector. This is similar to the ISP, with the exception of South New South Wales being split into CAN and SWNSW in this PACR. In addition, to more accurately capture the benefit of the options being considered, the CAN and SWNSW zones in New South Wales as well as Victoria were split into further nodes and an equivalent network was developed to accommodate the DC power flow with all transmission lines, both existing and defined in the options, explicitly modelled by its impedance and thermal limits.

For the Option 5A westerly sensitivity, an additional N-0 thermal constraint equation, in line with the AEMO NEM constraint equations methodology, was created to capture the limit of Wemen to the new Kerang substation.

Inter- and intra-regional constraints, such as Victoria to New South Wales and Snowy area constraints, are overlaid on the modelled DC power flow.

A8. Model updates between PADR and Additional Consultation Report

A8.1 Five new corridor variants were assessed following PADR consultation, including via a detailed multi-criteria analysis

As outlined in the Additional Consultation Report, five new options that connect VNI West to WRL further west than originally proposed, and taking account of a wider range of factors that may impair social licence, were considered and consulted on following the PADR.

Consideration of these five new corridor variants, as well as the two initial options assessed in the PADR, as part of the Additional Consultation Report included both an assessment of the estimated net benefits of each option, as well as a detailed MCA that assessed a range of other potential environmental, social and engineering constraints. The MCA methodology and results are detailed in Section 4 of the Additional Consultation Report.

A8.2 Alignment with the 2022 ISP

The wholesale market modelling assessment in the Additional Consultation Report (and in this PACR) was updated based on feedback from consultation on the PADR in order to better align with the 2022 ISP[121]. Specifically, this involved:

- Assuming the 2022 ISP scenario-specific retirement dates for coal plant, as opposed to modelling these directly as part of the wholesale market modelling (as was done for the PADR). The same retirement schedule has been applied for this plant under both the base case for each scenario and all option cases.
- Representing carbon budgets better matched to the 2022 ISP, progressively tightening the carbon budgets over time to avoid trading emissions between the early years and later years of study period.
- Extending the modelling horizon until 2049-50 in response to stakeholder feedback.
- Changing REZ transmission cost tranches, including for Darling Downs, South East South Australia, Central Highlands and North Queensland.
- Considering new offshore wind options in Portland and South East South Australia as options to be commissioned in the modelling, if least-cost to do so, with a transmission network limit modelled for Hunter Coast offshore wind.
- Updating the assumed timing of EnergyConnect and WRL from 1 July 2025 and 1 November 2025, respectively, to 1 July 2026 and 1 July 2027 respectively.
- Updating transmission limits for a number of REZs, including SW New South Wales, Wagga Wagga, North West Tasmania and Central Highlands.

[121] The timing of PADR publication meant that the assessment in the PADR was able to reflect the Draft 2022 ISP outcomes published in December 2021 but not the Final 2022 ISP outcomes published in June 2022.

AEMO (in its role as national transmission planner) is required to use the same assumptions as in the most recent ISP when applying the feedback loop. AVP and Transgrid consider that continuity between these two processes in terms of the inputs and assumptions is paramount and consistent with the actionable ISP framework and have therefore kept assumptions consistent with the 2022 ISP wherever possible.

While AEMO updated its NEM generation information database and expected retirement years in February 2023 and March 2023, respectively, the assessment in this PACR continues to apply the same dataset as the PADR and the 2022 ISP (that is, the generation information released by AEMO in February 2022)[122].

The wholesale market modelling undertaken as part of the Additional Consultation Report aligned the plant retirement assumptions with the 2022 ISP to ensure alignment with those assumptions to be used by AEMO in applying the feedback loop for this project. Further, the September 2022 announcement by AGL regarding Loy Yang A Power Station was considered.

In addition, while the 2021 IASR includes a South-West New South Wales REZ transmission limit increase of 900 MW from VNI West (via Kerang), this increase was not modelled in the PADR (or in the Draft 2022 ISP) due to the timing of this impact being made available[123]. AVP and Transgrid do not consider this to have had a material impact on the ranking of the options or the conclusion of the PADR assessment but note that it may have resulted in the benefits of the project for consumers being underestimated.

As part of aligning the assumptions used in this RIT-T with the 2022 ISP, AVP and Transgrid modelled the expected REZ transmission limit increase for the South-West New South Wales REZ (and all other affected REZ) as part of the assessment of VNI West options in the Additional Consultation Report.

A8.3 Option costs were updated to reflect the announced payments for landowners

The New South Wales and Victorian governments have announced that landowners who host new significant transmission infrastructure (like VNI West) will be eligible for additional annual payments. The New South Wales payments were reflected in the analysis presented in the February 2023 Additional Consultation Report, however the estimated km length underpinning these payments has been updated marginally for this PACR. The Victorian payments were not included given the timing of the announcement from the Victorian Government.

