AEMO
AUSTRALIAN ENERGY MARKET OPERATOR
Victorian Planning

Transgrid

VNI West Consultation Report – Options Assessment

February 2023

Regulatory Investment Test for Transmission

Important notice

Purpose

The Australian Energy Market Operator Limited (AEMO) in its Victorian transmission planning role under the declared network functions in the National Electricity Law (NEL) - and NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Networks Operations Trust trading as Transgrid (Transgrid) have prepared this Additional Consultation Report to support the consultation requirements of clauses 5.16A.4(c) – (h) of the National Electricity Rules and, in relation to AEMO and the Victorian section of the VNI West, to comply with functions conferred on AEMO under the order made on 20 February 2023 by the Victorian Minister for Energy and Resources pursuant to section 16Y the National Electricity (Victoria) Act 2005 (NEVA)(the NEVA Order).

Disclaimer

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

This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules or any other applicable laws, procedures or policies. AEMO and Transgrid have made every reasonable effort to ensure the quality of the information in this document but cannot guarantee its accuracy or completeness.

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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 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 for the Australian economy to achieve net zero emissions by 2050. The forecast closure of ageing coal-fired generators in Victoria and New South Wales over the coming decades presents a significant challenge to supply reliability. 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 to deliver benefits to consumers.

The Victoria – New South Wales Interconnector (VNI) West is a proposed new transmission link between Victoria and New South Wales that will help harness clean, low-cost electricity from renewable energy zones (REZs) in both states, helping reduce the cost of carbon emissions abatement and improving the reliability and security of electricity supply as ageing coal-fired power stations close. Western Renewables Link (WRL), a new double-circuit high voltage transmission line between Bulgana and Sydenham currently being progressed through the environmental and planning approvals process by AusNet, also supports this goal, by increasing transmission network capacity for existing and new renewable generation in western Victoria.

Under its declared network functions – including for Victorian transmission planning – set out in the National Electricity Law (NEL), AEMO Victorian Planning (AVP) is responsible for planning and directing augmentation on the Victorian electricity transmission Declared Shared Network (DSN). AusNet owns and operates much of that network. Transgrid operates and manages the high voltage electricity transmission network in New South Wales and the Australian Capital Territory and is the Jurisdictional Planning Body for New South Wales.

AVP and Transgrid are consulting on a proposal to increase the capacity to share electricity between Victoria and New South Wales via terminal stations near Kerang and Bulgana

As part of the Regulatory Investment Test for Transmission (RIT-T), AVP and Transgrid published a Project Assessment Draft Report (PADR) in July 2022 which evaluated the technical and economic feasibility of credible VNI West options. The PADR identified 'VNI West (via Kerang)' as the proposed preferred option and sought consultation and feedback from a wide range of stakeholders on the options assessed and analysis undertaken. Twenty-six submissions were received.

Additionally, on 20 February 2023, the Victorian Minister for Energy and Resources used powers under the National Electricity (Victoria) Act 2005 (NEVA)[1] to issue an order pursuant to section 16Y of the NEVA (NEVA Order). The NEVA Order confers upon AVP functions which include the assessment of alternate options to the preferred options[2] to expedite the development and delivery of those projects[3].

An updated cost benefit assessment of VNI West has now been undertaken in response to submissions received, including assessing the robustness of the analysis under a wider range of sensitivities and considering several new options that connect VNI West to Western Renewables Link (WRL) further west than originally proposed. In ranking these options, greater consideration is also now given to environmental, social and engineering matters that may increase likelihood of timely project delivery and better reflect local community needs.

AVP has had regard to its functions under the NEVA Order in assessing and ranking these options.

[1] See http://www.gazette.vic.gov.au/gazette/Gazettes2023/GG2023S060.

[2] As described in the VNI West PADR and the WRL Project Assessment Conclusions Report (PACR).

[3] Being the VNI West and WRL Specified Augmentations as described in clauses 3 and 4 of the Neva Order.

Based on this analysis, the proposed preferred VNI West option is now a 500 kilovolt (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.

This is a change from the proposed preferred option presented in the PADR that connected to WRL at the proposed terminal station north of Ballarat. The additional options analysis presented in this report finds that:

- Moving the point of connection with WRL west of the currently proposed terminal station location north of Ballarat (Djaara Country) to Bulgana (Wotjobaluk Country) provides greater net benefits for consumers, with this option delivering $1.39 billion of net benefits in present value terms.
- Regardless of where VNI West connects into WRL, it is beneficial to uprate the WRL segment from the proposed terminal station north of Ballarat to Bulgana to 500 kV (from the currently proposed 220 kV) to harness more renewable generation in Western Victoria as early as 2027.
- Connecting VNI West to WRL at Bulgana is most likely to assist in expediting the development and delivery of VNI West as it has the fewest environmental and social constraints identified in the area of interest.

There is found to be a 1% difference in net benefits between the top two ranked options in this report – referred to as 'Option 3A (to Waubra/Lexton with spur)' and 'Option 5 (to Bulgana)'. However, once other potential environment, social and engineering constraints are considered, using multi-criteria analysis (MCA), Option 5 clearly outperforms Option 3A (and all other options), so Option 5 is now the proposed preferred option.

Option 5 connects directly from the proposed new terminal station near Kerang to a new terminal station at Bulgana (near Ararat/Stawell). As it does not require a new terminal station near Bendigo, total costs are lower than for the alternatives, even once the costs of uprating the WRL segment to 500 kV are taken into account. Due to the long line length involved to connect directly from a terminal station near Kerang to a terminal station at Bulgana, impedances are relatively high and the design is more technically challenging from a power system perspective. While still harnessing an additional 3.4 gigawatts (GW) of new renewable generation in Victoria, these high impedances and a differing network configuration do result in less new renewable generation being supported (therefore delivering fewer gross benefits), compared to the other options considered. The lower costs and lower benefits tend to balance out, so the estimated net benefits of Option 5 remain equal highest.

Option 5 is also robust to changes in key inputs, tested through sensitivity analysis and boundary testing. In particular, assuming it is legislated, the legislation of the Victorian Government's offshore wind policy (modelled as a sensitivity) would result in Option 5 being the option that maximises net benefits for consumers. This is because the greater resource diversity created from the introduction of offshore wind increases system resilience and reduces the value of VNI West options that have the potential to harness significantly more renewable generation in Western Victoria than Option 5 (such as Option 3A). An increase in the assumed network capital costs for all options of 9% or more, or a discount rate of 6% or more, would also result in Option 5 delivering the greatest net benefits.

Option 5 (to Bulgana) is therefore the proposed preferred option for further development. Feedback is sought from stakeholders on the outcomes of this assessment. Specifically, views are sought on the feasibility of Option 5 and whether the MCA has captured the salient environment, social and engineering factors, including those that sit outside the scope of the RIT-T but may impact on timely project development.

Stakeholder feedback on the PADR has been taken into account in this report

AVP and Transgrid have been actively engaging with stakeholders and communities to capture feedback on the PADR since mid-2022. AVP and Transgrid are grateful for the feedback received and for the open and ongoing dialogue with stakeholders and communities. Genuine and positive engagement is essential for project success and AVP and Transgrid thank those stakeholder and community members for their contribution to the RIT-T process.

While submissions received on the PADR covered a range of topics, the 10 broad themes most commented on were:

- The importance of transparency and meaningful consultation with stakeholders
- Support for increased interconnection between Victoria and NSW; and the potential to accelerate delivery and expand capacity
- The importance of considering social license issues, including the impact of options on visual amenity, biodiversity, land use, culture, heritage, tourism and bushfire risk
- Support for consideration of alternative interconnection corridors, further west in Victoria
- The accuracy of the cost estimates used
- Interaction with the Western Renewables Link
- Interaction with other major NEM projects
- Concern about the consistency of the assessment with government policies relating to emissions and renewable generation
- Comments on the wholesale market modelling (including anticipatory benefits)
- Queries regarding the methodologies applied for the NPV modelling and terminal value

AVP and Transgrid have been actively engaging with stakeholders and communities to capture feedback on the PADR since mid-2022. A number of PADR submission themes helpfully identified the need for the PACR process to consider a number of selection criteria – including net benefits, environmental impacts, cultural heritage, social impacts, land use, and engineering among others – in identifying a preferred solution.

Stakeholder information sessions and meetings were held during and after the PADR consultation period. 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), many of which had made submissions to the PADR. The focus of these discussions was the technical and economic assessment published in the PADR. AVP and Transgrid extended offers to meet with all submitters.

Each of the points raised in PADR submissions and feedback received subsequently, along with AVP and Transgrid's responses, have been summarised in the VNI West PADR submissions report[4] released alongside this report.

How has the feedback influenced this current assessment?

AVP and Transgrid have updated the assessment in a number of areas in response to points raised in consultation on the PADR. AVP has also had regard to the NEVA Order in doing so. For example:

[4] At https://aemo.com.au/initiatives/major-programs/vni-west/stakeholder-consultation.

- Considering 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.
- Extending the modelling horizon until 2049-50 in response to stakeholder feedback.
- Updating the option costs for the New South Wales portion of investment to reflect the New South Wales Government Strategic Benefits Payment Scheme for landowners announced in October 2022[5].
- Improving alignment to the RIT-T instrument[6] and the Australian Energy Regulator's (AER's) cost benefit analysis (CBA) guidelines[7] through better alignment with the 2022 *Integrated System Plan* (ISP) parameters in a number of ways including:
  - Applying coal retirement outcomes in the same manner across the base case and all VNI West options updated with the most recent retirement announcements including Loy Yang A retirement in 2035 and Torrens Island B Power Station retirement in 2026.
  - 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.
- Modelling the Dinawan to Wagga Wagga portion of EnergyConnect as being built and operated at 330 kV under the base case (as opposed to being built to 500 kV but initially operated at 330 kV, as in the PADR).
- Expanding the scope of the sensitivity analysis and boundary testing conducted, including assessing the impact of changes in transmission costs, and the Victorian Government's announced (but not yet legislated) offshore wind policy[8].
- Increasing the transparency regarding cost estimates and approach to calculating terminal value.

Seven options were assessed as part of the process

In total, seven VNI West options were assessed: the two options presented in the PADR and the five new options connecting VNI West to WRL further west. All seven options assessed:

- Involve a 500 kV double-circuit transmission line.
- Originate at Dinawan, in New South Wales, with connection to EnergyConnect.
- Include new terminal stations near Kerang, in Victoria, with a connection to the existing 220 kV line to Kerang.

The differences in the options relate to the Victorian scope and can be summarised as:

- **Option 1 (to north of Ballarat)**, 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.

[5] There is currently no Victorian equivalent to the New South Wales Strategic Benefits Payment Scheme, although AVP notes that the Victorian Government has been consulting on compensation and benefit sharing arrangements in Victoria as part of Victorian Renewable Energy Zone development and proposed reforms to the Victorian Transmission Planning Framework outlined in the Victorian Transmission Investment Framework.

[6] See https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

[7] See https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Guidelines%20to%20make%20the%20ISP%20actionable%20-%2025%20August%202020.pdf.

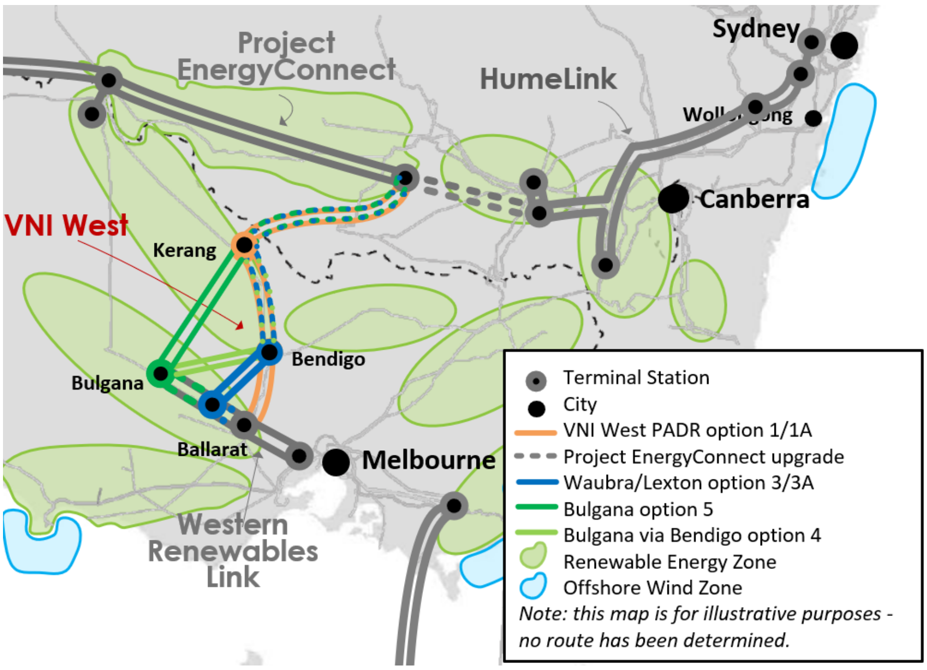
[8] As detailed in the 2021 *Inputs, Assumptions and Scenarios Report* (IASR), AEMO applies the 'public policy clause' set out in the National Electricity Rules (NER) when determining whether a policy is included in scenarios. As the Offshore Wind Policy signalled in the Victorian Government's Offshore Wind Policy Directions Paper March 2023 is not yet legislated, it does not satisfy any of the criteria listed in the NER and is therefore only modelled as a sensitivity.

 - **Option 1A (to north of Ballarat with spur uprate to 500 kV)** – is the same as Option 1 but with the 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.

- **Option 2 (to north of Ballarat plus non-network**), per the PADR – is 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 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.
  - **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.
- **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 5 (to Bulgana)** – connects from Dinawan, via the new terminal station near Kerang, directly to WRL at a new terminal station near Bulgana (Wotjobaluk Country). This option requires relocation of the WRL proposed terminal station from north of Ballarat to Bulgana and the uprate of the proposed WRL transmission line from 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.

The seven credible options assessed as part of the process are shown in Figure 1 below.

Figure 1 Credible options assessed



WRL is currently planned to be delivered in 2026. Under every VNI West option considered, including the existing option, delivery of WRL is assumed to be delayed to 2027. VNI West would be delivered in accordance with the ISP scenario-dependent timing. For example, for Option 5, the 500 kV double-circuit line from Sydenham to Bulgana (a variant of 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). The assumed one-year delay to WRL and its variants is based on the assumption that any change in the design would lead to schedule delays, but that continuing with the existing design (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.

AusNet is currently preparing an Environment Effects Statement (EES) for the WRL project. All necessary approvals would need to be obtained, including any changes in scope, prior to construction of WRL commencing.

The technical characteristics of the credible options are summarised in Table 1 below. Specifically, this table shows the indicative impact on transfer capability (in both directions) and the REZ transmission limit[9] (by affected REZ) for each option, based on AVP and Transgrid's power system analysis assessing both the thermal and voltage stability limits, as well as the estimated capital costs.

The interconnector transfer capability and REZ transmission limits vary considerably between options as a result of the different line lengths, line uprates, and network configurations between options. Options with longer, higher impedance lines result in existing parallel networks reaching their capacity limits before the new interconnector can be fully utilised. Options with shorter, lower impedance lines better share power flow between existing parallel networks, which allows greater utilisation of the new 500 kV network and maximises the interconnector transfer capability.

The exception to the longer route length having a lower interconnector transfer capability is Option 5, which is a direct result of this option including series compensation or additional power flow controllers on the 'near 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.

All else being equal, REZ transmission limits increase the further west the 500 kV is proposed to be extended by uprating the 220 kV segment of WRL, due to the higher capacity of the 500 kV lines. However, the differing network configurations between various options also have a significant impact on REZ transmission limits. For example, Options 1 through to 3A have Waubra Terminal Station and Waubra Wind Farm decoupled from the existing Ballarat–Waubra–Ararat–Crowlands–Bulgana 220 kV network and connected to the new parallel network (with the cost of this decoupling included in the total capital cost of the option). This releases network capacity on the existing 220 kV western Victoria network and allows greater utilisation of the new 220 kV or 500 kV network. Option 4 and Option 5 do not decouple Waubra from the existing 220 kV, which results in the existing 220 kV network reaching its limits before the new parallel 500 kV network can be fully utilised. More renewable generation might be able to be harnessed from these two options if Waubra Wind Farm was decoupled from the existing 220 kV in future and, for Option 5, if further augmentation was undertaken to manage loading on the existing Kerang–Bendigo 220 kV line.

The costs associated with any changes to WRL as a result of VNI West, such as uprating of lines from 220 kV to 500 kV or relocation of the proposed terminal station north of Ballarat, are included as part of the VNI West economic assessment. As a result, all new options have a higher capital cost than Option 1, predominately driven

[9] 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 generation such as wind and solar does not always operate at full capacity.

by the cost to uprate the WRL segment from 220 kV to 500 kV. Option 5 has only a marginally higher capital cost than Option 1 because it does not require a new terminal station near Bendigo, which largely offsets the additional costs of uprating the WRL segment to 500 kV.

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 1 (to north of Ballarat)	+1,930 megawatts (MW)	+1,800 MW	V2 - Murray River: +1,600 MW V3 - Western Vic (WRL timing): +600 MW V3 - Western Vic (VNI West timing): +550 MW N5 - South West NSW: +900 MW	+3,650 MW	3,254
Option 1A (to north of Ballarat with spur uprate to 500 kV)	+1,930 MW	+1,800 MW	V2 - Murray River: +1,600 MW V3 - Western Vic (WRL timing): +1,460 MW V3 - Western Vic (VNI West timing): +750 MW N5 - South West NSW: +900 MW	+4,710 MW	3,701
Option 2 (to north of Ballarat plus non-network)	+250 MW from the VTL +1,930 MW from Option 1 (to north of Ballarat)	+250 MW from the VTL +1,800 MW from Option 1 (to north of Ballarat)	Same as Option 1 (to north of Ballarat) once it is commissioned (that is, no additional REZ hosting capacity associated with VTL component)	+3,650 MW	3,873
Option 3 (to Waubra/Lexton)	+1,830 MW	+1,650 MW	V2 - Murray River: +1,600 MW V3 - Western Vic (WRL timing): +950 MW V3 - Western Vic (VNI West timing): +700 MW N5 - South West NSW: +900 MW	+4,150 MW	3,440
Option 3A (to Waubra/Lexton with spur uprate to 500 kV)	+1,830 MW	+1,650 MW	V2 - Murray River: +1,600 MW V3 - Western Vic (WRL timing): +2,590 MW V3 - Western Vic (VNI West timing): +1,400 MW N5 - South West NSW: +900 MW	+6,490 MW	3,685
Option 4 (to Bulgana via Bendigo)	+1,700 MW	+1,475 MW	V2 - Murray River: +1,600 MW V3 - Western Vic (WRL timing): +1,460 MW V3 - Western Vic (VNI West timing): +580 MW N5 - South West NSW: +900 MW	+4,540 MW	3,685
Option 5 (to Bulgana)	+1,930 MW	+1,650 MW	V2 - Murray River: +850 MW V3 - Western Vic (WRL timing): +1,460 MW V3 - Western Vic (VNI West timing): +200 MW N5 - South West NSW: +900 MW	+3,410 MW	3,282

* 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 the body of this report. That is, early works, substation works, line works, battery costs (for the VTL option), power flow controllers, property/land access/easements and biodiversity offset costs. The Option 2 capital costs are also inclusive of battery replacement costs that will be incurred in 2047.

The net present value (NPV) assessment finds that Option 3A and Option 5 are effectively jointly ranked first

On a scenario-weighted net benefit basis[10], Option 3A and Option 5 are found to be ranked effectively equally as the top-ranked options. Option 3A is expected to deliver net benefits of approximately $1,408 million, while Option 5 is found to have net benefits of approximately $1,388 million (1% less than Option 3A). From a net

[10] 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.

benefit perspective, these two options are the top-ranked two options under the *Step Change* and *Progressive Change* scenarios and are ranked equally with Option 1, Option 1A and Option 2 under the *Hydrogen Superpower* scenario.

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 main drivers of the increased benefits since the PADR modelling are the extended modelling period (to 2049-50) in response to stakeholder input, refinements in the assumptions around the unlocked transmission capacity for the South West New South Wales (N5) REZ (due to the interaction between EnergyConnect and VNI West) and the better alignment with the 2022 ISP parameters as required under the RIT-T instrument and AER CBA Guidelines.

Figure 2 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 any options that are found to have net benefits that are within 5% of the top-ranked option. All other options are shown with purple bars.

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 option 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.

Additionally, while WRL remains an anticipated project, cost benefit analysis has been conducted for WRL and VNI West projects combined and compared to an alternative base case without either project, to address stakeholder concerns with the allocation of costs and benefits in the RIT-T assessment process and that the total cost of both projects combined may not deliver net benefits to consumers.

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

- Assuming it is legislated, the Victorian Government's offshore wind policy reduces the expected net benefits of Option 3A and Option 5 (but they are still expected to generate significant net benefits in the order of $702 million and $1,008 million, respectively, under the *Step Change* scenario). Option 5 would become the highest ranked option under this sensitivity.
- The full costs of WRL and VNI West are significantly outweighed by the expected benefits from both projects, compared to a base case where neither investment goes ahead (Option 3A + WRL and Option 5 + WRL are expected to deliver $1,928 million and $1,909 million in net benefits, respectively, under this sensitivity).
- Assuming it is legislated, the Victorian Government's offshore wind policy reduces the expected net benefits from both projects combined, but significant net benefits are still generated. Option 5 would become the highest ranked option under this sensitivity (Option 3A + WRL and Option 5 + WRL are expected to deliver $918 million and $1,225 million in net benefits, respectively, under the *Step Change* scenario).
- Removing the *Hydrogen Superpower* scenario from the assessment, as was suggested by a submitter to the PADR, does not change the key findings of the assessment.
- If underlying capital costs were to increase by 9% or more, Option 5 delivers greater net benefits than any other option assessed.
- Similarly, Option 5 delivers greater net benefits than any other option assessed if a discount rate of 6%, or higher, is assumed. As highlighted in AEMO's Draft 2023 *Inputs, Assumptions and Scenarios Report* (IASR), pre-tax real discount rate estimates have increased in the past year due to strong inflationary pressures with an associated sharp increase in the risk-free rate (government long-term bond yields) and a higher debt premium. Assuming the central estimate of 7% from the Draft 2023 IASR, Option 5 would deliver $48 million more net benefits than Option 3A (8%)[11].

On balance, the sensitivity and boundary testing finds that Option 5 performs better than Option 3A when assumptions are varied in the direction the market currently appears to be heading, and the finding that both perform better than all other options is robust to these changes in assumptions.

Multi-criteria analysis shows connecting VNI West to WRL at Bulgana is the proposed preferred option

AVP, in conjunction with external consultants AECOM, has developed a detailed MCA methodology to further assess the options and help determine which option is most likely to facilitate timely delivery, consistent with the functions conferred by the NEVA Order[12]. The MCA methodology has been designed to focus on social and

[11] Under the NER, the RIT-T instrument specifies that the RIT-T proponent must adopt the most recent ISP parameters in undertaking its cost benefit assessment, or identify and provide demonstrable reasons for 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. As the 7% central discount rate proposed to be used in the next IASR remains within the upper and lower bound of the range tested under sensitivity analysis for this RIT-T, and does not materially change the findings of this analysis, AVP and Transgrid do not consider that a variation to this ISP parameter is necessary.

[12] See http://www.gazette.vic.gov.au/gazette/Gazettes2023/GG2023S060.

environmental impacts, 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 these factors has also been recently recognised by the Australian Energy Market Commission (AEMC)[13].

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

- Identification of constraints and opportunities.
- Identification of indicative alignments to allow the analysis to be undertaken.
- Development and implementation of 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 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).
- **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).

Based on the MCA and weighted scoring, Option 5 is found to be the highest ranked option due to the specific strengths of the option, including in relation to estimated net economic benefits, environment, cultural, land-use and social objectives. It is found to rank first, or equal first, across all six objectives considered. Furthermore,

[13] For example, as part of the 'Transmission Planning and Investment' review, the AEMC also 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.

Option 5 intersects the least with Aboriginal cultural heritage sensitivity areas. It does have some engineering complexity to be worked through, but these technical challenges are considered manageable These findings will be tested further with stakeholders, Traditional Owners and communities during the six-week consultation period that has now commenced.

Table 2 Results of the VNI West MCA

MCA Results							
Options		Option 1 to north of Ballarat	Option 1A to north of Ballarat with spur uprate to 500kV	Option 3 to Waubra/Lexton	Option 3A to Waubra/Lexton with spur uprate to 500kV	Option 4 to Bulgana via Bendigo	Option 5 to Bulgana
Net economic benefits ($M)		$ 1,299	$ 1,344	$ 1,285	$ 1,408	$ 1,144	$ 1,388
Grouping	Weighting (%)	WEIGHTED SCORING					
Net economic benefits	70%	2.10	2.10	2.10	1.40	3.50	1.40
Environment	5%	0.21	0.21	0.21	0.21	0.25	0.08
Cultural heritage	5%	0.12	0.12	0.10	0.10	0.15	0.10
Social	10%	0.40	0.40	0.42	0.42	0.41	0.21
Land use	5%	0.17	0.17	0.17	0.17	0.09	0.06
Engineering	5%	0.21	0.21	0.21.	0.21	0.24	0.16
Total	*100%*						
Weighted score		3.21	3.21	3.21	2.51	4.64	2.01
Rank		3	3	3	2	6	1

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.

All options except Option 5 require VNI West to pass via a proposed new terminal station to be located near Bendigo. These options include assessment of a new 220 kV double-circuit transmission line that would connect into the existing Bendigo Terminal Station on the outskirts of the city. The land surrounding the existing Bendigo Terminal Station is highly constrained by residential development and state and national parks. There is an existing 220 kV transmission line easement through the national park that could be utilised for a connection to Bendigo. Undergrounding would not be an option due to space constraints at the existing Bendigo Terminal Station as well as the greatly increased construction disturbance through the national and regional parks. To remain within the existing footprint within the national park, preliminary investigations indicate that the existing 220 kV transmission line would be rebuilt in its place within the same easement, if permitted. The complexity of navigating social and environmental constraints for options connecting into Bendigo has been factored into the MCA scoring for Options 1 through to 4.

As Option 5 does not pass near Bendigo, it does not face the same social and environmental constraints, but also does not increase transfer capability into Bendigo. AVP will continue to monitor electricity demand and generation growth in the Bendigo area as part of normal electricity supply planning practices. If, due to load growth or generation connections, network limitations emerge in the Bendigo area over the next 10 years, these will be assessed as part of the Victorian Annual Planning Report[14]. 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.

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

These MCA results have been scrutinised by sensitivity testing through increasing and reducing the weights applied to each objective and have been demonstrated to be robust to changes in objective weightings. Option 5 ranks first under all plausible objective and criteria weightings.

Conclusion from the NPV assessment and the MCA

Based on the MCA, Option 5 ranks highest across all options (including Option 3A) as it scores best across the range of objectives assessed (including the net benefits) and is expected to be at lower risk of delays in development and delivery than other options. Option 5 is also shown to be more robust under sensitivity analysis.

Specifically, Option 5:

- Is ranked effectively equally with Option 3A on a purely net benefits basis (on a scenario-weighted basis, there is found to be a 1% difference in net benefits between the options).
- Costs less than Option 3A (Option 5 has capital costs that are $402 million less than Option 3A) and the benefits are therefore less sensitive to potential cost increases or discount rate rises than Option 3A.
- Performs the best out of all options, across all objectives, in the MCA. Based on the indicative alignment identified for Option 5, it would intersect significantly fewer protected areas (such as Ramsar Wetlands and National and State Parks) and significantly less native vegetation, critical habitat and land with higher agricultural potential, than all other options. Option 5 also scores equal best with Option 4 in relation to separation from buildings (including residences).
- Runs further west than other options and avoids the Bendigo to Ballarat corridor that many submitters to the PADR suggested is problematic.
- Performs better than Option 3A in sensitivity analysis where it is assumed the Victorian Government's offshore wind commitments are legislated.

However, based on current power system analysis, Option 5 provides less REZ development potential than Option 3A. Option 5 offers the lowest indicative improvement to REZ transmission limits of all seven options assessed (+3,410 megawatts [MW]), while Option 3A has the highest improvement (+6,490 MW). While Option 5 enables the lowest levels of new REZ capacity of all seven options assessed, it is similar in magnitude to Option 1 (+3,650 MW)[15].

Under Option 5, modifications to the existing network, along with future decoupling of Waubra Wind Farm, have been identified as potential low-cost investments for further investigation in future to harness more renewable generation in western Victoria, if and when needed. It should also be noted that the REZ limits estimated for all options assume that developers have the social licence to build wind and solar generation at the scale assumed. This assumption has not been tested in the market, but if social licence is challenging, this would likely have more impact on options with the higher REZ transmission limits.

Feedback being sought through this consultation

This Consultation Report provides stakeholders, communities and Traditional Owner groups opportunity to provide feedback on this updated analysis prior to publication of the Project Assessment Conclusions Report (PACR). This consultation is over and above the minimum consultation requirements prescribed for the RIT-T and

[15] AVP and Transgrid note that the REZ limit assumed for Option 5 is considered a conservative estimate and that opportunities have already been identified to optimise this further. AVP and Transgrid also note that it has not been assessed whether there is social licence to develop the full 6.5 GW of REZ under Option 3A at this stage.

is a further demonstration of AVP and Transgrid's commitment to early engagement with local communities and consumer representatives to understand their views and concerns.

AVP and Transgrid welcome feedback from stakeholders on:

- the outcomes of the assessment undertaken in this report;
- the feasibility of Option 5; and
- whether the MCA has captured the salient environmental, social and engineering factors, including those that sit outside the scope of the RIT-T but which may impact on the timely development of the project having regard to the terms of the NEVA Order.

Invitation for written submissions

AVP and Transgrid invite written submissions on the matters raised in this consultation paper by 5 April 2023. Please email submissions to VNIWestRITT@aemo.com.au. Where possible, please provide evidence to support your view(s). If you do not want your submission to be publicly available, please clearly stipulate this at the time of lodgement.

Information about the submission process (including how to make a submission) and upcoming stakeholder engagement activities will be published on the VNI West dedicated webpages at www.transgrid.com.au/vni-west and www.aemo.com.au/vni-west. All feedback will be considered in the preparation of the final report (the PACR) and all written submissions will be published online, along with a summary of how feedback has been considered.

The consideration of feedback and preparation of the PACR will occur with regard to the NEVA Order.

Further stakeholder engagement opportunities

AVP and Transgrid will hold a series of webinars, briefings and community drop-in sessions prior to submissions closing to raise awareness of, and support understanding of the additional work being undertaken to assess potential connection opportunities between VNI West and WRL. These sessions are designed to consult further with stakeholders, Traditional Owners and communities, giving AVP and Transgrid an opportunity to listen to a broad range of views and gather valuable information before a final decision on the preferred option is made. Details about upcoming stakeholder engagement activities will be published on the Transgrid and AEMO websites and promoted via other local community channels.

The first online information session will be held on Thursday 9 March from 3.00 pm – 4.30 pm. Registration for the session is available through VNI West dedicated webpages at www.transgrid.com.au/vni-west and www.aemo.com.au/vni-west.

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 potential changes to WRL.

Concluding the RIT-T

Consistent with the terms of the NEVA Order and based on the assessment in this report, AVP and Transgrid propose to discontinue the assessment of Option 1A, Option 2, Option 3 and Option 4, and focus the PACR assessment on Option 5, Option 3A and Option 1 (for completeness as this is the candidate option identified in the 2022 ISP). This is on the basis that the other options do not deliver greater market benefits for consumers and are also considered unlikely to carry less delivery risk. Narrowing the number of options under consideration will enable collection of more detailed information if required to further refine MCA, and assessment of technical complexities of these options to ensure the optimal solution is ultimately selected as the preferred option at the conclusion of this RIT-T.

After consultation on the draft outcomes of the alternate options analysis (commencing following publication of this consultation report), in accordance with the NEVA Order, AVP is required to consult with VicGrid in relation to the VNI West PACR. AVP is also required to obtain approval of the Minister, or a further Ministerial Order, before entering into a VNI West construction agreement, or varying the contract with AusNet to implement an option other than the preferred option under the WRL PACR.

The final step of the RIT-T process, the PACR, will include consideration of VicGrid and other stakeholder feedback. AVP and Transgrid aim to publish the PACR in May 2023.

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1 Introduction

This report follows the Project Assessment Draft Report (PADR), released in July 2022, in relation to expanding the Victoria – New South Wales Interconnector (VNI) West[16], and has been prepared following feedback from stakeholders to further consult on options developed and to assess which option is most likely to facilitate timely delivery consistent with the terms of the NEVA Order. It serves as an additional step, ahead of the Project Assessment Conclusions Report (PACR), in the consultation process for this Regulatory Investment Test for Transmission (RIT-T).

1.1 Overview of this report

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 over the coming decades presents a significant challenge to supply reliability for the energy industry. This challenge is further increasing with the latest round of announced coal-fired generator closures[17] and various recent additional government announcements supporting the transition to renewables.

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 *Integrated System Plan* (ISP) at least every two years. The ISP identifies network investments that AEMO considers to be key to successfully underpinning the energy market transition (the 'optimal development path') and requires the RIT-T to be applied to those projects that are the priority, actionable ISP projects, to progress in the near term.

The opportunity to increase interconnection between Victoria and New South Wales was included as part of the 2018 ISP, referred to as SnowyLink[18]. VNI West was identified as an 'actionable ISP project' in the 2020 ISP[19] and this status continued in the 2022 ISP[20].

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 National Electricity Market (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

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[16] This project is identified as an 'actionable ISP project' in the 2022 *Integrated System Plan* (ISP). See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[17] 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.

[18] 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.

[19] 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.

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

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' process that is now part of the regulatory framework. AVP and Transgrid have now opted to apply the actionable ISP framework to VNI West and a Project Assessment Draft Report (PADR) was subsequently published in July 2022, following publication of the final 2022 ISP in June 2022. The PADR called for submissions by 9 September 2022.

Twenty-six submissions were received on the PADR, including three verbal submissions made by organisations at the Energy Consumer Submission Forum. Non-confidential submissions are available on the AEMO website[21]. Submissions included a broad range of feedback relating to the options assessed in the PADR, including concerns about social and environmental impacts of the proposed preferred option, and suggestions that additional options be considered in the PACR.

This feedback has 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 (NEVA Order). The Neva Order confers upon AVP functions which include the assessment of alternate options to the preferred options[22] to expedite the development and delivery of those projects[23].

AEMO has had regard to its functions under the NEVA Order in assessing and formulating these options. This includes giving greater consideration to the social and environmental impacts raised by stakeholders as concerns and which might impact expedition and delivery; these factors would otherwise have been difficult to incorporate within the RIT-T framework.

This report has been developed to provide stakeholders with the opportunity to review and comment on the additional options and analysis undertaken prior to AVP and Transgrid publishing the PACR.

1.2 Role of this report

This report serves as an additional step, ahead of the PACR, in the RIT-T consultation process for assessing options for increasing interconnection between Victoria and New South Wales. It also marks the start of consultation on the alternate options assessment as required under the NEVA Order.

This report:

- Describes the additional options that have been assessed, which have been informed by submissions received to the PADR as well as subsequent discussions with stakeholders.
- Presents the results of the updated net present value (NPV) analysis for each of the credible options assessed, as well as the key drivers of these results and the assessment that has been undertaken to ensure the robustness of the conclusion.

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

[22] As described in the VNI West PADR and the WRL Project Assessment Conclusions Report (PACR).

[23] Being the VNI West and WRL Specified Augmentations as described in clauses 3 and 4 of the NEVA Order.

- Outlines a detailed multi-criteria analysis (MCA) that has been developed to assist in understanding the environmental, social and engineering impacts and constraints that may present delivery and operational risks, to help differentiate the top-ranked options from the NPV analysis (given the closeness of the NPV results).
- Proposes that the list of options be refined to the top-ranked options for the PACR assessment to allow for a more detailed consideration of these options in that report.
- Seeks stakeholder views on all the above, which will be taken into account in preparing the PACR.

Overall, a key purpose of this report, and the RIT-T more broadly, is to provide interested stakeholders the opportunity to review the analysis and assumptions and have certainty and confidence that the preferred option at the end of the RIT-T process has been robustly identified as optimal, including in relation to the proposed new terminal station locations and the unique features of those areas. 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 are also releasing supplementary reports alongside this report, covering:

- the points raised in submissions to the PADR (and AVP and Transgrid's responses to them); and
- the wholesale market modelling that has been undertaken to estimate the benefits of the various options presented in this report.

Detailed cost benefit results and expected environmental, social and engineering constraints associated with each option are included as appendices to this report.

1.3 What is a NEVA Order?

In March 2020, the Victorian Government amended the National Electricity (Victoria) Act 2005 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).

The National Electricity (Victoria) Amendment Act 2020 (NEVA) inserts a new section 16Y into the NEVA which empowers the Minister for Energy and Resources 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, an Order may also specify an alternative test in place of the RIT-T.

On 20 February 2023, the Minister for Energy and Resources made a Ministerial Order under section 16Y of the NEVA which provides for AEMO to:

- carry out its VNI West early works program for the Victorian component on VNI West; and

- assess and consult on alternate VNI West options, including potential changes to the WRL connection point, which could provide more certainty over timely project delivery.

