Transgrid

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Appendix 3a: Net market benefits assessment - Transgrid

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Net Market Benefit Assessment

Project EnergyConnect

Region: Southern New South Wales

Executive Summary

The original Net Market Benefits Assessment (**NMBA**) for Project EnergyConnect (**PEC**) was approved by the AER in 2020 as part of the Regulatory Investment Test for Transmission (**RIT-T**). ElectraNet conducted an updated NMBA in 2020 as part of the Material Change in Circumstances (**MCC**) assessment that confirmed the option identified in the RIT-T remained the preferred option. This report provides an updated NMBA to assess the relative costs and benefits of eight options Transgrid identified to rectify the failure of the Engineering, Procurement and Construction (**EPC**) contract to deliver PEC.

The analysis presented in this document reflects analysis undertaken during the September to December 2024 period and is the 'Stage 3 analysis' referred to in the *Project Energy Connect Options Report*, dated 31 October 2024 and presented to the Transgrid Board on 7 November 2024.

As noted in the October 2024 board paper, net market benefit amounts for the options considered were refined as part of NMBA Stage 3. This report presents these updated final values. Notably, the relative rankings of the eight options have not changed since Stage 2 of the NMBA was presented in October 2024.

PEC is a critical transmission project that will support Australia's energy transition

PEC is a major Integrated System Plan (**ISP**) project that will connect New South Wales, South Australia and Victoria. The importance of PEC within the National Electricity Market (**NEM**) is evidenced by its inclusion in the Australian Energy Market Operator's (**AEMO**) first ISP in 2018 and its continuing status as a committed ISP project on the Optimal Development Path (**ODP**). PEC will enable significant renewable generation in NSW, SA and Victoria and contribute to meeting federal and state emissions and renewable generation targets. Without PEC, significant changes to AEMO's ODP would be required. This would cause significant delays to the energy transition and put federal and state government emissions and renewable generation targets at risk.

A failed contract required Transgrid to consider pathways for PEC

On 25 October 2023, Transgrid's Board recognised and accepted that the construction of PEC would not be completed by the competitively procured contractor, Secure Energy Joint Venture (**SEJV**), under the existing EPC contract and, if the project were to proceed, an alternative arrangement to delivery under the EPC Contract would be necessary. Transgrid refers to this event as Contract Failure.

Given the importance of PEC to the NEM, Transgrid needed to identify how best to proceed after taking interim measures consistent with a 'least regrets' approach. Transgrid undertook a detailed NMBA of the available options for the Project to identify the option that would deliver the highest net market benefit and therefore be in the best interests of consumers. The eight options are listed below:

- Option 1 Mutually agreed 'friendly' descope
- Option 2 Imposed 'unfriendly' descope
- Option 3 Contract termination
- Option 4 New contract with revised fixed price
- Option 5 Status quo
- Option 6 Project abandonment
- Option 7 Alliance models

- Option 8 Enforcing the existing EPC contract.

This updated NMBA identified Option 4 (a new contract with Elecnor with a revised fixed price) as the option which delivers the highest net market benefit.

The assessment has been undertaken on a forward-looking basis

The assessment of the eight options has adopted a methodology consistent with the AER's RIT-T[1] and Cost Benefit Analysis (**CBA**)[2] Guidelines for actionable ISP projects. Given that PEC is under construction, the NMBA adopts a forward-looking approach to evaluate the net market benefit of completing the project, referred to in this report as a 'forward-looking approach' or 'incremental assessment.'

This forward-looking approach focuses on the future expenditure and market benefits of each rectification option. However, it excludes non-recoverable costs (i.e., 'sunk costs') that have already been incurred, and any benefits that are already expected to arise associated with those sunk costs. Costs already incurred and benefits already realised are the same across all rectification options and therefore should not affect decision making regarding the future direction of PEC. The same forward-looking approach was adopted by Transgrid in the assessment underpinning the HumeLink Material Change in Circumstance Assessment (**MCC**) and accepted by the AER.[3]

The base case is 'project abandonment'

In order to perform a NMBA, it is necessary to identify a 'base case' against which other options are compared. Rectification options with a positive net market benefit represent good value to consumers and are therefore preferred to the base case. Similarly, options with negative net market benefits do not represent good value to the consumer and are considered to be a worse course of action compared to the base case. The AER's CBA Guidelines require the base case to be the option where economically prudent 'business as usual' (**BAU**) activities continue, rather than implementation of a project solution.[4] This assessment therefore identifies Option 6 (project abandonment) as the base case for the NMBA.

Market benefits and project costs have been updated since the Stage 2 Report

The total capital cost estimate for PEC has increased from the $2,662 million allowance approved in the CPA decision, to between $4,611 million and $5,379 million depending on the option.[5] Of this amount, $2,225 million has been spent as of 30 June 2024 across the NSW and SA components of the project (sunk costs, see section 2.2.1).

Completing PEC under a new contract with Elecnor provides the greatest net market benefit

The NMBA identifies Option 4 (new contract with Elecnor with revised fixed price) as the option which delivers the greatest net market benefits across all ISP scenarios and on a weighted basis. Option 4 delivers $2,389 million (PV 2022/23 dollars) of positive net market benefits to the NEM when assessed on a forward-looking

[1] AER, *Regulatory investment test for transmission,* November 2024
[2] AER, *Cost benefit analysis guidelines*, November 2024
[3] AER, Determination Transgrid's HumeLink Stage 2 Delivery Contingent Project Application, 2 August 2024, p. 18-19.
[4] AER, *Cost benefit analysis guidelines*, November 2024, p 64.
[5] An escalation factor of 1.17 has been used to convert the allowance of $2,275 million from 2017/18 to 2022/23 dollars.

basis. Table 1 below shows a summary of the forward-looking net benefits of each option compared to the base case (Option 6).

Table 1: PEC rectification option net market benefits (weighted basis)[6]

#	Option	Forward-looking gross benefits ($m, PV 2022/23)	Forward-looking net benefits ($m, PV 2022/23)	Ranking
1	Mutually agreed 'friendly' descope	3,386	2,199	2
2	Imposed 'unfriendly' descope	3,146	1,720	6
3	Contract termination	3,146	1,839	3
4	New contract with revised fixed price	3,386	2,389	1
5	Status quo	3,146	1,839	3
7	Alliance models	3,146	1,675	7
8	Enforcement of EPC contract	3,146	1,839	3

Once the forward-looking NMBA identified the preferred option, Transgrid also undertook an NMBA at the total project level for completeness. This total assessment considers all (future and sunk) costs and market benefits for each option, rather than just future costs and market benefits.

The purpose of the total project assessment is to identify whether Option 4 would have been preferred from the commencement of the PEC project (2019). For this assessment, the base case against which Option 4 is assessed is the option of PEC never existing. The total NMBA finds that Option 4 delivers gross market benefits on a weighted basis of $4,201 million and net market benefits of $964 million (PV 2022/23 dollars). This outcome demonstrates that from a total project perspective, PEC is still in consumers' best interests.

[6] These benefits are the weighted across the ISP's Progressive Change, Step Change, and Green Energy Export scenarios

Contents

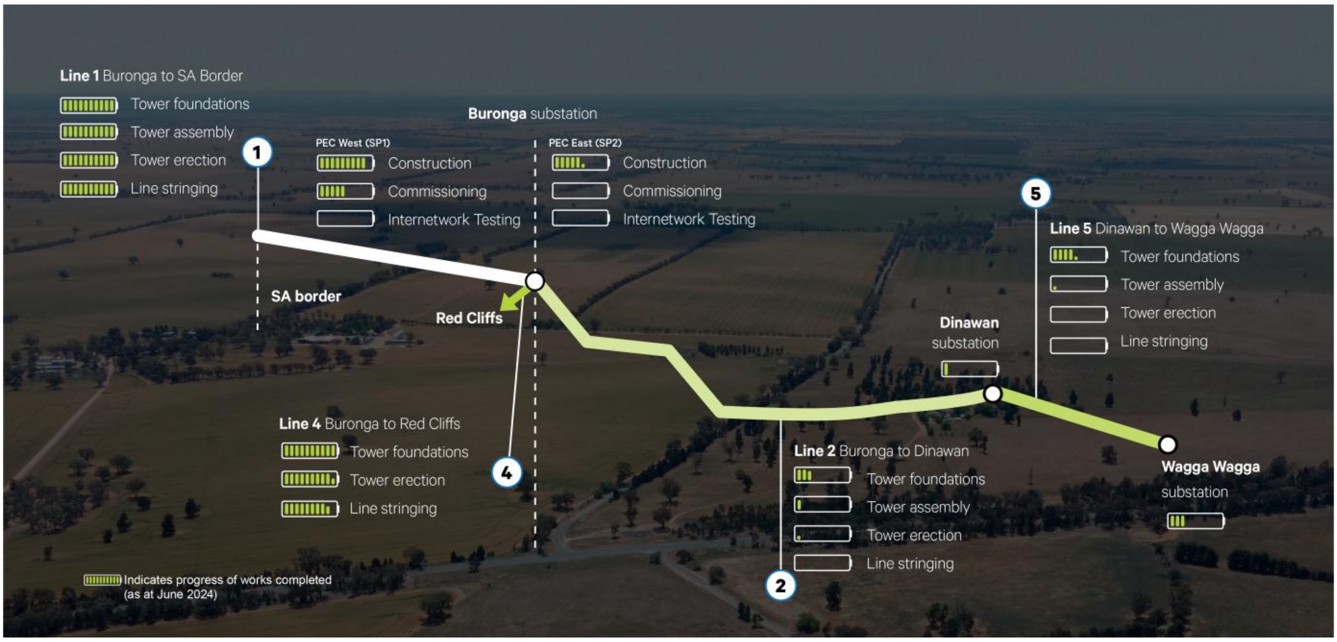
1. Context and purpose of this report

Project EnergyConnect (**PEC**) is a major Integrated System Plan (**ISP**) project that connects New South Wales, South Australia and Victoria. It involves the construction of a new 330 kV interconnector between Robertstown in mid-north South Australia and Wagga Wagga in New South Wales, via Buronga, with a further augmentation between Buronga and Red Cliffs. The 200km South Australia portion of PEC is the responsibility of ElectraNet and was completed in December 2023 and energised late 2024. The 700km New South Wales portion of PEC is the responsibility of Transgrid and is currently under construction, with construction completion estimated in September 2026.

The majority of the interconnector will be built and operated at 330 kV, while 160 km of the line (designated as 'Line 5' between the Dinawan Substation and Wagga Wagga) will be built to a 550 kV specification and initially operated at 330 kV.[7] This 160 km section of PEC will also form a part of the Victoria-New South Wales Interconnector West (**VNI West**) ISP project, with these shared works currently being progressed under the PEC project.