A8.4 Refined approach to modelling EnergyConnect in the base case

The Federal Government announced in September 2021 that it is providing up to $181.5 million in underwriting support to enable the section of transmission lines being built from Dinawan to Wagga Wagga as part of EnergyConnect to be constructed at a larger capacity than originally planned[124]. The agreement enables the Dinawan to Wagga Wagga portion of EnergyConnect to be built and operated at 500kV when required, but initially operated at 330 kV (as originally planned).

[122] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[123] As stated in Section 6.1 of the PADR.

[124] See https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw.

Part of the rationale for enhancing this portion of EnergyConnect is that building a single line with larger capacity will save consumers hundreds of millions of dollars by removing the need for duplicate lines as part of the subsequent construction of VNI West. In addition, delivery of a single line will minimise further disruption to landholders in the area and minimise the overall environmental impact[125].

The implications for this RIT-T are that the costs of this portion of the VNI West options assessed in the PADR consequently were reduced from the PSCR. Specifically, while the original scope included a new 500 kV line from Dinawan to Wagga Wagga, the new scope (and so cost) in the PADR and this PACR now only reflects the incremental cost involved with building the line at a higher capacity initially (that is, as a 500 kV line rather than a 330 kV line) and the subsequent costs associated with enabling the line to be operated at 500 kV rather than 330 kV.

The market modelling undertaken for the PADR assumed that the Dinawan to Wagga Wagga portion of EnergyConnect is built to 500 kV but operated at 330 kV under both the base case and the option cases, consistent with the approach taken in the 2022 ISP[126]. However, the base case (that is, if VNI West did not proceed) was updated as part of the updated modelling in the Additional Consultation Report and this PACR to more appropriately assume that this portion is built and operated at 330 kV, as initially intended. This is because building the Dinawan to Wagga Wagga portion of EnergyConnect to 500 kV but operating it at 330 kV is expected to have a different impact on the wholesale market, compared to if it was built and operated to 330 kV. This update has the effect of more accurately estimating the expected benefits of the project for consumers compared to the approach taken in the PADR[127].

A8.5 Additional early closures announced for coal power plants were incorporated

On 29 September 2022, AGL announced it will close the Loy Yang A Power Station up to 10 years earlier than previously planned, targeting the end of the 2035 financial year[128].

This follows earlier announcements made regarding the early closure of coal-fired power stations in the NEM:

- AGL announced in February 2022 that the Loy Yang A Power Station in Victoria would close by at least 2045 (three years earlier than previously indicated) and that Bayswater Power Station in New South Wales will close by at least 2033 (two years earlier than previously indicated)[129].
- Origin Energy submitted a notice to AEMO in February 2022 for the potential early retirement of Eraring Power Station in August 2025 (seven years earlier than previously indicated)[130].

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[125] See https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmissioninfrastructure-southwest-nsw.

[126] AEMO, 2022 ISP, June 2022, p. 66.

[127] See Section 2.6 of the PADR for a more detailed discussion of the approach taken for the PADR and why it was considered immaterial to the assessment overall.

[128] AGL Energy, *A clear pathway for a responsible energy transition,* p. 1, at https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/how-we-source-energy/loy-yang-power-station/220930-ly-transition.pdf.

[129] AGL Energy, *ASX and Media Release – 1H22 Results Announcement*, 10 February 2022, at https://cdn-api.markitdigital.com/apiman-gateway/ASX/asx-research/1.0/file/2924-02485194-2A1355883?access_token=83ff96335c2d45a094df02a206a39ff4.

[130] Origin Energy, *Media release – Origin proposes to accelerate exit from coal-fired generation*, 17 February 2022, at https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

The wholesale market modelling undertaken as part of this PACR aligns the coal-fired plant retirement assumptions with the 2022 ISP for each scenario to ensure alignment with those assumptions to be used by AEMO in applying the feedback loop for this project. Furthermore, the September 2022 announcement by AGL regarding Loy Yang A Power Station was considered. These updates are consistent with modelling for the Additional Consultation Report.

A8.6 Interaction with the Victorian Government's offshore wind policy was explicitly included as a sensitivity

The Victorian Government's Offshore Wind Policy does not currently meet the criteria under the NER necessary to be treated as a 'committed policy' and was therefore not included in the core scenarios for this cost benefit analysis. However, in light of increased government support for Victorian offshore wind, including 'Rewiring the Nation' funding and the Victorian Government's offshore wind targets set out in its Offshore Wind Policy Directions Paper[131], as well as the various points raised in submissions to the PADR and in engagement on the Additional Consultation Report regarding these developments, AVP and Transgrid investigated a sensitivity that assumes significant Victorian offshore wind development going forward.

Specifically, this sensitivity assumed 9 GW offshore wind in Victoria by 2040-41, increasing linearly from 2028-29, in both the base case and VNI West options, commensurate with levels of development anticipated if the Victorian Government's offshore wind policy is legislated. This sensitivity is presented in Section 6.4.1.

A8.7 Modelling horizon was extended

Some submitters to the PADR questioned why the NPV analysis ended in 2047-48, noting that this is 16 years after commissioning of VNI West (via Kerang) in the *Step Change* scenario and two years before the end of ISP modelling[132].