Depending on the assessment of alternate VNI West options, a further Ministerial Order under the NEVA may be required to progress the recommended project option.

1.4 Further information and next steps

AVP and Transgrid are seeking feedback on:

- the assessment undertaken in this report;
- the feasibility of the new options assessed; and
- whether the MCA has captured the salient social, environmental and engineering factors for each option, including those that sit outside the scope of the RIT-T but may impact on the timely development of the project having regard to the terms of the NEVA Order.

All feedback will be carefully considered in the preparation of the final report (the Project Assessment Conclusions Report [PACR]) and all written submissions will be published online, along with a summary of how feedback has been taken into account.

Submissions are due on or before 5 April 2023 and should be emailed to VNIWestRITT@aemo.com.au.

AVP and Transgrid will hold a series of forums and briefings prior to submissions closing to provide stakeholders with a detailed understanding of the assessment in this report and the next steps. Information about the submission process (including how to make a submission) and upcoming stakeholder engagement activities, including registration details for the online information sessions being held in week two and week four, will be published on the VNI West dedicated webpage on AEMO's website at www.aemo.com.au/vni-west. If you do not want your submission to be publicly available, please clearly stipulate this at the time of lodgement.

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 potential changes to WRL.

In accordance with the NEVA Order, following the alternate options analysis and consultation, AVP is required to consult with VicGrid in relation to the VNI West PACR.

The final step of the RIT-T process, the PACR, will include consideration of any submissions made in response to this report and feedback received from VicGrid. The PACR is targeted for publication in April 2023.

2 Overview of the options considered

This report assesses seven credible options in total. In addition to the two options presented in the PADR, five new options have been considered in response to stakeholder feedback on the PADR covering areas of interest, with or without 500 kilovolt (kV) spur expansions in Western Victoria to help meet the identified need.

As part of a broader set of integrated developments in the NEM, VNI West would connect Western Renewables Link (WRL) (exact location yet to be determined) with EnergyConnect (at Dinawan), via new terminal stations. WRL and EnergyConnect are both new projects under development. Specifically:

- EnergyConnect is a new 900 km overhead high-voltage transmission line connecting Robertstown in South Australia to Wagga Wagga in New South Wales, via Buronga in New South Wales, and including an additional spur line connecting to Red Cliffs in Victoria. The project includes:
  - A 275 kV double-circuit line from Robertstown to Bundey in South Australia.
  - A 330 kV double-circuit line from Bundey to Buronga to Dinawan in New South Wales.
  - A 500 kV double-circuit line from Dinawan to Wagga Wagga in New South Wales operating at 330 kV.
  - A second 220 kV circuit from Buronga to Red Cliffs in Victoria.
  - Five phase shifting transformers at Buronga 330 kV substation
  - Static and dynamic reactive plant at Bundey, Robertstown, Buronga and Dinawan.

  The western section of EnergyConnect (Robertstown to Buronga via Red Cliffs) obtained planning approval and construction has commenced. The New South Wales eastern section (Buronga to Wagga Wagga) received its environmental impact statement (EIS) approval on 2 September 2022.
- The WRL Project is a proposed new 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 includes:
  - A 220 kV double-circuit overhead line from Bulgana to a new terminal station north of Ballarat.
  - A 500 kV double-circuit overhead line from a new terminal station north of Ballarat to a new terminal station at Sydenham.
  - Network upgrades to support the new assets.

  AusNet, which has been contracted to build, own and operate the infrastructure, referred WRL to the Victorian Minister for Planning, under the *Environment Effects Act 1979*, in June 2020. In August 2020, the Minister determined that an Environment Effects Statement (EES) is required for the project. The EES is currently being prepared and is scheduled to be submitted to the Victorian Department of Transport and Planning (DTP) in early 2023 before being exhibited for public comment later in 2023.

The VNI West proposed preferred option presented in the PADR was a new high capacity 500 kV double-circuit overhead transmission line between Victoria and New South Wales, connecting WRL (at the proposed terminal station north of Ballarat) with EnergyConnect (at Dinawan) via new stations near Bendigo and Kerang.

Several submitters to the PADR expressed concerns that AVP and Transgrid had not considered a sufficient number of options[24]. A number of submissions also suggested that alternate options be considered to alleviate concerns raised about the VNI West (via Kerang) option in the PADR, particularly for the proposed section between Bendigo and Ballarat in Victoria.

Submissions suggested that the proposed option on the Victorian side should be moved further west, or along a Bulgana to Kerang corridor[25]. For example, RWE suggested a line route further west would involve lower density dwellings, increased wind resources, larger agriculture properties, less native vegetation and ecological constraints, fewer regions of cultural heritage sensitivity, and reduced flood risk. Similarly, Hepburn Shire Council stated that a route alignment along a Bulgana to Kerang corridor would impact fewer properties, communities and valuable natural resources. GNET also suggested that a route alignment further west would provide greater opportunity for renewable generation and a higher degree of social acceptance[26].

AVP and Transgrid note that throughout the process of considering additional interconnection between Victoria and New South Wales, many options have been considered and assessed. The PADR summarised the options that had been considered through the earlier ISP assessments and the reasons why the ISP candidate option had been narrowed down to VNI West (via Kerang) with the RIT-T also considering a non-network option alongside the network development. The options that were considered at earlier stages of this process, but not taken forward, are also summarised in this report (see Appendix A1).

Based on the earlier assessments, AVP and Transgrid do not consider that there is a need to re-examine earlier options. However, building on feedback provided by stakeholders following the PADR, five new options have been assessed.

All seven options assessed in this report (that is, the two original PADR options and the five new options):

- Involve a 500 kV double-circuit transmission line for VNI West.
- Originate at (or near) Dinawan, 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 to Kerang.

The differences in the options relate to the Victorian scope and can be summarised as:

- **Option 1 (to north of Ballarat),** 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 1A (to north of Ballarat with spur uprate to 500 kV)** – is the same as Option 1 but with the 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.
- **Option 2 (to north of Ballarat plus non-network**), per the PADR – is 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 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

[24] See for example AusNet, pp. 6-7, Moorabool and Central Highlands Power Alliance, p. 13, Hepburn Shire Council, p. 6.

[25] RWE, pp. 1 and 2. Hepburn Shore Council, p. 6. GNET, p.1.

[26] RWI, pp. 1 and 2.

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.

  - **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.

- **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 proposed WRL transmission line from north of Ballarat to Bulgana from 220 kV to 500 kV.
- **Option 5 (to Bulgana)** – connects from Dinawan, via the new terminal station near Kerang, directly to WRL at a new terminal station near Bulgana (Wotjobaluk Country). This option requires relocation of the WRL proposed terminal station from north of Ballarat to Bulgana and the uprate of the proposed WRL transmission line from 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.

All options except Option 5 require VNI West to pass via a proposed new terminal station to be located near Bendigo, with a new 220 kV double-circuit connecting into the existing Bendigo Terminal Station. Option 5 therefore does not increase transfer capability between Kerang, Bendigo and Ballarat. AVP will continue to monitor electricity demand and generation growth in this area as part of normal electricity supply planning practices. If, due to load growth or generation connections, network limitations emerge in the Bendigo area over the next 10 years, these will be assessed as part of the Victorian Annual Planning Report[27]. 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.

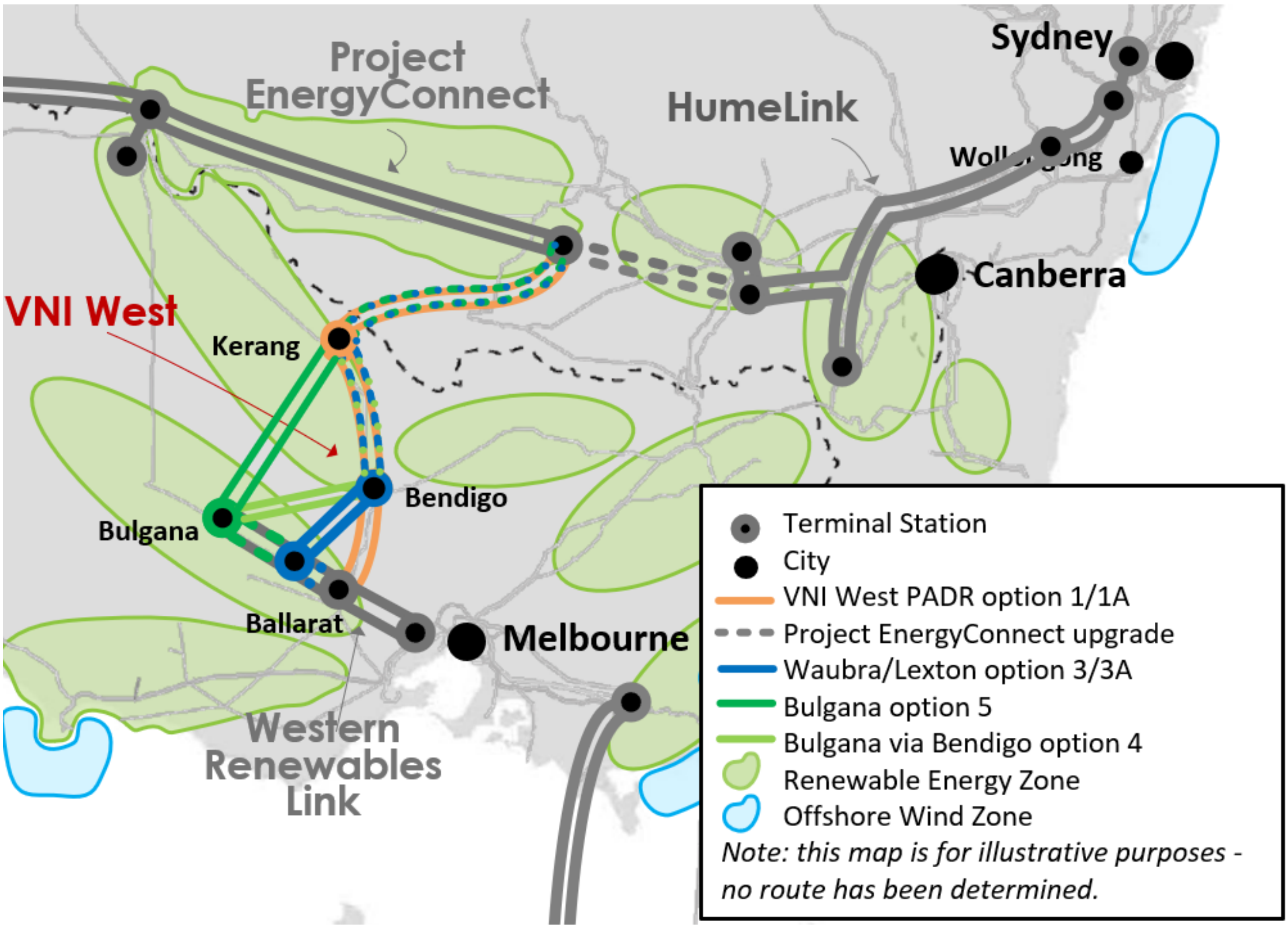
The five new options have been assessed to the same level of detail as the two PADR options, including in terms of their impact on the transmission network, and estimated cost.

The seven credible options assessed in this report are shown in Figure 3 below (see Appendix A1 for further details). All topologies shown are high-level schematic illustrations only, and specific line routes are not defined within this report.

None of the new options have been combined with a VTL, due to the finding in the PADR (which is confirmed in this report) that adding a VTL to Option 1 – VNI West (via Kerang) does not provide a further net benefit (instead, it imposes a net cost). This finding is expected to also apply if the new option variants were combined with a VTL, so this has not been investigated.

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

Figure 3 Credible options assessed



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 of the project. AVP and Transgrid have responded to this, and other points raised in submissions, in the VNI West PADR Submissions report, released alongside this report[28].

All options are assumed to be staged, 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.

WRL is currently planned to be delivered in 2026. Under every VNI West option considered, including the existing option, delivery of WRL is assumed to be delayed to 2027. VNI West would be delivered in accordance with the ISP scenario-dependent timing. For example, for Option 5, the 500 kV double-circuit line from Sydenham to Bulgana (a variant of 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).

The assumed one-year delay to WRL and its variants 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)

[28] At https://aemo.com.au/initiatives/major-programs/vni-west/stakeholder-consultation.

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.

Table 3 below summarises the assumed timing for key components of all seven options assessed in this report. The timing of the VTL component in Option 2 is assumed to be 1 July 2026 in all three scenarios, which reflects the earliest possible date it can be commissioned.

Table 3 Assumed timing for all seven options

Scenario	Stage 1 (early works)	Stage 2 (WRL components)	Stage 2 (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

Appendix A1 provides a detailed description of each option (including the specific components involved), as well as a discussion of all other options that have been previously considered as part of this RIT-T process (and the reasons why they are no longer being progressed).

2.1 Technical characteristics of the seven options assessed

The technical characteristics of the credible options are summarised in the table below. Specifically, Table 4 shows the indicative impact on interconnector transfer capability (in both directions) and the REZ transmission limit[29] (by affected REZ) for each option based on AVP and Transgrid's power system analysis considering thermal, and voltage and transient stability limits.

Options that have an area of interest further west are generally expected to have a longer overall line length between network nodes, and therefore higher impedance. As a result, the power flow on VNI West, relative to the existing and parallel 330 kV VNI and parallel 220 kV western Victoria network, reduces the further west the option is proposed. This results in the existing 330 kV VNI and 220 kV western Victorian networks reaching limits before the 500 kV VNI West is fully utilised, and thereby results in lower interconnector transfer capability on VNI West options proposed to traverse further west[30].

The exception to this is Option 5, which is a direct result of this option including 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.

While series compensation, in the form of series line capacitors, has been modelled in the options analysis presented in this Additional Consultation Report, the precise series compensation or power flow solution will be determined during detailed design if Option 5 is progressed. 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 sub-synchronous control interactions with synchronous machines and doubly fed induction generators can arise in systems with series capacitors and this will need to be studied in

[29] 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 VRE generation does not always operate at full capacity.

[30] 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.

detail. 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, Option 5 is progressed without series compensation on the 500 kV lines, the import and export transfer capability may be marginally reduced. Conversely, the further west the 500 kV is proposed to be extended in Victoria, by upgrading the 220 kV component of WRL, the larger the REZ transmission limit increase achievable due to the higher capacity lines connecting further into the Western Victoria REZ (V3). The exceptions to this are Option 4 and Option 5 due to the differing connection arrangement of Waubra Terminal Station and Waubra Wind Farm between the various options and, for Option 5, the absence of a connection via Bendigo. Options 1 through to 3A have Waubra decoupled from the existing Ballarat–Waubra–Ararat–Crowlands–Bulgana 220 kV network and connected to the new parallel network, which relives network constraints on the existing 220 kV western Victoria network. Due to shared network loading, relieving congestion on existing lines allows the new network to be more highly utilised. This decoupling is made possible due to these options having new 220 kV lines or a new terminal station (as part of WRL) in the vicinity of the existing Waubra Wind Farm.

Option 4 and Option 5 do not decouple Waubra from the existing 220 kV network as there is no 500 kV terminal station near Waubra/Lexton. Without decoupling Waubra Wind Farm from the existing 220 kV network, the existing 220 kV network reaches its limits sooner and thereby results in a lower REZ transmission limit relative to the other options.

Option 5 does not have a connection via Bendigo, which results in heavy loading on the Kerang–Bendigo 220 kV line and, due to shared network loading, limits the achievable REZ transmission limit of this option.

Modifications to the existing network, along with future decoupling of Waubra Wind Farm and, for Option 5, uprate of the Kerang–Bendigo 220 kV line, 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. It should also be noted that the REZ limits estimated for all options assume that developers have the social licence to build wind and solar generation at the scale assumed. This assumption has not been tested in the market, but if social licence is challenging, this would likely have more impact on options with the highest REZ transmission limits.

AVP and Transgrid note that all options involve substantial increases in interconnector transfer capability and are ultimately comparable to a large, multi-unit, baseload power station in the NEM[31,32].

[31] For example, Loy Yang A has a nameplate capacity of 2,225 megawatts (MW).

[32] The 1,930 MW and 1,800 MW for Option 1 remain the same as the PADR despite the refined approach taken to modelling EnergyConnect under the base case in this report. Additional analysis undertaken since the PADR has identified that the EnergyConnect enhancement is unlikely to change the VNI West transfer capability as it was thought to at the time of the PADR, since the VNI West flow is primarily limited by transient and voltage stability constraints.

Table 4 Summary of the credible options assessed – transfer capacities and REZ limits

Option	Indicative impact on transfer capability		Indicative impact on REZ transmission limit	
	VIC to NSW	NSW to VIC	Individually	Total
Option 1 (to north of Ballarat)	+1,930 megawatts (MW)	+1,800 MW	V2 – Murray River: +1,600 MW V3 – Western Vic (WRL): +600 MW V3 – Western Vic (VNI West timing): +550 MW N5 – South West NSW: +900 MW	+3,650 MW
Option 1A (to north of Ballarat with spur uprate to 500 kV)	+1,930 MW	+1,800 MW	V2 – Murray River: +1,600 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +750 MW N5 – South West NSW: +900 MW	+4,710 MW
Option 2 (to north of Ballarat plus non-network)	+250 MW from the VTL +1,930 MW from Option 1 (to north of Ballarat)	+250 MW from the VTL +1,800 MW from Option 1 (to north of Ballarat)	Same as Option 1 (to north of Ballarat) once it is commissioned (that is, no additional REZ hosting capacity associated with VTL component)	+3,650 MW
Option 3 (to Waubra/Lexton)	+1,830 MW	+1,650 MW	V2 – Murray River: +1,600 MW V3 – Western Vic (WRL timing): +950 MW V3 – Western Vic (VNI West timing): +700 MW N5 – South West NSW: +900 MW	+4,150 MW
Option 3A (to Waubra/Lexton with spur uprate to 500 kV)	+1,830 MW	+1,650 MW	V2 – Murray River: +1,600 MW V3 – Western Vic (WRL timing): +2,590 MW V3 – Western Vic (VNI West timing): +1,400 MW N5 – South West NSW: +900 MW	+6,490 MW
Option 4 (to Bulgana via Bendigo)	+1,700 MW	+1,475 MW	V2 – Murray River: +1,600 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +580 MW N5 – South West NSW: +900 MW	+4,540 MW
Option 5 (to Bulgana)	+1,930 MW	+1,650 MW	V2 – Murray River: +850 MW V3 – Western Vic (WRL timing): +1,460 MW V3 – Western Vic (VNI West timing): +200 MW N5 – South West NSW: +900 MW	+3,410 MW

2.2 Estimated costs of the options

2.2.1 Capital costs

The cost estimates presented in the VNI West PADR and 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.

Further, to assess the new options added since the PADR, AVP has produced new cost estimates for the Victorian portion of the project for each option. The cost estimate for the PADR Option 1 has also been revised based on the area of interest identified from the MCA process (see Section 4), and to incorporate updated information for land and easement cost estimates.

Table 5 shows the expected capital cost for each option by key component (in both Victoria and New South Wales)[33]. The methodology used to develop these estimates is summarised in Appendix A2.

For all five new options, the Victorian component costs include the direct costs of modifying the WRL project so that the cost of modifying WRL due to any change in where VNI West connects to WRL is justified 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 in varying degrees for all five new options, which at a high level are summarised as:

- Uprating segments, or all, of the new 220 kV transmission line from north of Ballarat to either Waubra/Lexton or Bulgana to 500 kV ('the 500 kV spur'), including costs for a wider easement.
- Relocation and reconfiguration of the proposed Terminal Station north of Ballarat to suit the option (that is, relocation to near Waubra/Lexton or Bulgana).
- Modification of the existing Waubra Terminal Station and Waubra Wind Farm connection with a short 220 kV transmission line to a new terminal station near Waubra/Lexton.

The cost estimates for any WRL scope changes have been derived from information provided by AusNet, and are considered to have an accuracy of +/- 30%.

The detailed description of each option in Appendix A1 also outlines modifications required to WRL's current scope to achieve each option. Additionally, Appendix A2 outlines the methodology used to estimate the WRL scope modification costs. While no decision has yet been made to modify the WRL scope, AVP notes that the NEVA Order also addresses the risk of significant delays by removing the need under the NER to re-apply the WRL RIT-T due to a material change in circumstances.

Any impact on the current EES process will be assessed by AusNet if/when a decision is made to modify scope. Similarly, 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.

Other points to note from Table 5 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
- Victorian substation/terminal station costs for Option 5 are lower than other options, as a new terminal station near Bendigo is not proposed in this option
- The additional costs associated with changing WRL scope are lower for both Option 4 and Option 5, as a new terminal station is not required north of Ballarat or near Waubra/Lexton.
- Option 5 costs include allowance for both power flow controllers and series compensation components.

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

Table 5 Summary of the credible options assessed in this report – capital costs, $m in FY2020-21 dollars

Cost component	Option 1 (to north of Ballarat)		Option 1A (to north of Ballarat with spur uprate to 500 kV)		Option 2 (to north of Ballarat plus non-network)		Option 3 (to Waubra/Lexton)		Option 3A (to Waubra/Lexton with spur uprate to 500 kV)		Option 4 (to Bulgana via Bendigo)		Option 5 (to Bulgana)	
	NSW	VIC	NSW	VIC	NSW	VIC	NSW	VIC	NSW	VIC	NSW	VIC	NSW	VIC
Stage 1 – Early works														
Early works – Property/access/ easements	66	69	66	85	83	86	66	76	66	84	66	67	66	59
Early works – other	50	88	50	88	50	88	50	88	50	88	50	88	50	60
EnergyConnect enhanced	182	-	182	-	182	-	182	-	182	-	182	-	182	-
Stage 2 – Implementation														
Substation/ terminal station works	354	641	354	810	354	641	354	704	354	791	354	681	354	415
Line works	751	692	751	954	751	692	751	807	751	958	751	1,080	751	912
Battery costs	-	-	-	-	288	295	-	-	-	-	-	-	-	-
Power flow controllers / series compensation	183	89	183	89	183	89	183	89	183	89	183	89	183	164
Biodiversity offset costs	66	24	66	24	66	24	66	24	66	24	66	28	66	22
Total (by state)	1,651	1,603	1,651	2,050	1,957	1,916	1,651	1,788	1,651	2,034	1,651	2,034	1,651	1,631
Total (all states)	3,254		3,701		3,873		3,440		3,685		3,685		3,282	
WRL – Incremental costs for alternate options (included in the totals above but separately itemised here as well for transparency)														
Included cost	-	-	-	447	-	-	-	182	-	427	-	315	-	315
WRL uprate length				104 km				42 km		104 km		104 km		104 km
Approximate line length A	184 km	229 km	184 km	229 km	184 km	229 km	184 km	230 km	184 km	230 km	184 km	268 km	184 km	205 km
Quantity substations/ terminal stations B	-	2	-	2	-	2	-	2	-	2	-	2	-	1

A. Approximate line length is the indicative total length (in kilometres) of lines between PEC (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 and includes both 500 kV and 220 kV lines, where cutting into the existing 220 kV network. Option 5 line length on the Victorian side is lower than all other options, however the total system path length between nodes is longer, which is what impacts on impedances.
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.

2.2.2 Estimate Class

The cost estimates for all seven options are considered to have an accuracy of ±30%, which AVP and Transgrid consider to be 'Class 4' estimates[34] 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 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 and design undertaken by AVP and Transgrid in the context of this project.

The AACE International methodology contains accuracy bands which are typically skewed to the positive side, reflecting higher likelihood of cost increases than decreases as the estimates progress. In recognition of this, the VNI West cost estimates include an allowance for known and unknown risks (which are detailed in the PADR report Section 8.1), that will or could arise during the further development and execution of this project. As an average allowance for unknown risks has been factored into the estimates, the VNI West cost estimate accuracy bands are considered to be symmetrical.

AVP and Transgrid note that the level of accuracy is consistent with current industry practice for this stage of the investment process[35]. The level of cost accuracy for the investments will be further refined and developed if the project is justified under the RIT-T process and proceeds through to the Contingent Project Application (CPA) and contestable procurement stages. 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 is intending to submit two CPAs to the AER in relation to the regulatory cost recovery for the project. One for the early works component, which is expected to be submitted shortly after publication of the PACR, and a subsequent CPA for project implementation, which will be informed by any early works undertaken.

The incremental uprate cost of EnergyConnect from 330 kV to 500 kV is a Class 2 estimate based on firm price variation costs included in the EnergyConnect contract. These were negotiated during the EnergyConnect tender period to ensure best market rates were obtained.

The VNI West (to north of Ballarat) Option 1 cost estimates used in this report (and the PADR) differ from those presented in the 2022 ISP by approximately $300 million, due to a change in the level of line cost contingency provisioned in the Victorian component of the project to account for remediation of social and environmental concerns. This recognises that, based on recent experience, a greater level of route diversion, tower redesign, or screening may be required beyond that anticipated and included in the Victorian component of the estimate presented in the 2022 ISP. This provision does not anticipate undergrounding costs and, if any partial undergrounding is ultimately required, a greater level of contingency would be needed. In developing the costs for the new options, this same cost contingency amount (in percentage terms) was also included in each option.

A specific route for the preferred option will only be confirmed following completion of the PACR. 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. As such, the costs specified are as accurate as possible at this stage but will be subject to further refinement.

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

[35] 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.

2.2.3 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 excludes 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. VTL components are assumed to incur routine operating and maintenance costs of $2.5 million per annum once the VTL components have been commissioned.

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. Specifically, the payments:[36]

- Will apply to a range of projects delivered under the *NSW Electricity Infrastructure Investment Act 2020* (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 from, 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*.

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 358 km, of which 85% is assumed to be on private land.

There is currently no Victorian equivalent to the New South Wales Strategic Benefits Payment Scheme, although AVP notes that the Victorian Government has been consulting on compensation and benefit sharing arrangements in Victoria as part of Victorian REZ development and proposed reforms to the Victorian Transmission Planning Framework outlined in the Victorian Transmission Investment Framework.

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

3 NPV assessment

The economic NPV assessment required under the RIT-T has been updated 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 reflect relevant external developments[37].

The NPV assessment finds that two of the additional options introduced since the PACR that run further west than Option 1 in the PADR, and have been introduced in response to stakeholder feedback, are effectively jointly top ranked on a purely NPV basis. These options are referred to as 'Option 3A' and 'Option 5' in this report and are estimated to deliver approximately $1.4 billion in net benefits in present value terms under the RIT-T.

This chapter summarises the NPV 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*. The specific outcomes for the *Progressive Change* and *Hydrogen Superpower* scenarios are presented in Appendix A3.

Forecast gross market benefits have increased relative to the PADR in all scenarios. The main drivers are the extended modelling period (to 2049-50) in response to stakeholder feedback[38], refinements in the assumptions around the unlocked transmission capacity for the South West New South Wales (N5) REZ (due to the interaction between EnergyConnect and VNI West) and the better alignment with the 2022 ISP parameters (particularly the carbon budgets) in accordance with the RIT-T instrument and AER CBA guidelines.

All costs and benefits in this report are presented in FY2020-21 dollars, unless otherwise stated, consistent with the PADR.

3.1 *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.

[37] For example, the modelling horizon has been extended until 2049-50 in response to stakeholder feedback, the option costs have been updated for the New South Wales portion of investment to reflect the New South Wales Government Strategic Benefits Payment Scheme for landowners announced in October 2022 and the alignment with the 2022 ISP parameters has been improved in a number of ways (including in terms of coal retirement outcomes and carbon budgets). Please refer to EY's wholesale market modelling report released alongside this report (at https://aemo.com.au/initiatives/major-programs/vni-west/stakeholder-consultation) for detail on the assumptions and methodologies that have been applied.

[38] For example, EUAA, p. 16 and Ted Woodley, p. 8. Also see section 2.10.4 in Attachment 1: Summary of stakeholder feedback on the PADR.

Under these assumptions, Option 3A and Option 5 are found to be ranked effectively equally as the top-ranked options. Option 3A (to Waubra/Lexton with spur uprate to 500 kV) is expected to deliver net benefits of approximately $1,905 million. Option 5 (to Bulgana) is found to have net benefits of approximately $1,842 million (3% less than Option 3A).

Option 3A has the largest gross market benefits of the two top-ranked options. This is mainly driven by the network configuration of this option decoupling Waubra Wind Farm from the existing 220 kV network and having a connection via Bendigo, both of which reduce power flow in the otherwise limiting parallel 220 kV networks between Ballarat, Waubra and Ararat, and between Kerang and Bendigo, and thereby releasing more transmission capacity in the Western Victoria REZ (V3).

Option 3A has the greatest indicative impact on REZ transmission limits of all seven options (+6,490 megawatts [MW]), while Option 5 has the lowest impact (+3,410 MW). Both Option 3A and Option 5 have mid-range indicative impact on nominal transfer capability in both directions within the seven options, but Option 3A has lower transfer capability from Victoria to New South Wales (+1,830 MW) than Option 5 (+1,930 MW) (see Section 2.1). Option 5 also has a lower capital cost, so while the gross market benefits are lower, the net benefits are within 3% of Option 3A.

Figure 4 presents the estimated net benefits for each option under the *Step Change* scenario.

Figure 4 Summary of estimated net benefits under the *Step Change* scenario

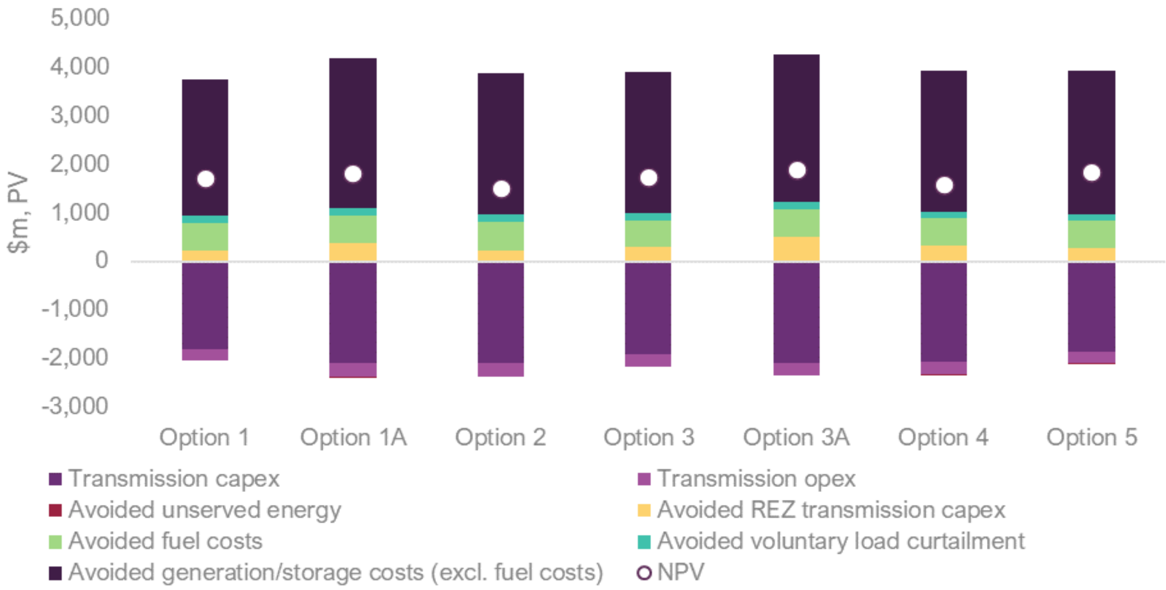
The results for the *Step Change* scenario also show that:

- Option 1 – the preferred option from the PADR – is ranked below Option 3A and Option 5, by $189 million (or 10%) and $126 million (or 7%) respectively.
- Option 2 is the lowest ranked option, and the additional cost of the VTL components is not outweighed by the additional expected market benefits (as is shown by Option 2 having lower net benefits than Option 1).
- Uprating WRL to 500 kV through to Bulgana is net beneficial – that is, Option 1A is ranked above Option 1 by $102 million (or 6%), and Option 3A is ranked above Option 3 by $175 million (or 10%).

- Option 4 is the worst performing purely interconnector option (that is, excluding Option 2 which includes a non-network solution).

Figure 5 shows the composition of estimated net benefits for each option under the *Step Change* scenario.

Figure 5 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 the primary sources of benefit for both top-ranked options.
  - Avoided/deferred generation and storage costs comprise approximately 71% and 75% of the estimated gross benefits of Option 3A and Option 5, respectively.
  - Avoided fuel costs comprise approximately 14% and 15% of the estimated gross benefits of Option 3A and Option 5, respectively.
- Avoided/deferred generation and storage costs (the darkest sections of each bar in Figure 5) are primarily driven by deferred/avoided investment of 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[39].
  - After commissioning, both options 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 Option 3A, 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.

[39] 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.

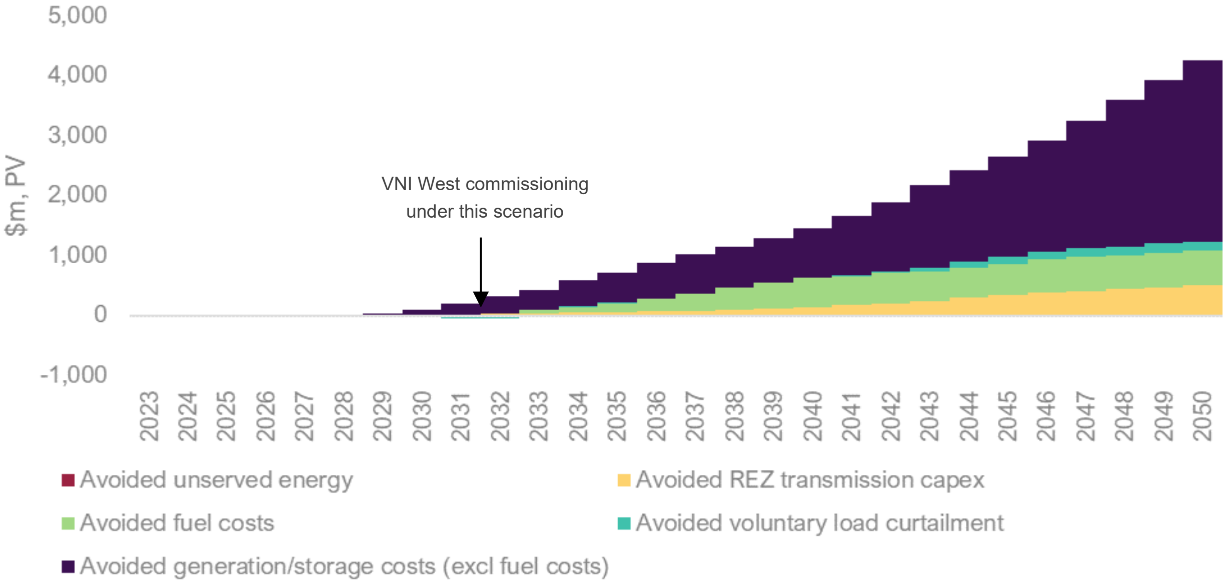
  - Overall, the amount of forecast capacity investment is also lower with both options while delivering more variable renewable generation than the base case, due to improved access to higher capacity factor REZs and reduced forecast spill. Across the NEM, both options are forecast to reduce solar and wind spill relative to the base case. However, the interaction of several factors affects the amount of spill in each REZ and region: 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 and reserve, due to the increased transfer limits between Victoria and New South Wales enabling more generation to be imported to Victoria to meet demand and reserve when required.
  - Option 3A unlocks significantly more transmission network capacity for Western Victoria REZ (V3), resulting in more wind investment in that REZ than Option 5, which reduces the need for wind investment in other Victorian REZs as well as other regions.
- Avoided fuel costs (the light green sections of each bar in Figure 5) arise primarily from avoided gas generation in Victoria after VNI West is commissioned through to the end of the modelling.
  - 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 replaced by increased wind, solar and storage generation in all mainland NEM regions. The majority of 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 5are 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 Ovens Murray (V1).
  - REZ transmission cost savings are notably more under Option 3A since this option unlocks significantly more transmission network capacity in Western Victoria (V3), saving renewable build in other Victorian REZs as well as other regions, resulting in less need for REZ transmission network expansion. This is a key driver of the higher expected gross market benefits of Option 3A, compared to Option 5.

Figure 6 below presents the estimated cumulative expected gross benefits for Option 3A for each year of the assessment period under the *Step Change* scenario[40]. It shows that benefits from avoided/deferred generation and storage costs mainly accrue from the late 2030s, while benefits from avoided fuel consumption begin accruing from commissioning in 2031-32 and accrue steadily to the early 2040s then level out (in the final four years of the study fuel cost savings are low and average zero). REZ transmission cost savings are also forecast to be relatively high for Option 3A (and mainly accrued in the 2040s).

[40] This figure, and all figures of this type in this report, only presents the annual breakdown of estimated gross benefits for Option 3A and Option 5 (the top ranked options on a weighted basis). The separately released spreadsheet presents an annual breakdown of costs and benefits for all 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 3A shown in Figure 5 above. This applies to all figures of this type in this document.