PEC is a critical piece of transmission infrastructure within the National Electricity Market (**NEM**) and forms an integral part of AEMO's Optimal Development Path (**ODP**),[8] both on its own and in combination with other actionable ISP projects. From Wagga Wagga, PEC connects into HumeLink, then continues towards Wollongong and Sydney. In South Australia, PEC connects to the Mid North South Australia REZ Expansion project and strengthens system security for South Australia.

Figure 1: NSW sections of PEC



The occurrence of the contract failure on 25 October 2023 necessitated an assessment of options on how to proceed with PEC. The October 2024 board paper provided the board with an overview of the Stage 2 NMBA, being a preliminary update of the market modelling based on the cost estimates set out in the October 2024 board paper. The board paper also notes that net market benefit amounts for the options considered were to

[7] AEMO, *VNI West Project Assessment Conclusions Report Volume 1: Identifying the preferred option for VNI West*, May 2023, p 114-115.
[8] AEMO, *2024 ISP*, June 2024.

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be refined as part of NMBA Stage 3. This report presents these final values. All dollar values presented within this report are real June 2022/23 dollars unless stated otherwise.

1.1. PEC is a critical component in the energy transition

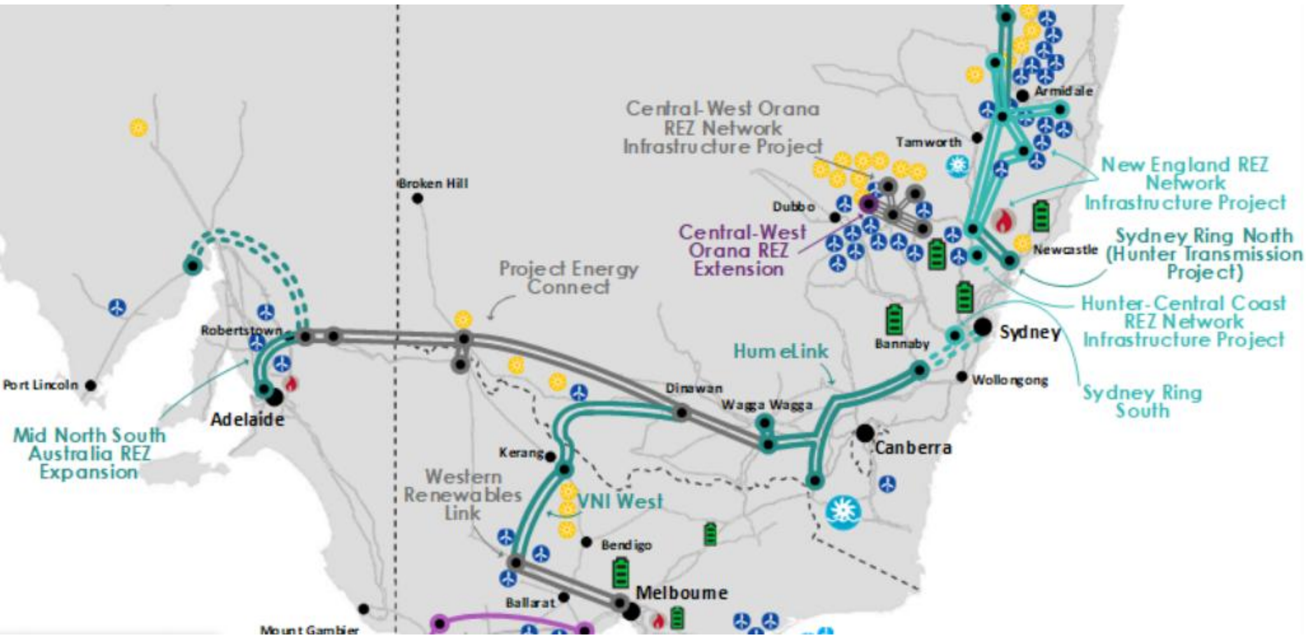
Once completed, PEC will provide 800 MW of additional transfer capacity between New South Wales and South Australia that can lower dispatch costs, increase access to supply options including to high quality renewable resources, enable emissions reductions targets, and enhance the critical security of electricity supply in South Australia.[9]

As part of AEMO's ODP, PEC forms part of the base case for other committed, actionable or anticipated ISP projects including:

- the Mid North South Australia REZ expansion,
- VNI West and the Western Renewables Link, and
- HumeLink.

The linkages between PEC and other ISP projects and renewable energy resources are illustrated in Figure 2.

Figure 2: Project EnergyConnect and its position within AEMO's ODP[10]



Given the importance of PEC to AEMO's ODP, the project forms an integral part of Federal and state government emissions reductions and renewable generation targets. These targets depend on PEC and other ISP projects to deliver emissions reductions by enabling connections to renewable generation resources and providing transfer capacity to transport energy across the NEM to meet demand. The absence of PEC would be a significant disruption to the assumptions that underpin AEMO's ODP. Reassessing the

[9] AEMO, *2020 ISP*, July 2020, p 86.
[10] AEMO, *2024 ISP*, June 2024, p 58.

ODP to account for the absence of PEC would cause material delays to the energy transition and put the achievement of emissions reductions targets at risk.

1.2. There has been a significant increase in the forecast cost to complete PEC

The AER approved a capital expenditure allowance of $2,275 million (2017/18 dollars)[11] for PEC (NSW and SA components) in May 2021.[12] The Contingent Project Application (**CPA**) was preceded by ElectraNet's Material Change in Circumstance (**MCC**) assessment (completed in September 2020) which confirmed that at this capital cost the preferred option from the PEC earlier RIT-T (i.e., Option 3.C) remained the preferred option and continued to provide positive net market benefits.[13]

The AER's CPA determination enabled Transgrid to enter an Engineering, Procurement and Construction (**EPC**) contract with SecureEnergy (**SEJV**), a joint venture between Elecnor Australia and Clough, to construct and deliver the NSW portion of PEC. Clough entered into voluntary administration in December 2022. Elecnor Australia committed to delivering PEC and assumed Clough's responsibilities under the EPC contract. On 25 October 2023, the EPC contract between Transgrid and Elecnor failed such that PEC could not be delivered under the terms of the EPC contract. A full account of the circumstances leading up to the event can be found in the PEC Reopener Application.

Given the importance of PEC to the NEM, Transgrid needed to identify how best to rectify the adverse consequences of the contract failure, after taking interim measures consistent with a 'least regrets' approach. Transgrid undertook a detailed NMBA of the available options for the Project to identify the option that would deliver the highest net benefit and be in the best interests of consumers. These eight options are:

- Option 1 Mutually agreed 'friendly' descope
- Option 2 Imposed 'unfriendly' descope
- Option 3 Contract termination
- Option 4 New contract with revised fixed price
- Option 5 Status quo
- Option 6 Project abandonment
- Option 7 Alliance models
- Option 8 Enforcing the existing EPC contract.

These options reflect different approaches to rectifying the adverse consequences of the contract failure, including approaches that contemplate abandoning the project, delaying the project, or entering new arrangements to facilitate the construction and delivery of the remaining works. Each option has differences with respect to their costs, risks, and timeframes for commissioning.

The updated NMBA presented within this report identifies which of the options is the best way to rectify the adverse consequences of the event by identifying the option with the greatest net market benefits.

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[11] Equivalent to $2,662 million in 2022/23 dollars.
[12] The AER approved $457 million for ElectraNet and $1,818 million for Transgrid. See [*AER, Final decision: Transgrid and ElectraNet - Project EnergyConnect contingent project*, 21 May 2021.]
[13] ElectraNet, *Project EnergyConnect Updated Cost Benefit Analysis*, September 2020, p 4.

1.3. PEC is partially completed

PEC is being delivered as two Separable Portions. Elecnor's scope of work for Separable Portion 1 (**SP1**) is:

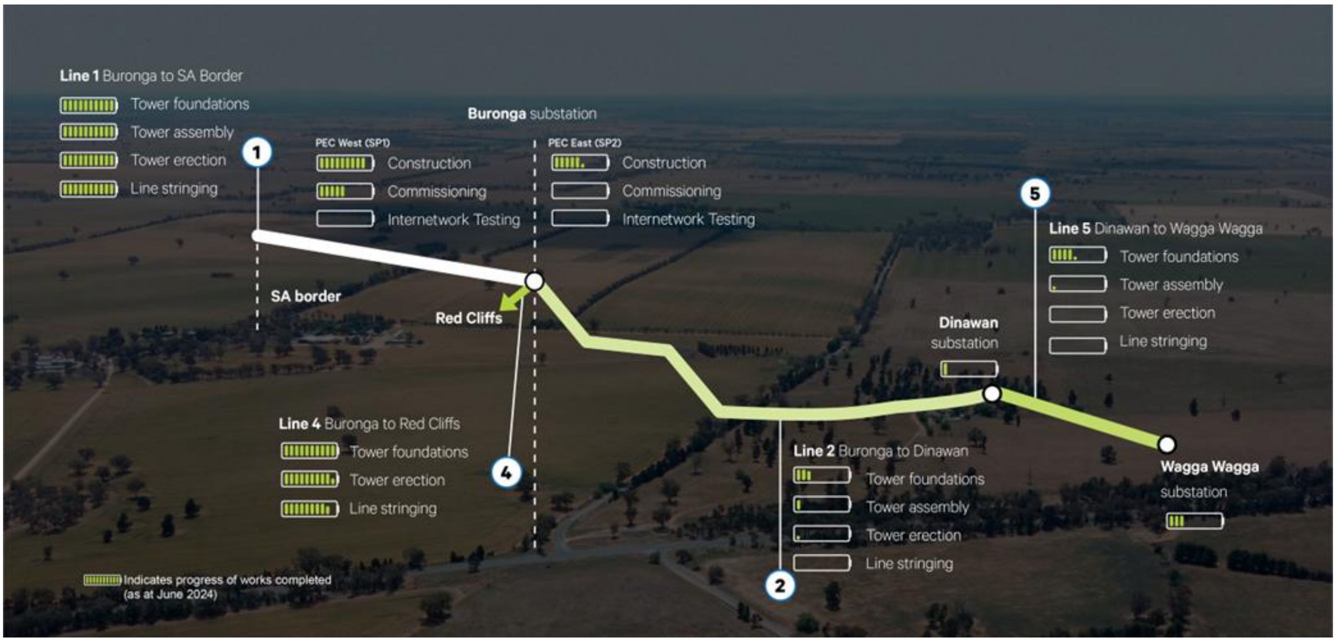
- Line 1 – Construction and all associated works to permit Tests for Energisation of 135km of 330kV transmission line, including 291 transmission towers from the border of South Australia to Buronga Substation.
- Line 4 – Construction and all associated works to permit Tests for Energisation of 24km of 220kV transmission line, including 79 poles from Buronga substation to Red Cliffs substation in Victoria.
- Substation 1a – Construction and all associated works to permit Tests for Energisation on the initial works at the Buronga substation, including one Synchronous Condenser to support 150MW capacity release between NSW and South Australia.