The 25-year modelling period adopted in the PADR is in line with other RIT-T assessments and provides a reasonable period over which to assess the costs and benefits associated with the options, noting that both costs and benefits accrue ahead of the commissioning of VNI West.

However, in light of submitter comments, AVP and Transgrid extended the market modelling period by two years (to 2049-50) based on the inputs available from the 2022 ISP. Extending the modelling period beyond 2049-50 would substantially increase the complexity of the modelling and run-time, require development of new input assumptions beyond what is available in the latest IASR, and is not expected to affect the relativities of the options assessed. Further, the payback period analysis (also undertaken in this PACR – see Section 6.3) shows that benefits are expected to exceed the full investment cost (without deducting the terminal value) during the assessment period.

[131] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.

[132] For example, EUAA, p. 16 and Ted Woodley, p. 8.

A9. Detailed results under *Progressive Change* and *Hydrogen Superpower* scenarios

A9.1 *Progressive Change* scenario

The *Progressive Change* scenario is summarised as 'pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time'. This scenario delivers the decarbonisation objectives of Australia's Emissions Reduction Plan, with a progressive build-up of momentum ending with significant reductions in emissions from the 2040s to meet net zero by 2050. Electric vehicles become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses.

Under these assumptions, Option 5 is found to be the top-ranked option of the options assessed and is expected to deliver net benefits of approximately $204 million. Option 5A is expected to deliver net benefits of $187 million, which is 8% less than Option 5.

Figure 26 presents the estimated net benefits for each option under the *Progressive Change* scenario.

Figure 26 Summary of estimated net benefits in the *Progressive Change* scenario

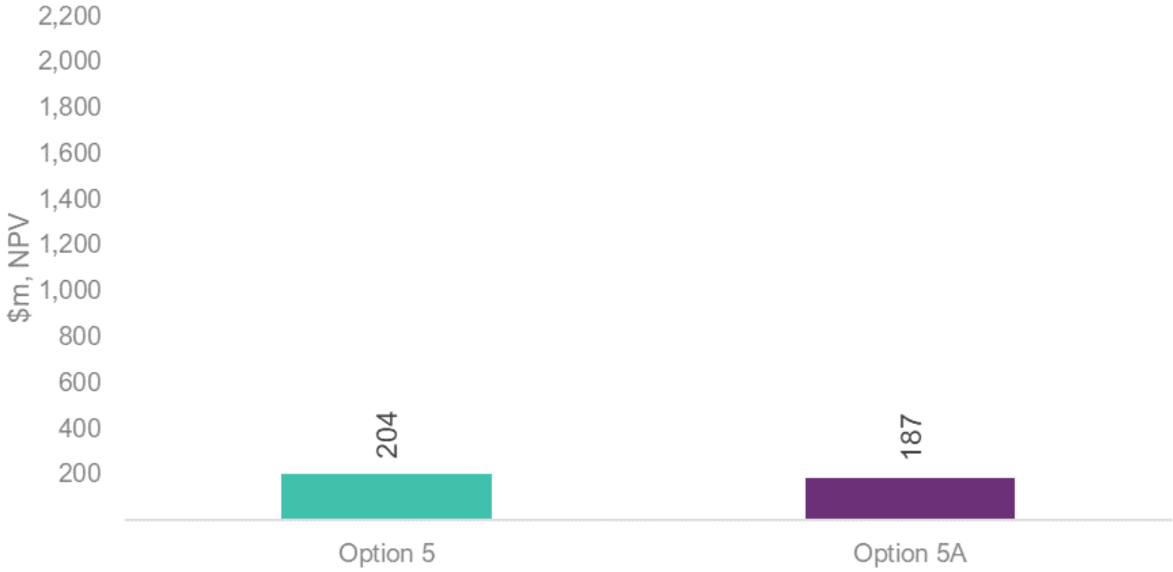
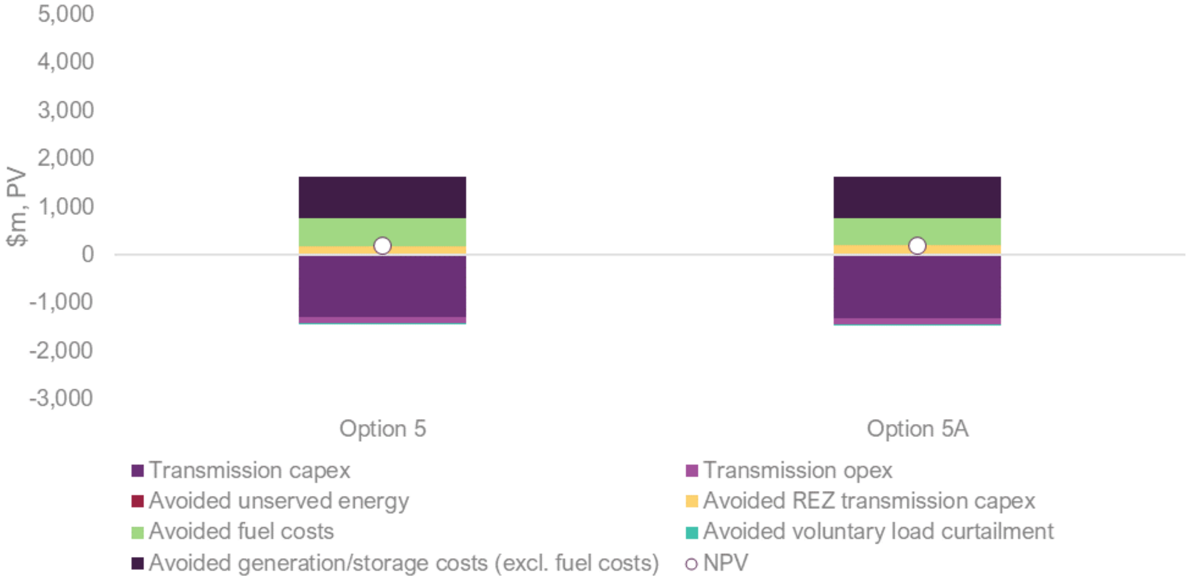