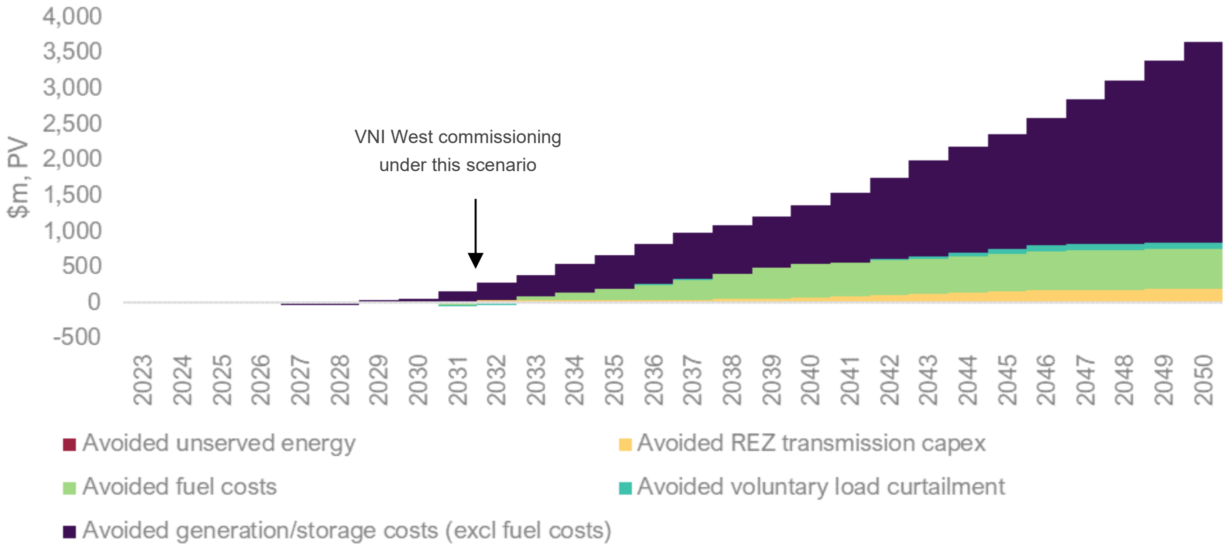
Following stakeholder feedback on, and an apparent misinterpretation of, the PADR versions of the charts below[41], AVP and Transgrid have revised the presentation of the types of charts below to present these benefits on an annualised basis in this report (which is also aligned with how they are presented in the ISP). However, for completeness and absolute transparency, the accompanying wholesale market modelling report presents the results using both approaches for reference.

Figure 6 Breakdown of cumulative gross benefits for Option 3A under the *Step Change* scenario



Similarly, Figure 7 presents the estimated cumulative expected gross benefits for Option 5 for each year of the assessment period under the *Step Change* scenario. It shows a similar pattern to Option 3A, although with less avoided REZ transmission capital expenditure (capex).

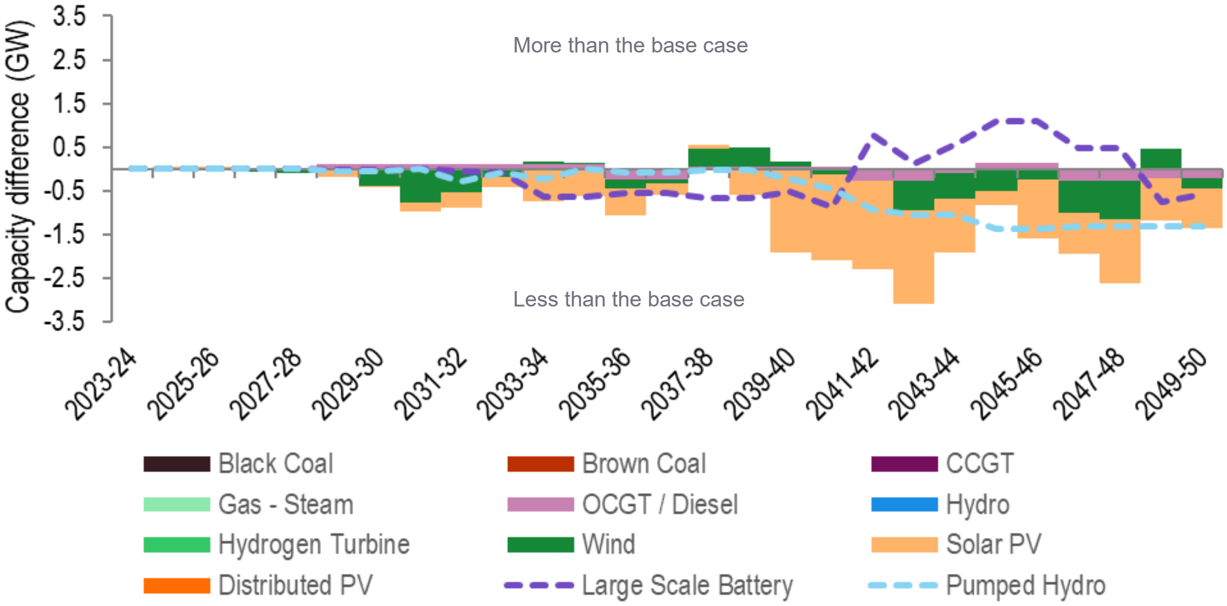
Figure 7 Breakdown of cumulative gross benefits for Option 5 under the *Step Change* scenario



[41] Specifically, as outlined in Section 2.9.1 of the accompanying report covering PADR submissions, there was a perception by some stakeholders that benefits were accruing earlier in the assessment period than if the results were presented on an annualised basis.

Figure 8 summarises the forecast difference in generation and storage capacity for Option 3A (in gigawatts [GW]), compared to the base case[42]. These capacity differences are driving the benefit associated with avoided or deferred generation and storage costs, which dominates all other benefits combined.

Figure 8 Difference in cumulative capacity build with Option 3A, compared to the base case, under the *Step Change* scenario



In the base case without any VNI West option, to achieve net zero by 2050 large volumes of solar capacity in combination with storage (both large-scale battery and pumped hydro), and in later years some peaking gas, is required to supply Victorian demand and meet the reserve requirement in this region. High volumes of solar, storage, and to some extent wind is also required in the other southern regions of Tasmania and South Australia in the base case. More pumped hydro is needed in the base case (typically 8-24 hours duration) to help ride through still days when the wind is not blowing, or meet demand overnight, as there is limited ability to access and share diverse sources of renewable generation between northern and southern regions.

With Option 3A in place, while there is still significant capacity investment in all regions, some investment in these southern regions is no longer required. By increasing interconnection with New South Wales, investment occurs in locations with higher quality renewable resources and are shared across regions as needed[43]. Snowy 2.0 is also able to be utilised more efficiently, though with similar capacity factors to the base case, through the stronger connection to Victoria. More solar and storage investment occurs in New South Wales, and in Murray River (V2) REZ, less storage is required in Victoria and less capacity investment is required overall. Option 3A is also assumed to provide significant transmission capacity to the Western Victoria REZ (V3), which is forecast to unlock significant additional wind build in this REZ relative to the base case. This displaces investment in wind capacity in the remaining Victorian REZs as well as other regions REZs such as Wagga Wagga (N6), Isaac (Q4), Banana (Q9), Far North Queensland (Q1), Leigh Creek (S6), North East Tasmania (T1) and Central Highlands (T3). Overall, the amount of forecast capacity investment is also lower with Option 3A due to improved access to higher

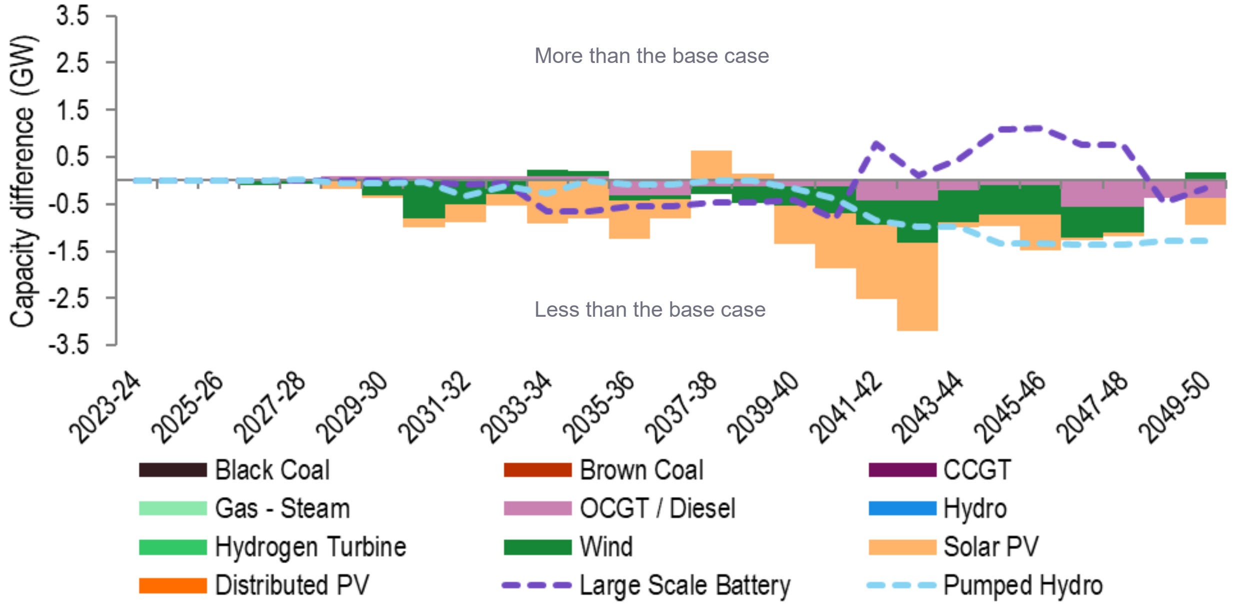
[42] For the avoidance of doubt, all figures of this type in the PACR are showing the differences in cumulative capacity *across the NEM*, compared to the base case.

[43] Higher quality variable renewable resources are ones that produce more generation per MW capacity installed on average, or have a typical daily generation profile that better aligns with when the NEM most needs that generation.

capacity factor REZs and reduced forecast spill. Across the NEM, Option 3A is forecast to reduce solar spill volume by 4% and wind spill volume by 9% relative to the base case.

Figure 9 summarises the difference in generation and storage capacity modelled for Option 5 (in GW), compared to the base case[44]. These capacity differences are driving the benefit associated with avoided or deferred generation and storage costs.

Figure 9 Difference in cumulative capacity build with Option 5, compared to the base case, under the *Step Change* scenario



Option 5 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 wind and solar capacity investment. As with Option3A, less capital investment is forecast since Option 5 enables greater existing and future NEM generation diversity and more efficient utilisation of Snowy 2.0, though with similar capacity factors to the base case.

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

A system with Option 5 is forecast to generally build more wind and in later years more solar in Western Victoria (V3), while more solar is forecast to be built in Murray River (V2). South West NSW (N5) is generally expected to see more solar and to a smaller extent wind built in later years, with Option 5 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.

[44] 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.

On the other hand, Option 5 reduces the capacity otherwise forecast in the remaining Victorian REZs, particularly Ovens Murray (V1) and Gippsland (V5), as well as other regions REZs such as Wagga Wagga (N6), and some Queensland and Tasmanian REZs.

Figure 10 summarises the difference in generation and storage output modelled for Option 3A (in terawatt hours [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.

Generally, peaking gas generation is required in Victoria in the base case to supply peak demand 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 study is expected to be around 98% and the carbon budget constraint is forecast to be met in the base case and 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). Generation from other technologies such as wind and solar follow similar trends to the difference in forecast capacity due to Option 5, discussed earlier. However, generally less spill is expected for wind and solar, resulting in better utilisation of these resources with Option 3A. Furthermore, with VNI West, generally more wind capacity and generation is forecast in Victoria compared to the other options assessed and the base case. 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 10 Difference in output with Option 3A, compared to the base case, under the *Step Change* scenario

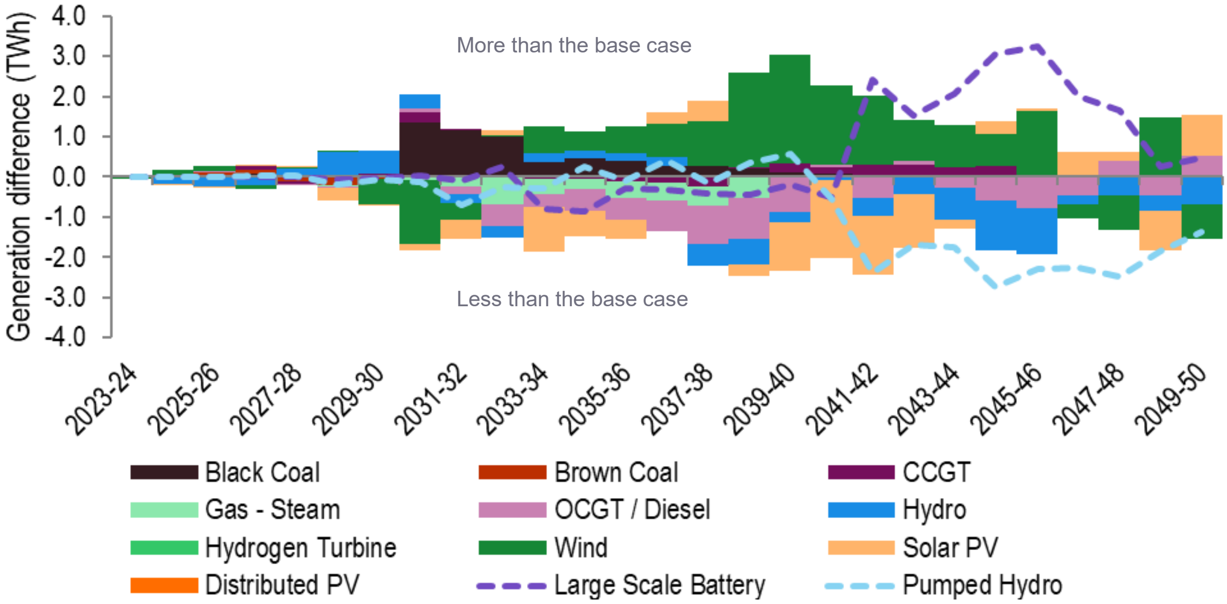
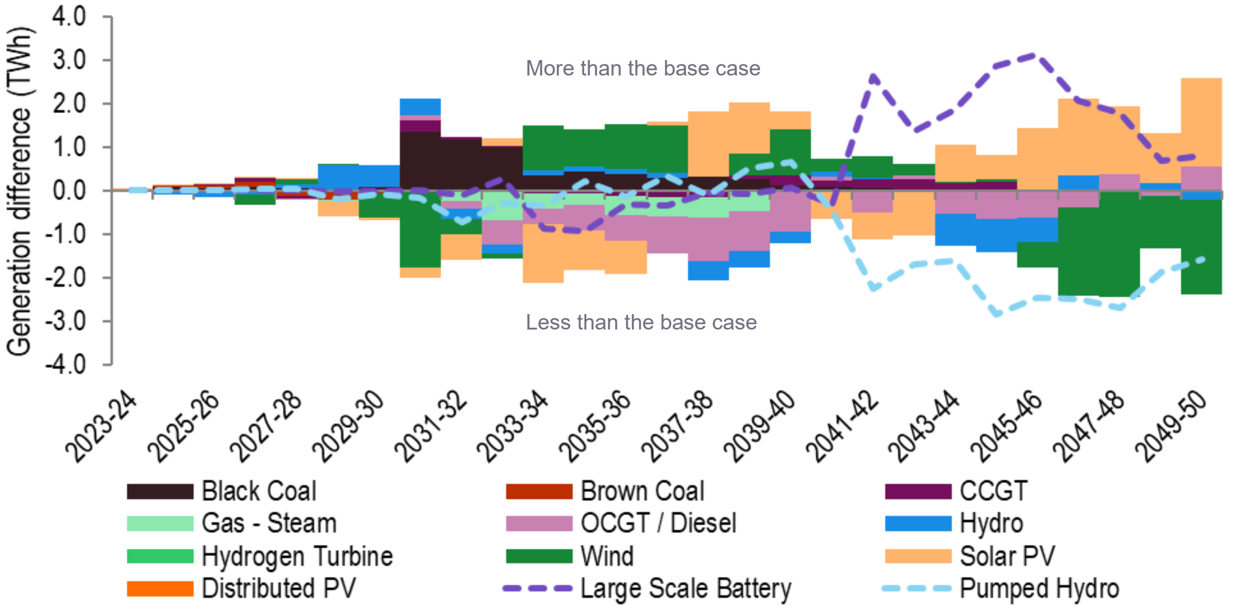


Figure 11 summarises the difference in generation and storage output modelled for Option 5 (in TWh), compared to the base case. These generation differences are driving the avoided fuel cost benefit. Fuel cost savings are again driven by a decrease in gas generation. Other trends are similar to Option 3A, except there is a cumulative decrease in wind generation and increase in solar generation with Option 5.

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



3.1.1 VNI flow duration curve

This section discusses the VNI flow (that is aggregate interconnection flow between Victoria and New South Wales, including from existing interconnectors) expected in the base case, Option 5 and Option 3A across three selected financial years after VNI West is commissioned in the *Step Change* scenario. In this section the export direction is defined as flow from Victoria to New South Wales, and the import direction as flow from New South Wales to Victoria.

Figure 12 shows three annual duration curves for VNI in the base case, Option 5 and Option 3A. 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.

In the base case, 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.

The full range of the upgraded interconnector is expected to be utilised, and congestion on the interconnector is expected to be relieved compared to the base case. As is 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 was mentioned above for the base case although is constrained on import far less.

For more detail about the assumptions, modelling methodology, network representation as well as constraints such as thermal and stability, refer to the EY market modelling report[45].

[45] *VNI West Market Modelling report for additional options*, at https://aemo.com.au/initiatives/major-programs/vni-west/stakeholder-consultation.

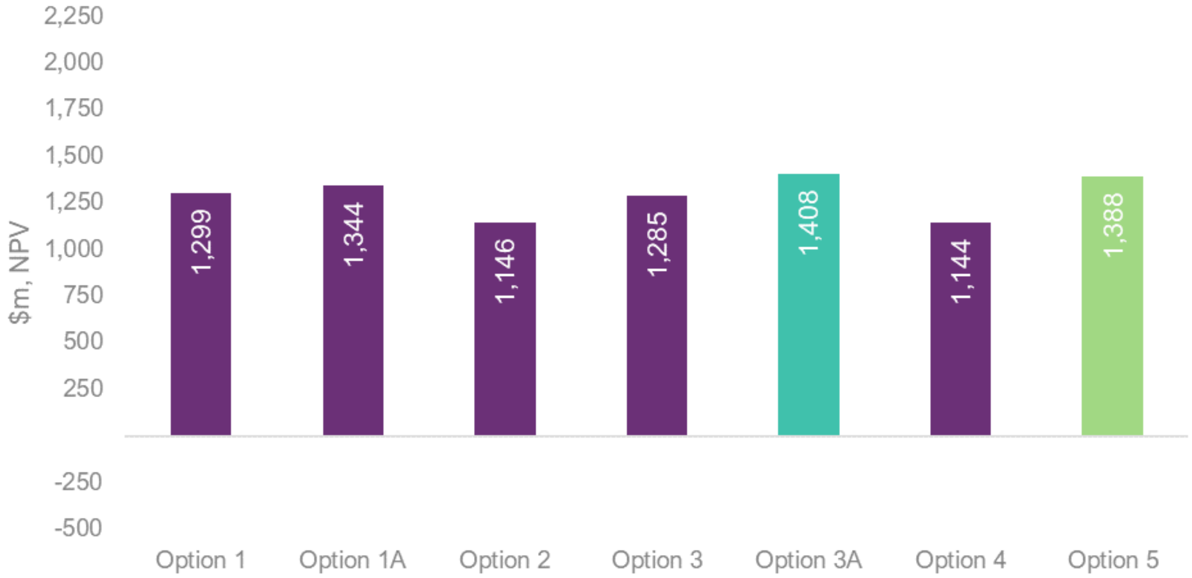
Figure 12 Flow duration curve – base case (top), Option 5 (centre) and Option 3A (bottom)

3.2 Weighted results

On a scenario weighted basis,[46] Option 3A and Option 5 are found to be ranked effectively equally as the top-ranked options. Option 3A (to Waubra/Lexton with spur uprate to 500 kV) is expected to deliver net benefits of approximately $1,408 million. Option 5 (to Bulgana) is found to have net benefits of approximately $1,388 million (1% less than Option 3A).

Figure 13 presents the estimated net benefits for each option on a scenario weighted basis.

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



All other key observations from the weighted results are consistent with the *Step Change* scenario discussed above; that is:

- Option 1 – the proposed preferred option from the PADR – is ranked below Option 3A and Option 5, by $108 million (or 8%) and $89 million (or 6%) respectively.
- The additional cost of the VTL components is not outweighed by the additional expected market benefits (as is shown by Option 2 having lower net benefits than Option 1).
- The two spurs are net beneficial; that is Option 1A is ranked above Option 1 by $44 million (or 3%), and Option 3A is ranked above Option 3 by $123 million (or 10%).
- Option 4 is the worst performing purely interconnector option.

While Option 1A is ranked within 5% of Option 3A and Option 5, it presents 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.

[46] 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.

3.3 Payback period and terminal value

A number of submissions to the PADR raised concerns with the use of terminal values in the analysis and the assumptions regarding any assumed benefits extending beyond the end of the assessment period.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture costs and benefits over the remaining asset life as required by the AER's CBA Guidelines[47]. The terminal values have been calculated as the undepreciated value of capital costs at the end of the analysis period[48], consistent with practices employed in several other recent ISP RIT-T assessments.[49] This ensures that the costs of long-lived options over the assessment period are appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life.

The terminal value at the end of the assessment period, as well as its present value (which is effectively subtracted from the present value of the direct costs in the net benefit calculation), is shown in Table 6 below for Option 3A and Option 5.

Table 6 Terminal values for Option 3A and Option 5 in real and present value terms under each scenario

Option	*Step Change*		*Progressive Change*		*Hydrogen Superpower*	
	$m, real	$m, PV	$m, real	$m, PV	$m, real	$m, PV
Option 3A	2,207	467	2,751	582	2,129	451
Option 5	1,976	418	2,457	520	1,907	404

AVP and Transgrid note that these terminal values may appear large. This reflects the size of initial investments required, the long life of transmission assets, and the years those assets are commissioned during the analysis period. No direct assumptions have been made regarding benefits beyond the end of the assessment period (for example, from avoided fossil fuel costs).

However, it is also helpful to consider the materiality of any benefits beyond the end of the assessment period in conjunction with the payback period for the investment. Assumptions regarding ongoing benefits post the assessment period are only relevant if the payback period is longer than the assessment period.

Table 7 below shows the year that the cumulative benefits in present value terms of the two top-ranked 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 the *Progressive Change* scenario; that is, the costs (including 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.

[47] See https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[48] Straight-line depreciation has been assumed in this calculation.

[49] See for example, the RIT-T assessments for HumeLink, Queensland – New South Wales Interconnector (QNI) Minor, EnergyConnect.

Table 7 Payback periods for Option 3A and Option 5 (including opex until the payback year)

Scenario	Option 3A	Option 5
Step Change	2046	2045
Progressive Change	>2050	>2050
Hydrogen Superpower	2042	2041
Weighted	2047	2046

Moreover, if the full operating and maintenance expenditure (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 slightly longer payback periods. This is shown in Table 8 below.

Table 8 Payback periods for Option 3A and Option 5 (including lifetime opex)

Scenario	Option 3A	Option 5
Step Change	2047	2046
Progressive Change	>2050	>2050
Hydrogen Superpower	2043	2042
Weighted	2048	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 (and an indicative assessment undertaken as part of preparing this report suggests that these benefits are expected to be significant beyond the end of the assessment period). Some stakeholders raised concerns that the operating cost of the investment would exceed any market benefits beyond 2050, particularly since the NEM transition to net zero would have completed. While operating costs can be higher as asset age increases, these are expected to remain below the benefits that continue from avoided investment in generation, storage and other capacity.

3.4 Sensitivity testing

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 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.
- Interaction with WRL.
- Interaction with Victorian Government's offshore wind policy and WRL (that is, a sensitivity combining the first two sensitivities).
- Removing the *Hydrogen Superpower* scenario from the analysis.

- Changes in the capital costs of the credible options.
- Alternate commercial discount rate assumptions.

These sensitivity tests are discussed in the sections below.

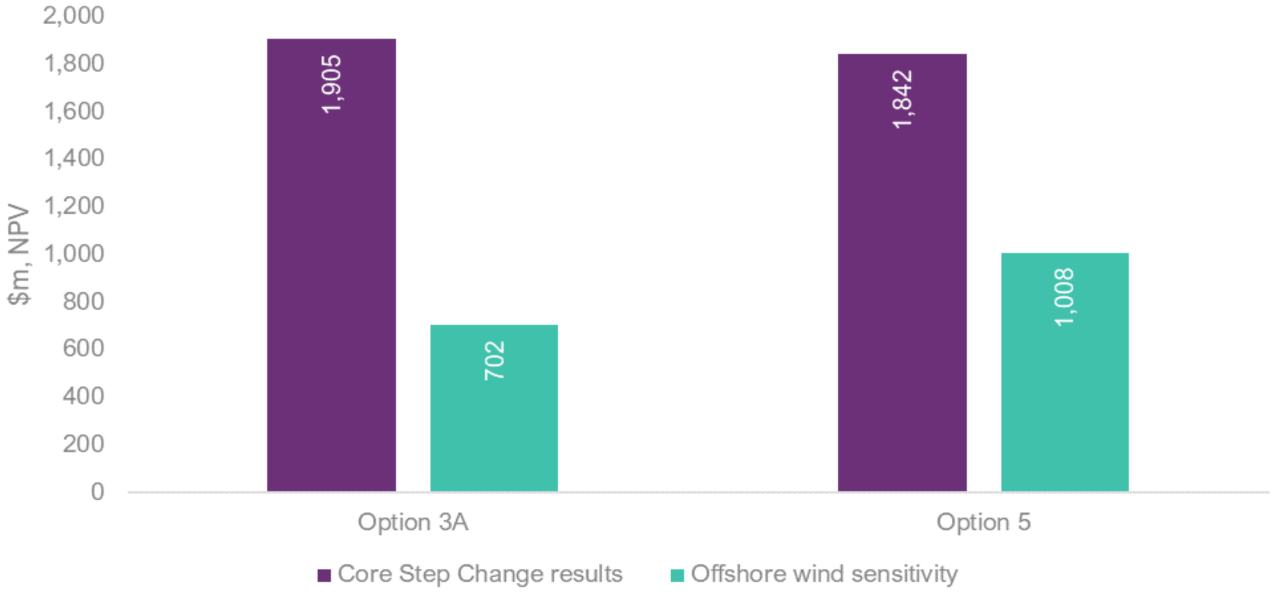
3.4.1 Interaction with the Victorian Government's offshore wind policy

The Victorian Government's Offshore Wind Policy does not meet the criteria under the Rules 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[50], as well as the various points raised in submissions to the PADR regarding these developments, AVP and Transgrid investigated a sensitivity as part of this report that assumes significant Victorian offshore wind development going forward.

Specifically, this sensitivity assumes 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.

Figure 14 presents the net benefits of Option 3A and Option 5 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 3.1).

Figure 14 Estimated net benefits of Option 3A and Option 5 in the *Step Change* scenario with the Victorian Government's offshore wind policy

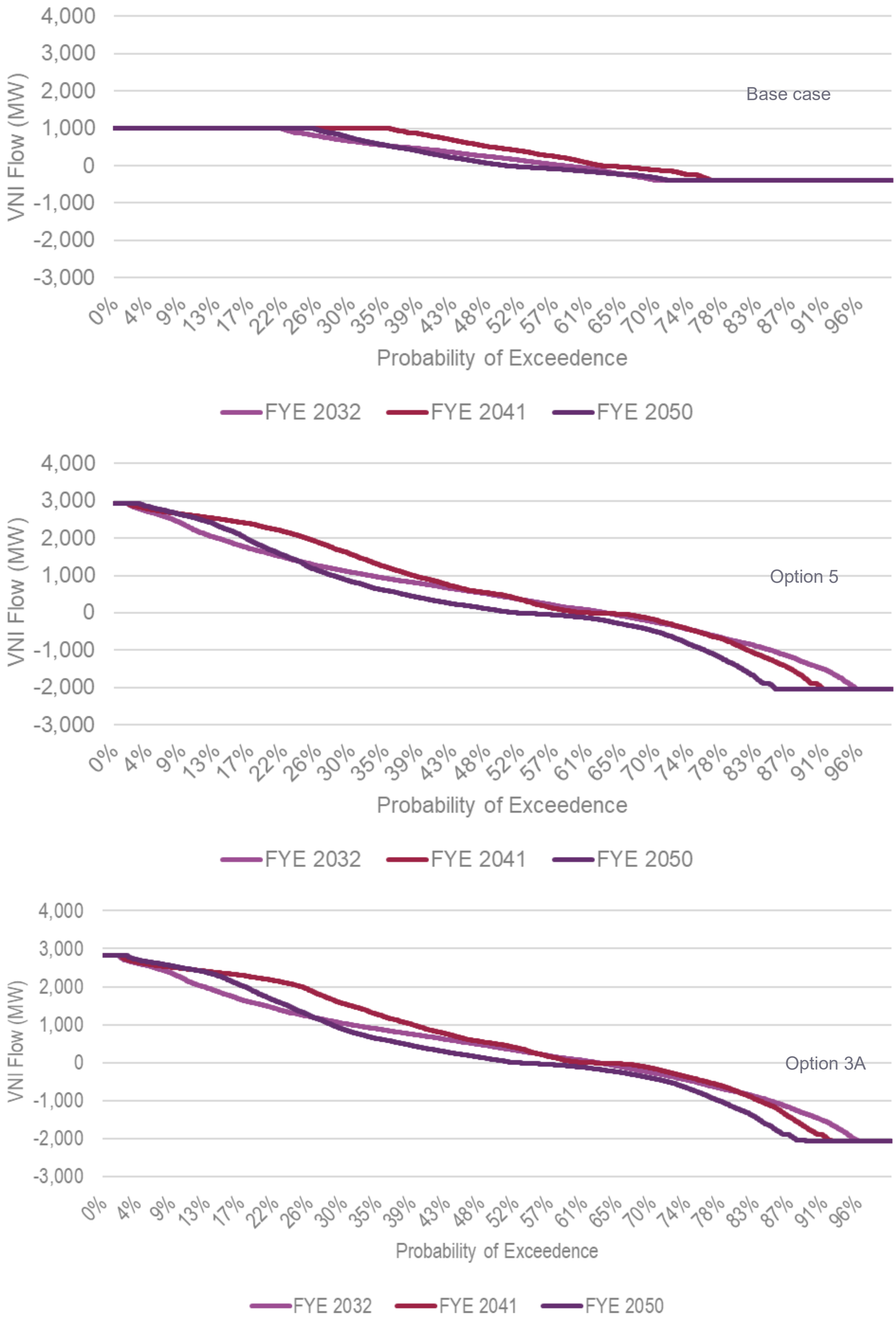


Both Option 3A and Option 5 continue to deliver positive net benefits under this sensitivity with offshore wind targets imposed, although the net benefits are smaller. There remains value in harnessing wind and solar in western Victoria (V3) and Murray River (V2) REZs to provide renewable resource diversity, and the increase in interconnector transfer capability provides greater opportunities for offshore wind generation to export into the

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

northern regions. As Figure 15 shows, the increase in export capability is more heavily utilised in the offshore wind sensitivity as soon as VNI West is built and to a greater degree than in the *Step Change* core simulations in Section 3.1.1.

Figure 15 Flow duration curve in the *Step Change* scenario with the Victorian Government's offshore wind policy – base case (top), Option 5 (centre) and Option 3A (bottom)



Option 5 is less affected by offshore wind developments, because it has less renewable generation development along its route than Option 3A. In particular, the expected net benefits of Option 5 fall by 45% under this sensitivity relative to the core *Step Change* results, while the expected net benefits of Option 3A fall by 63%.

Forecast capex and fixed operating and maintenance (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 option cases. This reduces the opportunity for VNI West to produce savings by altering investment and dispatch in Victoria. 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; this is particularly true for Victoria and New South Wales.
- 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, particularly in New South Wales and Victoria.
- 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.
- The slightly higher northward limit increase provided by Option 5 is forecast to deliver more benefits for this option relative to Option 3A in the offshore wind sensitivity, given it allows more resource sharing to New South Wales during peak export periods to New South Wales.

3.4.2 Interaction with Western Renewables Link

Several submissions to the PADR queried whether the modelling treated the interactions between VNI West and WRL appropriately when determining both the costs and benefits of VNI West. Concerns included:

- Whether or not WRL costs should be considered in the counterfactual base case.
- The potential misallocation of costs across the two projects and that some costs have not been catered for in either this RIT-T or the RIT-T for WRL.
- Whether there was any double-counting of the benefits between the two RIT-T assessments.

The 2022 ISP considers WRL as an ‘anticipated’ project (with a delivery date of July 2026) and includes it in its optimal development path[51]. The project has completed the RIT-T process and has progressed through the contestable appointment of AusNet as the developer of the new infrastructure[52]. WRL 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 AER CBA Guidelines[53]. As outlined in Section 2.2, the direct cost associated with any changes to WRL scope due to VNI West has been considered and included, where applicable, in the NPV assessment in this report.

In terms of how the benefits of the two investments are captured, a key principle underlying the RIT-T and the modelling undertaken is to identify the *incremental* benefits (as well as the *incremental* costs) arising from each option relative to the base case. Since WRL is assumed in both the base case and the VNI West case, the

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

[52] The current progress of the Western Renewables Link project can be found at https://www.westernrenewableslink.com.au/about/.

[53] AER, *Cost Benefit Analysis Guidelines*, August 2020, pp. 62 and 63.

modelling only calculates the incremental benefits for VNI West (and any associated WRL modifications) *over and above* those accruing from WRL. As a result, there is no double-counting of benefits for WRL and VNI West.

While WRL remains an anticipated project, in light of submissions to the PADR, AVP and Transgrid have investigated a sensitivity that addresses the concerns raised that there may have been a misallocation of costs across the two projects and that some benefits may have been double-counted across the two separate RIT-T assessments.

Specifically, AVP and Transgrid constructed an alternate base case for this sensitivity that excludes not only the VNI West investment but also excludes the WRL investment. That is, the base case for this sensitivity assumes that neither VNI West nor WRL go ahead, while the option cases assume that both go ahead. Gross benefits were then compared against the full cost of both projects.

Figure 16 presents the estimated net benefits of all options using the alternate base case against the full cost of both projects on a weighted basis. It shows Option 3A and Option 5 are effectively ranked equal first (within 1% of each other). Importantly, it shows that the full cost of both investments (VNI West and WRL) is outweighed by their expected benefits, compared to a case where neither investment goes ahead.

Figure 16 Summary of estimated net benefits on a weighted basis under alternate base case (no VNI West or WRL)

On an NPV scenario weighted basis, net benefits of $1.9 billion are forecast to be delivered by WRL and VNI West combined (regardless of whether Option 3A or Option 5 is modelled)

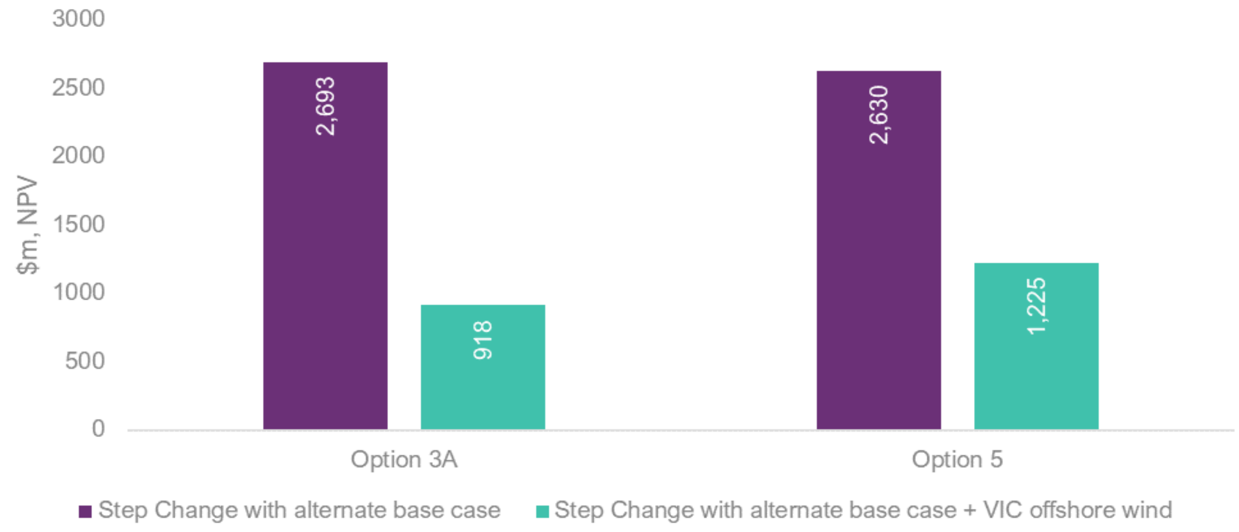
In the alternate base case without WRL or VNI West, capex and FOM expenditure on generation and storage in the NEM is expected to significantly increase, particularly in Victoria, followed by an increase in REZ transmission expansion costs. Without WRL to unlock constraints on existing wind capacity, it is forecast that more wind investment in Victoria needs to be brought forward before 2030.