Elecnor's scope of work for Separable Portion 2 (**SP2**) is:

- Line 2 – Construction and all associated works to permit Tests for Energisation of 376km of 330kV transmission line, including 800 transmission towers from the Buronga substation to Dinawan substation.
- Line 5 – Construction and all associated works to permit Tests for Energisation of 157km of 330kV transmission line, including 334 transmission towers from Buronga Substation to Dinawan substation.
- Substation 1b – Construction and all associated works to permit Tests for Energisation on the remaining works at the Buronga substation, including the second Synchronous Condenser.
- Substation 2 – Construction and all associated works to permit Tests for Energisation for all works at the new Dinawan substation, including two Synchronous Condensers.
- Substation 3 - Augmentation and all associated works to permit Tests for Energisation of Wagga Wagga 330 kV Substation for the new Line 5 entry bays and all necessary connections.

Energisation tests will be undertaken by Transgrid, prior to internetwork testing by AEMO (supported by Transgrid). Figure 3 below presents the construction progress of PEC across each SP as at 30 June 2024.

Figure 3: Construction progress of PEC as at June 2024



2. Approach to the net market benefit assessment

This section sets out Transgrid's net market benefit assessment of the options identified to rectify the failure of the EPC contract to deliver PEC. This assessment has adopted a methodology consistent with the AER's RIT-T and Cost Benefit Analysis (**CBA**) Guidelines for actionable ISP projects. It also incorporates updated assumptions on wholesale market inputs, and updated capital expenditure estimates for rectification options. This includes:

- updated wholesale market modelling that reflects assumptions in the 2023 Inputs, Assumptions and Scenarios Report (IASR)[14] and the 2024 ISP (published in June 2024)[15]; and
- estimates of the capital expenditure and cashflows required to complete PEC as of October 2024. These estimates incorporate potential sources of external funding from bonds, legal settlements, and parent company guarantees.

2.1. Options assessed

Transgrid identified eight options for responding to the contract failure and rectifying the adverse consequences of the event. The primary adverse consequence of the event is a failure to complete SP2 of PEC. Adverse impacts on (among other things) reliability and security of the network in NSW and SA flow from the failure to complete SP2. All feasible options, including project abandonment, were considered throughout the process. In options that contemplate the delivery of PEC, Transgrid considered options to continue with Elecnor under various scenarios, as well as the appointment of a new contractor. The rectification options are set out in Table 2 below.

Table 2: Rectification options

#	Name	Description	Notes	Commissioning year[16]
1	Mutually agreed 'friendly' descope	Agreement with Elecnor to descope with transition assistance to Transgrid, tenderers and new contractor. This option was proposed by Elecnor in May 2024.	Elecnor's proposal for a 'friendly descope' was withdrawn in July 2024. Although no longer possible, this option has been included in the NMBA for completeness.	Lines: 2026/27 Substations: 2026/27 Lines and biodiversity offset: 2026/27
2	Imposed 'unfriendly' descope	Unilateral descope of Elecnor with no transition assistance to Transgrid, tenderers or a new contractor.	Without the assistance of Elecnor Australia, it would take significant additional time to procure a new contractor and require a long mobilisation before works could commence on site. Equipment, plant and project teams would be lost.	Lines: 2027/28 Substations: 2027/28 Lines and biodiversity offset: 2027/28

[14] AEMO '2023 Inputs, Assumptions and Scenarios Report', July 2023
[15] AEMO, *2024 ISP*, June 2024
[16] Electranet's lines, substation, biodiversity offset, land and easements assets are assumed to commission in 2024/25 in all options.

			This option assumes it would take 6-9 months to procure a new contractor and 3-6 months for the alternative contractor to familiarise itself with the project.	
3	Contract termination	Transgrid terminates the EPC Contract and appoints a new contractor, commences proceedings for breach, enforces its rights under the Elecnor SA parent company guarantee, and calls on Elecnor guarantees.	This option assumes a period of 18 months to negotiate a contract with a new contractor, engage subcontractors and mobilise construction. Litigation could take upwards of 7 years to resolve. This would not necessarily delay the completion of PEC but would delay financial settlement.	Lines: 2027/28 Substations: 2027/28 Lines and biodiversity offset: 2027/28
4	New contract with revised fixed price	Transgrid and SEJV enter into a new contract to complete the project, including a new fixed price.		Lines: 2026/27 Substations: 2026/27 Lines and biodiversity offset: 2026/27
5	Status quo	Transgrid and Elecnor Australia continue to provide additional emergency payments to complete PEC.	Not technically possible to deliver PEC under this option, as Elecnor indicated it would cease emergency payments. This option has been included for completeness.	Lines: 2027/28 Substations: 2027/28 Lines and biodiversity offset: 2027/28
6	Project abandonment	Transgrid and Elecnor to complete works on SP1, Dinawan line and substation works, remediate Line 2, and mothball all other works. Completed towers remain in situ.	This option was selected as the 'base case' for the NMBA.	Lines: N/A Substations: N/A Lines and biodiversity offset: 2027/28
7	Alliance models	Transgrid and either both or either of Elecnor and another tier 1 contractor enter an 'alliance contract' to complete PEC.	Establishing an alliance contract would take at least 12 months.	Lines: 2027/28 Substations: 2027/28 Lines and biodiversity offset: 2027/28
8	Enforcement of EPC contract	Transgrid ceases emergency payments and enforces the EPC contract.	This would entail the risks and costs of contract termination (option 3), and the timetable shift associated with an unfriendly descope (Option 2).	Lines: 2027/28 Substations: 2027/28 Lines and biodiversity offset: 2027/28

Each rectification option addresses the adverse consequences of the event, with differing approaches. These differences in approach impact both the costs for completion of PEC and the resulting timing for completion. In particular:

- Options 1 (friendly descope) and 4 (new contract) enable completion of PEC in 2026/27, in line with the timing in the 2024 ISP.
- Option 5 (status quo) envisages retaining Elecnor as the delivery partner but involves significant delay of more than 12 months to the completion of PEC due to the technical impossibility of delivering a project under a failed contract. Proceeding with this option would not be technically possible due to the outstanding contractual issues and Elecnor unwillingness to continue additional emergency payments.
- Options 2 (unfriendly descope), 3 (contract termination), 7 (alliance model) and 8 (enforce EPC contract) involve significant delay of more than 12 months to the completion of PEC.

The capital costs for each of the options are discussed in section 2.5.

2.2. Forward-looking assessment approach

As PEC is under construction, this assessment adopts a forward-looking approach to evaluate the net market benefit of completing the project. This forward-looking approach focuses on the future expenditure and market benefits of each option. It excludes non-recoverable costs ('sunk costs') that have already been incurred as well as any benefits associated with those sunk costs that are already expected to arise. Costs and benefits that have already been incurred are the same across all options and do not impact decision making on a forward-looking basis.

The same forward-looking approach was adopted by Transgrid in the assessment underpinning the HumeLink Material Change in Circumstance Assessment (**MCC**) and accepted by the AER.[17] This approach is widely accepted in economic analysis to inform decision making where costs have already been incurred.

2.2.1. Sunk costs and benefits

PEC has incurred $2,225 million in construction costs across SA and NSW for the 2018/19 to 2023/24 period.[18] From this amount, approximately $1,690 million was incurred for NSW and $535 million for SA. A breakdown of these sunk costs on a total (NSW and SA) and a NSW-only basis is set out in Table 3.

Table 3: Actual capital cost to 30 June 2024 ($m, 2022/23)

Item	Cost for NSW	Cost for SA	Cost for NSW and SA
Lines	1,049	340	1,389
Substations	369	134	503
Land	146	29	175
Biodiversity cost	126	32	158
Total	**1,690**	**535**	**2,225**

[17] AER, *Determination Transgrid's HumeLink Stage 2 Delivery Contingent Project Application*, 2 August 2024, p. 18-19.
[18] As at June 2024.

In estimating actual capital costs for the purposes of this assessment, Transgrid has adopted its own actual capital expenditure and spend profile for the financial years between 2018/19 to 2023/24, as well as an estimate of actual expenditure for ElectraNet based on the amount shown in the AER's CPA determination.[19]

As SP1 is materially complete (as at June 2024), SP1 will provide market benefits regardless of the status of SP2. The forward-looking assessment approach therefore does not incorporate approximately $814 million of market benefits associated with the delivery of SP1.

2.3. Selection of the base case

In order to perform a NMBA, it is necessary to identify a 'base case' against which options are compared against. Rectification options with a positive net market benefit represent good value to consumers and are therefore preferred to the base case. Similarly, options with a negative net market benefit do not represent good value to the consumer and are considered to be a worse course of action compared to the base case.

The AER's CBA Guidelines require the base case to be the option where economically prudent 'business as usual' (**BAU**) activities continue, rather than implementation of a project solution.[20] This assessment therefore treats Option 6 (project abandonment) where the completed PEC project is not implemented as the base case for the NMBA. Net market benefits for the other rectification options are presented relative to a project abandonment base case.

2.3.1. Assumptions in the base case

The base case option incurs unique 'abandonment costs' after 2023/24 that are not applicable to the other seven options where work to complete PEC continues. Transgrid's capital expenditure estimate for the base case include the estimated costs of contractor payments, demobilisation and making good. The cost of project abandonment ('abandonment costs') assumed in the base case Option 6 are $291 million. These abandonment costs include:

- **Penalties and legal costs:** payment of contractor and supplier penalties and 'make good' costs required to release Transgrid from its legal commitments and obligations.
- **Lessor costs:** final payments to Transgrid's lessors to end camp, storage, staging, and work sites.
- **Site works:** rehabilitation, clearing and demobilisation of camp, storage, staging, and work sites.
- **Staffing costs:** final payments to Transgrid and contractor staff working on PEC.
- **Social licence costs:** payments and expenditure associated with heightened social licence risk of project abandonment.

The cost estimate for the base case was developed based on actual costs and commitments made. Provision was also made for 'make good' works, however, given the limited level of data available, the estimation of 'make good' works are at a lower level of accuracy.

Abandonment costs assumed in the base case do not include the cost of removing completed construction works, other than work completed on L2. Work on L2 is more advanced and an allowanced of $57m was made for the removal of towers from L2.