Figure 27 shows the composition of estimated net benefits for each option under the *Progressive Change* scenario.

Figure 27 Breakdown of estimated net benefits under the *Progressive Change* scenario



The key findings from the assessment of each option under the *Progressive Change* scenario are:

- Estimated avoided/deferred generation and storage costs (the darkest sections of each bar in Figure 27) are the largest source of benefit for all options.
  - Estimated avoided/deferred generation and storage costs comprise approximately 53% of the estimated gross benefits of both Option 5 and Option 5A.
  - Similar to the *Step Change* scenario, deferring and avoiding solar, storage and wind are the major drivers for these benefits.
  - While significant new investment is forecast by the end of the modelling period, benefits in this scenario are significantly lower than the *Step Change* scenario due to underlying assumptions, particularly a less restrictive carbon budget assumption and a slower pace of demand growth. This is projected to result in slower coal withdrawals and less renewable and large-scale storage investments in the NEM, which reduces the benefits associated with improved resource diversity through more interconnection.
- Estimated avoided fuel costs (the light green sections of each bar in Figure 27) are the second largest source of benefit for all options.
  - Avoided fuel costs comprise approximately 36% of the estimated gross benefits of both Option 5 and Option 5A.
  - These potential benefits arise primarily from reduced gas generation in Victoria, which is mostly replaced by increased variable renewable energy (VRE) generation in New South Wales and Victoria.
- Estimated Victoria REZ transmission cost savings (shown by the yellow sections of each bar in Figure 27 above) are relatively small in this scenario, and are driven by VNI West improving transmission access to Murray River (V2), Western Victoria (V3) and South West New South Wales (N5) REZs. The higher expected renewable build in these REZs reduces the need for investment in REZ transmission to access wind and solar in other REZs such as South West Victoria (V4), Central North Victoria (V6), Central Highlands (T3) and northern Queensland REZs (and their relevant group REZ transmission constraints).

Figure 28 presents the estimated cumulative expected gross benefits for Option 5A for each year of the assessment period under the *Progressive Change* scenario.

Figure 28 Breakdown of forecast cumulative gross benefits for Option 5A under the *Progressive Change* scenario

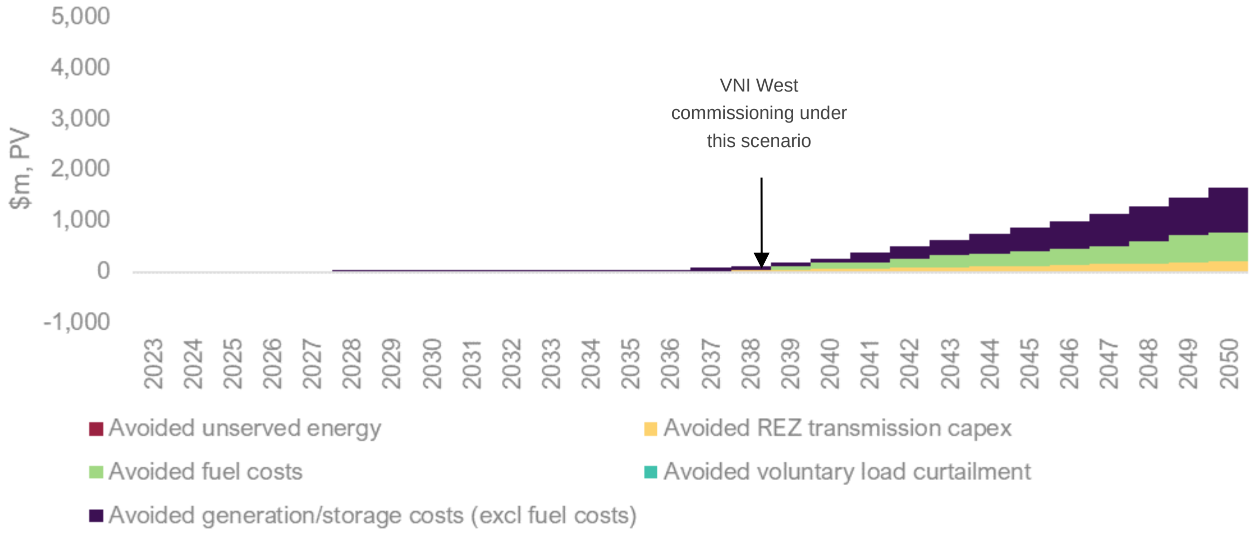


Figure 29 summarises the difference in generation and storage capacity forecast for Option 5A (in GW), compared to the base case. These differences drive the forecast benefits associated with avoided or deferred generation and storage costs.