More offshore wind is also forecast in the alternate base case with no WRL or VNI West (even without any offshore wind targets imposed). This is because all accessible onshore wind resources in Victoria are fully utilised due to limited access to REZs. Total system costs in the alternate base case are therefore higher, since the capital costs of offshore wind are higher than onshore wind, and this provides greater opportunity for VNI West to deliver savings from capital deferral. Without WRL or VNI West, the transmission capacity of the Western Victoria REZ is limited to the existing network (which is already congested), resulting in new investment in Victoria shifting to other REZs such as Central North Victoria (V6) and South West Victoria (V4). This is forecast to result in the need for more (or advanced) transmission upgrades for these REZs, and as such more REZ transmission costs.

3.4.3 Interaction with Victorian Government's offshore wind policy and WRL

Figure 17 below presents the net benefits of Option 3A and Option 5 under the *Step Change* scenario with the Victorian Government's offshore wind policy assumed to be in place *and* where the alternate base case from Section 3.6.2 above is also assumed (that is, a base case that excludes not only the VNI West investment but also excludes the WRL investment). It compares the results of this combined sensitivity to the net benefits under the *Step Change* scenario assuming the alternate base case (that is, feeding into the weighted results shown in Section 3.6.2 above).

Figure 17 Estimated net benefits of Option 3A and Option 5 in the *Step Change* scenario with the Victorian Government's offshore wind policy and assuming the alternate base case (no VNI West or WRL)



As shown in Section 3.6.1, Option 5 is less affected by offshore wind commitments, because it has less renewable development along its route than Option 3A. In particular, the expected net benefits under the *Step Change* scenario for Option 5 reduce by 53% under this sensitivity, while the expected net benefits of Option 3A reduce by 66%.

Importantly, VNI West and WRL combined continue to deliver positive net benefits, even if offshore wind is legislated, as there is value in the resource diversity and greater export opportunities that these network investments combined offer.

3.4.4 Removing the *Hydrogen Superpower* scenario

In its submission to the PADR, PIAC stated it is of the view that there is no credibility for an 18% weighting for the *Hydrogen Superpower* scenario in any project where costs are partly socialised among consumers. It stated that the *Hydrogen Superpower* scenario should be excluded unless a different cost recovery mechanism is proposed.

AVP and Transgrid note that under the actionable ISP framework, stakeholder consultation on the ISP scenarios and the weighting that should be applied to them occurs as part of the development of the *Inputs, Assumptions and Scenarios Report* (IASR). The RIT-T assessment is then required to adopt the specific scenarios and weightings for a particular ISP project specified in the ISP[54].

AVP and Transgrid note that AEMO specified in the 2022 ISP that the scenario weighting to be applied to the *Hydrogen Superpower* scenario in the RIT-T for VNI West should be 18%.

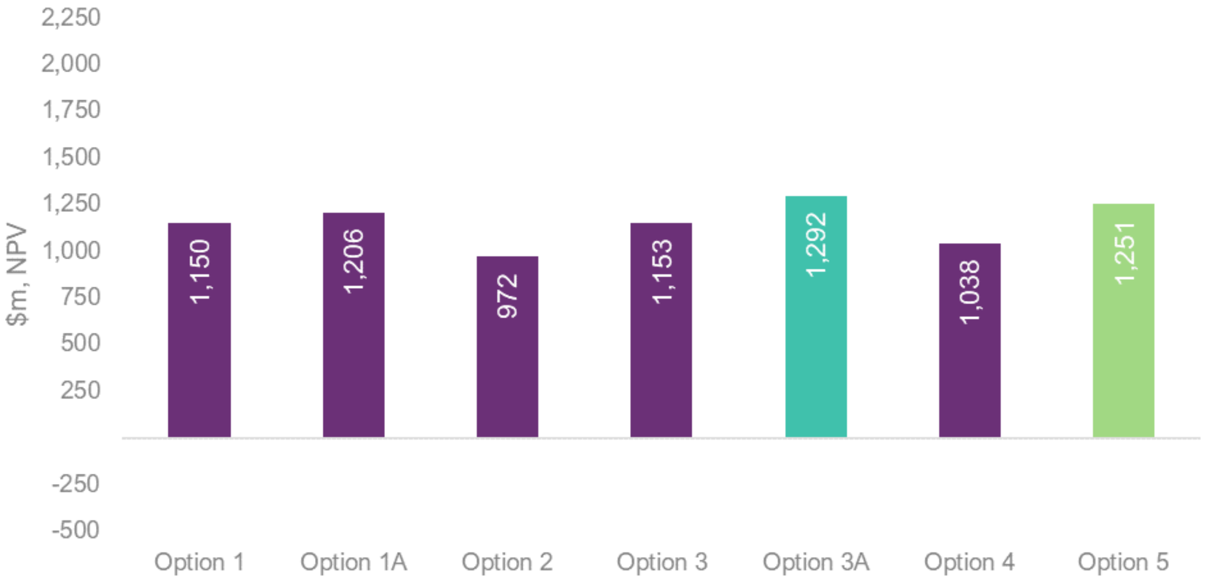
While the 18% weighting (and the corresponding 2022 ISP weights for the other two scenarios) was applied to weight the estimated market benefits in the core assessment (shown in Section 3.2), AVP and Transgrid have also carefully considered the results in each scenario (in Sections 3.1-3.3) to better understand how differences in the future 'states of the world' can impact the benefits of the options assessed.

In addition, AVP and Transgrid investigated a sensitivity that removes the *Hydrogen Superpower* scenario from the assessment. The other two scenario weights are scaled up in this sensitivity according to their 2022 ISP weights to make the combined 100%.

Figure 18 presents the results of this sensitivity and shows that it does not warrant any change to the key findings. Specifically, this sensitivity finds that Option 3A and Option 5 are effectively ranked equal first and all other observations from the core assessment also hold.

AVP and Transgrid note that the draft IASR for the 2024 ISP, released in December 2022, proposes to continue to include a very fast decarbonisation scenario similar to the *Hydrogen Superpower* scenario, and refers to it as the '*1.5°C Green Energy Exports*' scenario. The proposed *1.5°C Green Energy Exports* scenario continues to reflect very strong decarbonisation activities domestically and globally contributing to limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification[55].

Figure 18 Summary of estimated net benefits on a weighted basis without the *Hydrogen Superpower* scenario



[54] AER, *Regulatory investment test for transmission*, 25 August 2020, p. 7 and 9.

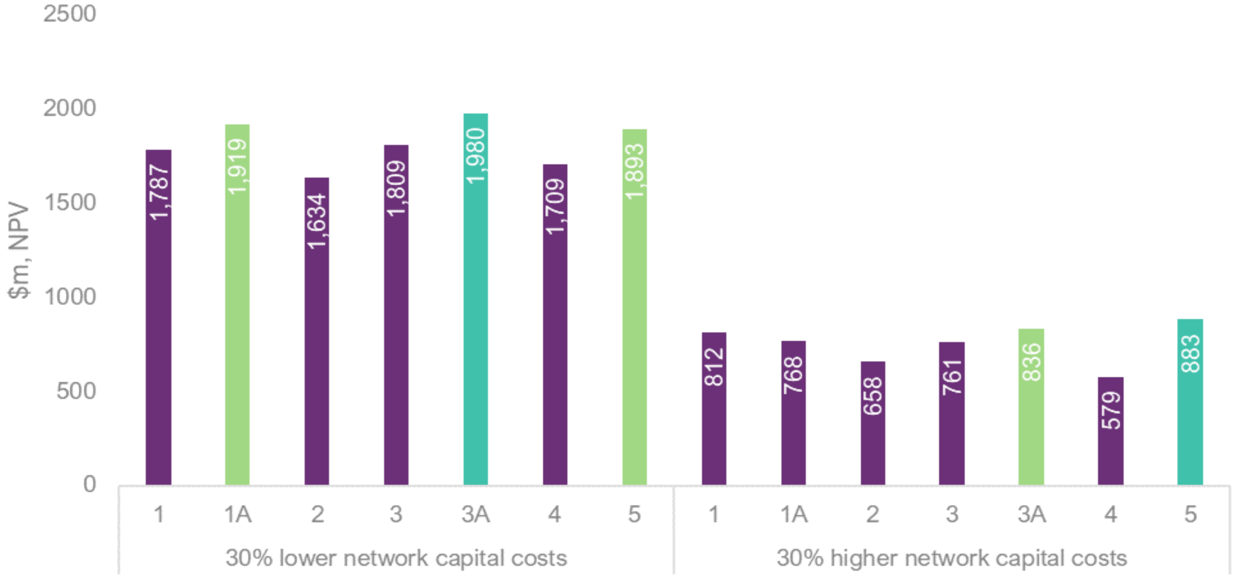
[55] AEMO, *Draft 2023 Inputs, Assumptions and Scenarios Report*, December 2022, p. 5.

3.4.5 Changes in the network capital 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[56] (see Section 2.2.2). 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 19 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 3A (and Option 1A).

Figure 19 Estimated weighted net benefits with 30% lower and higher network capital costs



Extending these sensitivity tests to investigate key boundary values finds that:

- The conclusion that Option 3A is ranked higher than Option 1A is completely robust to the assumed network capital costs (that is, there is no upper or lower boundary to this conclusion).
- If network capital costs decrease by at least 19%, Option 1A is preferred over Option 5 (however, AVP and Transgrid consider a cost reduction of this magnitude is unlikely).
- If network capital costs increase by at least 9%, Option 5 is preferred over Option 3A.
- The central estimates of network capital costs would need to increase by around 74% for Option 3A to have negative net benefits, or 82% for Option 5 to have negative net benefits (however, AVP and Transgrid consider this unlikely given the cost estimates have been estimated at a +/-30% level of accuracy at this stage).
- VTL battery-related capital costs would need to be 95% lower for Option 2 to have the same net benefits as Option 3A, or 88% lower to have the same net benefits as Option 5.

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

Figure 20 below extends this sensitivity and investigates how the results change in the *Step Change* scenario under both 30% lower and 30% higher assumed network capital costs, *as well as* assuming the Victorian Government's offshore wind commitments.

Option 5 is found to be ranked ahead of Option 3A under both 30% lower and higher assumed capital costs if the Victorian Government's offshore wind policy is assumed to be legislated. Further, an increase of greater than 34% in network capital costs would be required for Option 3A to have negative net benefits, or 55% for Option 5 to have negative net benefits, under this sensitivity.

Figure 20 Estimated net benefits in the *Step Change* scenario with 30% lower and higher network capital costs with the Victorian Government's offshore wind policy

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 submission[57]. This sensitivity has been undertaken on the core scenario-weighted results (those presented in Section 3.2) and does not change the key conclusions of the analysis. Option 3A and Option 5 remain jointly top-ranked and are expected to deliver positive net benefits (on a weighted basis).

3.4.6 Alternate commercial discount rate assumptions

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

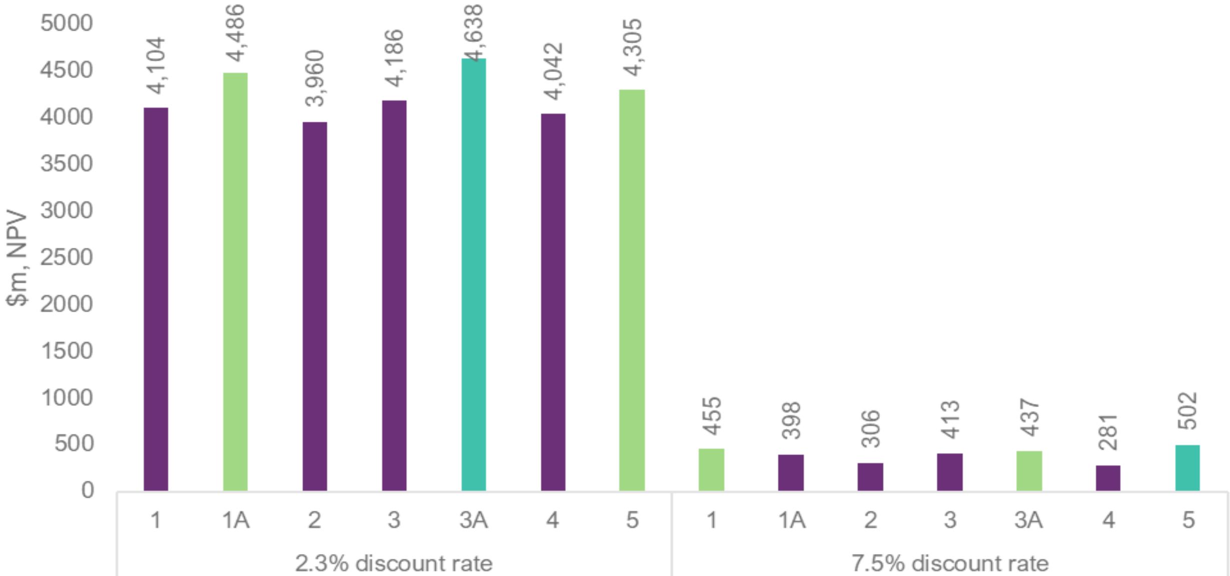
- A lower bound discount rate of 2.30% (equal to the latest AER Final Decision for a transmission network service provider's (TNSP's) regulatory proposal at the time of preparing this report[58]).
- An upper bound discount rate of 7.50% (consistent with the upper bound in the latest final IASR).

[57] Simon Bartlett (late submission), p. 2.

[58] 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. See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powerlink-determination-2022%E2%80%9327/final-decision.

Figure 21 below shows the results under both these assumed discount rates. A higher assumed discount rate favours Option 5, while a lower assumed discount rate favours Option 3A (and Option 1A).

Figure 21 Estimated weighted net benefits with lower and higher assumed discount rates



Extending these sensitivity tests to investigate key boundary values finds that:

- The finding that Option 3A is preferred over Option 1A is robust to the assumed discount rate (for example, a rate of more than 2,080% is required for Option 1A to have greater net benefits than Option 3A).
- If the discount rate is below 4.56%, Option 1A is preferred over Option 5 (however, AVP and Transgrid note that 4.56% is lower than both the 2022 ISP central rate of 5.50% and the draft 2023 IASR central rate of 7%).
- If the discount is greater than 5.86%, Option 5 would be preferred over Option 3A.
- The discount rate would need to be greater than 8.97% for Option 3A to have negative net benefits, or 9.44% for Option 5 to have negative net benefits.

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%.

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 Option 5 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.

Figure 22 below extends this sensitivity and investigates how the results change in the *Step Change* scenario under both lower and higher assumed discount rates, *as well as* assuming the Victorian Government's offshore wind commitments.

Figure 22 Estimated net benefits in the *Step Change* scenario with a lower and higher discount rate, assuming the Victorian Government's offshore wind policy is legislated

Option 5 is found to be ranked ahead of Option 3A under both lower and higher assumed discount rates and the Victorian Government's offshore wind commitments. Further, a discount rate of greater than 7.26% would be required for Option 3A to have negative net benefit with the Victorian Government's offshore wind policy assumed to be in place, while a discount rate of greater than 8.26% would be required for Option 5 to have negative net benefit with the Victorian Government's offshore wind policy assumed to be in place. AVP and Transgrid note that this threshold rate is above the Draft 2023 IASR central discount rate estimate of 7% but below the higher estimate of 9%.

4 MCA methodology and outcomes

AVP, in conjunction with external consultants AECOM, has developed an MCA Framework to further assess and rank the options consistent with the functions conferred by the NEVA Order. The MCA methodology considered net economic benefit, environment, cultural heritage, land use and engineering aspects and enabled ranking of the options according to their performance against each criterion. This was to better incorporate a wider range of criteria and risks in decision-making to facilitate delivery of VNI West.

The complex decision-making process, especially for a project like VNI West, needs to consider a multitude of perspectives, constraints and variables. A multi-criteria decision analysis or MCA is a well-documented process used to support decision-makers, such as Infrastructure Australia, which provides a guide for the application of MCA for decisions about infrastructure[59]. MCA has been utilised for numerous major infrastructure projects in Victoria such as the Western Outer Ring Main transmission gas pipeline and Suburban Rail Loop (SRL).

The process includes a series of systematic steps to structure the decision-making process, identify preferences, and build decision recommendations consistent with those preferences[60]. The term MCA encompasses all methods and techniques where multiple potentially conflicting criteria are used to determine preferences during a decision-making process.

The MCA process is a scientific decision-making method used, in the case of VNI West, to evaluate and rank proposed network and non-network options in order of preference based on criteria formulated around key objectives: net economic benefit, environment, cultural heritage, social, land use and engineering.

Social and environmental factors that sit outside of the scope of the RIT-T are increasingly being seen as important in building social licence. For example, as part of the 'Transmission Planning and Investment' review, the Australian Energy Market Commission (AEMC) noted the importance of these factors in the delivery of transmission investments, and considered that there is an opportunity for the AER to provide guidance on how they can be assessed (including potential studies and analysis that TNSPs could undertake)[61]. However, these factors are difficult to convert into quantifiable risks, as required in the RIT-T framework, and in any case, economic impacts that accrue to parties other than those who produce, consume and transport electricity in the market are treated as externalities under the RIT-T. RIT-T proponents must exclude externalities from the costs and market benefits of a credible option, thereby excluding them from the determination of net benefit.

In relation to AVP and the Victorian section of the VNI West, consistent with the functions conferred by the NEVA Order, these social, environmental and engineering factors can be taken into account in assessing which options are more likely to facilitate and expedite the development, delivery, construction and energisation of VNI West.

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.

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[59] Infrastructure Australia. *Guide to multi-criteria analysis* July 2021, at https://www.infrastructureaustralia.gov.au/sites/default/files/2021-07/Assessment%20Framework%202021%20Guide%20to%20multi-criteria%20analysis.pdf.

[60] See https://www.sciencedirect.com/science/article/pii/S0305048319310710.

[61] AEMC, *Transmission Planning and Investment – Stage 2*, Final Report, 27 October 2022, pp. 29-30.

AVP acknowledges the application of this MCA is based on professional judgement and includes some qualitative analysis, but there are significant advantages in applying an MCA as part of the decision-making process, as outlined in Table 9.

Table 9 Benefits of applying an MCA process

Benefit	Description
Clear, consistent structured framework	• Structured comparison of options against objectives • Clearly show how ranking of options were formulated • Where required, some MCA can be applied to a range of circumstances
Transparency	Subjective considerations, limitations and assumptions are made clear and explicit allowing for a better understanding and more effective reviews or suggestions MCA enables stakeholder and community engagement participation that is not always feasible in a strictly quantitative analysis
Flexibility	MCA Framework accommodates both qualitative and quantitative data and information, minimising the issue of criteria which may be based on tangible information which is difficult to quantify.

As the MCA is a flexible framework, formed by project-specific requirements and available information, there are few set methodological rules. Hence this analysis is utilised as a ranking or filtering tool, identifying the option that will undergo further detailed analysis, allowing the decision-making process to progress.

The MCA must be seen as a dynamic iterative process where the analysis can be repeated once further information is made available or feedback is received. This will allow the results to become more and more refined, increasing confidence in the decision-making process as a whole.

The publication of this consultation report marks the start of a six-week consultation period during which time AVP is seeking input from all stakeholders, communities, Councils, and Traditional Owners in the broad areas of interest, and potentially impacted landowners on the WRL route, so that the MCA can be refined before a decision on the preferred option is made.

4.1 MCA process

The MCA process included the following key steps, which are detailed further below, and in Appendix A4:

- Constraints analysis.
  - Identification of constraints and opportunities.
  - Identification of an Area of Interest (AoI) and an indicative alignment within this AoI for each option.
- MCA.
  - Establishment of an assessment framework including evaluation criteria, rating guidance and criteria weightings for the evaluation of the options under consideration.
  - Evaluation of indicative alignments within Areas of Interests for each option using geographic information system (GIS) analysis.
  - Application of the assessment framework.
  - Scoring and subsequent ranking of options.

4.1.1 Constraints analysis

The constraints analysis process consisted of gathering appropriate data and information from publicly available sources, private data and stakeholder discussions and reviewing lessons learnt from previous and current projects. The aim was to identify objects, areas, places and communities that may potentially be impacted by any of the proposed options (collectively termed 'constraints').

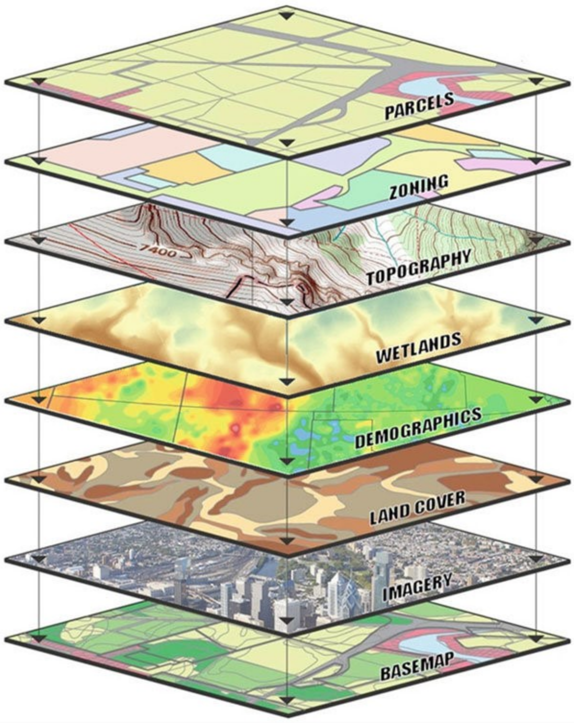
This information was analysed, grouped and mapped into the following themes which formed the basis of the MCA objectives:

- Net economic benefit.
- Environment.
- Cultural heritage.
- Social.
- Land use.
- Engineering.

During the analysis, areas in the broad geographical area that have previously been disturbed (such as existing transmission lines, roads and tracks, and utility easements), where potential impacts could be minimised (for example, through co-locating with existing linear infrastructure), were also identified.

These constraints were reclassified and overlayed as the first step in creating a suitability map for the geographically broad project area (Figure 23).

Figure 23 Example of overlaying various datasets to determine suitability



Overlaying data in GIS

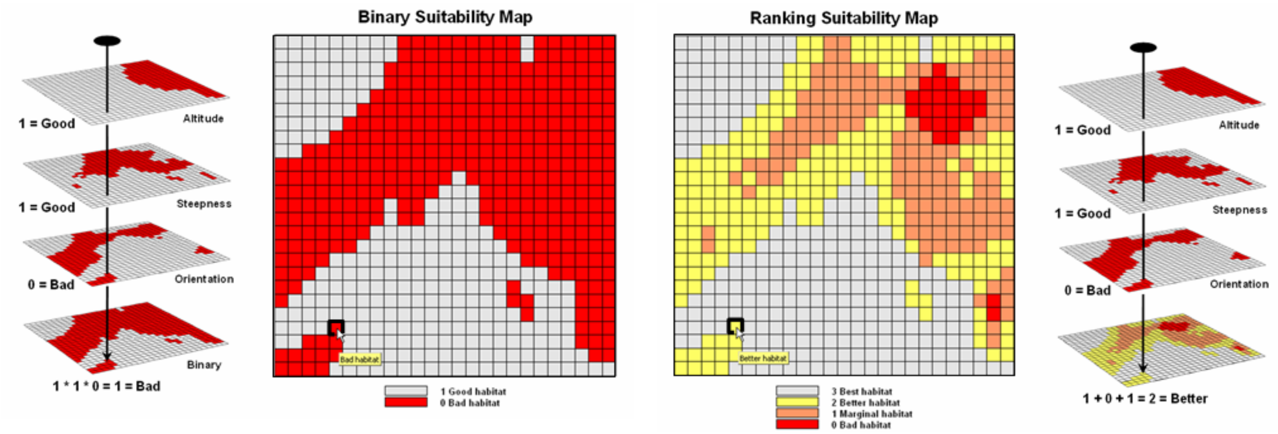
Different types of data can be integrated and visually represented in a GIS system – for example, zoning, flooding, wetlands, residential areas, vegetation, and national parks.

By overlaying these data, spatial trends and relationships become evident, therefore providing insight about relevant characteristics of a specific location.

Source: https://www.usgs.gov/information-policies-and-instructions/copyrights-and-credits.

However due to the significant sensitivities within the landscape, this overlaying is very limited in the information that it produces in its binary form, because it only differentiates where is deemed suitable and unsuitable for the options to be located (Figure 244).

Figure 24 Overlaying data with and without ranking



Source: http://www.innovativegis.com/basis/mapanalysis/Topic23/Topic23.htm.

Once all the data and information has been included in the overlay, there is no area that is not ranked unsuitable. Hence the need to rank the data to ensure a more detailed granular picture is painted, which represents what the data presents and what relevant legislation dictates. For example, an area with a Strategic Biodiversity Value of 0.1 does not hold the same level of suitability as an area with a value of 1.0.

To enable this level of detail, each constraint was categorised in terms of its complexity from either an approvals, social or engineering perspective, from 'very high' (such as town/city centres, national parks, large waterbodies) through to 'very low' (for example, brownfield sites, gentle terrain). This resulted in a suitability heat map from which an indicative 100-metre alignment was developed for each option within a refined broad geographical area or 'area of interest'. This process allows biophysical elements and socio-cultural conditions of the landscape to be included in the decision-making process.

It should be stressed that this assessment has been based on desktop information only. The 100-metre wide alignment was used to assess the area of a particular criteria intersected by an option, relative to the other options, without undertaking any field work to validate the public data sources. Field-based surveys still need to be undertaken to determine the extent of actual native vegetation, which is expected to be considerably less than that of the desktop mapping. Route selection and refinement would be undertaken to avoid and minimise any social and environmental impacts. Tower locations and access tracks would then be identified and refined to further minimise social and environmental impacts. In the example of native vegetation, the actual area of native vegetation that would be cleared for the construction of the preferred option would be considerably less than the areas identified for the purpose of the MCA. For the avoidance of doubt, an indicative alignment intersecting less than 280 hectares of native vegetation would score well in this MCA, relative to other indicative alignments under consideration, but this does not mean that clearance of this level of native vegetation is considered acceptable. Nor does it reflect the likely environmental impact once these other steps have been undertaken to minimise risks.

The MCA does not identify a preferred transmission line route, design or location of new infrastructure required for VNI West. The intention of this MCA is to identify the best performing transmission option. It provides a starting point for engagement with potentially affected landowners and other stakeholders. Further investigation, including on-ground surveys, will also be needed in relation to environmental, social and engineering constraints. For the purposes of the MCA, an indicative alignment was used; however, a significantly wider area of interest will be adopted for the next stage of investigations.

The data and information included in the constraints analysis is described in Table 17 of Appendix A4. It is acknowledged that there are criteria which have not been addressed in the MCA due to the analysis being based on desktop information only, the nature of the analysis, and limitations imposed by relying on existing datasets.

As this MCA process is dynamic in nature, it is encouraged that any information currently not included in the MCA, that may potentially add value to the analysis, be highlighted or provided for inclusion. As stakeholder, Traditional Owner and community engagement progresses, more qualitative information around these important themes would be able to be included in the MCA.

4.1.2 MCA steps

Once the indicative alignments have been determined, the MCA was designed and undertaken. The series of systematic steps associated with the VNI West MCA process is described in Table 10.

Table 10 MCA steps

Stage	Step		Description
MCA Framework	1	Set objectives	• Key overarching outcomes looking to be achieved by each option included in the analysis. • Based on defined problems and/or opportunities.
	2	Develop Criteria	• Outcomes or indicators by which the options were assessed against the stated objectives. • Criteria were scored and weighted to give a single score for each objective.
	3	Formulate measures	• Developed measures that inform the criteria using available quantitative information and, where required, informed qualitative judgements. • As there were multiple measures per criteria in some instances, they were scored (and potentially weighted) in a similar way to the criteria (see Fig. 35). • Use of quantifiable metrics
	4	Weighting	• The approach to weighting was defined based on current understanding of the relative importance of each criterion. • Weightings were used to develop a weighted score for each of the defined objectives. • Weightings were also applied to define the relative importance of the measures that inform the criteria and to combine scores for objectives into a single score for each option. • In its basic form, weighting is equally divided between the objectives and criteria however, given the nature and complexity of the VNI West project, there was a need to place greater emphasis on some objectives and criteria which may have greater influence in the decision-making process. • The overall goal was to use previous experience and project information from engagement undertaken to date to come up with the weighting. For transparency, these weightings have been provided in Table 2 of Attachment 3.
Analysis and testing	5	Scoring	• Applied the MCA Framework to assess how each option performs against the established criteria. • Based on qualitative ratings underpinned by quantitative score ranges and qualitative measures. • Scored independently from weights, to minimise any bias. • Bias, meaning, relativity and outliers were taken into consideration during scoring. • Sensitivity and scenario testing undertaken to ensure risk and uncertainty was taken into consideration.

4.2 VNI West MCA Framework

The following tables list objectives, criteria, measures, weightings and scoring for VNI West specifically.

Table 11 VNI West objectives

MCA objective theme	MCA objective
Net economic benefit	Maximise net benefit of the project (consistent with RIT-T assessment).
Environment	Avoid and/or minimise impact on the natural environment (for example, protected areas, native vegetation, waterways).
Cultural heritage	Avoid and/or minimise impact on Cultural and Historic Heritage (Aboriginal and non-Aboriginal).
Social	Avoid and/or minimise impact on local communities (for example, impact on amenities, residential areas, community sentiment).
Land use	Avoid and/or minimise impacts on existing and future land use (for example, agriculture, forestry).
Engineering	Limit engineering complexities during construction and impacts on existing infrastructure (for example, topography, constructability).

AVP identified and developed the criteria, measures and weightings in consultation with AECOM and based on experience and expertise. The criteria used to assess the options have been selected as they represent potential delivery risks to the project. The measures and weightings have been developed based on the likelihood and consequence of these delivery risks. Consideration has been given to learnings from other recent transmission projects in Victoria, including WRL.

Table 12 VNI West criteria

MCA objective	MCA criteria	Criteria weighting	Objective weighting
Maximise economic benefit of the project	Maximise economic benefit	100%	70%
Avoid and/or minimise impact on the natural environment	Protected areas	40%	5%
	Native vegetation	30%	
	Habitats	20%	
	Waterways	10%	
Avoid and/or minimise impact on Cultural and Historic Heritage	Non-Aboriginal cultural heritage	40%	5%
	Aboriginal cultural heritage	60%	
Avoid and/or minimise impact on local communities	Amenity	70%	10%
	Affected parties	30%	
Avoid and/or minimise impacts on existing and future land use	Severance	20%	5%
	Agriculture	50%	
	Forestry	15%	
	Resource development	15%	
Limit engineering and operational complexities and impacts on existing infrastructure	Third party infrastructure	20%	5%
	Engineering complexity	20%	
	Bushfire	20%	
	Technical complexity	30%	
	Constructability	10%	

Table 13 MCA measures per criteria

Theme	MCA criteria	MCA measure
Net economic benefit	Maximise economic benefit	Net present value (NPV) growth benefit ($m)
Environment	Protected areas	Area within protected areas (Ramsar wetlands, National Parks and State Parks)
	Native vegetation	Area of native vegetation intersected
		Area of highly significant native vegetation (EPBC listed threatened Ecological Communities and state endangered EVCs)
	Habitats	Area of critical habitat intersected (critical habitat for threatened or migratory species listed under EPBC Act (Cth) and FFG Act (Vic))
	Waterways	Number of waterways intersected
Cultural Heritage	Non-Aboriginal cultural heritage	Area of Non-Aboriginal heritage items or conservation areas listed under Commonwealth and State heritage registers intersected
	Aboriginal cultural heritage	Area of potential Aboriginal cultural heritage significance intersected (areas of cultural heritage sensitivity)
		Native title
Social	Amenity	Area within residential zones as a proxy for amenity impacts (noise, dust, visual) (RZ)
		Number of buildings within 300 metres of corridor centre line
		Area within significant landscape overlay (SLO)
	Affected parties	Number of land parcels affected
Land use	Severance	Number of land parcels by sectors where smallest portion is >20%
	Agriculture	Areas of land with agricultural potential score of >6
	Forestry	Area of forestry tenure land intersected
	Resource development	Area of resource tenure land (production and exploration) intersected
Engineering	Third party infrastructure	Number of arterial roads
		Number of Transmission lines intersected
		Number of Railways intersected
		Number of pipelines intersected
	Engineering complexity	Topography Slope > 1:5 (AEMO to confirm)
		Area within land subject to inundation (LSIO)
	Technical complexity	Relative quantity of power flow control systems, series compensation and complex control schemes
	Bushfire	Area within bushfire overlay
	Construction complexity	Available area for construction

4.3 Results of the MCA

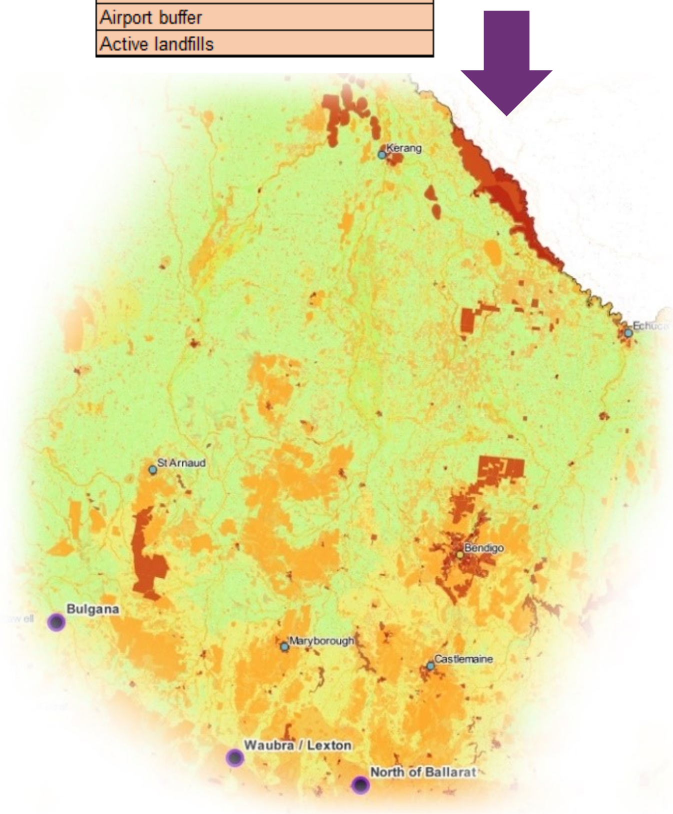
An Area of Interest (AoI) was identified for each option based on the constraints analysis. Using an indicative alignment within these AoIs, the MCA determined that Option 5 ranks first when the weighted MCA is applied and is found to rank first, or equal first, for all of the objectives considered.

4.3.1 Constraints analysis

The constraints analysis identified a range of significant environmental, cultural and social constraints and opportunities, resulting in a better understanding of existing and known conditions relevant to the options. Figure 25 describes and visually represents the data and information included in the constraints analysis, including ratings.

Figure 25 Data utilised to undertake constraints analysis

Complexity ratings				
5 - Very high	4 - High	3 - Medium	2 - Low	1 - Very low
World heritage (Cultural and natural)	Indigenous Heritage - Commonwealth	Indigenous Heritage - State (Derived)	Biodiversity (Strategic Biodiversity Value / native vegetation)	Agricultural potential (very low)
Ramsar Wetlands of International Importance	Historical Heritage - National	Native title	Agricultural potential (low)	
Public Use Zones (Education, Health and Community)	Historical Heritage - Commonwealth	Historical Heritage - State	Areas of flooding	
Residential Zones	Wetlands (Importance Directory)	Biodiversity (Strategic Biodiversity Value / native vegetation)		
Public land - National Parks	Waterways	Agricultural potential (moderate)		
Built up areas (high density)	Biodiversity (Strategic Biodiversity Value / native vegetation)	Environmentally significant land		
Houses / buildings	Threatened species and known habitats			
Airports	Threatened ecological communities - Commonwealth (State / EPBC Act)			
Commonwealth land (Defence)	Agricultural potential (high)			
Waterbodies	Potato growing potential			
Active mining tenements	Public land - State Parks / Forest			
	Nature Conservation Reserves/ NPA Schedule / Natural Features			
	Significant landscapes (visual impact)			
	Bushfire risk areas			
	Airport buffer			
	Active landfills			



This more detailed analysis, informed by stakeholder feedback in PADR submissions, indicates the potential challenges of building transmission along the Bendigo – Ballarat corridor. As shown in this map (in Figure 25), much of the area between Bendigo and Ballarat is coloured orange or dark orange. The area surrounding Bendigo is also highly constrained (shown in red) with no feasible options for a new line into Bendigo, outside of the existing 220 kV line easement.