[19] Specifically, Transgrid has estimated ElectraNet's actual capital expenditure based on the AER's CPA determination for EletraNet and applying an s-shaped spend profile that is common to large transmission projects.
[20] AER, *Cost benefit analysis guidelines*, November 2024, p 64.

2.4. Assumptions about related projects

For the purposes of the NMBA, it is assumed that VNI West will proceed regardless of whether PEC is completed. Therefore, the shared section between PEC and VNI West (Line 5 between Dinawan and Wagga Wagga) has been included in the options to reflect this assumption. Whilst the assumed cost of these works in the base case is $880 million, this cost varies slightly across the options due to the different timeframes and approaches taken under each option.

2.5. Updated capital costs estimates

The desktop net market benefits assessment conducted in Stage 1 of the NMBA was conducted on the basis of escalated costs from the 2019 PACR.

Transgrid has forecast the capital expenditure needed from 2024/25 to complete SP2. This forecast amount is additional to the $2,225 million in sunk construction costs that have already been incurred across SA and NSW for the 2018/19 to 2023/24 period.

Figure 4 shows the updated capital cost estimates for the options to continue with PEC, compared to the capital cost estimate in the CPA. The total project capital costs have increased by between 71 per cent (for Option 4) and 99 per cent (for Option 7).

Figure 4 Revised PEC capital expenditure cost estimates for each rectification option compared to the AER's CPA capital expenditure allowance

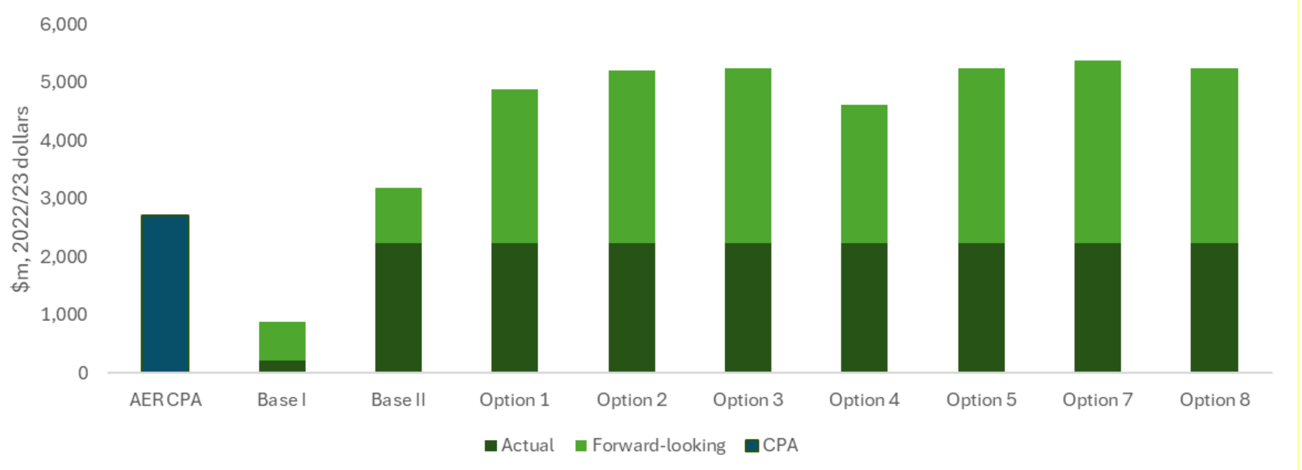


Table 4 presents the forward-looking capital expenditure required to rectify the adverse consequences of the event. The forward-looking capital expenditure estimates have been estimated by Transgrid, and are based on:

- Component costs informed by Transgrid’s internal database of transmission asset costs
- Spend profile for each component
- Adjustments for cost escalation
- Time costs based on the expected duration of each option
- Legal / contractual costs associated with each option, including reallocation of project risk

Table 4: Updated forward looking capital expenditure estimates ($m, 2022/23)

Item	1	2	3	4	5	6 (base case)	7	8
Lines	1,713	1,989	2,018	1,545	2,018	678	2,138	2,018
Substations	709	765	776	645	776	269	781	776
Land	93	95	97	79	97	6	98	97
Biodiversity cost	133	135	138	118	138	16	138	138
Total	**2,648**	**2,984**	**3,029**	**2,387**	**3,029**	**969**	**3,154**	**3,029**

2.5.1. Re-contracting costs

Re-contracting to complete PEC involves re-allocating various project risks such that they are allocated to the party that can most efficiently manage those risks, in order to deliver PEC at the most efficient cost possible given cost increases for labour, materials and equipment.

The estimated cost of recontracting was calculated using the total direct cost estimate from Elecnor and information provided to Transgrid from alternate contractors. A risk premium was also applied to reflect the deviation away from a more certain delivery path.

2.5.2. Cost to complete PEC

In each option, Transgrid allowed for direct costs, indirect costs, risk allowances and contingency, and external contributions (as relevant for each option). Direct and indirect costs are set out in Table 5 below. Risk allowances and contingency and external contributions are discussed in section 2.5.4.

Table 5: Direct and indirect costs

Cost category	Explanation / comment
Direct costs	Work packages: • L1 SA Boarder to Buronga (330kV) • L2 Buronga to Dinawan (330kV) • L4 Buronga to Red Cliffs (220kV) • L5 Dinawan to Wagga Expansion (500kV) • S1a Buronga Initial Works (330kV) • S1b Buronga Balance of Works (330kV) • S2 Dinawan (330 kV) • S3 Wagga Wagga (augmentation)
Indirect costs	• Camps, site facilities, laydown areas and the extensive storage yard at Deniliquin • Transgrid costs including project management and administration • Insurance and bank guarantees • Other resourcing costs

Transgrid estimated the forward-looking capital costs of the options to complete PEC using the Elecnor pricing and programme ICC submission as the foundations for the estimates. The Elecnor pricing and programme submission is a Class 1 estimate according to the Association for the Advancement of Cost Engineering (AACE) international cost estimate classification system.

The Elecnor pricing and programme is the most useful and accurate basis to determine the capital costs to complete PEC, as it is based on almost 100% design completion (98-99% complete), includes extensive subcontractor price coverage for the works, and well-developed pricing for procurement and manufacture of equipment and materials. The estimate also includes demonstrated productivity from Transmission Lines 1 and 4 and Substation at Buronga as well as travel allowances from camps to each worksite.

The cost to complete PEC under Option 4 is the price of the ICC contract. Adjustments to the ICC price were made to determine the cost of other options including:

- **Escalation due to delayed commissioning**: An adjustment factor of [redacted] per annum for each year of delay past 2027 was applied to all options except Options 4 and 6. The adjustments for escalation are consistent with indices commonly used in the industry.[21]
- **Cost of recontracting with an alternative contractor impact on existing subcontractors**: Allowances for recontracting with an alternative contractor and the impact upon the existing subcontractors have a lower range of accuracy, given the limited suitable data available for each scenario

2.5.3. Residual values

To ensure capital costs match the period for which wholesale market benefits are estimated, residual values for the remaining undepreciated asset value (i.e., capital expenditure less accumulated depreciation) are included the last year of the assessment for each option. These residual values ensure the remaining life of each option is recognised in the assessment in present value terms, so that the costs and benefits are measured over the same period. The approach also ensures capital costs reflect depreciation during the assessment period and the timing of capital expenditure spend profiles.

2.5.4. Risk allowances and contingency

The contingency for each Option was created using a similar approach to direct and indirect costs. That is, Option 4's risk profile acted as a foundation from which other options deviate from, given its robust development and strong understanding of contractor risk (which Transgrid does not own and is reflected in the revised contract price) and client risk (which Transgrid does own). Inherent risk was not considered given the accuracy of the scope of works.

Contingency for Option 4's client risk was built up through a quantitative risk assessment prepared by the Transgrid's PEC management team. This updated quantitative risk assessment excluded risks no longer relevant after October 2023 and focused on risks that could materialise going forward (e.g. risks tied to move towards an active client role and prolongation of the project itself). Options 3, 5, 6, and 8 have similar contingencies to Option 4, however they deviate slightly according to their work schedule. Options 1,2, and 7 further advance Option 4's client contingency to recognise risks associated with moving to an alternative contractor.

2.5.5. External funding contributions

Transgrid has considered external funding contributions arising from contractual arrangements (i.e. Clough bonds), expected legal settlements, and parent company guarantees that have the effect of offsetting some of the capital expenditure for each option.

[21] Based on a [redacted] annual increase in final demand, see [Producer Price Indexes, Australia, June Quarter 2024 | Australian Bureau of Statistics]

While best endeavours have been made to estimate the size of expected contributions from legal settlements and parent company guarantees, a degree of uncertainty concerning the size of these external contributions exist due to the uncertain nature of litigation. [redacted]

Table 6 sets out the estimated external funding contributions arising from contractual arrangements for each option and the expected timing of the realisation of the contributions.

Table 6: Estimates of external contributions for each rectification option and expected timing ($m, 2022/23)

External contributions	Expected timing[22]	1	2	3	4	5	6 (base case)	7	8
[redacted]									
[redacted]	[redacted]								
[redacted] surety and LDs	[redacted]				109	[redacted]			
[redacted]									
Total		[redacted]							

2.6. Operating expenditure assumptions have been updated

Annual operating expenditure for all eight rectification options is assumed to be 0.8 per cent of capex relating to lines and substations (i.e., excluding land and biodiversity offset costs). This assumption has been updated from the assumption that was adopted in the RIT-T, which was 0.5 per cent of capital expenditure, based on a bottom-up review of estimated operating expenditure.

2.7. Market benefits have been updated to reflect 2024 ISP assumptions

Market benefits from the development of PEC relate its impact on wholesale energy market capacity and dispatch outcomes. Market modelling at the time of the PACR in February 2019 (as well as ElectraNet's 2020 MCC assessment) highlighted material benefits to the wholesale market arising from:

- **avoided generation dispatch and fuel costs:** a reduction in the use of gas for generation dispatch in South Australia as soon as interconnection is established, due to the alleviation of South Australia system security constraints and increased options for sourcing relatively lower cost electricity from other regions;
- **avoided generation and storage investment costs:** a reduction in generator capital and fixed operating costs (particularly in South Australia), where the timing, mix of plant technologies and distribution of renewable build changes as a result of PEC;
- **avoided REZ transmission expansion costs:** incentivises build in a different distribution of REZs identified by AEMO in the ISP, avoiding the need for additional intra-regional transmission investment

[22] Expected timing of external contribution payment.

that would otherwise be required. This provides a benefit reflecting the difference in timing of unrelated transmission investment; and

- **avoided involuntary and voluntary load shedding:** a reduction in unserved energy (both involuntary and voluntary) is a benefit to electricity consumers.