Option 5A is forecast to generally result in avoiding some solar, battery storage and pumped hydro capacity, though it is also forecast that this option results in a change to the timing of wind build. With this option in place, relatively less investment is required in Victoria and southern regions, although more wind and solar investment is expected in New South Wales. More resource diversity and less expected spill results in generally less forecast need for new capacity than the base case.

Figure 29 Difference in forecast cumulative capacity built with Option 5A, compared to the base case, under the *Progressive Change* scenario

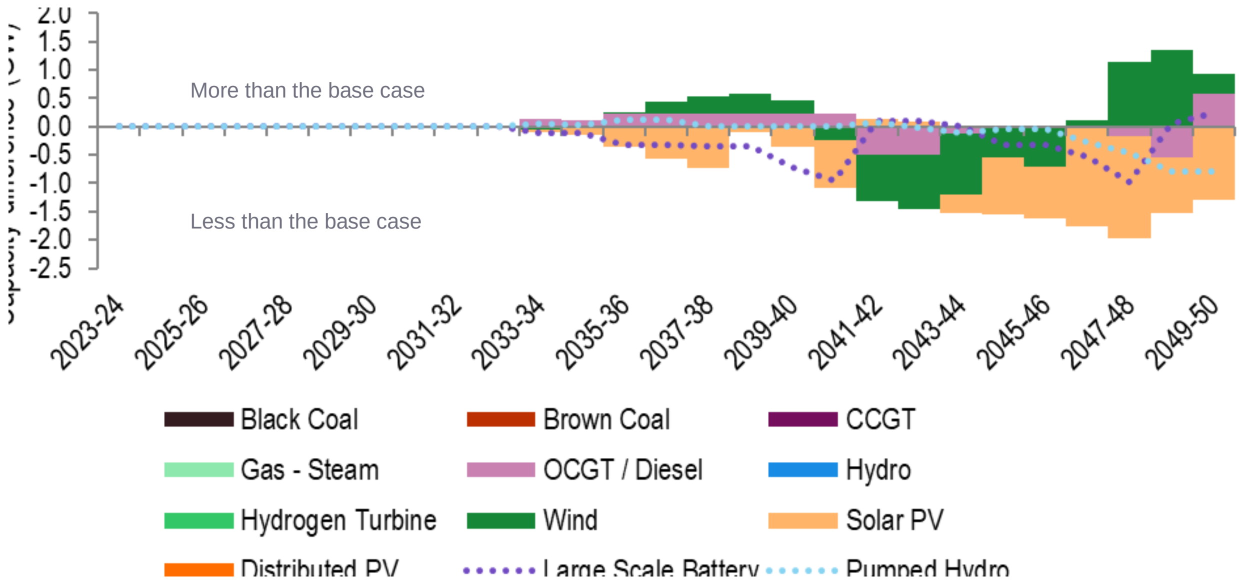
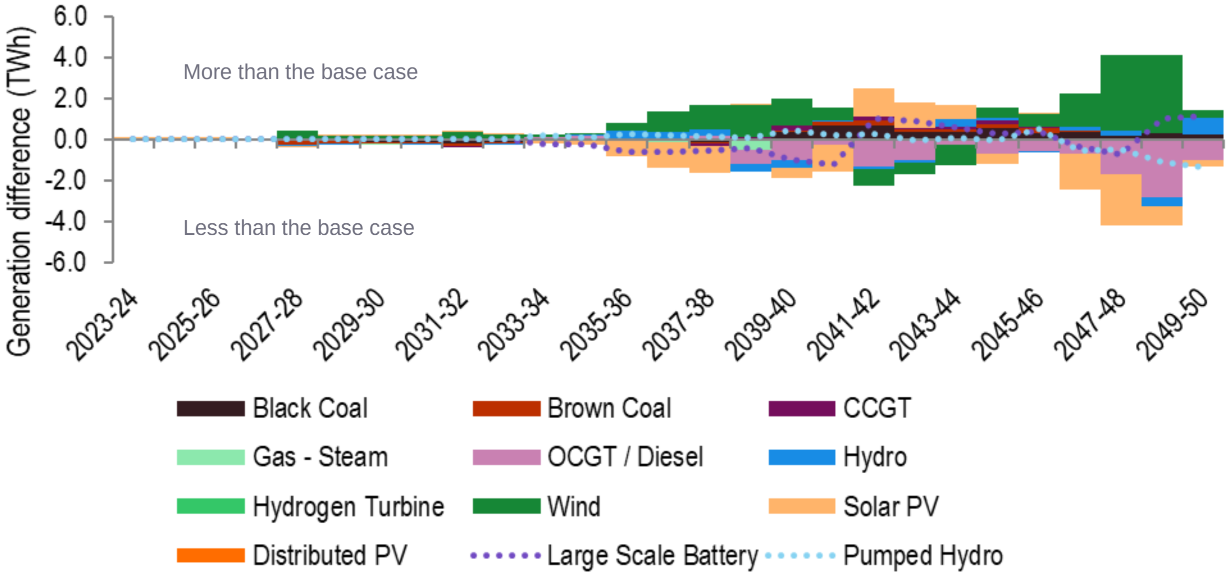