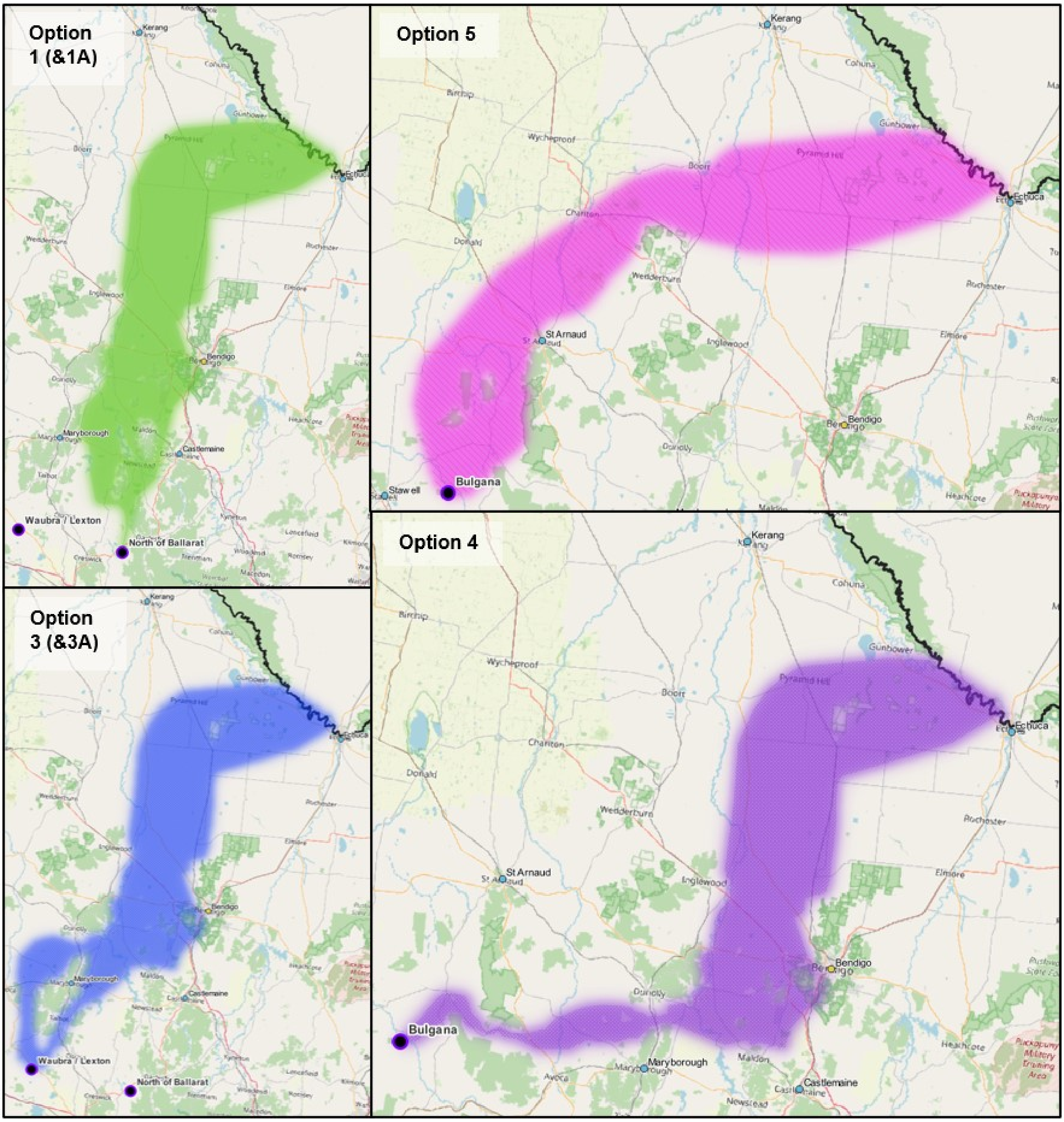
No matter what AoIs were explored, all options except Option 5 were highly constrained when connecting into the existing Bendigo Terminal Station on the outskirts of the city, due to residential development and state and national parks (as seen by the red areas in Figure 25). There is an existing 220 kV transmission line easement through the national park that could be utilised for a connection to Bendigo. Undergrounding would not be an option, due to space constraints at the existing Bendigo Terminal Station as well as the greatly increased construction disturbance through the national and regional parks. To remain within the existing footprint within the national park, preliminary investigations indicate that the existing 220 kV transmission line would be rebuilt in its place within the same easement, if permitted.

The complexity of navigating social and environmental constraints for options connecting into Bendigo has been factored into the MCA scoring for Options 1 through to 4[62]. As Option 5 does not pass near Bendigo, it does not face these same social and environmental constraints.

The visual representation of constraint information provided in Figure 25 allowed for the broad geographical area to be refined to individual AoIs for each option, avoiding or minimising the length of line intersecting areas shaded orange or red wherever possible (Figure 26).

[62] As Option 2 presents identical environment, social, land use and engineering impacts/constraints as Option 1, it was not assessed separately within the MCA Report

Figure 26 Areas of interest for each option



4.3.2 Ranking

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. More detail on the rating system is provided in Table 17 of Appendix 4, and each options' score against each individual measure is provided in Table 18 of Appendix 4.

A two-stage weighting system was used in this MCA for the analysis of the options. Weightings were first given to each of the measures within their criteria. Subsequently these weighted scores were added together and the criteria as a whole were weighted to give the final score for each objective (please see Table 12 for the detailed ratings and weightings). A 70% weighting on net economic benefits was chosen in recognition of the importance of selecting an option that delivers strong, positive net benefits for consumers, aligned with the objectives of the RIT-T. The final scores are presented in Table 14.

Table 14 Results of the VNI West MCA

MCA Results							
Options		Option 1 to north of Ballarat	Option 1A to north of Ballarat with spur uprate to 500kV	Option 3 to Waubra/Lexton	Option 3A to Waubra/Lexton with spur uprate to 500kV	Option 4 to Bulgana via Bendigo	Option 5 to Bulgana
Net economic benefits ($M)		$ 1,299	$ 1,344	$ 1,285	$ 1,408	$ 1,144	$ 1,388
Grouping	Weighting (%)	WEIGHTED SCORING					
Net economic benefits	70%	2.10	2.10	2.10	1.40	3.50	1.40
Environment	5%	0.21	0.21	0.21	0.21	0.25	0.08
Cultural heritage	5%	0.12	0.12	0.10	0.10	0.15	0.10
Social	10%	0.40	0.40	0.42	0.42	0.41	0.21
Land use	5%	0.17	0.17	0.17	0.17	0.09	0.06
Engineering	5%	0.21	0.21	0.21.	0.21	0.24	0.16
Total	*100%*						
Weighted score		3.21	3.21	3.21	2.51	4.64	2.01
Rank		3	3	3	2	6	1

Based on the analysis and weighted scoring, Option 5 was found to be the most favourable option. This was due to the specific strengths of this option in relation to all objectives, that is, net economic benefit, environment, cultural heritage, social, land use and engineering. However, while this option had the best overall score, it did score comparatively less well for the criterion in relation to land subject to inundation, and technical engineering complexity (both under the "engineering" grouping). Further designs and mitigation measures may be applied to address these risks.

With fewer potential constraints than the other options, AVP consider it reasonable to assume that Option 5 would be exposed to the least delivery risk, with potential to impact time and cost, while still delivering equal highest net benefits for consumers.

The results were scrutinised by sensitivity and scenario testing through increasing and reducing the weights applied to each objective. As Option 5 scores the lowest or equal lowest on all groupings, there is no scenario where this option would not perform best, or equal best, through adjusting the grouping weightings.

Option 5 also scored the lowest, or equal lowest on all individual criteria except for native title, land subject to inundation, and reactive power compensation (see Appendix A4, Table 18). These three criteria would need to be weighted implausibly high for Option 5 to not perform best, or equal best under this MCA.

4.3.3 Key findings by MCA objectives

The detailed key findings are discussed below, with a summary of key differences provided in Table 15.

Net economic benefit

The scores for net economic benefit are driven by the NPV assessment conducted as part of this RIT-T. The results of the NPV analysis in Section 3 show that Options 3A and 5 effectively performed equal best and have therefore been assigned the same rating in this MCA.

Environment

All options performed well with respect to environment, largely because the key environmental constraints within the area of interest have been avoided in the identification of the indicative alignments. However, all indicative alignments intersect a narrow section of the Terrick Terrick National Park. All options except Option 5 also intersect the Greater Bendigo National Park along the existing transmission line easement (the new terminal station near Bendigo to Bendigo Terminal Station connection) as discussed above. All options were comparable in relation to the environment, except for Option 5 which was superior to the others, primarily because of the lesser amount of native vegetation (including highly sensitive ecological communities) and habitat for listed fauna species intersected.

Cultural heritage

All options performed comparably with respect to cultural heritage, largely because the key cultural heritage constraints known in the area of interest have been avoided through the placement of the indicative alignments. All options were rated the same in relation to non-Aboriginal cultural heritage, with some differences observed in relation to Aboriginal cultural heritage. The differences were largely due to the relative area of Aboriginal cultural heritage sensitivity intersected with Options 3, 3A and 5 determined to be best performing overall.

Social

The performance of project options in relation to social aspects confirmed that addressing potential social effects will be critical to project success. All options performed moderately against the social criteria with Option 5 performing significantly better than the other options. The main reasons for this difference are separation from residential zoned land and the relatively low level of intersection with areas covered by significant landscape overlays.

Land use

All options were comparable in relation to land use with Options 4 and 5 performing somewhat better. The differences were largely due to a relatively low level of impact on land scored to have high agricultural potential.

Engineering

All options performed well with respect to engineering, largely because the locations for the indicative alignments were in areas where the terrain is sympathetic to linear infrastructure and construction would not be significantly constrained by lack of space or poor access. Option 5 performed better than the other options because of lower number of intersections with other linear infrastructure. Nevertheless Option 5 had greater length within areas subject to inundation and therefore would require heightened attention to the management of flooding risk. It also had greater technical engineering complexity due to the need for additional series compensation to help reduce impedances of the longer line route between network nodes.

Table 15 MCA key differences

Objectives	Options					
	Option 1	Option 1A	Option 3	Option 3A	Option 4	Option 5
	NB-BE-KG-DIN	NB-BE-KG-DIN 500	WB-BE-KG-DIN	WB-BE-KG-DIN 500	BG-BE-KG-DIN	BG-KG-DIN
Environment					Intersects a comparatively larger area of native vegetation including significant/threatened species and communities (both state and federally significant)	Significantly less impact on protected areas due to avoiding the Greater Bendigo National Park and significantly less native vegetation intersected
Cultural heritage			Low area of Aboriginal cultural heritage sensitivity intersected and no areas of native title claim intersected	Low area of Aboriginal cultural heritage sensitivity intersected and no areas of native title claim intersected	Higher area of cultural sensitivity intersected, due to increased number of tributaries intersected (all named waterways assigned as culturally sensitive)	Least area of Aboriginal cultural heritage sensitivity intersected but one area of native title claim intersected
Social			A comparatively high number of buildings located within 300 m and significantly more land parcels affected compared to Options 1 and 1A	A comparatively high number of buildings located within 300 m and significantly more land parcels affected compared to Options 1 and 1A		Highest likelihood of achieving social licence sufficient to obtain planning and environmental approvals in timely manner Minimised area within bushfire management overlay Less parcels impacted
Land use	Larger area of high quality agricultural land intersected, but less severance, than Options 3 and 3A	Larger area of high quality agricultural land intersected, but less severance, than Options 3 and 3A	Lesser area of high quality agricultural land intersected than Options 1 and 1A but more severance	Lesser area of high quality agricultural land intersected than Options 1 and 1A but more severance		Comparatively little impact on high potential agricultural land Comparatively low level of severance of land parcels
Engineering					More land subject to inundation intersected compared to other options and more significant constraints regarding construction areas	Fairly flat area, eliminating steep terrain, significantly less interfaces with existing infrastructure and considerably less area of bushfire overlay intersected compared to other options. Technical complexity of series compensation and some land subject to inundation
Rank	3	3	3	2	6	1

4.3.4 Further investigation of the best performing option

The intention of the work done to date was to compare the seven VNI West options, based on desktop assessment only, to support the selection of the preferred option in the PACR, for further investigation. From that decision, investigations will be carried out within wider areas of interest for that option and engagement will be undertaken with potentially affected landowners and other stakeholders. The AoI will be subject to ongoing refinement, informed by further investigations including on-ground surveys and stakeholder engagement.

It is expected that the next stage of investigations will include a focus on better understanding:

- Opportunities to avoid effects on National and State Parks in the vicinity of the project.
- Areas of intense agriculture and locations of irrigation infrastructure.
- Aboriginal cultural heritage values informed by input from Traditional Owners.
- Sensitive viewing locations from National and State Parks which could potentially be subject to visual impacts.
- Locations of residences in rural and semi-rural area.

For the purposes of the MCA an indicative alignment was used with a width of 100 metres. However, a significantly wider area of interest will be adopted for the next stage of investigations. This wider area of interest – shown in Figure 26 above and Figure 55 in Appendix A4, with a width of up to approximately 30 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 are identified in the course of future site investigations and consultation.

5 Conclusion and views sought from stakeholders

AVP, in conjunction with external consultants AECOM, has developed a detailed MCA methodology to assess the options and help determine which option is most likely to facilitate timely delivery, consistent with the functions conferred by the NEVA. The MCA methodology focuses on social, environmental and engineering impacts and constraints, and combines with the technical and cost-benefit considerations of the NPV assessment undertaken jointly with Transgrid, to better incorporate stakeholder concerns and to help distinguish between the options on the basis of delivery risk.

Option 5 is found to be the highest ranked option when the MCA is applied and is therefore the proposed preferred option. It scores first or equal first in all objectives considered and is therefore more likely to facilitate and expedite the development, delivery, construction and energisation of VNI West. Option 5 is therefore the proposed preferred option for further development.

Specifically, Option 5:

- Delivers $1.4 billion of net market benefits in NPV terms. On a scenario-weighted basis, there is found to be a 1% difference in net benefits between Option 5 and Option 3A which maximises benefits for consumers.
- Costs less than Option 3A (Option 5 has capital costs that are $402 million less than Option 3A) and the benefits are therefore less sensitive to potential cost increases or discount rate rises than Option 3A.
- Performs the best out of all options, across all objectives, in the MCA. Based on the indicative alignment identified for Option 5, it would intersect significantly fewer protected areas (such as Ramsar Wetlands and National and State Parks) and significantly less native vegetation, critical habitat and land with higher agricultural potential, than all other options. Option 5 also scores equal best with Option 4 in relation to separation from buildings (including residences).
- Runs further west than other options and avoids the Bendigo to Ballarat corridor that many submitters to the PADR suggested is problematic.
- Performs better than Option 3A in sensitivity analysis where it is assumed the Victorian Government's offshore wind commitments are legislated.

Option 5 does have the longest line length between nodes (that is, from near Kerang to Bulgana) and this results in high impedances. The current proposal to reduce impedances and reduce loading on the existing 200kV lines is through use of series capacitors. Even with the use of series capacitors, power system analysis indicates that Option 5 harnesses less REZ development than Option 3A due to network load-sharing. Consequently, Option 5 offers the lowest indicative improvement to REZ transmission limits of all seven options assessed (+3,410 MW). In contrast, Option 3A has the highest improvement (+6,490 MW) assuming developers have sufficient social licence to reach the development potential[63]. While Option 5 enables the lowest levels of new REZ capacity of all seven options assessed, it is similar in magnitude to Option 1 (+3,650 MW), the proposed preferred option in the PADR. Furthermore, additional augmentations to the existing network, along with future decoupling and reconnection of

[63] AVP and Transgrid note that the REZ limit assumed for Option 5 is considered a conservative estimate and that opportunities have already been identified to optimise this further. AVP and Transgrid also note that it has not been assessed whether there is social licence to develop the full 6.5 GW of REZ under Option 3A at this stage.

Waubra Wind Farm, may allow more renewable generation to be harnessed in western Victoria in future, if and when needed.

AVP and Transgrid welcome industry feedback on some of the complexities that can be introduced with series capacitors, along with thoughts on potential alternative solutions to better share power flow between the existing and newly proposed parallel networks.

AVP and Transgrid invite written submissions on this assessment by 5 April 2023. Specifically, views are sought on:

- The outcomes of the assessment undertaken in this report;
- The feasibility of Option 5; and
- Whether the MCA has captured the salient social, environmental and economic factors including those that sit outside the scope of the RIT-T, but may impact on the timely development of the project consistent with the objectives of the NEVA Order.

Please email submissions to VNIWestRITT@aemo.com.au. Where possible, please provide evidence to support your view(s). If you do not want your submission to be publicly available, please clearly stipulate this at the time of lodgement.

Information about the submission process (including how to make a submission) and upcoming stakeholder engagement activities will be published on the VNI West dedicated webpages at www.transgrid.com.au/vni-west and www.aemo.com.au/vni-west.

All feedback will be carefully considered in the preparation of the final report (the PACR) and all written submissions will be published online, along with a summary of how feedback has been considered.

A1. Additional detail on the options

This appendix provides additional information on each of the seven different options assessed in this report. It also outlines a significant number of additional options that have been considered at various stages over the course of this RIT-T, as well as the associated ISP assessments, and the reasons why they have not been progressed.

Option 1 (to north of Ballarat)

Option 1 is a new high-capacity 500 kV double-circuit transmission line to connect WRL (north of Ballarat) with EnergyConnect (at Dinawan) via new terminal stations near Bendigo and near Kerang. This aligns with the ISP candidate option in the 2022 ISP[64] and 'VNI 7' in the PSCR and the 2020 ISP[65].

Option 1 will also connect to the existing 220 kV line at a new terminal station near Bendigo to help manage loading on the existing 220 kV network, particularly between Kerang and Bendigo. It does this by improving load sharing between the existing 220 kV network and the proposed 500 kV network. Option 1 (to north of Ballarat) then wholly relies on WRL to connect to the Melbourne 500 kV grid, utilising the proposed 500 kV WRL transmission line from north of Ballarat to Sydenham.

Option 1 comprises the following augmentations:

- A new 500 kV double-circuit overhead line from north of Ballarat to near Bendigo to near Kerang to locality of Dinawan.
- 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.
- New terminal stations near Bendigo and near Kerang.
- Two 500/220 kV 1,000 MVA transformers at each of the new terminal stations near Bendigo and near Kerang.
- 220 kV double-circuit connections from the existing terminal station at Bendigo to a new terminal station near Bendigo.
- 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 four following 500 kV circuits: (i) north of Ballarat – near Bendigo, (ii) near Bendigo – near Kerang, (iii) near Kerang – Dinawan and (iv) Dinawan – near Wagga Wagga.

[64] AEMO, 2022 ISP, Appendix 5. Network investments, June 2022, p. 27.

[65] Table 6 in the PADR outlined that there were a number of modifications to the scope of this option since the PSCR.

- Up to +/- 400 megavolt-amperes reactive (MVAr) dynamic reactive compensation at the new 220 kV terminal station near Kerang.
- Two new 500 kV bays and line exits with a total of two 100 MVAr 500 kV line shunt reactors at WRL's terminal station north of Ballarat have been included in the VNI West costs.

This scope aligns with the ISP candidate option in the 2022 ISP[66].

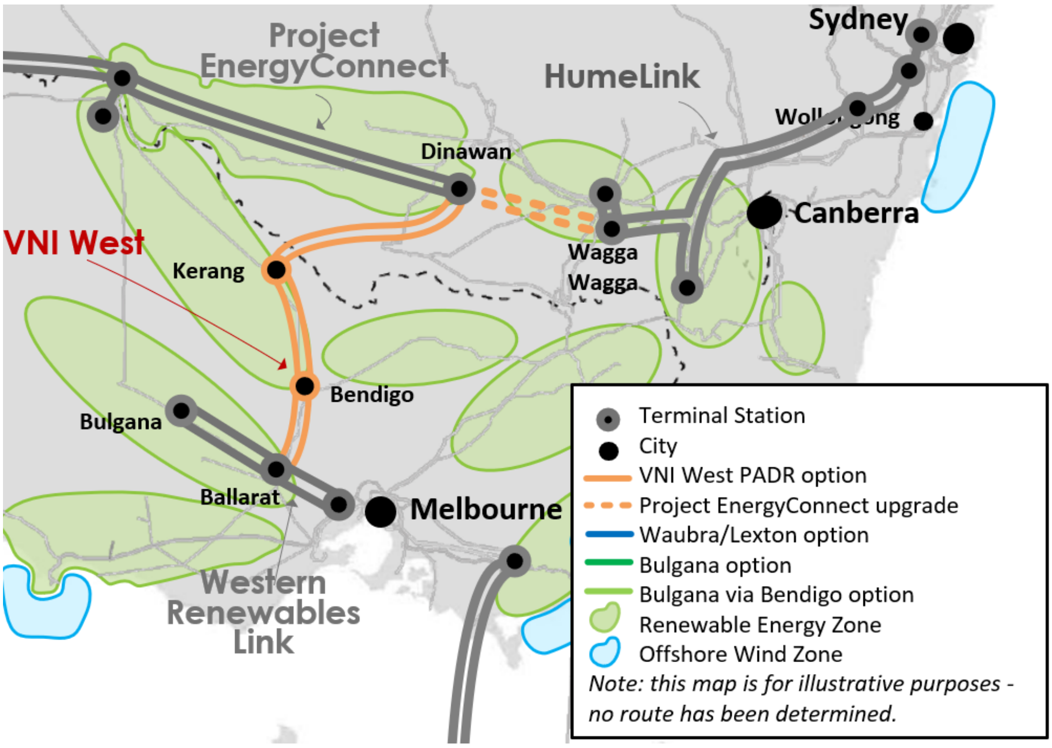
Figure 27 below provides a plan view, and Figure 28 a single-line diagram, for Option 1.

Modelling indicates that this option will result in additional transfer capability of approximately 1,930 MW from Victoria to New South Wales and 1,800 MW from New South Wales to Victoria.

It is also estimated that Option 1 will increase the transmission limit at the following REZs by:

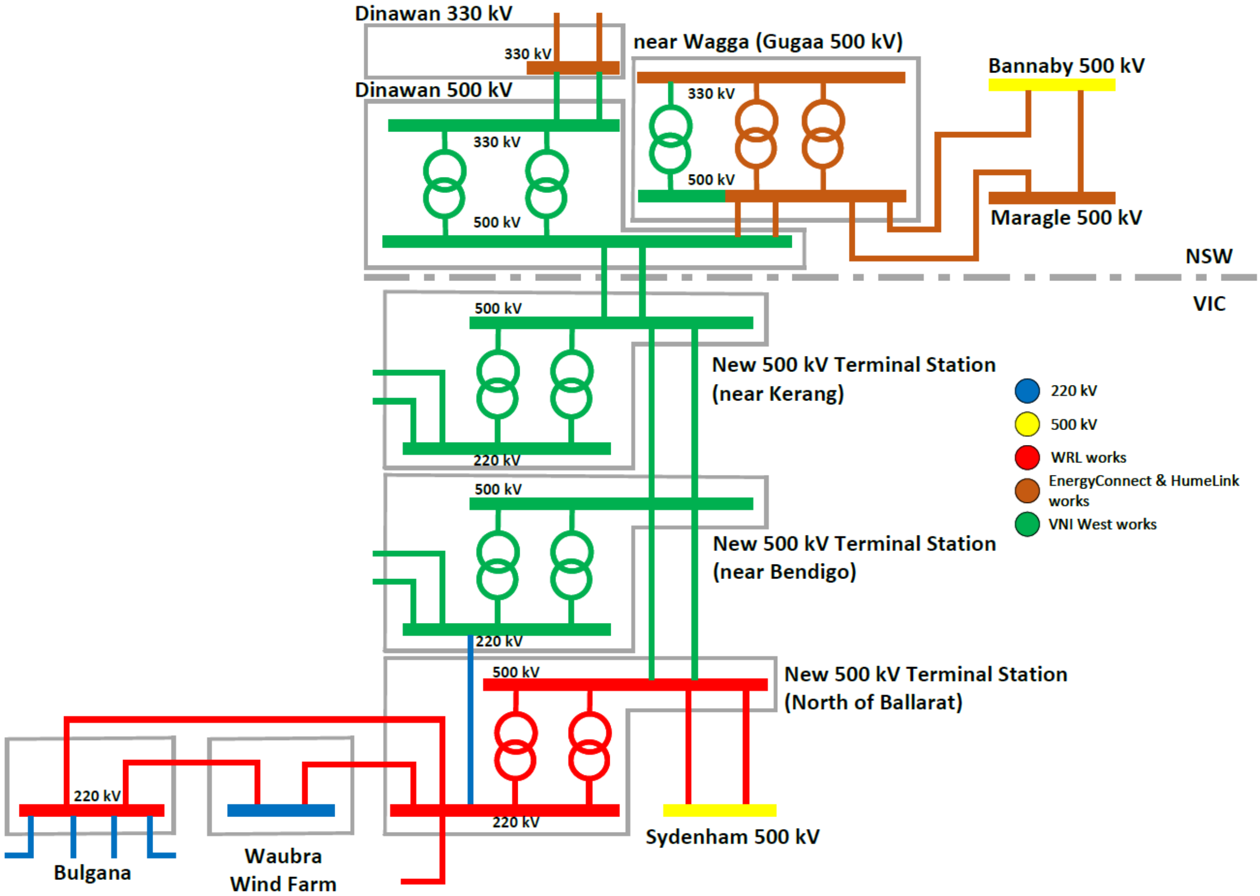
- 1,600 MW in the Murray River REZ (V2).
- 600 MW in the Western Victoria REZ (V3) from the WRL uprate.
- 550 MW in the Western Victoria REZ (V3) from VNI West.
- 900 MW in the South West NSW REZ (N5).

Figure 27 Summary of Option 1



66 AEMO, 2022 ISP, Appendix 5. Network investments, June 2022, p. 27.

Figure 28 Single-line diagram for Option 1



The estimated capital cost of this option is approximately $3,254 million, which is comprised of $1,603 million in Victoria and $1,651 million in New South Wales.

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, as outlined in Table 3.

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 as the NEVA Order enables AEMO to commence early works now, working towards undertaking first Spring Surveys in 2023.

Option 1A (to north of Ballarat with spur uprate to 500 kV)

Option 1A is a variant of Option 1 that has been modelled following consultation on the PADR. It is the same as Option 1 with the additional uprating of the WRL 220 kV spur line from north of Ballarat to Bulgana to 500 kV.

It comprises the following augmentations:

- A new 500 kV double-circuit overhead line from north of Ballarat to near Bendigo to near Kerang to locality of Dinawan.

- 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.
- New terminal stations near Bendigo and near Kerang.
- Two 500/220 kV 1,000 MVA transformers at each of the new terminal stations near Bendigo and near Kerang.
- 220 kV double-circuit connections from the existing terminal station at Bendigo to a new terminal station near Bendigo.
- 220 kV connections from the new terminal station near Kerang to the existing 220 kV lines to 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 four following 500 kV circuits: (i) north of Ballarat – near Bendigo, (ii) near Bendigo – near Kerang, (iii) near Kerang – Dinawan and (iv) Dinawan – near Wagga Wagga.
- Up to +/- 400 MVAr dynamic reactive compensation at the new 220 kV terminal station near Kerang.
- Two new 500 kV bays and line exits with a total of two 100 MVAr 500 kV line shunt reactors at WRL's terminal station north of Ballarat have been included in the VNI West costs.
- Construction of the WRL spur line from north of Ballarat to Bulgana as a double-circuit 500 kV line, rather than a double-circuit 220 kV line.
- 500 kV switchyard with two 500/220 kV transformers at the existing Bulgana terminal station.

The cost of constructing Bulgana to north of Ballarat at 500 kV rather than 220 kV has been included as part of the cost of this option. The costs estimated also include the modifications necessary to the WRL North Ballarat and Bulgana terminal stations (that is, equipment quantity, configuration and rating) to accommodate the change in voltage.

Figure 29 below provides a plan view and Figure 30 a single-line diagram for Option 1A.

Preliminary modelling indicates that this option will result in additional transfer capability of approximately 1,930 MW from Victoria to New South Wales and 1,800 MW from New South Wales to Victoria.

It is also estimated that Option 1A will increase the transmission limit at the following REZs by:

- 1,600 MW in the Murray River REZ (V2).
- 1,460 MW in the Western Victoria REZ (V3) from the WRL uprate.
- 750 MW in the Western Victoria REZ (V3) from VNI West.
- 900 MW in the South West NSW REZ (N5).

Figure 29 Summary of Option 1A

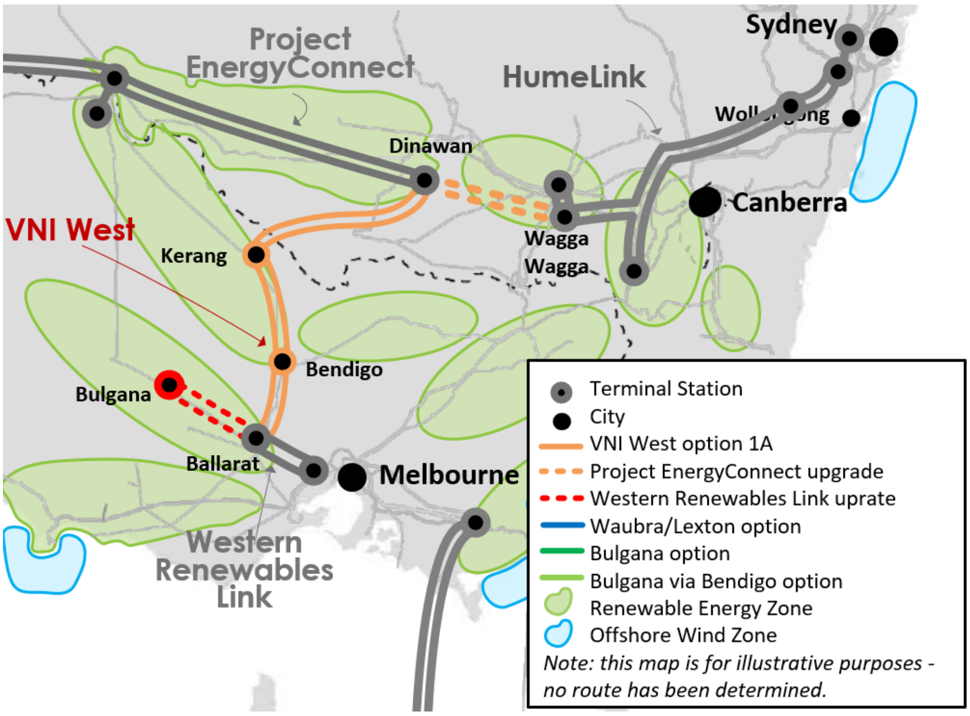
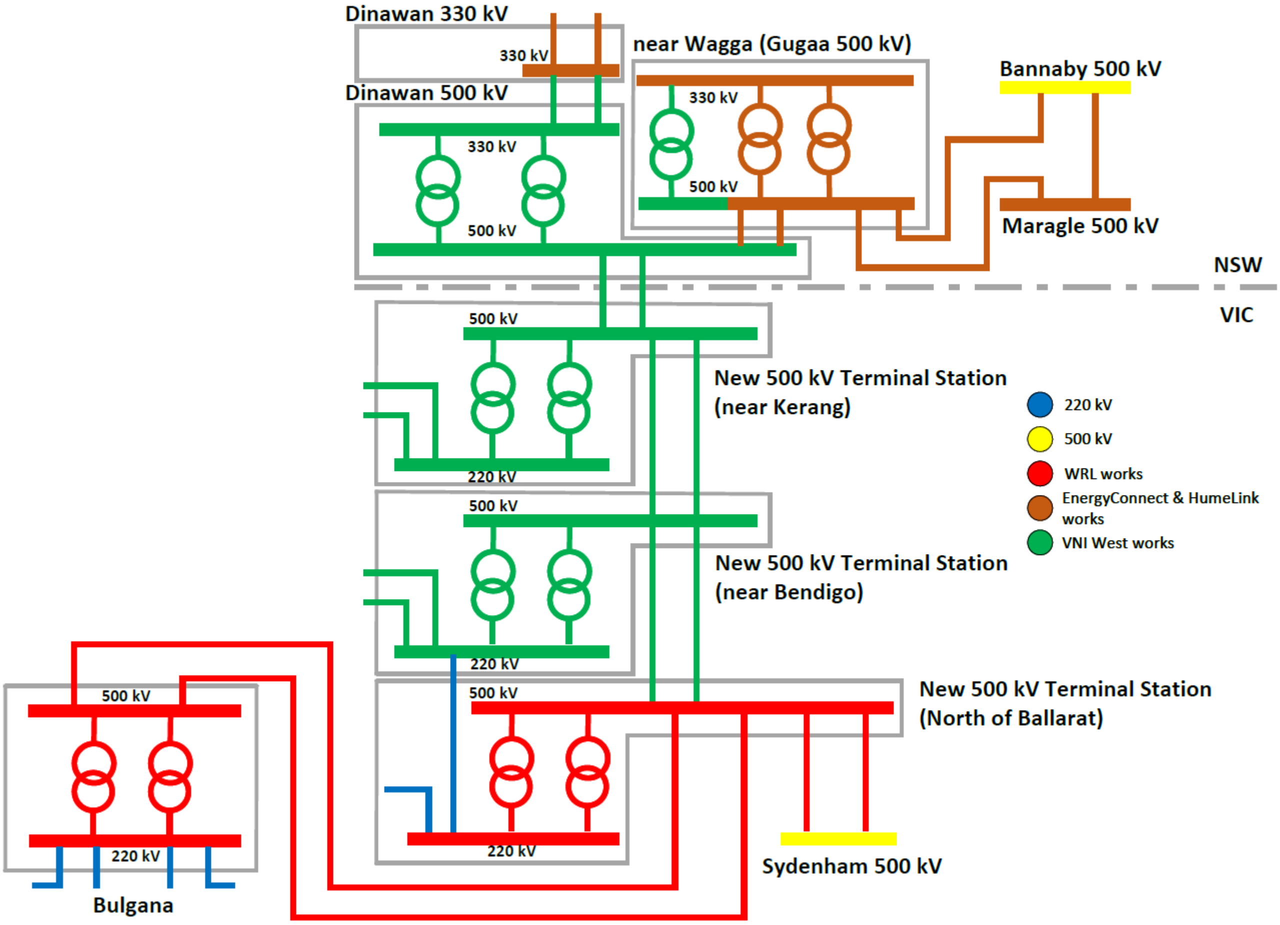


Figure 30 Single-line diagram for Option 1A



The estimated capital cost of this option is approximately $3,701 million, which is comprised of $2,050 million in Victoria and $1,651 million in New South Wales.

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 at 500 kV rather than 220 kV would 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 as the NEVA Order enables AEMO to commence early works now, working towards undertaking first Spring Surveys in 2023.

Option 2 (to north of Ballarat plus non-network)

In response to consultation with proponents following the PSCR, and further assessment by AVP and Transgrid, the PADR included a non-network VTL as a component of Option 2, combined with VNI West (via Kerang). Specifically, the VTL component is assumed to be commissioned ahead of any wider network development.

The VTL solution involves installing battery energy storage solution (BESS) pairs and, in the event of a contingency, co-ordinating the charging/discharging of the batteries, enabled by a purposely designed controller, to quickly reduce post-contingent power flows to within post-contingent transmission limits. The fast and co-ordinated post-contingent action of the batteries allows an increased pre-contingent VNI capability while managing potential post-contingent overloads.

The VTL solution in this report is the same as that assessed in the PADR. It has been optimised as two 250 MW/125 megawatt hour (MWh) BESS systems based on the existing interconnector lines utilising their highest-capacity, shortest-duration, ratings operationally feasible. That is, the optimised BESS sizing allows pre-contingent transfer across the existing VNI to be maximised while maintaining sufficient time, through BESS charging/discharging, to re-dispatch generation post-contingency without overloading the existing VNI lines.

A VTL has not been investigated in combination with any of the new options introduced in response to submissions on the PADR due to the finding that adding a VTL to VNI West (via Kerang) does not provide a further net benefit (instead, it imposes a net cost). This finding is expected to also apply to if the new options were combined with a VTL, and so this has not been investigated.

A VTL could be implemented ahead of Option 1 (to north of Ballarat) to provide benefits sooner

AVP and Transgrid do not consider that a VTL solution constitutes a credible standalone option as it, by itself, cannot meet the identified need as set out in the 2022 ISP[67]. In particular, AVP and Transgrid do not consider that a VTL alone can realistically satisfy the element of the identified need referring to '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 plant closes earlier than expected'[68], since it is not of sufficient capacity to provide the required risk mitigation. Using Loy Yang A as an example, this group of

[67] As outlined in Section 6.3.1 of the PADR.

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

generator units has a combined nameplate capacity of 2,225 MW, which is significantly greater than the VTL (250 MW).

However, this does not preclude a VTL or similar technology from being considered as a stand-alone solution to a separate need identified by AVP or Transgrid in their annual planning processes.

A VTL option has the potential to be implemented more quickly than investment in a new transmission line and to relieve network congestion ahead of the line being in place. This in turn has the potential to facilitate the efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales and enable more efficient sharing of resources between NEM regions (the other two elements of the identified need for this RIT-T).

A VTL has therefore been assessed in this report (and the earlier PADR) as an additional component that could be put in place ahead of the commissioning date for VNI West (to north of Ballarat-). Inclusion of this as an option in the RIT-T tests whether the addition of a VTL to VNI West is expected to provide additional net benefits over and above the VNI West Option 1.