Since the publication of the RIT-T PACR (February 2019) and ElectraNet's MCC assessment (September 2020), there have been significant developments in the NEM, including in response to new government policies. Transgrid therefore engaged EY to update the market modelling for this Stage 3 NMBA, to reflect AEMO's most recent assumptions as set out in the 2024 ISP.

In addition to the market benefits categories above, changes to the NER in February 2024 now mean that ***changes to greenhouse gas emissions*** are included as a benefit/disbenefit category in the RIT-T assessment.[23] For PEC, the key impact on greenhouse gas emissions arises from changes in the timing of emissions associated with changes in generation dispatch.

EY has modelled the market benefits and greenhouse gas emission changes associated with each of the options (which are distinguished in terms of the assumed commissioning date for PEC), as well as for the forward-looking base case[24] (which recognises that the South Australian portion of PEC is completed and is expected to provide market benefits). The modelling has been undertaken for each of the three scenarios in the 2024 ISP: Progressive Change, Step Change and Green Energy Exports. In undertaking this modelling, EY has drawn on:

- AEMO's 2024 ISP Inputs and Assumptions v6.0, published in July 2024;
- the latest information on generation commission timing, as published by AEMO in its NEM Generation Information from July 2024,[25] consistent with the ISP Methodology; as well as
- the timing for other ISP projects as set out in the 2024 ISP, published on 26 June 2024, or the earliest in-service date advised by the Project proponent when this is later than the modelled date in the 2024 ISP.

A detailed discussion of EY's wholesale market modelling is provided in the separate EY report accompanying this report. Key inputs and assumptions underpinning this report can be found in **Appendix A**.

There have been significant changes in the policy assumptions that underpin the analysis undertaken for the RIT-T and the assessment presented in this report. Emissions targets and renewable energy policies today are much more ambitious than those applied in the three scenarios adopted in the RIT-T. As shown below in Table 7, the targets for emissions reduction from 2005 levels within the PACR are as follows.

Table 7: 2030 emissions reduction targets considered within the PACR by scenario

Central	High	Low
28 per cent reduction from 2005 levels	52 per cent reduction from 2005 levels	No explicit target

In contrast, all three scenarios modelled for this assessment have much more stringent carbon budgets to 2030 and 2050 and have a target of at least a 43 per cent emissions reduction by 2030 and net zero by

[23] A decrease in cost of emissions is reflected as a benefit, which can result from lower emissions, or different timing of emissions, or both. An increase in emissions costs due to different timing of emissions or higher emissions is a disbenefit.

[24] Referred to as PEC Stage 1 within the accompanying EY report.

[25] NEM Generation Information from July 2024 was used as the wholesale market modelling by EY began prior to the most recent version of NEM Generation Information.

2050.[26] In terms of carbon abatement ambition, the slowest scenario modelled today is Progressive Change and the ambition is only moderately lower than in the 2019 PACR's most ambitious scenario.

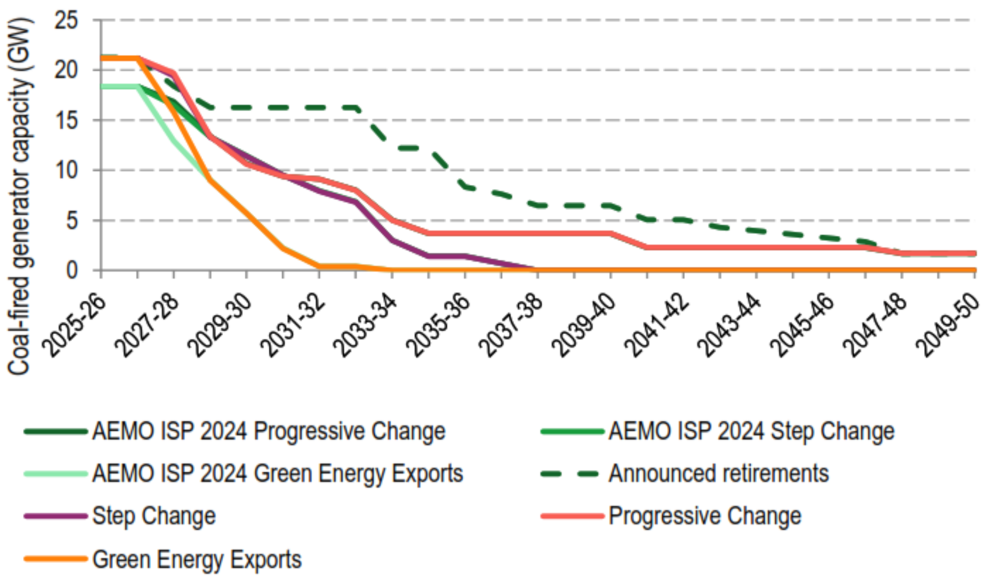
Renewable energy targets are more ambitious compared to those in place at the time of the RIT-T. Table 8 sets out policies that are assumed in all scenarios in the 2024 ISP (and therefore this assessment):[27]

Table 8: Jurisdictional renewable energy targets

Jurisdiction	Renewable energy target
Commonwealth	82 per cent by 2029/30
Queensland	**QRET:** 50 per cent by 2030, 70 per cent by 2032 and 80 per cent by 2035
Victoria	**VRET:** 75 to 80 per cent by 2035 and net zero by 2045 **Offshore Wind Target:** 2 GW by 2032, 4 GW by 2035, and 9 GW by 2040. **Storage Target:** 2.6 GW by 2030 and 6.3 GW by 2035
Tasmania	**TRET:** 150 per cent of 2020 generation levels by 2030, and 200 per cent by 2040
New South Wales	**EII Roadmap:** 12 GW of renewable generation, and at least 2 GW/16 GWh of long duration storage by 2030

The overall effect of these policies is to accelerate the exit of coal-fired generators from the NEM and accelerate the transition to renewable energy and storage. The solid green line in Figure 5 shows the 2024 ISP outcome. The red, orange, and purple lines show EY's modelled coal retirement schedule which is aligned with ISP 2024 (except for the retirement of Eraring). The dotted green line shows announced retirement dates as at the time of the publication of the 2024 ISP.

Figure 5 Assumed coal-fired generator capacity in the NEM across all ISP scenarios[28]



[26] AEMO, *2023 IASR*, July 2023, p 20.
[27] AEMO, *2024 ISP*, June 2024, p 31.
[28] More detail can be found within the accompanying EY report.

2.8. General NPV modelling parameters

The updated PEC assessment presented in this report adopts general NPV modelling parameters set out in Table 9 below.

Table 9: General NPV modelling parameters

General parameter	Forward-looking assessment
Assessment period	26 years
First year of assessment	2024/25
Market modelling period	25 years
Discount rate	7 per cent
Base year for inputs	2022/23 dollars

An assessment period of 26 years for the forward-looking assessment has been adopted to accommodate actual capital expenditures expected to be incurred from 2024/25.

A real, pre-tax discount rate of 7 per cent has been adopted for this analysis to align with AEMO's 2023 Inputs, Assumptions and Scenarios Consultation report.[29] For the purposes of this report, all figures are expressed in 2022/23 dollars, unless otherwise stated.

[29] AEMO '*2023 Inputs, Assumptions and Scenarios Report*', July 2023, p 123.

3. Forward-looking net present value results

This section presents the net present value (**NPV**) results for the assessment prepared on a forward-looking basis for each of the options considered. The NPV results include the outcomes under each ISP scenario and these outcomes on a weighted basis. Detailed market modelling outcomes are provided in the separate EY market modelling report. Key inputs and assumptions underpinning this report can be found in **Appendix A**.

The NPV results show that Option 4 is the highest-ranking option and is expected to deliver approximately $2,389 million (PV, 2022/23 dollars) in net market benefits on a weighted, forward-looking basis. Option 4 is estimated to provide 9 per cent more net market benefits than 'the second-ranked option (Option 1: friendly descope).

This outcome is robust to a range of sensitivities including different capex and discount rate assumptions, higher opex assumptions, and lower benefit assumptions. Amounts provided within section 3 are expressed in June 2022/23 present value terms, unless otherwise stated.

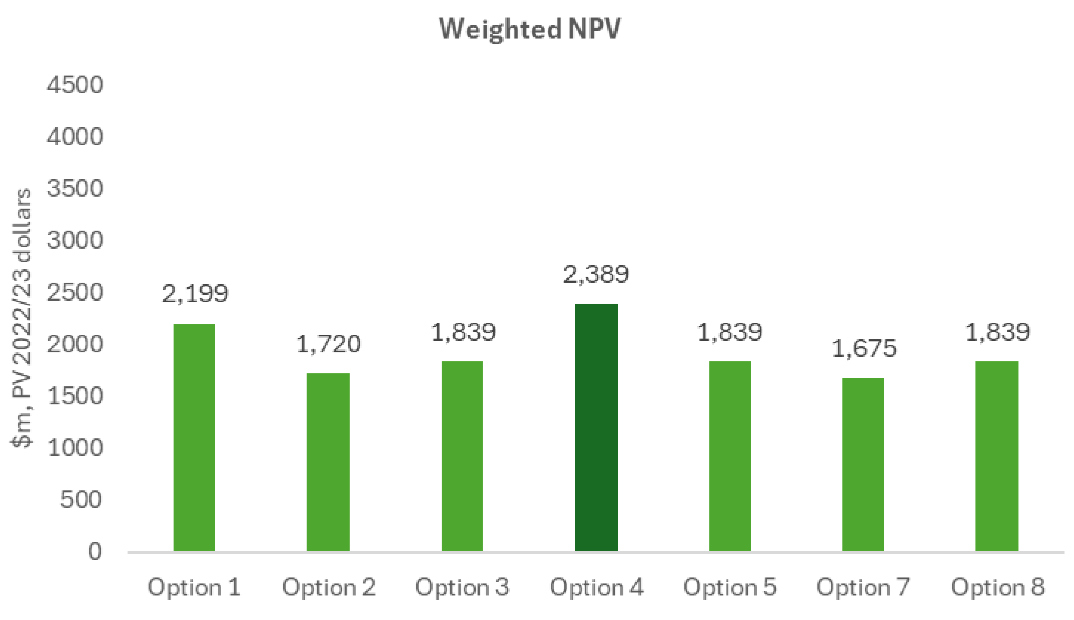
3.1. Weighted forward-looking net market benefits

The scenario weighting applied in this NMBA is as set out in the 2024 ISP:

- 43 per cent for the Step Change scenario
- 42 per cent for the Progressive Change scenario
- 15 per cent for the Green Energy Exports scenario.