Figure 30 summarises the difference in generation and storage output forecast for Option 5A (in TWh), compared to the base case. These differences drive the forecast avoided fuel cost benefit.

With Option 5A, generally more renewable generation is expected to result in less gas generation in the NEM.

Figure 30 Differences in forecast output with Option 5A, compared to the base case, under the *Progressive Change* scenario



A9.2 *Hydrogen Superpower* scenario

The *Hydrogen Superpower* scenario is summarised as ‘strong global action and significant technological breakthroughs.

While the two previous scenarios assume nearly the same doubling of demand for electricity to support industry decarbonisation, the *Hydrogen Superpower* scenario nearly quadruples NEM energy consumption to support a hydrogen export industry. In this scenario, households with gas connections progressively switch to a hydrogen-gas blend before appliance upgrades achieve 100% hydrogen use[133]. Large-scale solar capital costs are relatively cheap, compared to wind, in this scenario as it is assumed that solar technology cost reductions are a strong driver of hydrogen’s ubiquity.

Under these assumptions, Option 5A is expected to deliver net benefits of approximately $2,025 million. Option 5 is forecast to have net benefits of approximately $2,016 million (0.5% less than Option 5A).

Figure 31 presents the estimated net benefits for each option under the *Hydrogen Superpower* scenario.

[133] AEMO, 2022 ISP, June 2022, p. 31.

Figure 31 Summary of estimated net benefits under the *Hydrogen Superpower* scenario

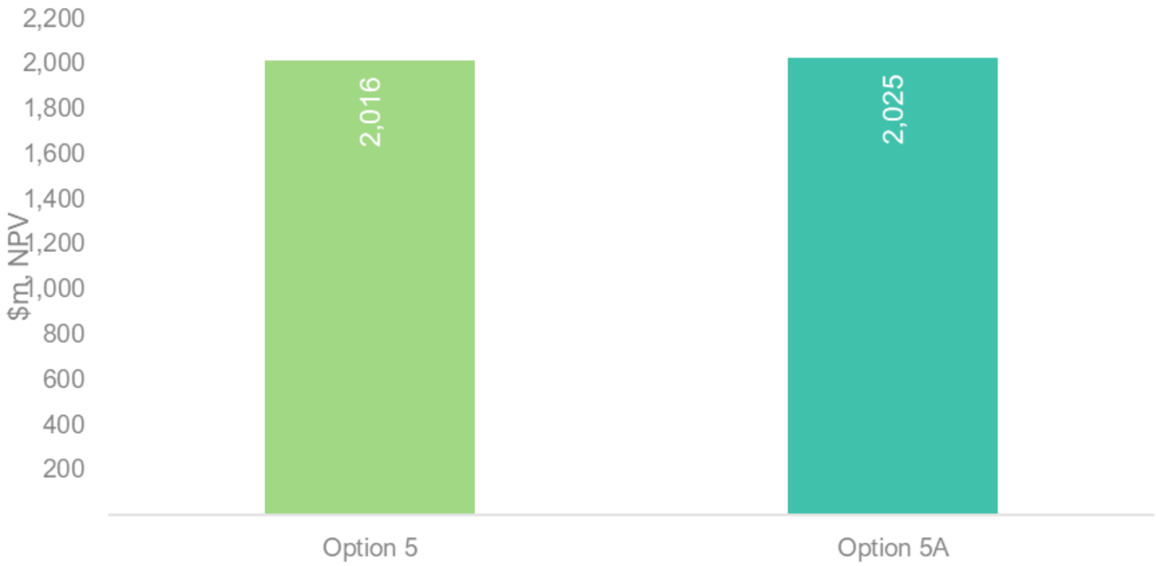
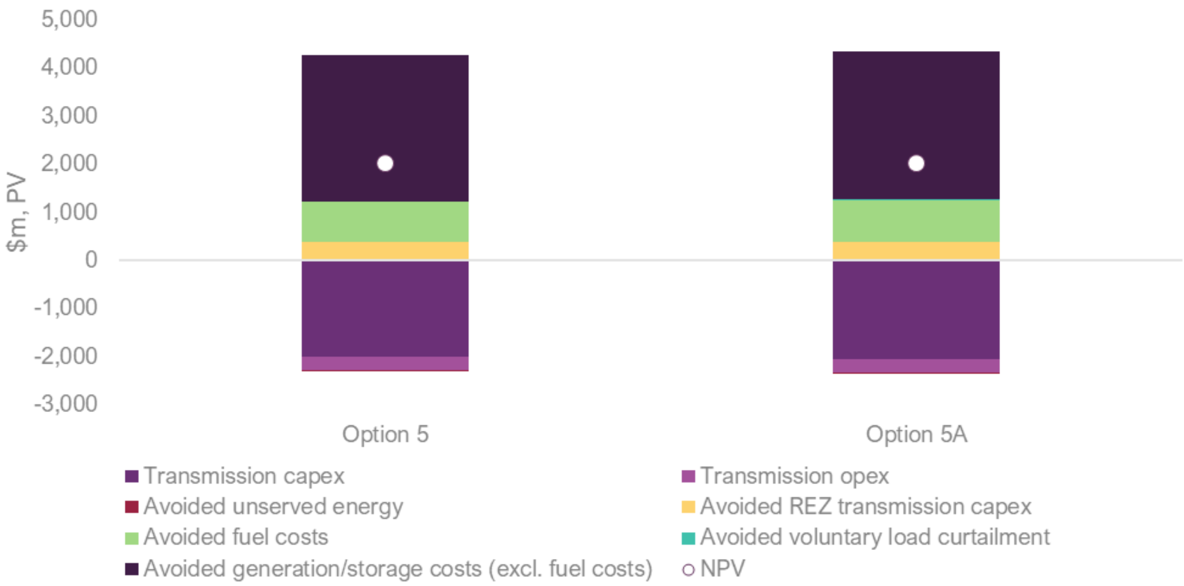