The timing of the VTL component is assumed to be the earliest possible date it can be commissioned (1 July 2026 – that is, 2026-27 – reflecting a three-year development/build time). The assumed VTL in-service date is the same in all three scenarios and the timing of the VNI West (to north of Ballarat) component remains the same as that for Option 1, for each scenario.

Scope of a VTL

In the specific circumstances of this RIT-T, the VTL option assessed involves two new batteries (one at South Morang in Victoria and one at Sydney West in New South Wales) that will receive signals from relevant locations of the network.

The specific scope of the VTL component modelled in this report (and the earlier PADR) has been informed by submissions from proponents to the PSCR and is as follows:

- 1 x 250 MW/125 MWh BESS at South Morang in Victoria.
- 1 x 250 MW/125 MWh BESS at Sydney West in New South Wales.
- 1 x 220/33 kV transformer at South Morang, and associated works.
- 1 x 330/33 kV transformer at Sydney West, and associated works.

This VTL is intended to be operated in response to a network contingency during periods when existing VNI transfer is constrained by transmission limitations in either Victoria or New South Wales. In the jurisdiction experiencing the constraint, the BESS will be available to discharge instantaneously at rated capacity (250 MW) for a period of 30 minutes in response to a contingency event, which allows the network operator to run thermally constrained lines at higher short-term emergency ratings pre-contingency and can also increase transient stability limitations. The BESS will also be available to inject reactive power to boost voltages in areas of the network that experience voltage instabilities. This effectively increases the VNI transfer limit from the existing interconnector by up to 250 MW, in either direction, by allowing higher transfers across highly loaded lines.

AVP has entered into the System Integrity Protection Scheme (SIPS) Support Agreement with the Victorian Big Battery to allow additional import (from New South Wales to Victoria) of electricity over the existing VNI of up to 250 MW at peak times between November and March. The implications of this are that the expected benefits of the VTL component are now lower than they otherwise would be, since the base case includes the operation of the SIPS until March 2032 (after this the Big Battery is assumed to be able to freely arbitrage in the base case as an uncontracted battery). Nonetheless, even with the SIPS contract in place, a VTL could still operate for the period each year outside of the contracted SIPS period (which is from 1 November to 31 March each summer), could operate for increased export to New South Wales (including during the SIPS period), and could reduce the impact of voltage and transient stability constraints that limit VNI transfer under some network conditions.

Under this Option 2, it is assumed that AVP and Transgrid would only contract the VTL for the period before Option 1 (to north of Ballarat) is commissioned – that is, the assumed contract term varies depending on the scenario modelled:

- *Progressive Change* – the VTL is contracted from 1 July 2026 to 1 July 2038.
- *Step Change* – the VTL is contracted from 1 July 2026 to 1 July 2031.
- *Hydrogen Superpower* – the VTL is contracted from 1 July 2026 to 1 July 2030.

While the two batteries are not assumed to be able to arbitrage for the duration of the assumed VTL contract period for each scenario (that is, they are assumed to be contracted year-round for the VTL service), they are assumed to revert to having their full capacity available for energy arbitrage market operation after conclusion of the VTL contract period.

The estimated capital cost of the VTL component is approximately $618 million, which is comprised of:

- $583 million in battery costs ($295 million in Victoria and $288 million in New South Wales).
- $35 million in property/land access/easements ($17.5 million in Victoria and $17.5 million in New South Wales).

The cost of the VTL component has been based on generic costs for the battery component at this stage, including from the 2021 IASR, and informed by the costs put forward by the two proponents. The associated network components have been estimated in line with the network components of Option 1.

Technical feasibility would need to be investigated further

AVP and Transgrid note that there are voltage and transient stability limits that may limit the feasibility of the VTL component of Option 2 (and which form the binding constraints, ahead of thermal limitations[69], in the market modelling).

In addition, AVP and Transgrid note that the technical feasibility of this option depends on the response time of the batteries (which is expected to need to be within 200 milliseconds [ms] ramp-up time) and also the protection and control systems, including the network communications. AVP and Transgrid would need to undertake additional system studies to confirm response times if the VTL forms part of the preferred option for this RIT-T. Initial discussions with proponents confirmed that the proposed solutions can be designed to have the required response times.

For the purposes of this report (and the earlier PADR), the VTL component is assumed to be technically feasible in order to determine whether it is likely to form part of the overall preferred option (which would justify the significant additional work required to comprehensively determine technical feasibility). However, AVP and Transgrid note that both the PADR and this report do not find the VTL option to be preferred and so the additional work required to determine technical feasibility is unlikely to be warranted.

[69] The thermal constraint becomes the binding constraint during the peak demand period after the SIPS contract concludes.

Option 3 (to Waubra/Lexton)

Option 3 is a new option that has been modelled following consultation on the PADR. It connects to WRL further west than Option 1 and involves a new high-capacity 500 kV overhead double-circuit transmission line to connect WRL with EnergyConnect (at Dinawan) via new terminal stations near Waubra/Lexton and near Bendigo and near Kerang.

It comprises the following augmentations:

- A new 500 kV double-circuit overhead line from near Waubra/Lexton to near Bendigo to near Kerang to locality of Dinawan.
- 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.
- New terminal stations near Bendigo and near Kerang.
- Two 500/220 kV 1,000 MVA transformers at each of the new terminal stations near Bendigo and near Kerang.
- 220 kV double-circuit connections from the existing terminal station at Bendigo to new terminal station near Bendigo.
- 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 four following 500 kV circuits: (i) near Waubra – near Bendigo, (ii) near Bendigo – near Kerang, (iii) near Kerang – Dinawan and (iv) 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 a site near Waubra/Lexton. This includes a 500 kV switchyard with two 500/220 kV transformers at the terminal station near Waubra/Lexton.
- Two new 500 kV bays and line exits with a total of two 100 MVAr 500 kV line shunt reactors at the new terminal station near Waubra/Lexton have been included in the VNI West costs (with the remainder of the terminal station assumed part of the existing WRL scope).
- Decoupling of Waubra Wind Farm from the existing 220 kV line between the existing Ballarat and existing Ararat terminal stations, and reconnection to the new terminal station near Waubra/Lexton via a short 220 kV transmission line.
- Construction of WRL spur line from north of Ballarat through to Waubra/Lexton at 500 kV rather than 220 kV.

Option 3 will also connect to the existing 220 kV line at a new terminal station near Bendigo to help manage loading on the existing 220 kV network, particularly between Kerang and Bendigo. It does this by improving load sharing between the existing 220 kV network and the proposed 500 kV network.

Under Option 3, the current WRL project scope will be modified and a portion of the line will be uprated from 220 kV to 500 kV from north of Ballarat to Waubra/Lexton. The proposed terminal station at north of Ballarat will be relocated to a site near Waubra/Lexton, where VNI West will connect to WRL. Additionally, to relieve congestion in the 220 kV network, the existing Waubra Terminal Station and Wind Farm will be connected to the new terminal station near Waubra/Lexton, via a short 220 kV transmission line, and decoupled from the existing 220 kV line that runs from Ballarat to Bulgana.

Option 3 wholly relies on WRL to connect to the Melbourne 500 kV grid, utilising the proposed 500 kV WRL transmission line from Waubra/Lexton to Sydenham. The incremental cost of uprating the line from Waubra/Lexton to north of Ballarat from 220 kV to 500 kV, the relocation of a proposed new terminal station at north of Ballarat, the decoupling and reconnection of Waubra Wind Farm and construction of this new terminal station near Waubra/Lexton have been considered as part of the cost of this option.

Figure 31 and Figure 32 below provide a plan view and single-line diagram for Option 3.

Modelling indicates that this option will result in additional transfer capability of approximately 1,830 MW from Victoria to New South Wales and 1,650 MW from New South Wales to Victoria.

It is also estimated that Option 3 will increase the transmission limit at the following REZs by:

- 1,600 MW in the Murray River REZ (V2).
- 950 MW in the Western Victoria REZ (V3) from the WRL uprate.
- 700 MW in the Western Victoria REZ (V3) from VNI West.
- 900 MW in the South West NSW REZ (N5).

Figure 31 Summary of Option 3

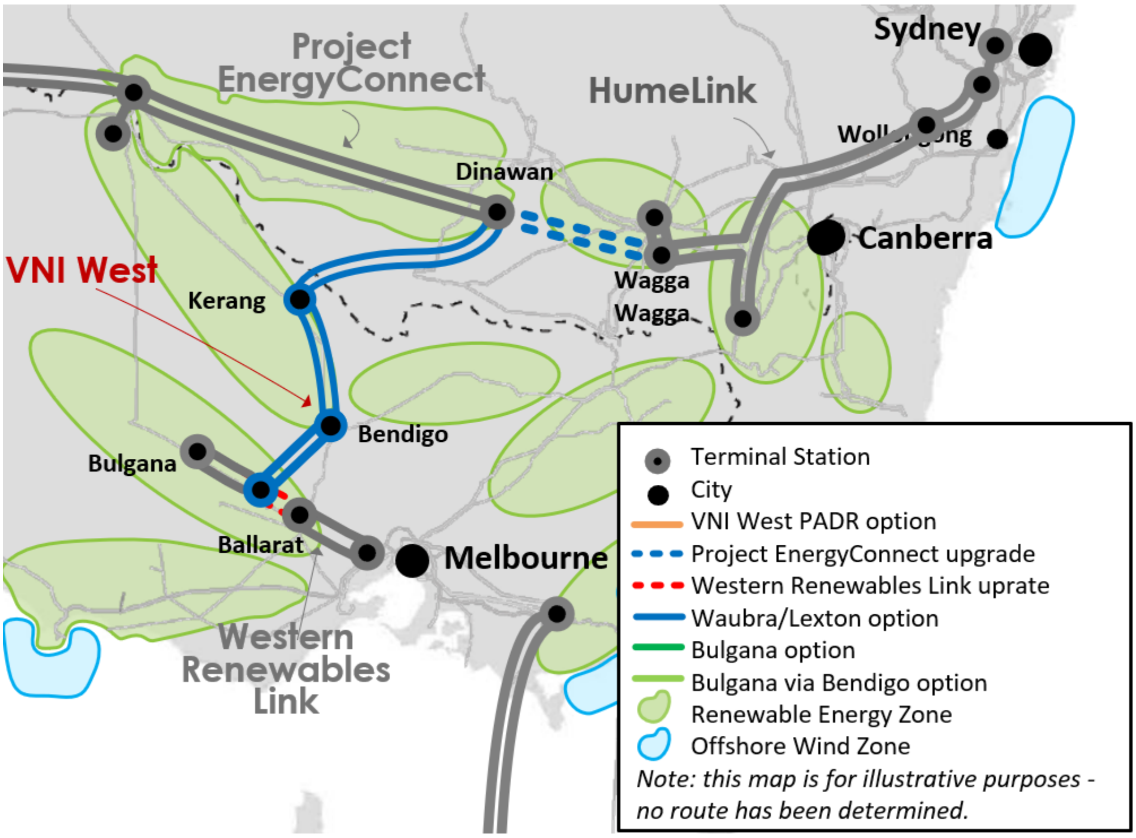
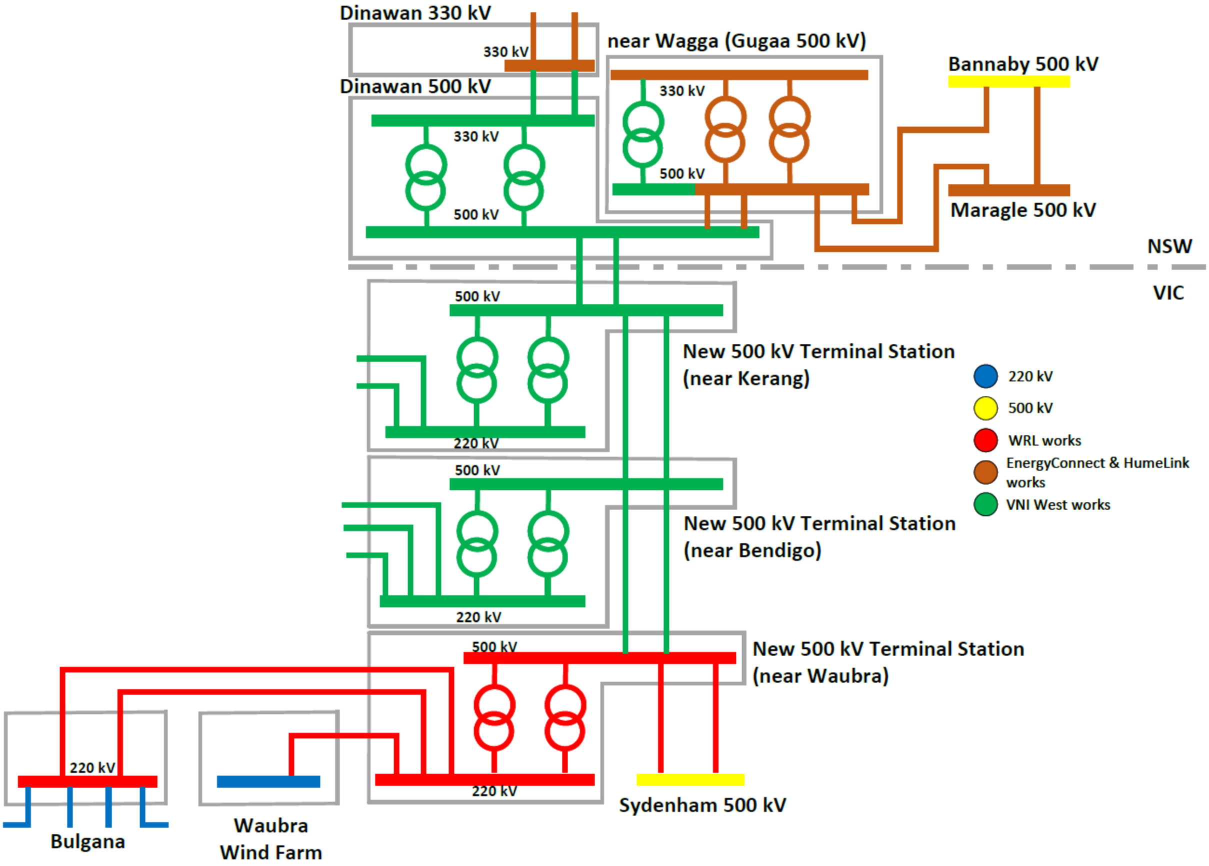


Figure 32 Single-line diagram for Option 3



The estimated capital cost of this option is approximately $3,440 million, which is comprised of $1,788 million in Victoria and $1,651 million in New South Wales.

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. Under this option, construction and commissioning of the WRL at 500 kV from Sydenham to Waubra/Lexton, and 220 kV from Waubra/Lexton to Bulgana is expected 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 as the NEVA Order enables AEMO to commence early works now, working towards undertaking first Spring Surveys in 2023.

Option 3A (to Waubra/Lexton with spur uprate to 500 kV)

Option 3A is a variant of Option 3 that has been modelled following consultation on the PADR. It is the same as Option 3, with the additional uprating of the proposed 220 kV spur line from Waubra/Lexton to Bulgana to 500 kV.

It comprises the following augmentations:

- A new 500 kV double-circuit overhead line from near Waubra/Lexton to near Bendigo to near Kerang to locality of Dinawan.

- 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.
- New terminal stations near Bendigo and near Kerang.
- Two 500/220 kV 1,000 MVA transformers at each of the new terminal stations near Bendigo and near Kerang.
- 220 kV connections from the existing terminal station at Bendigo to a new terminal station near Bendigo.
- 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 four following 500 kV circuits: (i) near Waubra – near Bendigo, (ii) near Bendigo – near Kerang, (iii) near Kerang – Dinawan and (iv) 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 a site near Waubra/Lexton. This includes a 500 kV switchyard with two 500/220 kV transformers at the terminal station near Waubra/Lexton.
- Two new 500 kV bays and line exits with a total of two 100 MVAr 500 kV line shunt reactors at a new terminal station at a site near Waubra/Lexton have been included in the VNI West costs (with the remainder of the terminal station assumed part of the existing WRL scope)
- Decoupling of Waubra Wind Farm from the existing 220 kV line between the existing Ballarat and existing Ararat terminal stations, and reconnection to the new terminal station near Waubra/Lexton via a short 220 kV transmission line. This decoupling also required a 500/220 kV transformer at the Waubra/Lexton terminal station.
- Construction of the WRL spur line to Bulgana as a double-circuit 500 kV line, rather than a double-circuit 220 kV line
- 500 kV switchyard with two 500/220 kV transformers at the existing Bulgana Terminal Station

Option 3A will also connect to the existing 220 kV line at a new terminal station near Bendigo to help manage loading on the existing 220 kV network, particularly between Kerang and Bendigo. It does this by improving load sharing between the existing 220 kV network and the proposed 500 kV network.

Under Option 3A, the WRL terminal station proposed at a site north of Ballarat will be relocated to a site near Waubra/Lexton, where VNI West will connect. Additionally, to relieve congestion in the 220 kV network the existing Waubra Terminal Station and Wind Farm will be connected to the new terminal station near Waubra/Lexton, via a short 220 kV transmission line, and decoupled from the existing 220 kV line that runs from Ballarat to Bulgana.

Option 3A then wholly relies on WRL to connect to the Melbourne 500 kV grid, utilising the proposed 500 kV WRL transmission line from Waubra/Lexton to Sydenham. The incremental cost of uprating from Bulgana to north of Ballarat from 220 kV to 500 kV, the relocation of the proposed new terminal station north of Ballarat , construction of this new terminal station near Waubra/Lexton, the decoupling and reconnection of Waubra Wind Farm and modifications to the Bulgana Terminal Station (required under WRL) to accommodate the 500 kV spur uprate have been considered as part of the cost of this option.

Figure 33 and Figure 34 below provide a plan view and single-line diagram for Option 3A.

Modelling indicates that this option will result in additional transfer capability of approximately 1,830 MW from Victoria to New South Wales and 1,650 MW from New South Wales to Victoria.

It is also estimated that Option 3A will increase the transmission limit at the following REZs by:

- 1,600 MW in the Murray River REZ (V2).
- 2,590 MW in the Western Victoria REZ (V3) from the WRL uprate.
- 1,400 MW in the Western Victoria REZ (V3) from VNI West.
- 900 MW in the South West NSW REZ (N5).

Figure 33 Summary of Option 3A

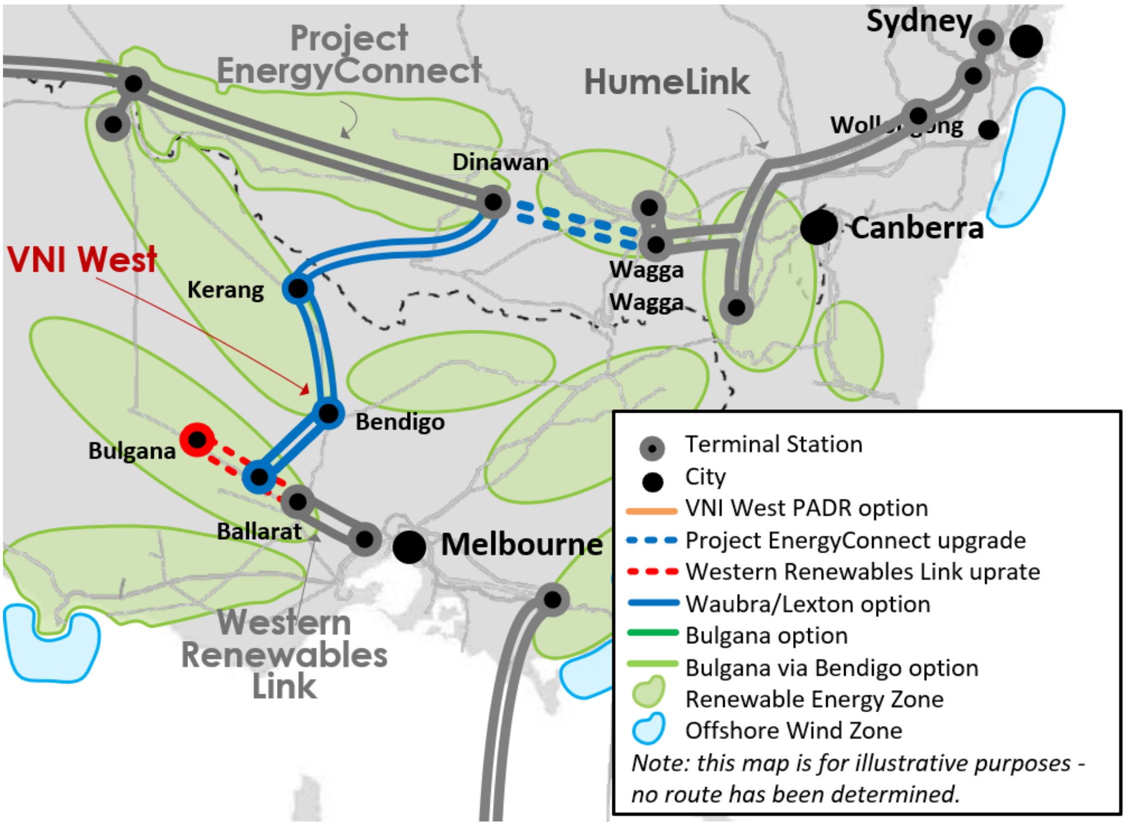
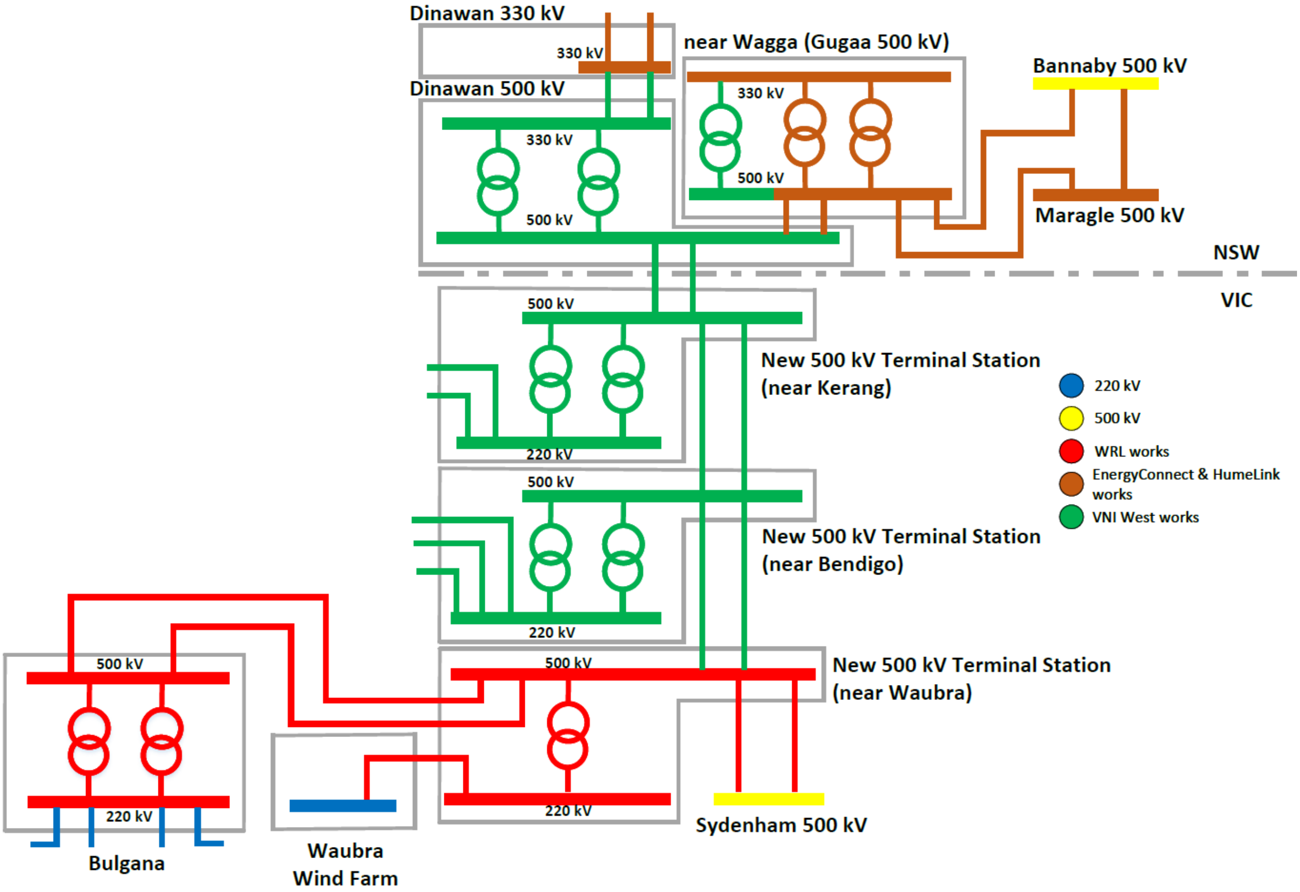


Figure 34 Single-line diagram for Option 3A



The estimated capital cost of this option is approximately $3,685 million, which is comprised of $2,034 million in Victoria and $1,651 million in New South Wales.

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. Under this option, construction and commissioning of the WRL spur to Bulgana at 500 kV rather than 220 kV is expected 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 as the NEVA Order enables AEMO to commence early works now, working towards undertaking first Spring Surveys in 2023.

Option 4 (to Bulgana via Bendigo)

Option 4 is a new option that has been modelled following consultation on the PADR. It goes further west than Option 1 and involves a new high-capacity 500 kV overhead double-circuit transmission line to connect WRL (at a proposed new terminal station at Bulgana) with EnergyConnect (at Dinawan) via new terminal stations at Bulgana and near Bendigo and near Kerang.

It comprises the following augmentations:

- A new 500 kV double-circuit overhead line from at Bulgana to near Bendigo to near Kerang to locality of Dinawan.
- 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.
- New terminal stations near Bendigo and near Kerang.
- Two 500/220 kV 1,000 MVA transformers at each of the new terminal stations near Bendigo and near Kerang.
- 220 kV double-circuit connections from the existing terminal station at Bendigo to a new terminal station near Bendigo.
- 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 four following 500 kV circuits: (i) Bulgana – near Bendigo, (ii) near Bendigo – near Kerang, (iii) near Kerang – Dinawan and (iv) 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 100 MVAr 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 existing 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

Option 4 will also connect to the existing 220 kV line at a new terminal station near Bendigo to help strengthen supply to the Bendigo Terminal Station and manage loading on the existing 220 kV network, particularly between Kerang and Bendigo. It does this by improving load sharing between the existing 220 kV network and the proposed 500 kV network. Option 4 then wholly relies on WRL to connect to the Melbourne 500 kV grid, utilising the proposed 500 kV WRL transmission line from Bulgana to Sydenham.

Under Option 4, the WRL double-circuit line from Bulgana to Sydenham will be constructed at 500 kV rather than 220 kV. That is, the current project scope will be modified and the entire line will be uprated from 220 kV to 500 kV from north of Ballarat to Bulgana. The proposed terminal station north of Ballarat will be relocated to Bulgana.

Option 4 then 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 incremental 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 Bulgana Terminal Station to accommodate the 500 kV spur uprate have been considered as part of the cost of this option.

Figure 35 and Figure 36 below provide a plan view and single-line diagram for Option 4.

Preliminary modelling indicates that this option will result in additional transfer capability of approximately 1,700 MW from Victoria to New South Wales and 1,475 MW from New South Wales to Victoria.

It is also estimated that Option 4 will increase the transmission limit at the following REZs by:

- 1,600 MW in the Murray River REZ (V2).
- 1,460 MW in the Western Victoria REZ (V3) from the WRL uprate.
- 580 MW in the Western Victoria REZ (V3) from VNI West.
- 900 MW in the South West NSW REZ (N5).

Figure 35 Summary of Option 4

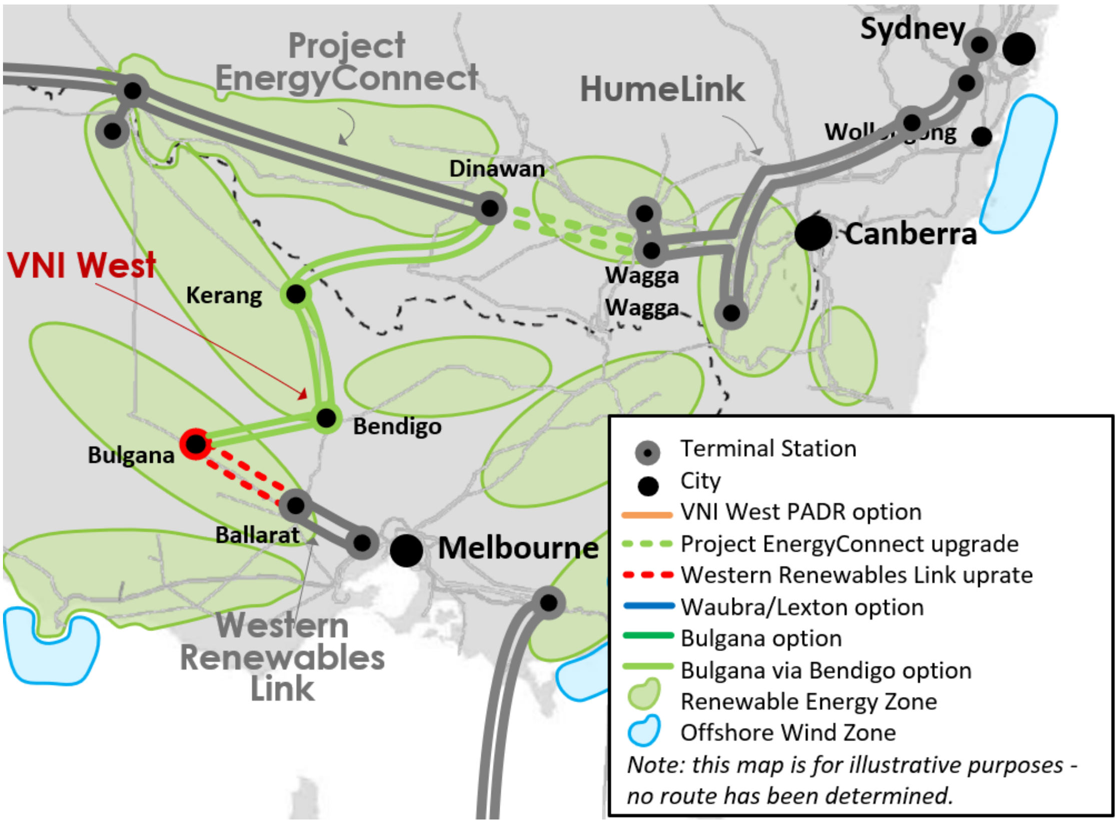
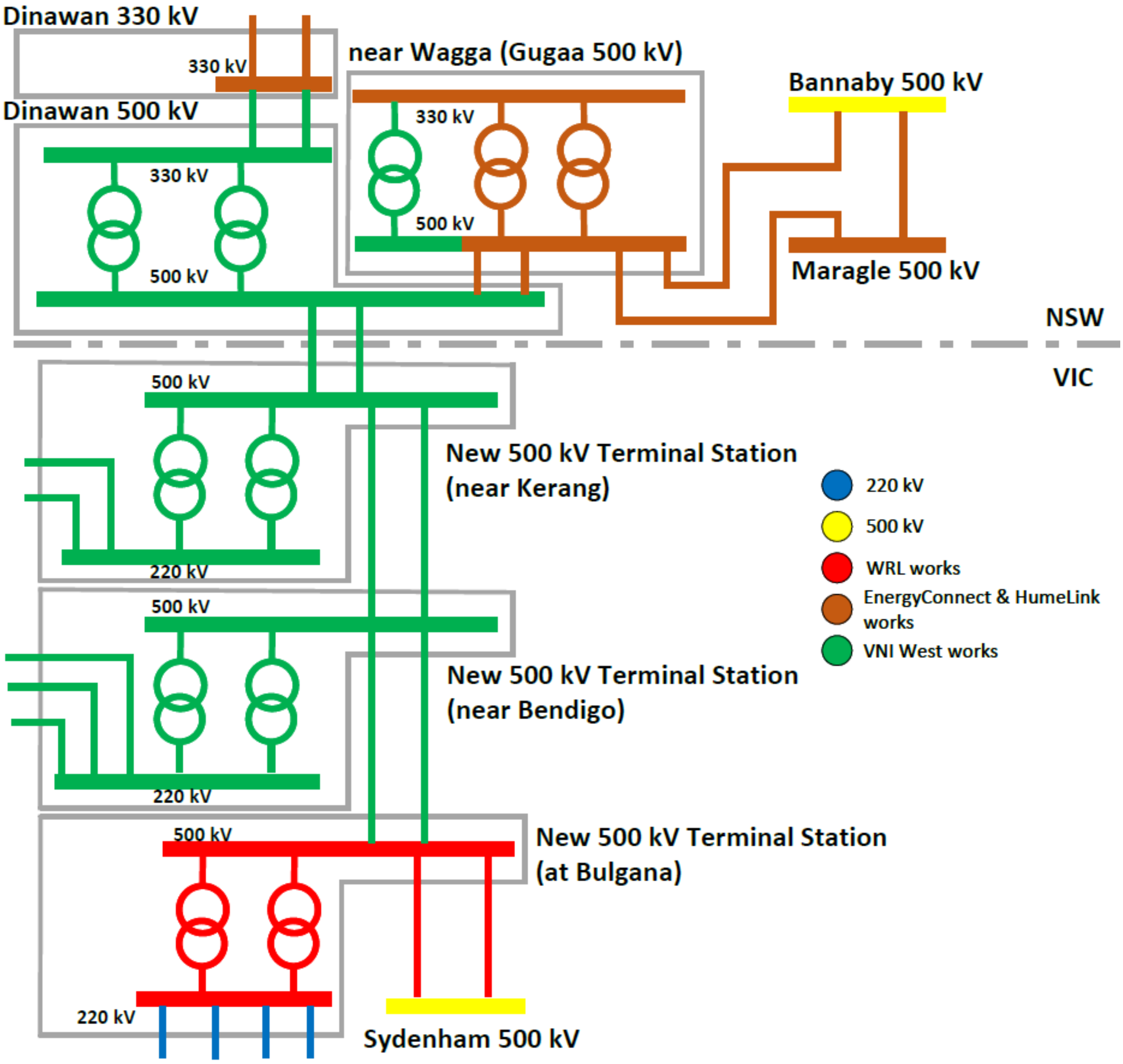


Figure 36 Single-line diagram for Option 4



The estimated capital cost of this option is approximately $3,685 million, which is comprised of $2,034 million in Victoria and $1,651 million in New South Wales.

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 would 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 as the February NEVA Order enables AEMO to commence early works now, working towards undertaking first Spring Surveys in 2023.

Option 5 (to Bulgana)

Option 5 is a new option that has been modelled following consultation on the PADR. It represents the most westerly connection to WRL and 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. Unlike the other options, it does not require a new terminal station near Bendigo.

It comprises the following augmentations:

- A new 500 kV double-circuit overhead line from at 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.
- A new terminal station near Kerang.
- Two 500/220 kV 1,000 MVA transformers at the new terminal station near Kerang.
- 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 100 MVAr 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 existing 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

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 to 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 Option 5, 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.

Option 5 then 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 have been considered as part of the cost of this option.

Figure 37 and Figure 38 below provide a plan view and a single-line diagram for Option 5.

Modelling indicates that this option will result in additional transfer capability of approximately 1,930 MW from Victoria to New South Wales and 1,650 MW from New South Wales to Victoria.

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

- 1,600 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 NSW REZ (N5).