On a weighted basis, Option 4 is the highest-ranked option and is expected to deliver approximately $2,389 million in net market benefits on a forward-looking basis, which is around 9 per cent greater than the net market benefits of the second-ranked option (Option 1). Figure 6 shows the estimated forward-looking net market benefits for each option under each ISP scenario and weighted across the three ISP scenarios.

Figure 6: Summary of the estimated forward-looking net market benefits, weighted across the three scenarios



Maintaining a 2026/27 commissioning date contributes to $241m of gross market benefits (on a weighted basis). This is a key contributing factor to the high net market benefits exhibited by Options 1 and 4, where this commissioning date is maintained. Discussion of the impact of delayed commissioning is set out in in section 2.

3.2. Step Change scenario

Table 10 Estimated forward-looking net market benefits for Step Change scenario[30]

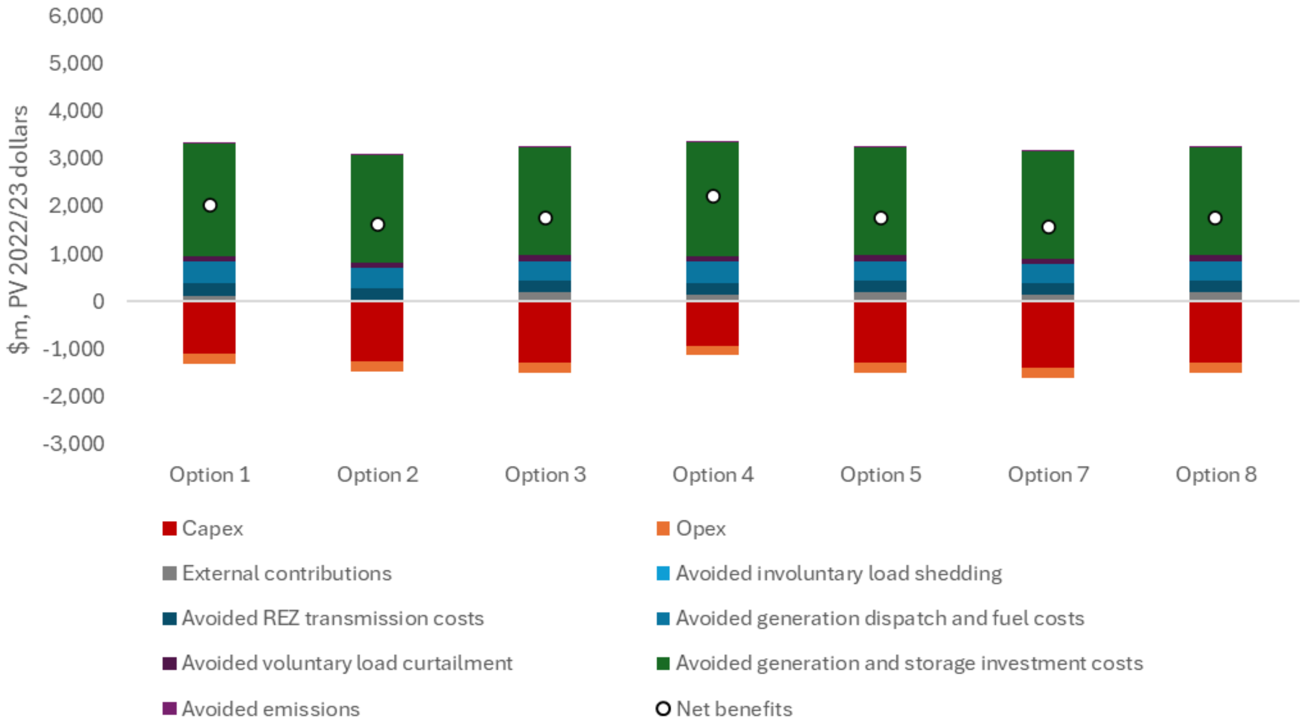
Option	Gross market benefits ($m, PV 2022/23)	Forward-looking costs ($m, PV 2022/23)	Forward-looking net market benefits ($m, PV 2022/23)
1	3,214	1,188	2,026
2	3,051	1,426	1,625
3	3,051	1,306	1,744
4	3,214	997	2,216
5	3,051	1,306	1,744
7	3,051	1,470	1,580
8	3,051	1,306	1,744

Under the Step Change scenario, Option 4 provides gross market benefits of $3,214 million, of which the largest market benefit category is avoided generation/storage investment costs that makes up approximately $2,375 million or 74 per cent of gross market benefits. The second largest benefit category is avoided fuel and dispatch costs, which makes up approximately $455 million or 14 per cent of gross market benefits. The remaining 12 per cent of benefits are shared between avoided REZ transmission costs and voluntary load curtailment.

Options that are commissioned in 2026/27 (Options 1 and 4) have $163 million higher gross market benefits under the Step Change scenario compared to options that are commissioned in 2027/28 (Options 2, 3, 5, 7 and 8). Figure 7 provides a breakdown of costs and benefits for each option under the Step Change scenario.

[30] Values may not foot due to rounding

Figure 7: Breakdown of forward-looking net market benefits for each rectification option under the Step Change scenario



3.3. Progressive Change scenario

Table 11: Estimated forward-looking net market benefits for Progressive Change scenario[31]

Option	Gross market benefits ($m, PV 2022/23)	Forward-looking costs ($m, PV 2022/23)	Forward-looking net market benefits ($m, PV 2022/23)
1	2,942	1,188	1,754
2	2,713	1,426	1,287
3	2,713	1,306	1,406
4	2,942	997	1,945
5	2,713	1,306	1,406
7	2,713	1,470	1,242
8	2,713	1,306	1,406

Under the Progressive Change scenario, Option 4 provides gross market benefits of $2,942 million. This is comprised of:

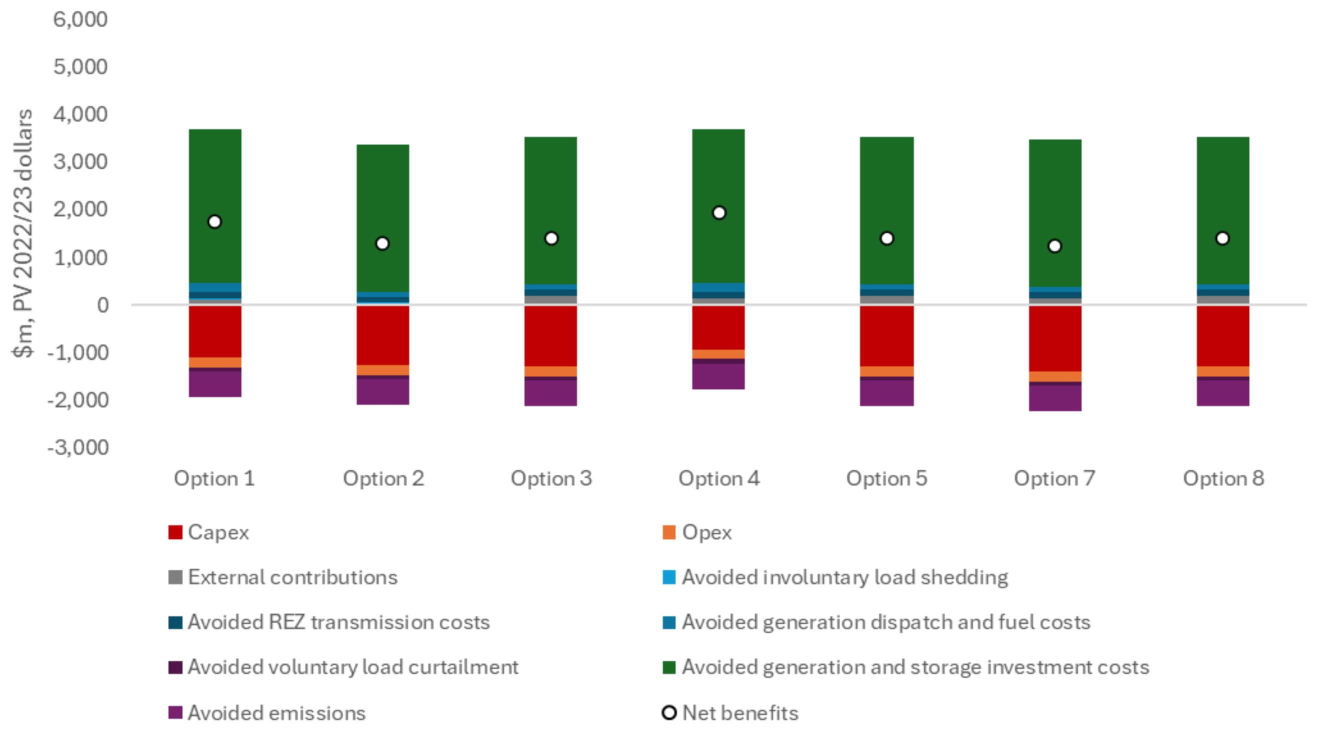
- positive market benefits of $3,576 million. The largest market benefit category is avoided generation/storage investment costs contributing $3,242 million to gross market benefits. The second largest benefit category is avoided fuel and dispatch costs, which contributes $175 million to gross market benefits; less

[31] Values may not foot due to rounding

- $634 million of market disbenefits. These market disbenefits are separate from capital and operating expenditure and offset positive market benefits. These market disbenefits relate to increased emissions ($541 million) and increased voluntary curtailment costs ($93 million) totalling $634 million when compared to the base case.

Options that are commissioned in 2026/27 (Options 1 and 4) have $229 million higher gross market benefits under the Progressive Change scenario compared to options that are commissioned in 2027/28 (Options 2, 3, 5, 7 and 8). Figure 8 provides a breakdown of costs and benefits for each option under the Progressive Change scenario.