Figure 32 shows the composition of estimated net benefits for each option under the *Hydrogen Superpower* scenario.

Figure 32 Breakdown of estimated net benefits under the *Hydrogen Superpower* scenario



The key findings from the assessment of each option under the *Hydrogen Superpower* scenario are:

- Estimated avoided/deferred generation and storage costs (the darkest sections of each bar in Figure 32) are the largest source of potential benefit for all options.
  - Estimated avoided/deferred generation and storage capital costs comprise approximately 71% of the estimated gross benefits of Option 5A and 72% of Option 5.

  - These forecast benefits are primarily driven by avoided solar capacity in lower quality and overall more expensive areas, deferred and avoided hydrogen turbines and large-scale storage capacity (mostly in Victoria). Instead, there is increased solar and battery storage capacity in New South Wales and wind capacity in Victoria, although total forecast capital investment is lower as the capacity built can be used more efficiently. VNI West effectively allows for more technological diversity which delivers associated efficiencies. The timing of this avoided capacity occurs mostly after the assumed commissioning of VNI West in 2030-31.
  - South Australia and Tasmania are also forecast to require extra solar, large-scale battery and wind capacity in the counterfactual base case. Specifically, with the assumed significant hydrogen demand growth in Tasmania in the last few years of the planning horizon, significant solar and storage is forecast in this region in the base case, some of which is forecast to be avoided with VNI West.
  - Due to significant renewable investment forecast in this scenario, particularly the heavy reliance on large-scale solar sized to meet winter consumption but surplus to requirements in seasons when solar irradiance is highest, considerable renewable spill is forecast in the base case and option cases, being significantly more than other scenarios. However, similar to other scenarios, with improved interconnection through VNI West, resources are forecast to be more efficiently utilised. Across the NEM, VNI West reduces expected solar and wind spill relative to the base case.
- Estimated avoided fuel costs (the light green sections of each bar in Figure 32) are the second largest source of potential benefit for all options.
  - Estimated avoided fuel costs comprise approximately 20% of the estimated gross benefits of both Option 5A and Option 5.
- Estimated REZ transmission cost savings (shown by the yellow sections of each bar in Figure 32 above) are driven by the unlocked transmission network capacity for the REZs in the VNI West path as well as VNI West harnessing generation and capacity diversity between Victoria and northern states such as New South Wales and Queensland to replace/defer REZ transmission expansion in REZs such as Central North Victoria (V6), Gippsland (V5) and other regions' REZs.

Figure 33 presents the estimated cumulative expected gross benefits for Option 5A for each year of the assessment period under the *Hydrogen Superpower* scenario.

Figure 33 Breakdown of forecast cumulative gross benefits for Option 5A under the *Hydrogen Superpower* scenario