Figure 37 Summary of Option 5

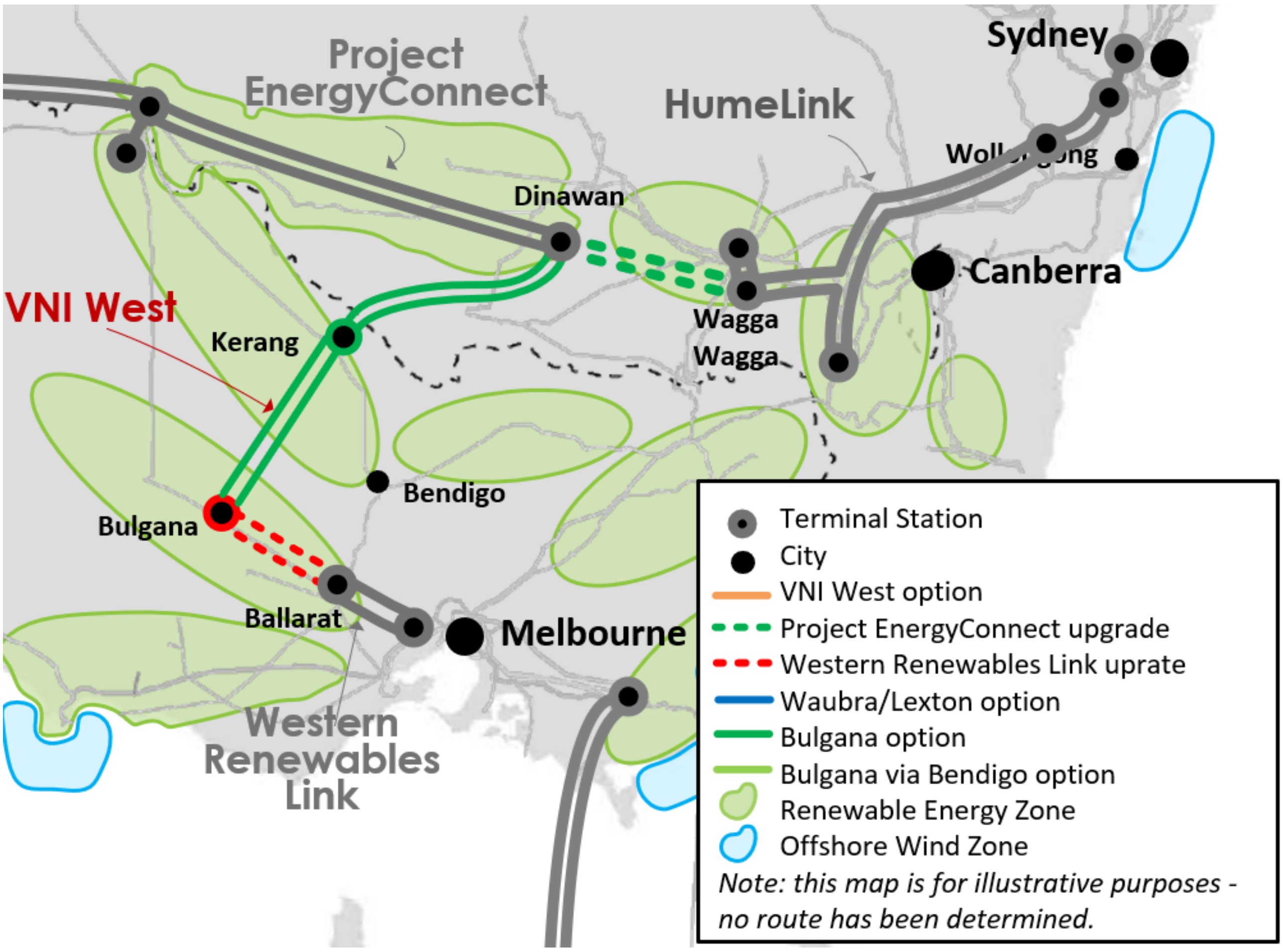
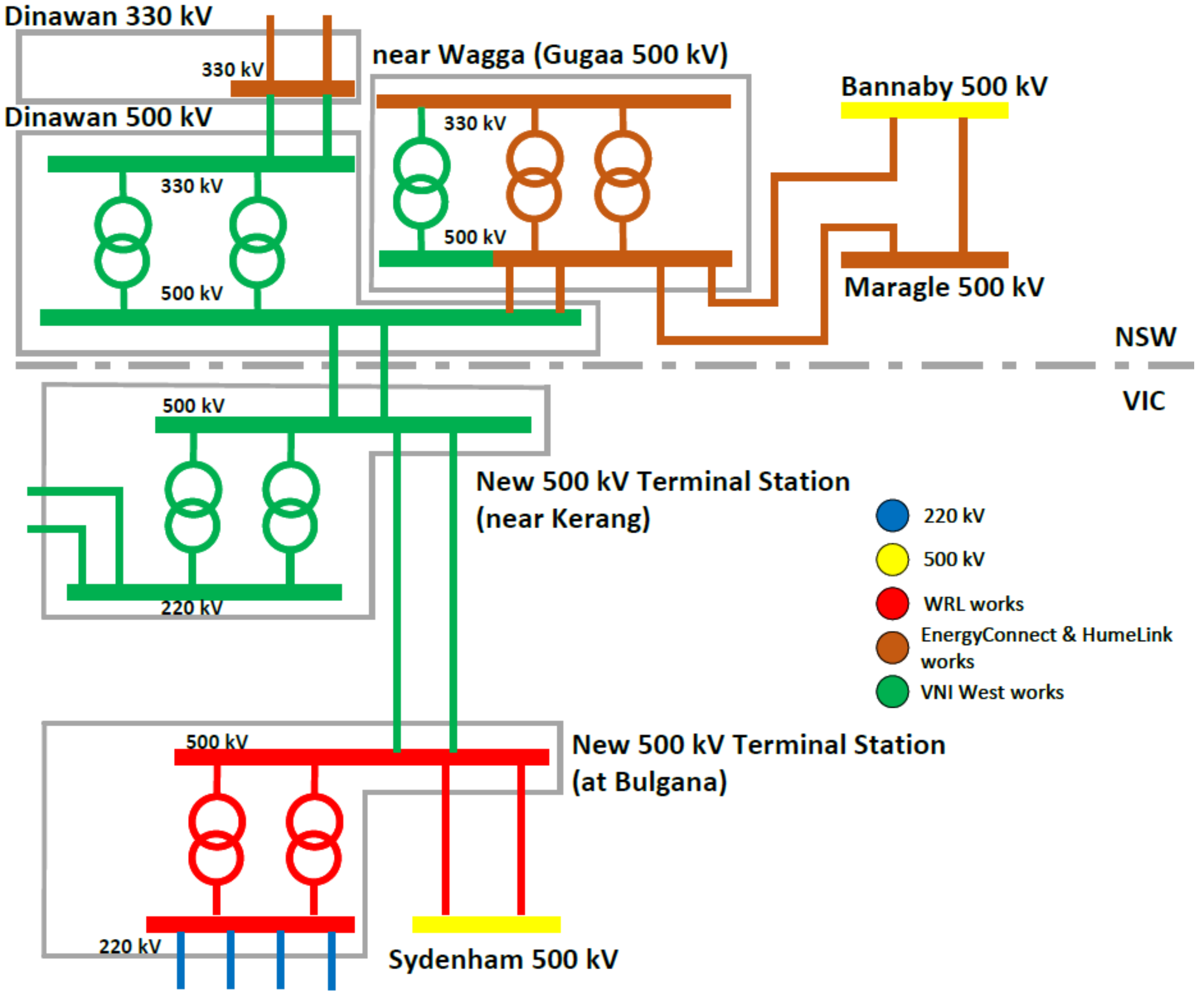


Figure 38 Single-line diagram for Option 5



The estimated capital cost of this option is approximately $3,282 million, which is comprised of $1,631 million in Victoria and $1,651 million in New South Wales.

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 would 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 as the NEVA Order enables AEMO to commence early works now, working towards undertaking first Spring Surveys in 2023.

Alternate options considered over the course of this RIT-T

Although this report is focused on the assessment of seven options, including five developed in response to submissions on the PADR, a significant number of additional options have been considered at various stages over the course of this RIT-T, and the associated ISP assessment. These include:

- 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 Alternate options considered but not progressed

Option	Overview	Reason(s) it has not been progressed
Options proposed in submissions to the PADR		
Underground HVDC	Several submissions suggested undergrounding of cables HVDC should be considered for a number of reasons including reducing impact for access, environment, visual amenity, private properties, and heritage sites.	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,

Option	Overview	Reason(s) it has not been progressed
		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 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 REZs.[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 NSW 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

Option	Overview	Reason(s) it has not been progressed
		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–Wodonga 330 kV line, an additional 330/220 kV transformer at Dederang, and additional reactive plant.	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 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 high voltage direct current (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	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.

Option	Overview	Reason(s) it has not been progressed
	terminal station north of Ballarat via Kerang and Darlington Point to Wagga, and avoiding Bendigo.	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.

A2. Cost estimating methodology

Additional work has been undertaken since the PADR 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. For options involving changes to WRL scope, AusNet has provided cost estimates.

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

A2.1 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 Transmission Cost Database . This section describes how each of the cost categories were estimated.

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, 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.

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. The new Kerang substation also includes 400 MVAr of dynamic reactive compensation on the 220 kV network.
- A new 500/220 kV substation near Bendigo, including two 1,000 MVA transformers and four 100 MVAr 500 kV line shunt reactors.

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.

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. Specifically for Option 1, the length of the more costly 500 kV line has reduced, and even though the length of relatively less costly 220 kV line has increased, the net estimated capital cost has reduced slightly.

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.

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.

Battery costs (for the VTL option)

The VTL option was estimated in two parts:

- The first part consists of the battery system and is based on inputs to AEMO's 2021 IASR. Capital costs are also inclusive of battery replacement costs that will be incurred in 2047.
- The second part consists of the terminal station works to interface the battery system to the substations. The estimate for this work followed the same approach as 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 this bottom-up estimate 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).

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 the substation estimates 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 this bottom-up estimate 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).

For Option 5, this line item also contains an allowance for series compensation that will be required on the Bulgana – Kerang section of the transmission line, 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, near Bendigo, 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.

Biodiversity offset costs

The biodiversity offset calculations required the determination of the extent of native vegetation that could potentially be impacted by an indicative proposed option[70]. 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.
- Large Tree losses, estimated at five per hectare within vegetation classes comprising a tree canopy element.

[70] The indicative option for biodiversity offsets is assumed to be Option 1 due to a density of vegetated areas, parks and reserves within the area of interest comparable to that of all options, with the exception of Option 5, which has a lower density of vegetated areas, parks and reserves within the area of interest.

- Species Habitat Unit (SHU) offset requirements, measured as species habitat units for impacts to rare or threatened species.

Significant impacts on Environmental Protection and Biodiversity Conservation (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 will be refined for the PACR, based on the indicative alignment identified for each option, by undertaking an EnSym scenario test for each of these.

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 segments or all of the transmission line spur 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 suit the option (relocation to near Waubra or 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) 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.
- Decoupling of the Waubra Wind Farm from the existing terminal station and reconnection with a short 220 kV transmission line to a new terminal station near Waubra.

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.

A2.2 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'[71]. 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.

[71] MTWO is a virtual-to-physical 5D BIM enterprise solution, designed to bring together all stakeholders and workflows on a single, cohesive platform. Built upon 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.

EnergyConnect enhanced works (incremental line build cost)

Following the Federal Government underwriting[72], 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 the proposed Dinawan Substation (south of Coleambally) and Wagga Wagga. The $181.5 million underwriting will see 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 include:

- 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.

Battery costs (for the VTL option)

The VTL option was estimated in two parts:

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

- The first part consists of the battery system and is based on inputs to AEMO's 2021 IASR. Capital costs are also inclusive of battery replacement costs that will be incurred in 2047.
- The second part consists of the terminal station works to interface the battery system to the substations. The estimate for this work followed the same approach as 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 this bottom-up estimate were based on historical data available to Transgrid and where applicable, updated with current market costs and site conditions and include the items listed for the substation estimates (outlined above).

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. Specifically, the payments:[73]

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 358 km, of which 85% is assumed to be on private land.

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

A3. NPV assessment for other scenarios

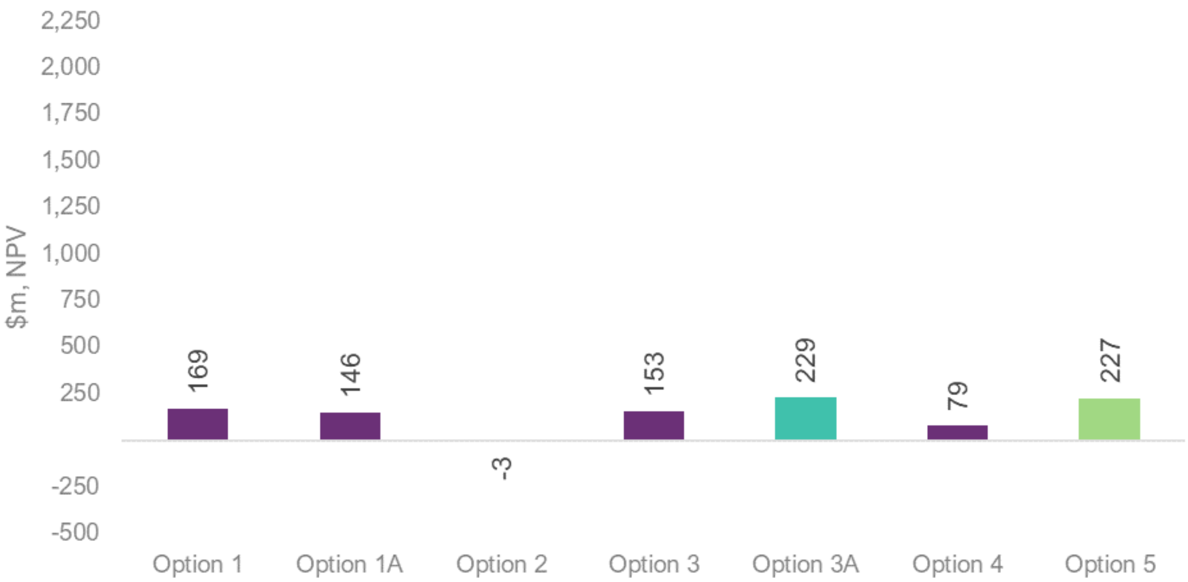
A3.1 *Progressive Change* scenario

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 3A is found to be the top-ranked option and is expected to deliver net benefits of approximately $229 million. Option 5 is the second ranked option, expected to deliver net benefits of $227 million, which is 1% less than Option 5.

Figure 39Figure 39 presents the estimated net benefits for each option under the *Progressive Change* scenario.

Figure 39 Summary of estimated net benefits in the *Progressive Change* scenario



The results for the *Progressive Change* scenario also show that:

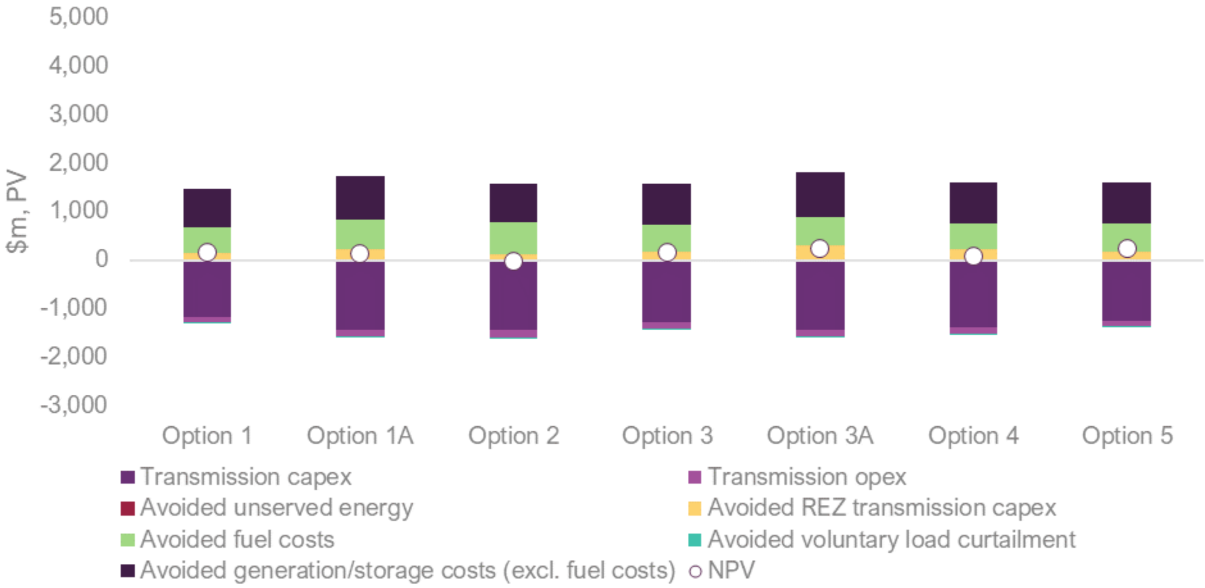
- If VNI West connects to WRL at Waubra/Lexton, uprating the WRL spur to Bulgana is net beneficial; that is, Option 3A is ranked above Option 3 by $76 million.
- If WNI West connects to WRL north of Ballarat, uprating the WRL spur to Bulgana is not net beneficial; that is, Option 1A is ranked below Option 1 by $23 million. This is in contrast to the *Step Change* outcomes, where the Option 1A spur is net beneficial. In the *Progressive Change* scenario, the gross market benefits increase with the Option 1A spur, but the incremental cost outweighs the increased benefits. The slower demand growth and less restrictive carbon budget in the *Progressive Change* scenario mean the forecast need for renewable generation is deferred relative to the *Step Change* scenario but the cost of the spur remains coincident with

WRL construction schedule. Consequently, the benefits associated with improved transmission access to renewables do not accrue until later and do not outweigh the incremental cost of the spur.

- As with the *Step Change* scenario, Option 2 is the lowest ranked option and the additional cost of the VTL components is not outweighed by the additional expected market benefits (as is shown by Option 2 having lower net benefits than Option 1).
- As with the *Step Change* scenario, Option 4 is the worst performing purely interconnector option.

Figure 40 shows the composition of estimated net benefits for each option under the *Progressive Change* scenario.

Figure 40 Breakdown of estimated net benefits under the *Progressive Change* scenario



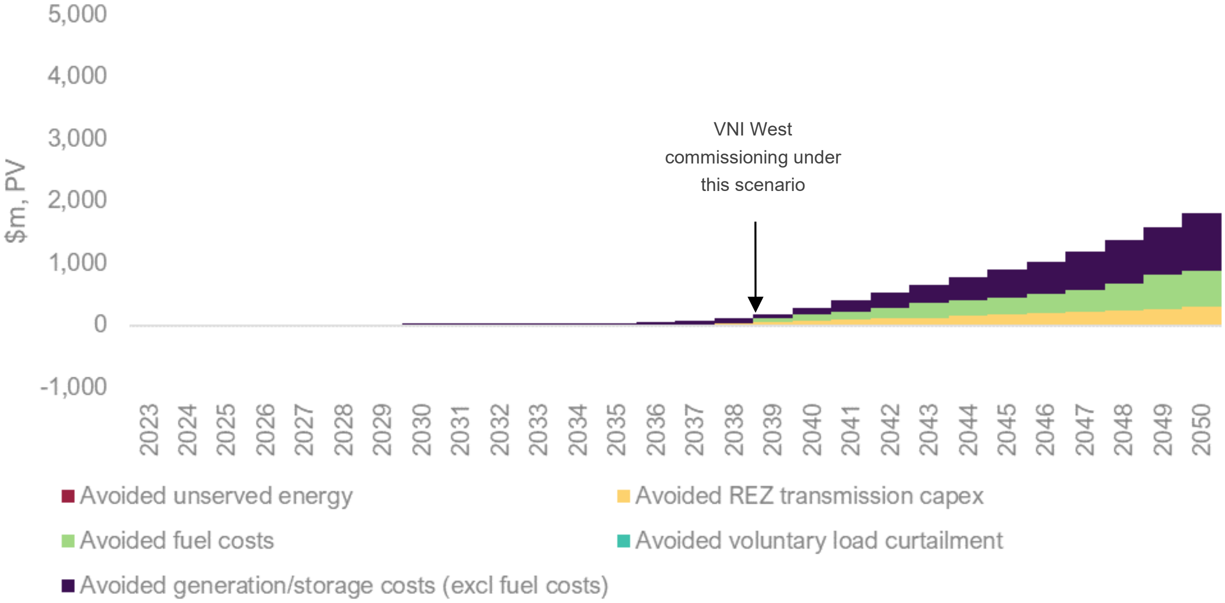
The key findings from the assessment of each option under the *Progressive Change* scenario are:

- Avoided/deferred generation and storage costs (the darkest sections of each bar in Figure 40) are the largest source of benefit for all options.
  - Avoided/deferred generation and storage costs comprise approximately 51% and 54% of the estimated gross benefits of Option 3A and Option 5, respectively.
  - Similar to the *Step Change* scenario, deferring and avoiding solar, storage and gas 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.
- Avoided fuel costs (the light green sections of each bar in Figure 40) are the second largest source of benefit for all options.

  - Avoided fuel costs comprise approximately 33% and 35% of the estimated gross benefits of Option 3A and Option 5, respectively.
  - These benefits arise primarily from reduced peaking gas generation in Victoria, which is mostly replaced by increased wind and solar generation in New South Wales
- Victoria REZ transmission cost savings (shown by the yellow sections of each bar in Figure 40 above) are relatively small in this scenario, and are driven by VNI West improving transmission access to Murray River (V2) and Western Victoria (V3) and South West NSW (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 northern Queensland REZs (and their relevant group REZ transmission constraints), and to a lesser extent in other REZs such as Central North Victoria (V6), Western Victoria (V3), and Central Highlands (T3).

Figure 41 below presents the estimated cumulative expected gross benefits for Option 3A for each year of the assessment period under the *Progressive Change* scenario.

Figure 41 Breakdown of cumulative gross benefits for Option 3A under the *Progressive Change* scenario



Similarly, Figure 42 presents the estimated cumulative expected gross benefits for Option 5 for each year of the assessment period under the *Progressive Change* scenario. It shows a similar pattern to Option 3A.

Figure 42 Breakdown of cumulative gross benefits for Option 5 under the *Progressive Change* scenario

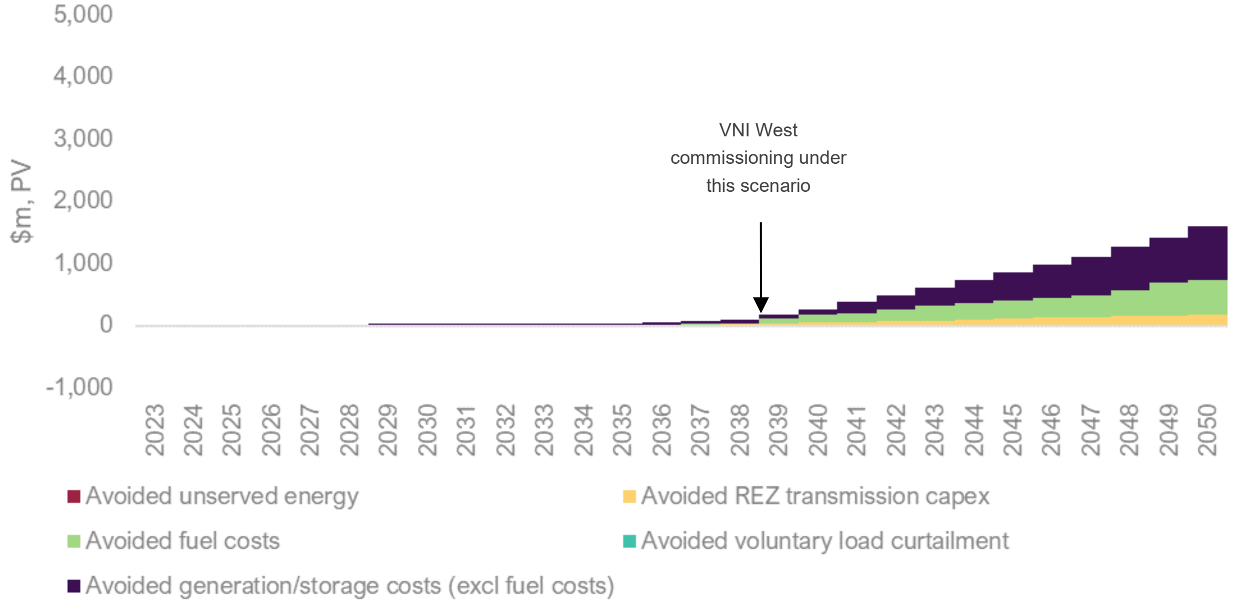
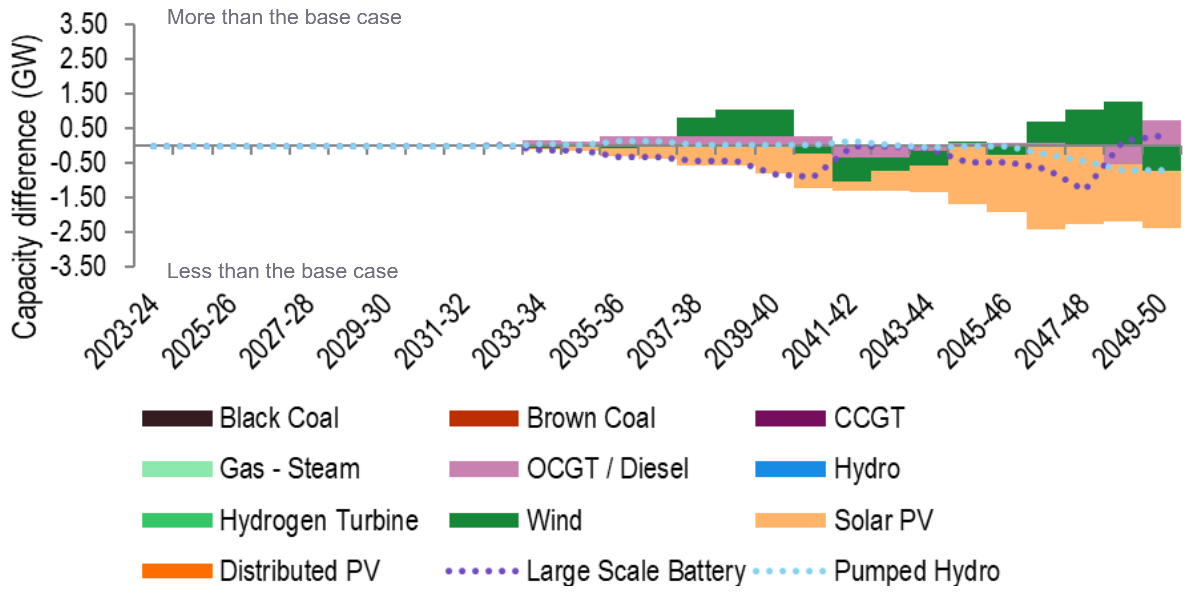


Figure 43 summarises the difference in generation and storage capacity forecast for Option 3A (in GW), compared to the base case. These differences drive the benefits associated with avoided or deferred generation and storage costs.

Figure 43 Difference in cumulative capacity built with Option 3A, compared to the base case, under the *Progressive Change* scenario



Similar to the *Step Change* scenario, in the *Progressive Change* scenario Option 3A is forecast to generally result in avoiding some solar and storage investment, though this option accelerates forecast wind and peaking gas build relative to the base case.

With Option 3A and the associated assumption of improved transmission capacity to certain REZs, as well as more interconnection with New South Wales, more wind investment is forecast in the affected REZs in Victoria, which reduces the need for investment in other Victorian REZs. The overall benefits of Option 3A are forecast to be a reduced need for solar and storage in Victoria (with some being relocated to New South Wales), less investment in wind in New South Wales, as well as generally less wind, solar and storage build in Tasmania, South Australia and Queensland.

The *Progressive Change* scenario is forecast to have relatively less renewable spill compared with the *Step Change* scenario. However, similar to the *Step Change* scenario, it is forecast that with more interconnection and REZ access enabled by Option 3A for Victoria to New South Wales and the rest of the mainland, resources are more efficiently utilised. Overall, across this NEM this option is forecast to reduce solar spill by 4% and wind spill by 10% relative to the base case.

Figure 44 summarises the difference in generation and storage capacity forecast for Option 5 (in GW), compared to the base case. These differences drive the benefits associated with avoided or deferred generation and storage costs.

Similar to Option 3A, Option 5 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 changing of the timing of wind and gas 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 result in generally less forecast need for new capacity than the base case.

Figure 44 Difference in cumulative capacity built with Option 5, compared to the base case, under the *Progressive Change* scenario

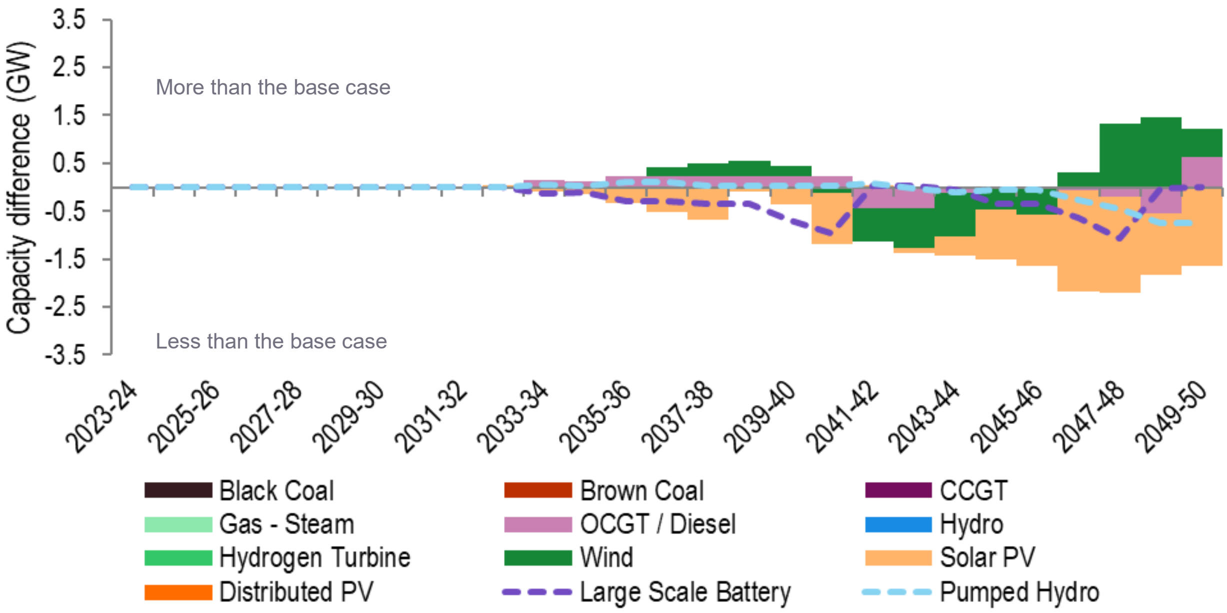


Figure 45 summarises the difference in generation and storage output forecast for Option 3A (in TWh), compared to the base case. These differences drive the avoided fuel cost benefit. With Option 3A, more renewable generation, which is to some extent due to less spill, and more diversity of generation, is expected to result in less gas generation in the NEM. The difference in renewable generation between Option 3A and the base case is expected to have a similar trend to the capacity difference, though less wind and solar spill results in better utilisation of these resources with Option 3A in place.

Figure 45 Differences in output with Option 3A, compared to the base case, under the *Progressive Change* scenario

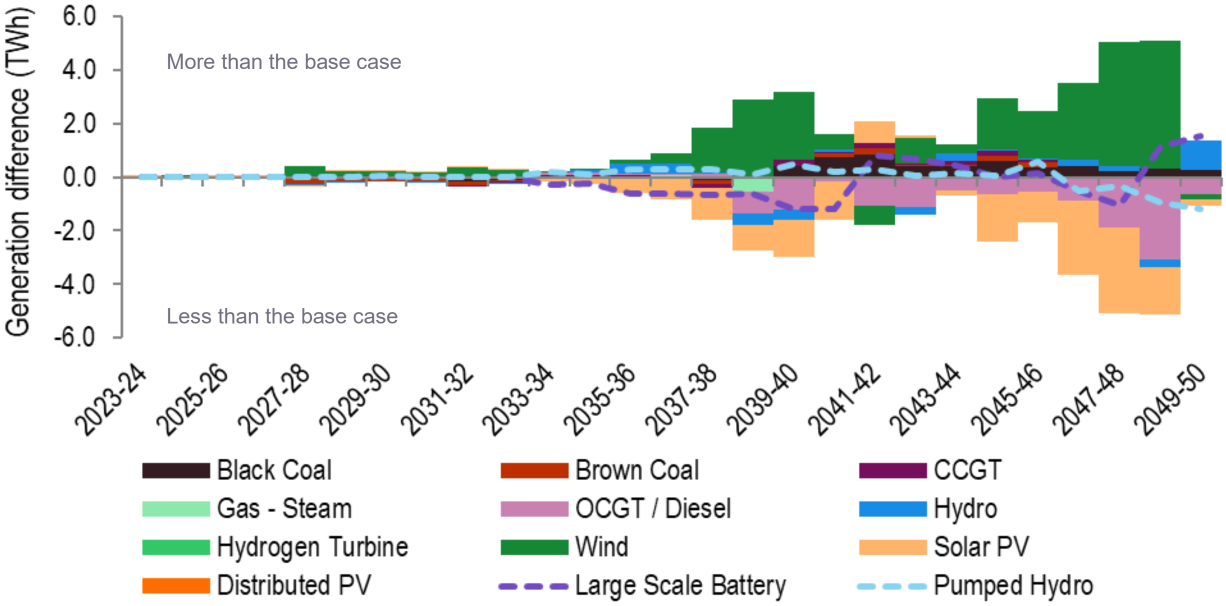
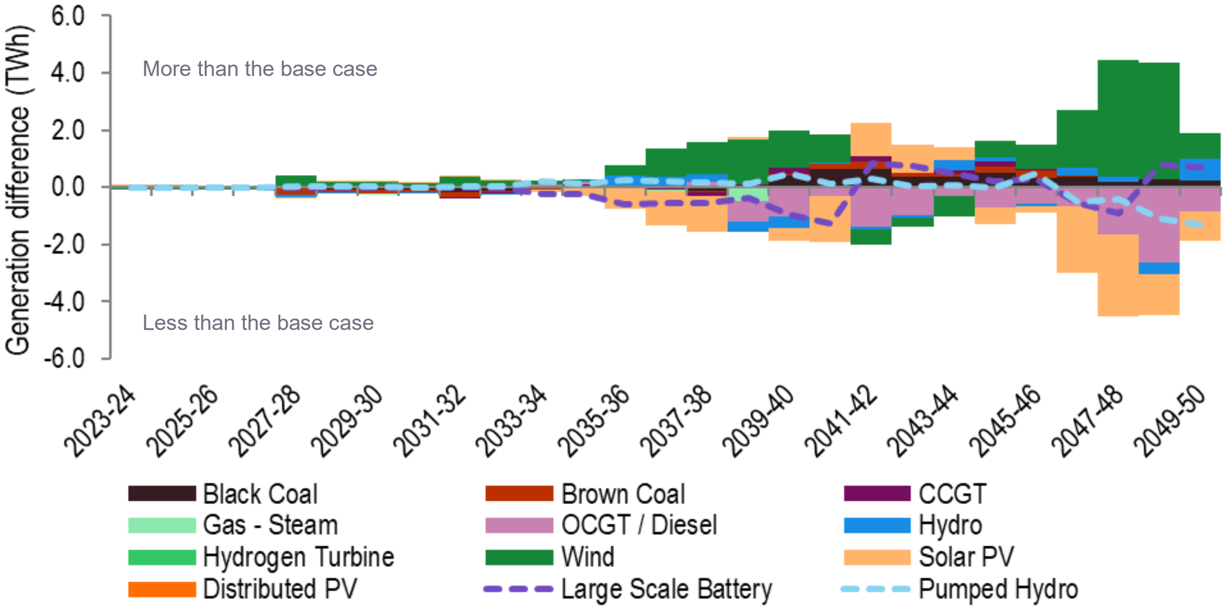


Figure 46 summarises the difference in generation and storage output forecast for Option 5 (in TWh), compared to the base case. These differences drive the avoided fuel cost benefit.

Similar to Option 3A, with Option 5, generally more renewable generation is expected to result in less gas generation in the NEM.

Figure 46 Differences in output with Option 5, compared to the base case, under the *Progressive Change* scenario



A3.2 *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[74]. Large scale solar PV 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, all options except Option 3 and Option 4 are found to deliver net benefits within 4% of each other and so are considered to be ranked effectively equally as the top-ranked options.

Option 5 (to Bulgana) is expected to deliver net benefits of approximately $2,012 million. Option 3A – VNI West plus a 500 kV spur line from near Waubra to Bulgana – is found to have net benefits of approximately $1,936 million (4% less than Option 5).

This is in contrast to the forecast *Step Change* outcomes, which showed slightly greater net benefits for Option 3A than Option 5. Option 5 is associated with a smaller improvement in transmission capacity to Western Victoria (V3) REZ than Option 3A, but a 100 MW higher northward VNI limit. In the *Hydrogen Superpower* scenario, there are significant benefits associated with the higher northward VNI limit due to the significant assumed hydrogen demand in northern states in this scenario. The additional interconnection of Option 5 is more valuable than the improved REZ associated with Option 3A.

Figure 47 presents the estimated net benefits for each option under the *Hydrogen Superpower* scenario.

Figure 47 Summary of estimated net benefits under the *Hydrogen Superpower* scenario

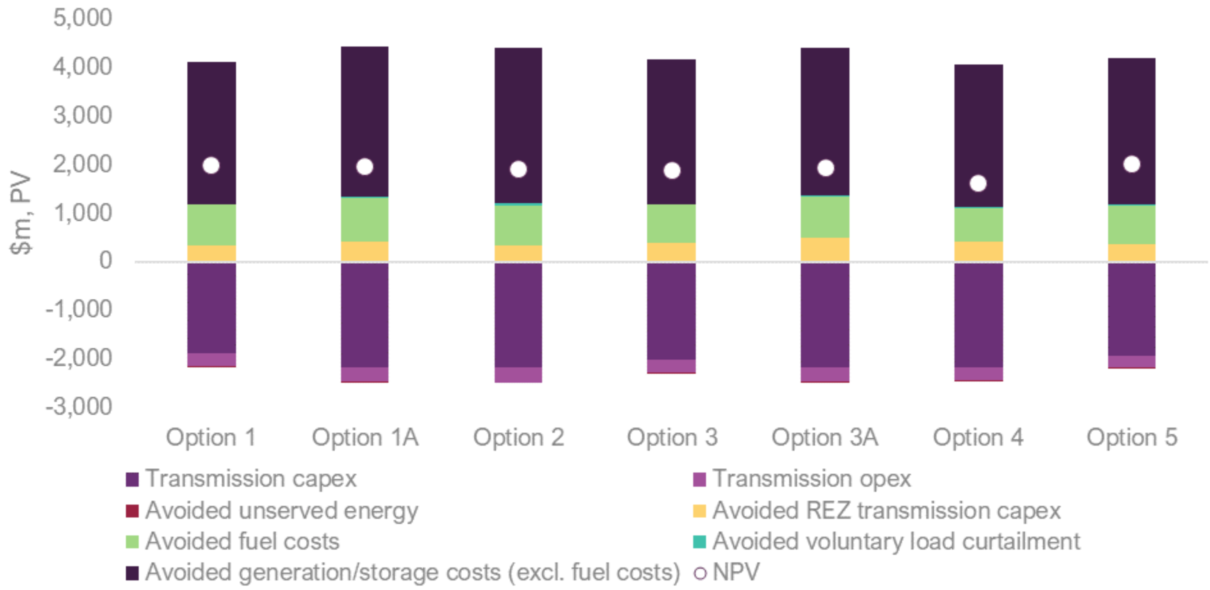
The results for the *Hydrogen Superpower* scenario also show that:

[74] AEMO, 2022 ISP, June 2022, p. 31.