Figure 8: Breakdown of forward-looking net market benefits for each rectification option under the Progressive Change scenario



3.4. Green Energy Exports scenario

Table 12: Estimated forward-looking net market benefits for Green Energy Exports scenario[32]

Option	Gross market benefits ($m, PV 2022/23)	Forward-looking costs ($m, PV 2022/23)	Forward-looking net market benefits ($m, PV 2022/23)
1	5,126	1,188	3,938
2	4,631	1,426	3,205
3	4,631	1,306	3,324
4	5,126	997	4,129
5	4,631	1,306	3,324
7	4,631	1,470	3,160

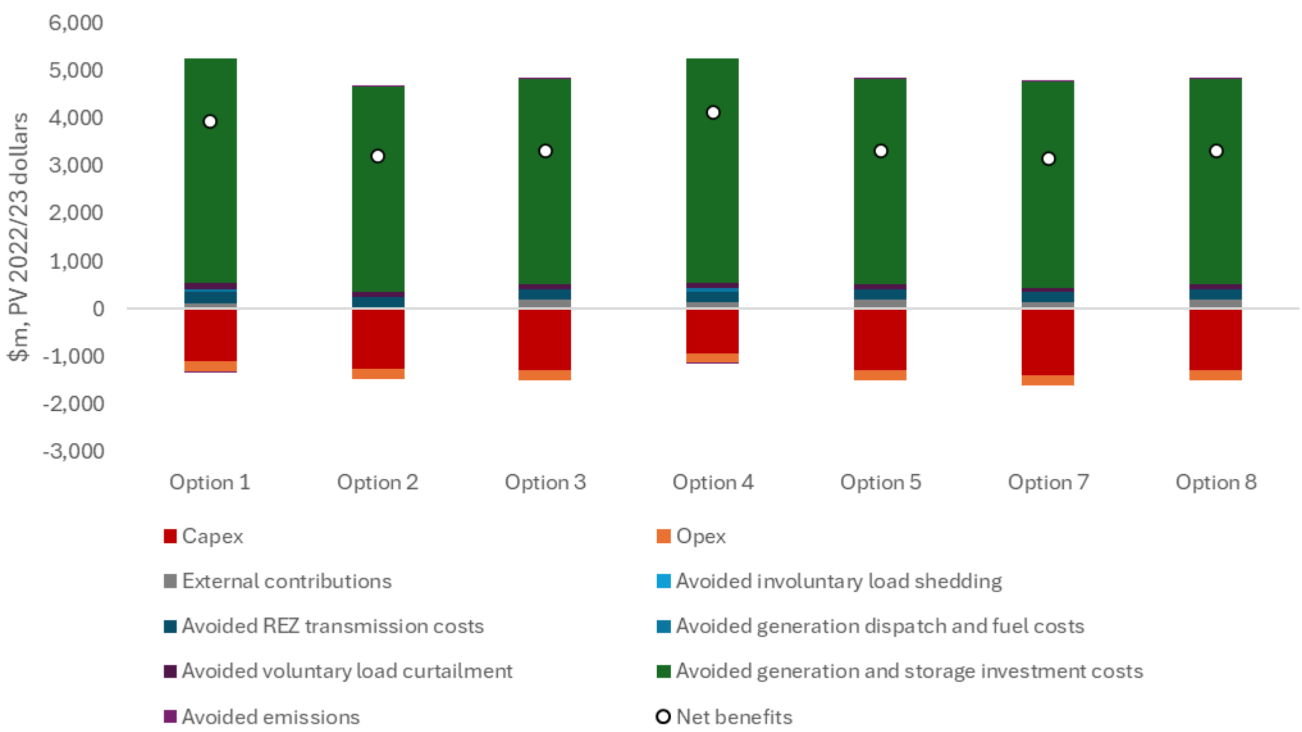
[32] Values may not foot due to rounding

8	4,631	1,306	3,324

Under the Green Energy Exports scenario, Option 4 provides gross market benefits of $5,126 million, of which the largest market benefit category is avoided generation/storage investment costs that makes up approximately $4,715 million or 92 per cent of gross market benefits. The second largest benefit category is avoided REZ transmission costs, which makes up approximately $229 million or 4 per cent of gross market benefits. The remaining 4 per cent of gross market benefits is shared between avoided fuel and dispatch costs, avoided fuel costs and voluntary load curtailment costs.

Options that are commissioned in 2026/27 (Options 1 and 4) have $496 million higher gross market benefits under the green energy export scenario compared to options that are commissioned in 2027/28 (Options 2, 3, 5, 7 and 8). Figure 9 provides a breakdown of costs and benefits for each option under the Green Energy Exports scenario.

Figure 9: Breakdown of forward-looking net market benefits for each rectification option under the Green Energy Export scenario



3.5. Sensitivity analysis

Five sensitivity tests have also been conducted to investigate the robustness of the results. These sensitivities adopt:

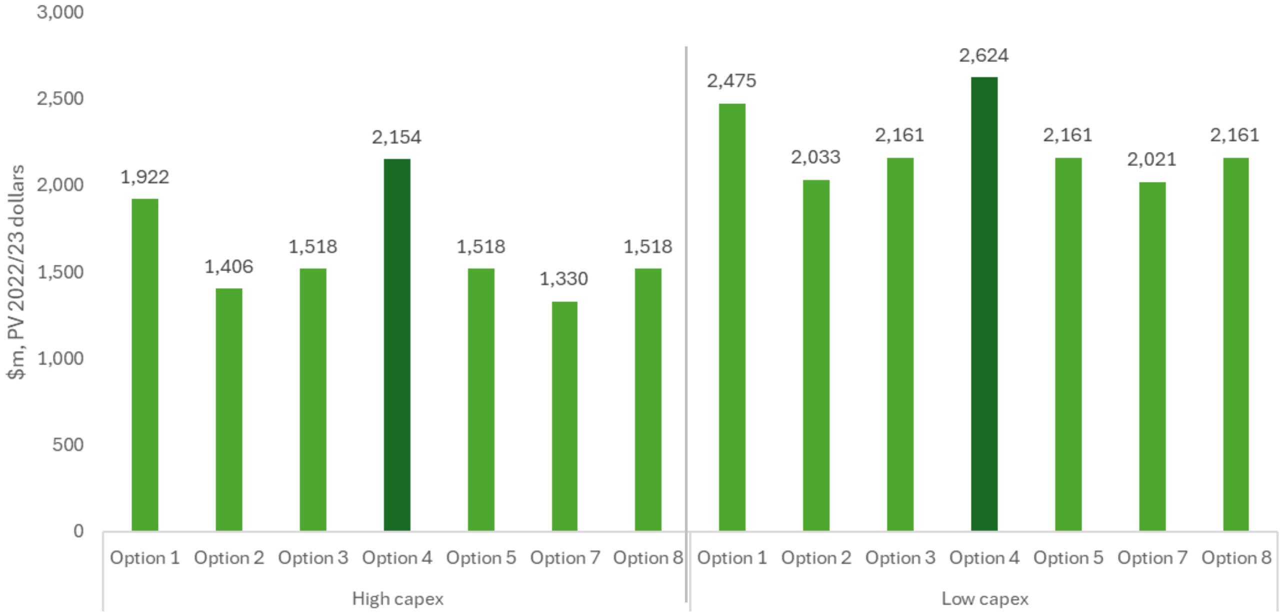
- higher and lower network capital costs (+/- 25 per cent);
- higher operating costs;
- lower gross market benefits;
- alternate commercial discount rate assumptions; and
- higher external contribution amounts for Option 3.

Each of the sensitivity tests are discussed below.

3.5.1. Higher and lower capital expenditure costs

The sensitivity of results to capital cost assumptions have been assessed by modelling the impact of a 25% higher and lower capital expenditure cost assumption for each option. The results of this sensitivity testing are shown in Figure 10.

Figure 10: Impact of 25 per cent higher and lower network capital costs, weighted outcome ($m, PV 2022/23)

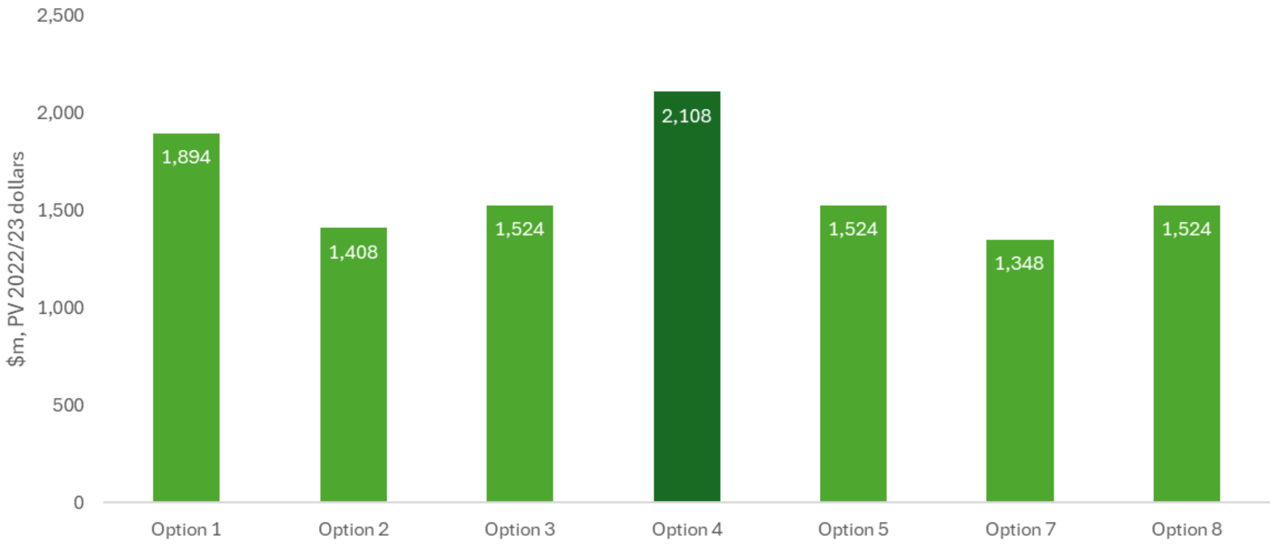


The sensitivity test demonstrated that Option 4 remains the top-ranked option if the capital cost assumptions are varied. If capital costs are assumed to be 25% lower, the net market benefits of Option 4 increase to $2,624 million. If capital costs are assumed to be 25% higher, Option 4 is found to have net market benefits of $2,154 million. Under both higher and lower capital expenditure cost scenarios, Option 4 remains the highest-ranked option.

3.5.2. Higher operating costs

This sensitivity assumes operating cost assumptions are increased to 2% of capital expenditure (from 0.8% assumed in the main assessment). The results of this sensitivity test are set out in Figure 11.