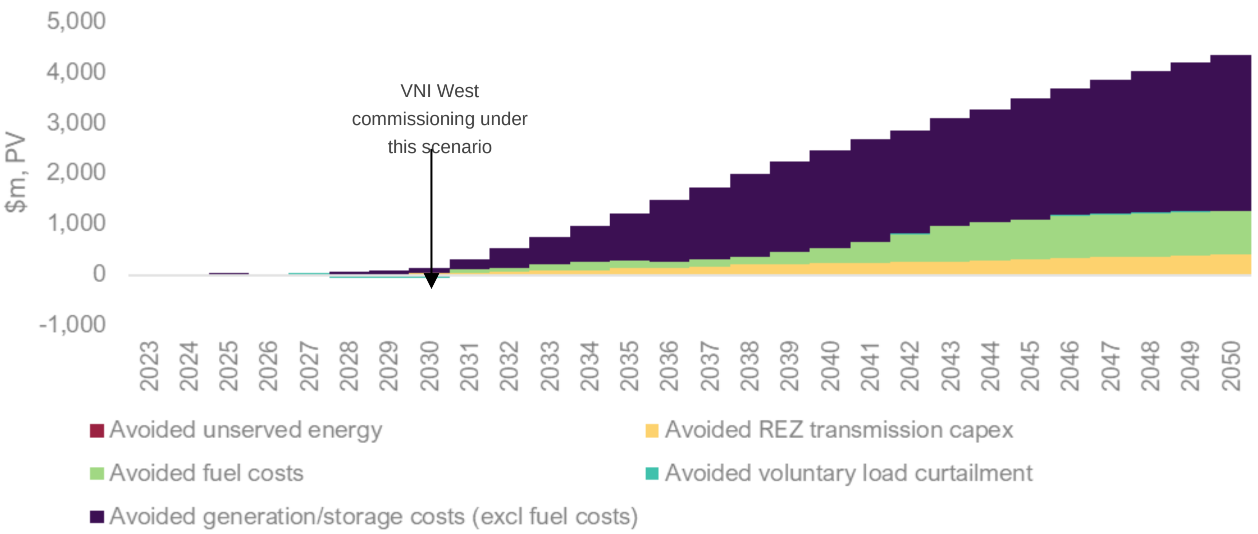


Figure 34 summarises the difference in generation and storage capacity forecast for Option 5A (in GW), compared to the base case. These differences drive the forecast benefit associated with avoided or deferred generation and storage costs. Option 5A is forecast to result in more wind capacity and less solar and storage compared to the base case. The reduction in solar investment exceeds the increased investment in wind so that in aggregate, there is reduced investment in renewable capacity forecast. However, total expected investment in wind and solar is still substantial relative to today. In most years of the assessment period levels of renewable generation are similar with and without VNI West or greater with VNI West, but the generation can be produced more efficiently, with less capital investment, with VNI West. In addition, some forecast hydrogen turbine capacity investment is avoided.

Figure 34 Difference in forecast cumulative capacity built with Option 5A, compared to the base case, under the *Hydrogen Superpower* scenario

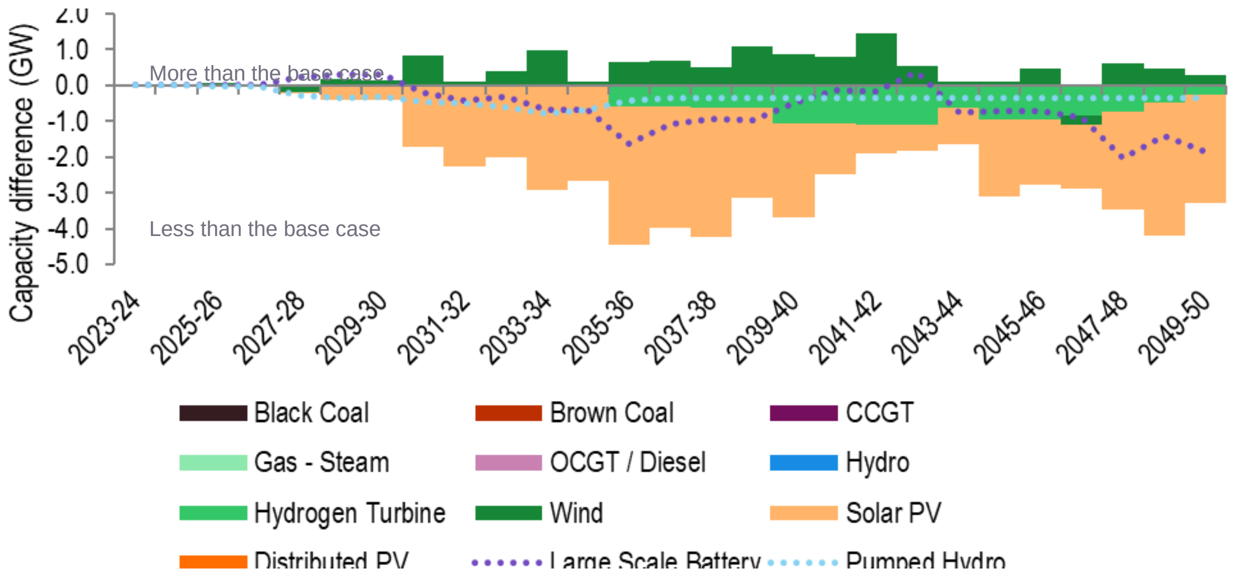


Figure 35 summarises the difference in generation and storage output forecast for Option 5A (in TWh), compared to the base case. These differences drive the potential avoided fuel cost benefits.

Reduced hydrogen turbine generation is expected to be the main contributor to forecast fuel cost savings observed over much of the planning horizon.

Figure 35 Difference in forecast output with Option 5A, compared to the base case, under the *Hydrogen Superpower* scenario