- The spur from near Waubra/Lexton to Bulgana is net beneficial; that is, Option 3A is ranked above Option 3 by $52 million.
- As with the *Progressive Change* scenario, the spur from north of Ballarat to Bulgana is not net beneficial; that is, Option 1A is ranked below Option 1 by $9 million. Again, gross market benefits increase with the Option 1A spur, but the incremental cost outweighs the increased benefits.
- As with the other two scenarios, the additional cost of the VTL components is not outweighed by the additional expected market benefits (as is shown by Option 2 having lower net benefits than Option 1).
- As with the other two scenarios, Option 4 is the worst performing purely interconnector option.

Figure 48 shows the composition of estimated net benefits for each option under the *Hydrogen Superpower* scenario.

Figure 48 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:

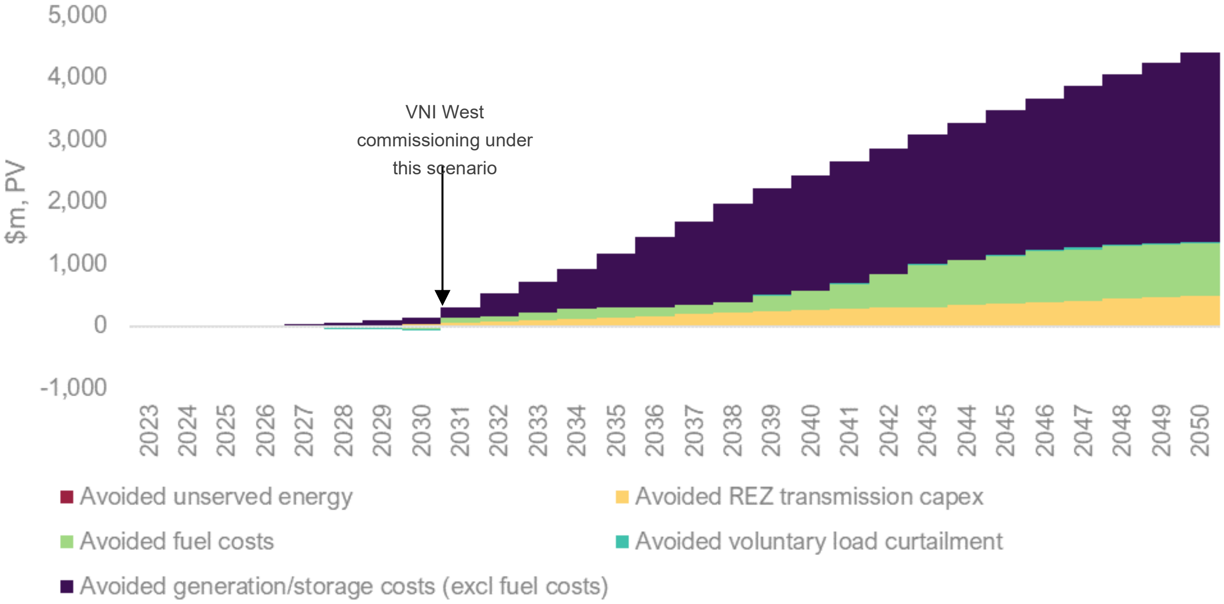
- Avoided/deferred generation and storage costs (the darkest sections of each bar in Figure 48) are the largest source of benefit for all options.
  - Avoided/deferred generation and storage capital costs comprise approximately 69% and 72% of the estimated gross benefits of Option 3A and Option 5 respectively.
  - These benefits are primarily driven by avoided solar generation in lower quality areas, hydrogen turbines and large-scale storage capacity (mostly in Victoria). The reduced generation from these avoided investments in Victoria is primarily met by increased solar and battery storage capacity in New South Wales and wind capacity in Victoria. 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 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 in this scenario, particularly the heavy reliance on large-scale solar PV 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 reduce expected solar and wind spill relative to the base case. Avoided fuel costs (the light green sections of each bar in Figure 48) are the second largest source of benefit for all options.
   – Avoided fuel costs comprise approximately 19% of the estimated gross benefits of both Option 3A and Option 5.
- REZ transmission cost savings (shown by the yellow sections of each bar in Figure 48 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), South West Victoria (V4) and other regions' REZs.

Figure 49 below presents the estimated cumulative expected gross benefits for Option 3A for each year of the assessment period under the *Hydrogen Superpower* scenario. It shows that benefits from avoided/deferred generation and storage costs begin accruing from when Option 3A is commissioned and increase steadily from there. Avoided fuel consumption accrues once VNI West is commissioned until around the late 2040s, and is mostly due to avoided hydrogen turbine generation.

Figure 49 Breakdown of cumulative gross benefits for Option 3A under the *Hydrogen Superpower* scenario



Similarly, Figure 50 resents the estimated cumulative expected gross benefits for Option 5 for each year of the assessment period under the *Hydrogen Superpower* scenario. It shows a similar pattern to Option 3A.

Figure 50 Breakdown of cumulative gross benefits for Option 5 under the *Hydrogen Superpower* scenario

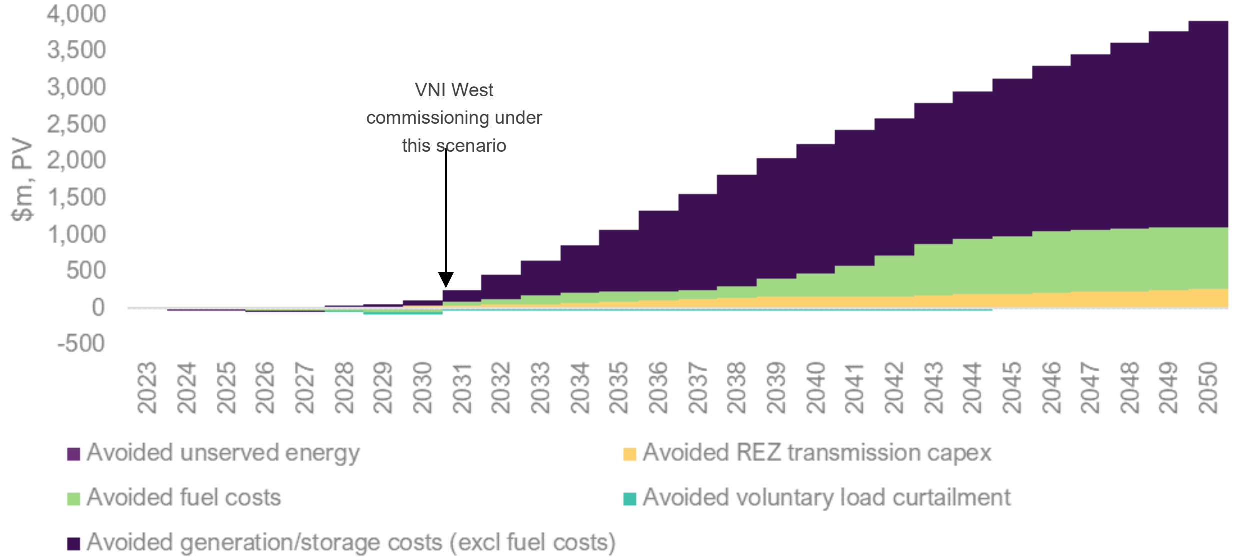


Figure 51 summarises the difference in generation and storage capacity forecast for Option 3A (in GW), compared to the base case. These differences driving the benefits associated with avoided or deferred generation and storage costs.

Similar to the *Step Change* scenario, in the *Hydrogen Superpower* scenario Option 3A is forecast to provide greater resource diversity by enabling more renewable generation, particularly wind[75], and avoiding some solar and storage capacity investment. In addition, some investment in hydrogen turbine capacity is avoided.

Without Option 3A, extra solar capacity in combination with storage, and in later years hydrogen turbine, is required to supply Victoria demand. Without VNI West, with the limited access to Western Victoria (V3) and Murray River (V2) REZs, as well as less interconnection to New South Wales, it is forecast that significant solar is built in Victoria with relatively high seasonal spill.

With Option 3A, some of the capacity in Victoria is forecast to be avoided and instead be replaced by some extra solar and storage mostly in New South Wales, although at a lower capacity. In addition, with the assumed increase in transmission capacity in the Western Victoria (V3) REZ, more wind capacity is forecast in this REZ, replacing mostly solar capacity elsewhere in Victoria. Overall, the volume of solar capacity avoided is more than the increase in wind investment with Option 3A included. This is to some extent due to the need for solar overbuild in Victoria in the base case. VNI West reduces the scale of this overbuild as a result of enabled generation diversity and more interconnection to New South Wales.

Renewable spill is forecast to be significantly more than other scenarios, mainly due to significant renewable build in this scenario. Similar to other scenarios, with improved interconnection associated with Option 3A, resources are forecast to be more efficiently utilised. Across the NEM, Option 3A is forecast to reduce renewable spill, particularly wind spill volume by 4% relative to the base case.

[75] As the cost of the WRL spur 500kV uprate is lower from Waubra/Lexton to Bulgana than from north of Ballarat to Bulgana, the incremental value of accessing more wind to create resource diversity is net beneficial for Option 3A, whereas it is not for Option 1A.

Figure 51 Difference in cumulative capacity built with Option 3A, compared to the base case, under the *Hydrogen Superpower* scenario

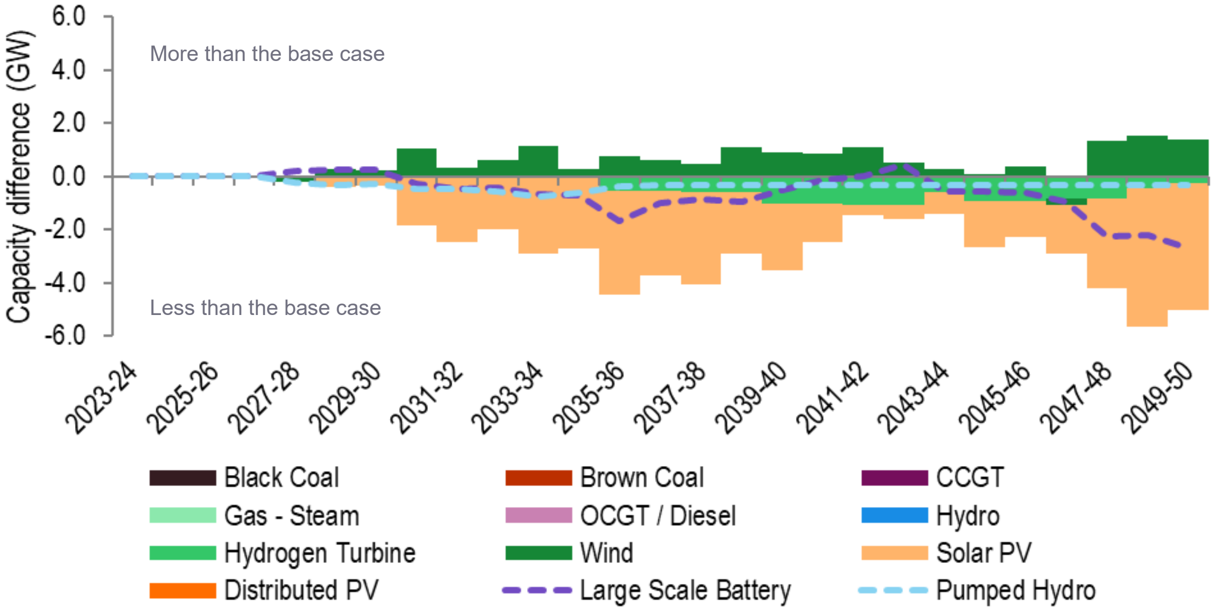


Figure 52 summarises the difference in generation and storage capacity forecast for Option 5 (in GW), compared to the base case. These differences drive the benefit associated with avoided or deferred generation and storage costs.

Similar to Option 3A, Option 5 is forecast to result in more wind capacity and less solar and storage compared to the base case, although total investment in wind and solar is still substantial. In addition, some hydrogen turbine capacity investment is avoided. However, due to relatively less unlocked transmission network capacity for Western Victoria (V3) REZ, relatively less additional wind is forecast in Option 5 relative to the base case than Option 3A relative to the base case.

By utilising resources more efficiently with this option, across the NEM, Option 5 is forecast to reduce solar spill by 1% and wind spill volume by 4% relative to the base case.

Figure 52 Difference in cumulative capacity built with Option 5, compared to the base case, under the *Hydrogen Superpower* scenario

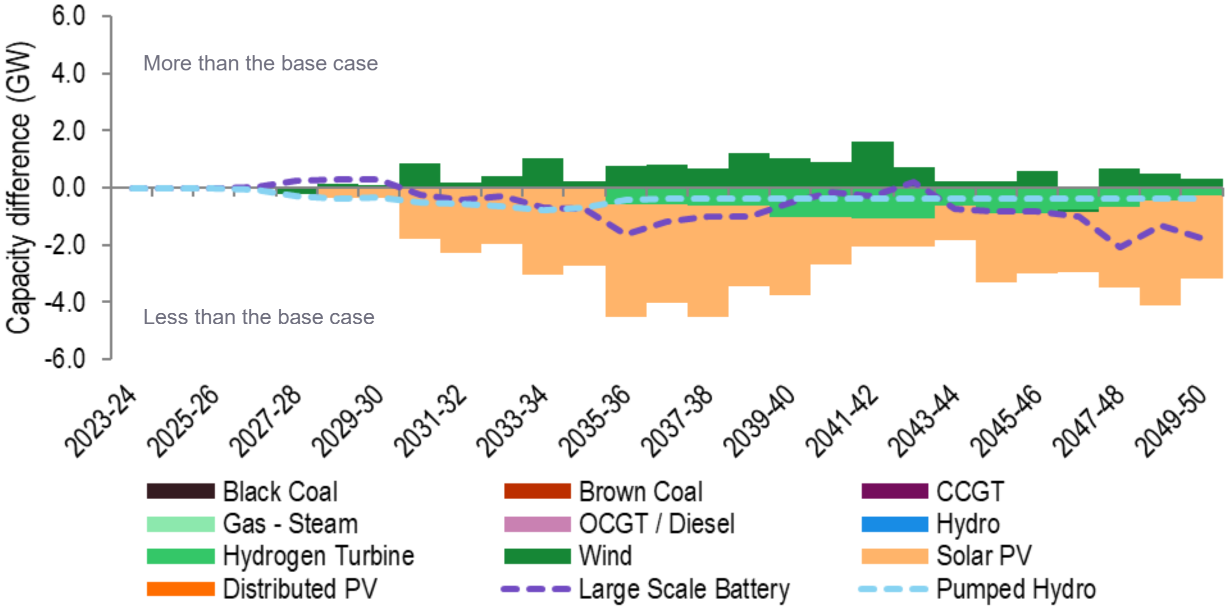


Figure 53 summarises the difference in generation and storage output forecast for Option 3A (in TWh), compared to the base case. These differences drive the avoided fuel cost benefit.

It is generally forecast that Option 3A results in avoiding some hydrogen turbine generation, resulting in fuel cost savings in some years. In addition, due to less solar capacity and more wind investment with this option in place, generally less solar generation and more wind generation is expected. Reduced expected wind and solar spill also contribute to the generation difference between this option and the counterfactual base case, contributing indirectly to fuel cost savings.

Figure 53 Difference in output with Option 3A, compared to the base case, under the *Hydrogen Superpower* scenario

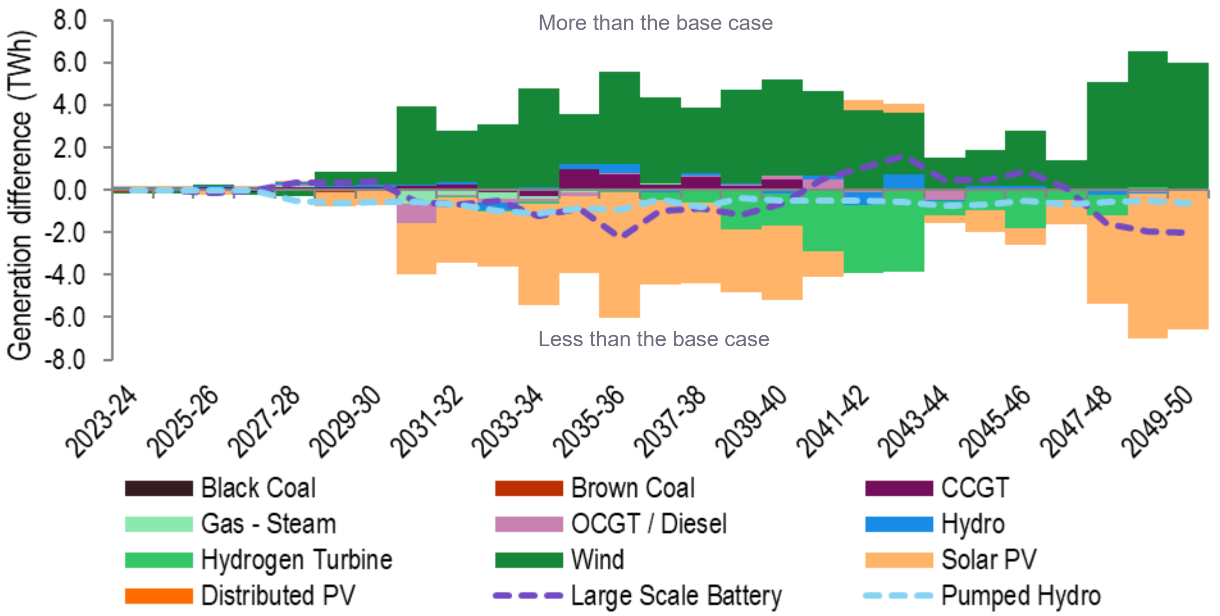
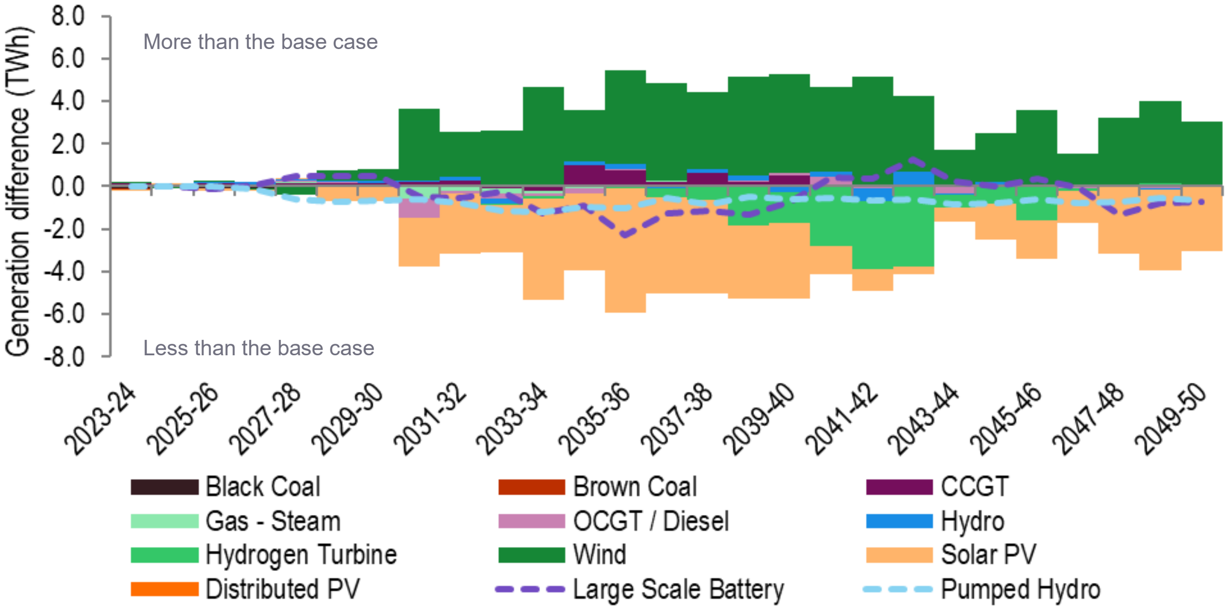


Figure 54 summarises the difference in generation and storage output forecast for Option 5 (in TWh), compared to the base case. These differences drive the avoided fuel cost benefit.

A similar generation trend to Option 3A is expected in Option 5, although at a smaller scale for wind and solar. Reduced hydrogen turbine generation is again expected to be the main contributor to forecast fuel cost savings observed over much of the planning horizon.

Figure 54 Difference in output with Option 5, compared to the base case, under the *Hydrogen Superpower* scenario



A4. Multi-criteria analysis

AECOM Australia Pty Ltd (AECOM) was engaged by AEMO to undertake an assessment of indicative alignments for the Victorian section of VNI West connecting into WRL. The analysis used Geographic Information Systems (GIS) data and constraints analysis to help identify the best performing indicative alignment(s).

The MCA options assessment method, based on desktop assessment only, included the following key steps:

- Identification of constraints and opportunities.
- Identification of indicative alignments.
- Establishment of an assessment framework including evaluation criteria, rating guidance and criteria weightings for the evaluation of the indicative alignments.
- Evaluation of indicative alignments using GIS analysis.
- Application of the assessment framework to the GIS output.
- Evaluation of indicative alignments and selection of the best performing indicative alignment.

While the shortest route between the start and end point of the proposed transmission line would typically represent the most cost-effective option, it was apparent that such a route would intersect numerous highly sensitive areas. It was therefore advantageous to look for indicative alignments that avoided and minimised impacts on these constraints.

Taking into account constraints, a number of areas of interest across the region were identified within which transmission alignments could potentially occur (see Figure 55). Key constraints that were considered included (but are not limited to) intersection with National Parks and State Parks, areas of cultural significance, townships, and existing infrastructure.

The criteria used to evaluate the options considered net economic benefit (using the net benefit NPV analysis summarised in Section 3), environment, cultural heritage, social, land use and engineering aspects.

The evaluation method involved using GIS datasets to measure the performance of each option against the evaluation criteria. The evaluations were based on indicative 100-metre-wide alignments. These indicative alignments do not represent intended routes, but network options affecting different areas.

Outputs generated from the GIS analysis were related to either the area of intersection for that criterion or for the number of features intersected by that option.

Guidance was developed to rate the relative merit of the options in relation to each criterion. Each criterion was then assigned a rating as either ‘very low’, ‘low’, ‘medium’, ‘high’ or ‘very high’ for each option. These ratings were constructed relative to the spread of the raw GIS data outputs. A full breakdown of how scores were assigned for each criterion is provided in Table 17.

Figure 55 Areas of interest for indicative alignments

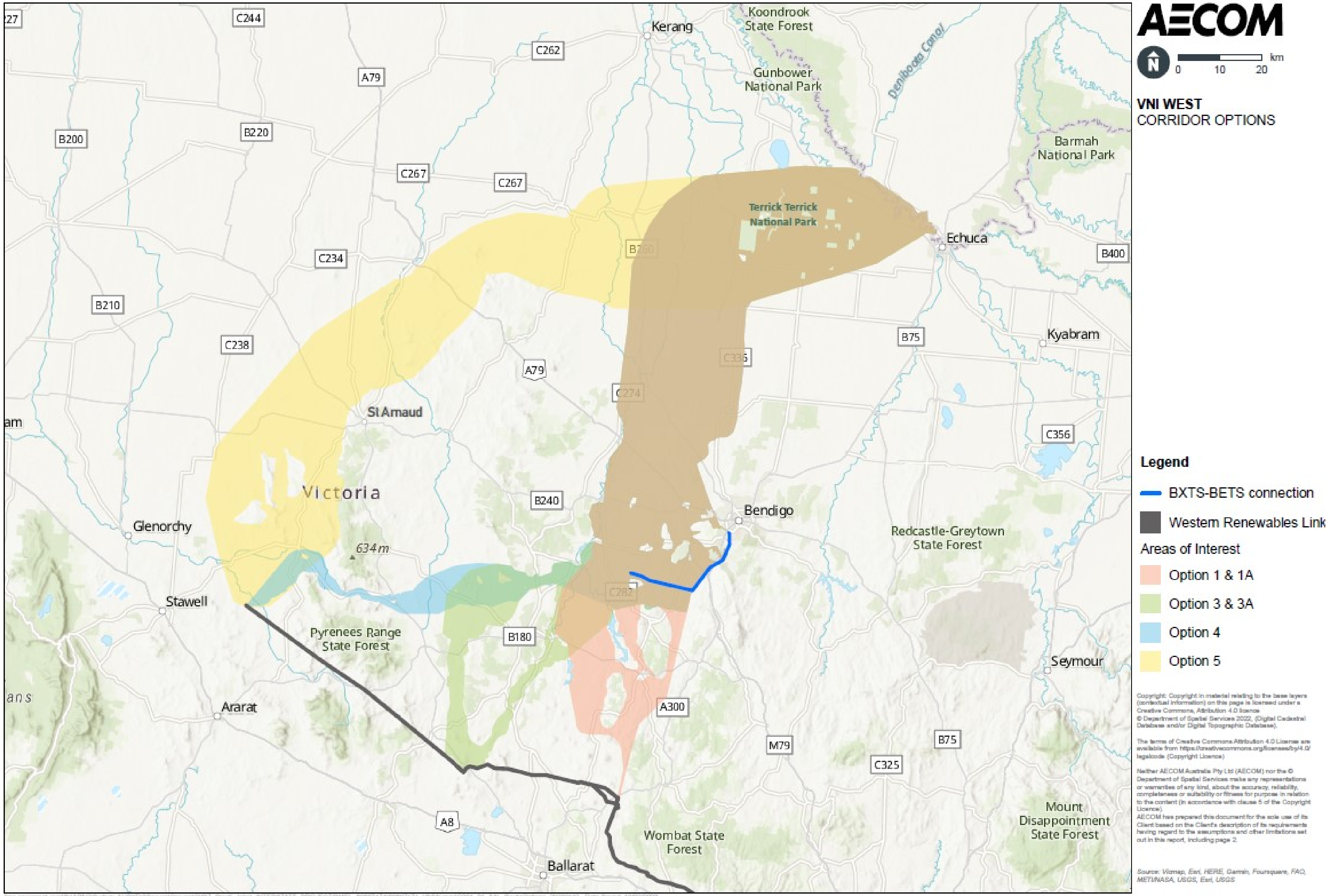


Table 17 Evaluation criteria

Grouping	Aspect	Evaluation criteria	Data source (GIS data accessed 06/12/2022)	Rating guidance
Net economic benefit	Maximise economic benefit	NPV of net benefit ($M)	NPV assessment described in section 3 of this Consultation Report	VL(5): NPV < $1150M, L(4): NPV $1150M-1250M, M(3): NPV $1250M-1350M, H(2): NPV $1350M-1450M, VH(1): NPV >1450M
Environment	Protected areas	Area within protected areas (Ramsar wetlands, National Parks and State Parks)	Ramsar wetlands Wetlands of Importance Directory	VL: Not traversed, L: Area >0-2.5 ha, M: Area >2.5-5 ha, H: Area >5-7.5 ha, VH: Area >7.5 ha
	Native vegetation	Area of native vegetation intersected	Native Vegetation Regulation Extent (2017)	VL: Area 0-280 ha, L: Area >280-430 ha, M: Area >430-580 ha, H: Area >580-730 ha, VH: Area >730 ha
		Area of highly significant native vegetation (EPBC listed threatened ecological communities and state endangered ecological vegetation classes)	Native Vegetation - Modelled 2005 Ecological Vegetation Classes	VL: Area 0-270 ha, L: Area >270-413 ha, M: Area >413-556 ha, H: Area >556-700 ha, VH: Area >700 ha
	Habitats	Area of critical habitat intersected (critical habitat for threatened or migratory species listed under EPBC Act (Cth) and FFG Act (Vic))	Victorian Biodiversity Atlas flora records and Victorian Biodiversity Atlas fauna records	VL: Area 0-165 ha, L: Area >165-327 ha, M: Area >327-492 ha, H: Area >492-657 ha, VH: Area >657 ha
	Waterways	Number of waterways intersected	VicMap Hydrography - Watercourse	VL: Number intersected >300-330, L: Number intersected >330-360, M: Number intersected >360-390, H: Number intersected >390-420, VH: Number intersected >420
Cultural heritage	Non-Aboriginal cultural heritage	Area of Non-Aboriginal heritage items or conservation areas listed under Commonwealth and State heritage registers intersected	Victorian Heritage Register Commonwealth Heritage List National Heritage List World Heritage Areas	VL: Not traversed, L: Area >0-2.5 ha, M: Area >2.5-5 ha, H: Area >5-7.5 ha, VH: Area >7.5 ha
	Aboriginal cultural heritage	Area of potential Aboriginal cultural heritage significance intersected (areas of cultural heritage sensitivity)	Areas of Cultural Heritage Sensitivity, including national parks and waterways Commonwealth Heritage List World Heritage Areas	VL: <185 ha, L: Area 185-200 ha, M: Area >200-215 ha, H: Area >215-230 ha, VH: Area >230 ha
		Native title	NTD Register Native Title	VL: Not traversed, L: 0-3,

Grouping	Aspect	Evaluation criteria	Data source (GIS data accessed 06/12/2022)	Rating guidance
				M: 3-4, H: 5-6, VH: >6
Social	Amenity	Area within residential zones as a proxy for amenity impacts (noise, dust, visual)	VicPlan (residential zones)	VL: Area 0 ha, L: Area >0-2 ha, M: Area 2-4 ha, H: Area 4-6 ha, VH: Area >6 ha
		Number of buildings within 300 metres of the centre of the alignment	Building points (supplied by AEMO)	VL: <20 buildings, L: >20-30 buildings, M: >30-40 buildings, H: >40-50 buildings, VH: >50 buildings
		Area within significant landscape overlay	VicPlan (Significant landscape overlay)	VL: Not traversed, L: Area >0-0.5 ha, M: Area >0.5-1 ha, H: Area >1-1.5 ha, VH: Area >1.5 ha
	Affected parties	Number of land parcels affected	VicMap Property - Parcel	VL: 0-150 land parcels, L: >150-300 land parcels, M: >300-450 land parcels, H: >450-600 land parcels, VH: >600 land parcels
Land use	Severance	Number of land parcels bisected where smallest portion is >20% and therefore more likely to have an adverse effect on existing land uses	VicMap Property - Parcel	VL: 0-50 land parcels, L: >50-75 land parcels, M: >75-100 land parcels, H: >100-125 land parcels, VH: >125 land parcels
	Agriculture	Areas of land with agricultural potential score of >6	Land Systems of Victoria The prediction of inherent production potential is based on identifying and assessing the characteristics of the land that are likely to be limiting to agricultural or horticultural production. The assessment is qualitative and provides a ranking of production potential of between 0 and 10 for each land system. Given that this prediction is of the inherent potential for plant biomass production, the impact of land management practices that improve production such as fertilizers, lime, gypsum or irrigation is not included. This assessment is not intended to replace more detailed assessments of the productive capacity of the land based on more empirical evidence. However, such assessments are not currently available, and these production potential	VL: Not traversed, L: Area >0-30 ha, M: Area >30-60 ha, H: Area >60-90 ha, VH: Area >90 ha

Grouping	Aspect	Evaluation criteria	Data source (GIS data accessed 06/12/2022)	Rating guidance
			assessments may fill certain needs until such empirically based assessments do become available.	
	Forestry	Area of forestry tenure land intersected	Public Land Management (PLM25)	VL: <200 ha, L: Area >200-800 ha, M: Area >800-1400 ha, H: Area >1400-2000 ha, VH: Area >2000 ha
	Resource development	Area of resource tenure land (production and exploration) intersected	Current mining licences and leases	VL: <200 ha, L: Area >200-800 ha, M: Area >800-1400 ha, H: Area >1400-2000 ha, VH: Area >2000 ha
Engineering	Third party infrastructure	Number of arterial roads intersected	VicMap Transport - Roads	VL: 0 roads, L: >0-75 roads, M: >75-150 roads, H: >150-225 roads, VH: >225 roads
		Number of transmission lines intersected	Geoscience Australia – Electricity Transmission Lines	VL: 0 transmission lines, L: >0-5 transmission lines, M: >5-10 transmission lines, H: >10-15 transmission lines, VH: >15 transmission lines
		Number of railways intersected	VicMap Transport - Railways	VL: 0 railways, L: >0-5 railways, M: >5-10 railways, H: >10-15 railways, VH: >15 railways
		Number of pipelines intersected	VicMap FOI - Line	VL: Not Traversed, L: >0-2 pipeline, M: >2-4 pipelines, H: >4-6 pipelines, VH: >6 pipelines
	Engineering complexity	Topography slope > 1:5	SRTM 1 Second DEM-S	VL: Not > 0-1, L: >1:0-2:0, M: >2:0 - 3:0, H: >3:0 - 4:0, VH: >4:0
		Area within land subject to inundation	VicPlan (Land subject to inundation overlay)	VL: 390-438 ha, L: Area >438-486 ha, M: Area >486-534 ha, H: Area >534-582 ha, VH: Area >582 ha

Grouping	Aspect	Evaluation criteria	Data source (GIS data accessed 06/12/2022)	Rating guidance
	Bushfire	Area within bushfire overlay	VicPlan (Bushfire overlay)	VL: Not Traversed, L: Area >0-15 ha, M: Area >15-30 ha, H: Area >30-45 ha, VH: Area >45 ha
	Technical complexity	Reactive power compensation	Supplied by AEMO	VL: none L: PFC in 1-2 locations M: PFC > 2 locations H: Series compensation VH: > 4 locations, complex control schemes
	Constructability	Construction complexity; available space.	Non-GIS criteria (provided impact footprint of alignments)	VL: >220 ha, L: >196 - 220 ha, M: >173 - 196 ha, H: >150 - 173 ha, VH: <150 ha

Table 18 Multi criteria analysis scores

Grouping	Evaluation criteria	Option 1 (and Option 2)	Option 1A	Option 3	Option 3A	Option 4	Option 5
Net economic benefit	NPV of net benefit ($M)	3	3	3	2	5	2
Environment	Area within protected areas (Ramsar wetlands, National Parks and State Parks)	5	5	5	5	5	2
	Area of native vegetation intersected	4	4	4	4	5	1
	Area of highly significant native vegetation (EPBC listed threatened ecological communities and state endangered ecological vegetation classes)	4	4	4	4	5	2
	Area of critical habitat intersected (critical habitat for threatened or migratory species listed under EPBC	4	4	4	4	5	1

Grouping	Evaluation criteria	Option 1 (and Option 2)	Option 1A	Option 3	Option 3A	Option 4	Option 5
	Act (Cth) and FFG Act (Vic))						
	Number of waterways intersected	2	2	2	2	5	1
Cultural heritage	Area of non-Aboriginal heritage items or conservation areas listed under Commonwealth and State heritage registers intersected	2	2	2	2	2	2
	Area of potential Aboriginal cultural heritage significance intersected (areas of cultural heritage sensitivity)	4	4	3	3	5	2
	Native title	1	1	1	1	2	2
Social	Area within residential zones as a proxy for amenity impacts (noise, dust, visual)	3	3	3	3	3	1
	Number of buildings within 300 metres of the centre of the alignment	4	4	5	5	3	3
	Area within significant landscape overlay	5	5	5	5	5	1
	Number of land parcels affected	4	4	4	4	5	3
Land use	Number of land parcels by sectors where smallest portion is >20%	3	3	5	5	5	2
	Areas of land with agricultural potential score of >6	5	5	4	4	1	1
	Area of forestry tenure land intersected	1	1	1	1	1	1
	Area of resource tenure land (production and	1	1	1	1	1	1

Grouping	Evaluation criteria	Option 1 (and Option 2)	Option 1A	Option 3	Option 3A	Option 4	Option 5
	exploration) intersected						
Engineering	Number of arterial roads intersected	4	4	4	4	5	3
	Number of transmission lines intersected	5	5	5	5	4	2
	Number of railways intersected	3	3	3	3	3	2
	Number of pipelines intersected	4	4	5	5	3	1
	Topography slope > 1:5	5	5	5	5	5	1
	Area within land subject to inundation	3	3	3	3	5	4
	Area within bushfire overlay	5	5	5	5	5	1
	Reactive power compensation	2	2	2	2	2	5
	Construction complexity; available space.	2	2	1	1	4	1