Figure 11: Impact of assuming operating cost of 2 per cent of capital costs, weighted outcome

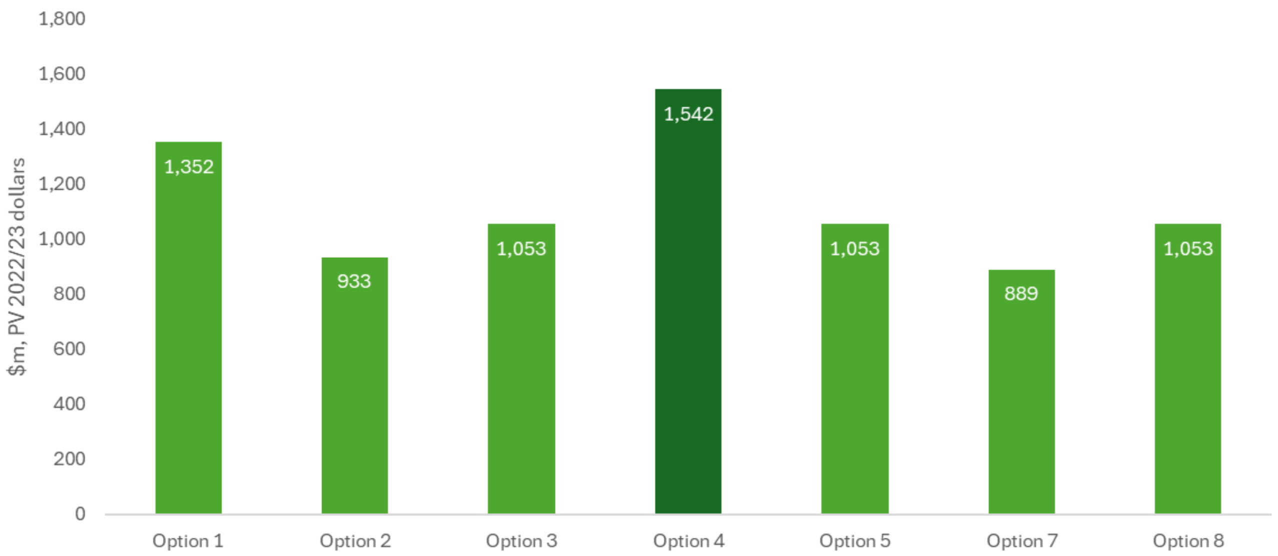


The higher operating costs sensitivity demonstrates that Option 4 remains the highest-ranked option. Under the assumption of operating cost of 2 per cent of capital cost, the net market benefits of Option 4 decrease to $2,108 million.

3.5.3. Lower gross market benefits

This assessment checks the sensitivity of the results to lower gross market benefits. This sensitivity explores the scenario in which EY's estimates of gross market benefits is overstated. The sensitivity assumes 25% lower gross market benefits on a weighted average basis. The results of this sensitivity are shown in Figure 12.

Figure 12: Impact of 25 per cent lower gross market benefits, weighted outcome

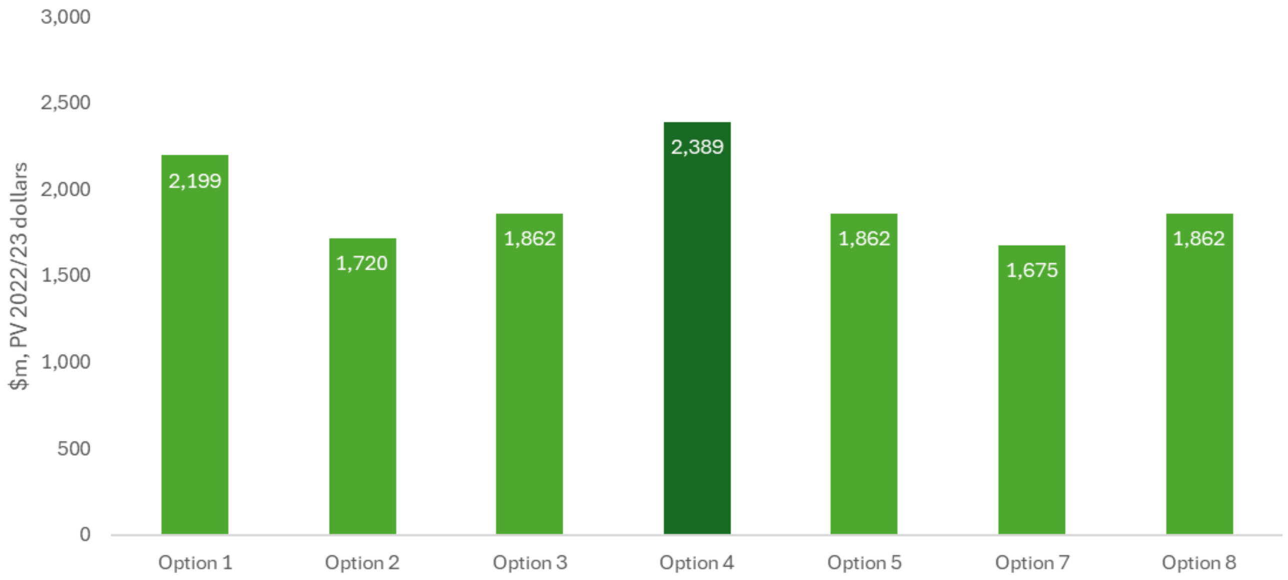


EY estimated $3,386 million in gross market benefits and costs[33] for Option 4 on a weighted basis. This sensitivity test shows that Option 4 remains the top-ranked option if the gross market benefit assumptions are decreased by 25 per cent. Under the sensitivity of 25 per cent lower gross market benefits, the net market benefits of Option 4 decrease to $1,542 million.

3.5.4. Higher and lower external contribution amounts for Option 3

The sensitivity of the results to higher or lower external contribution amounts for Option 3 have been tested. This sensitivity was assessed to account for uncertainty regarding these parameters of this option. Figure 13 shows the results of this sensitivity. A 25 per cent increase in external contributions for Option 3 equates to an increase of $22 million.

Figure 13: Impact of assuming higher external contributions for Option 3, weighted outcome



Option 4 remains the top-ranked option if external contributions for Option 3 are 25 per cent higher.

3.5.5. Alternate commercial discount rate assumptions

Figure 14 illustrates the sensitivity of the results to adopting different discount rate assumptions in the NPV assessment.

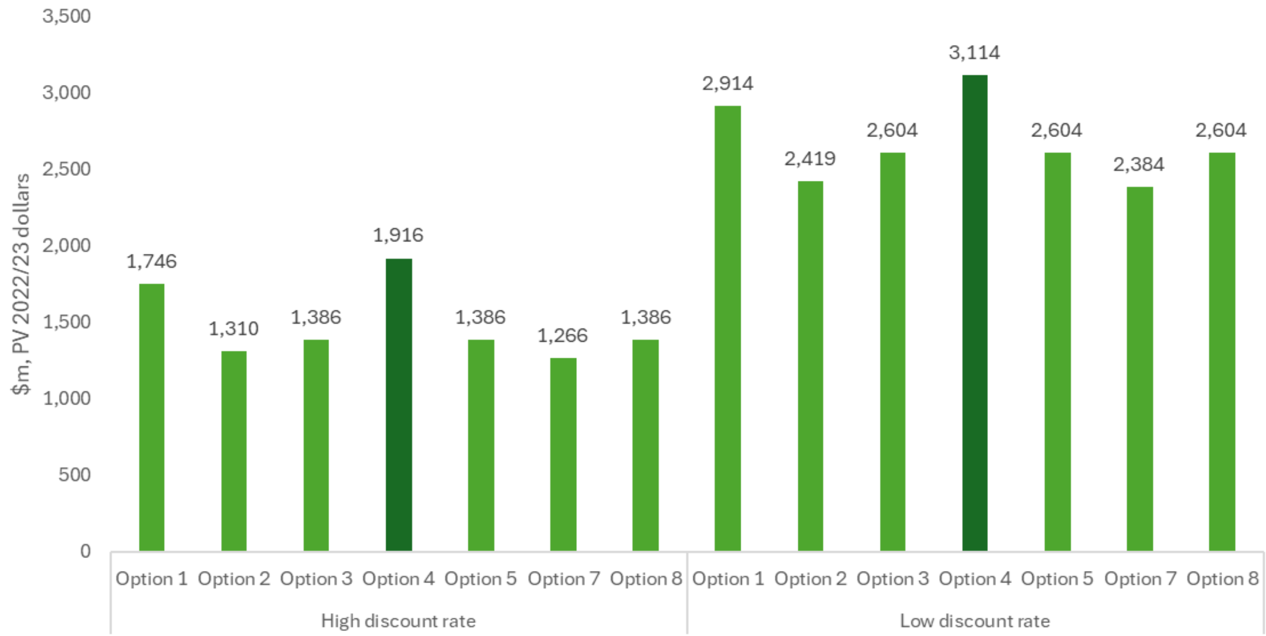
In particular, it illustrates the impact of adopting upper and lower bound discount rate assumptions 2023 IASR assumptions:

- high discount rate of 10.5 per cent;[34] and
- low discount rate of 3.63 per cent.[35]

Under both high and low discount rate, Option 4 is the top-ranked option and continues to deliver positive net market benefits.

[33] $3,386 million in gross market benefits and costs consists of $3,610 million of gross market benefits and $224 million of gross market costs relating to emissions.
[34] AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, p 123.
[35] AER, *Final decision TasNetworks Transmission 2024-29 PTRM*, April 2024.

Figure 14: Impact of higher and lower assumed discount rates, weighted outcome



3.6. Threshold testing capital costs of Option 4

In addition to the sensitivity testing set out in section 3.5 above, the robustness of the results to changes in the capital costs of Option 4 have been assessed. This 'threshold testing' assesses the increase that would need to occur in forward-looking capex for Option 4 to no longer be the preferred option. This threshold testing also assesses how much forward-looking capex for Option 4 would need to increase for Option 4 to demonstrate net costs (i.e. negative net market benefits). For the purposes of this threshold assessment, capex estimates for other options remain unchanged.

In undertaking the threshold analysis, forward looking capex for Option 4 would need to increase by:

- 10 per cent for Option 4 to no longer be the preferred option on a weighted basis, assuming capital costs for other options do not change; and
- at least 122 per cent for Option 4 to exhibit negative net market benefits.

The required increases in capital costs for Option 4 to no longer be the preferred option or no longer exhibit positive net market benefits is unlikely given that:

- forward looking cost increases would affect all options such that option rankings are likely to remain unchanged; and
- an increase in forward looking costs of over 100 per cent for Option 4 is considered improbable.

We therefore consider NPV results presented in this assessment to be robust to changes in capital costs.

3.7. Threshold testing of discount rates of Option 4

The robustness of results to changes in discount rates has been considered. This assessment considered the discount rates that would be required for Option 4 to no longer be the highest-ranked option. This threshold assessment demonstrated that discount rates would need to be over 70 per cent for Option 4 to no longer be the highest-ranked option. A discount rate of over 70 per cent is unrealistic. It follows NPV results presented in this assessment is robust to changes in discount rates.

4. Conclusion

The NMBA presented in this report finds that Option 4 provides the largest net market benefit on a forward-looking basis. Accordingly, Option 4 is the option that should be pursued to rectify the adverse consequences of the event.

Option 4 is the most cost-effective option to deliver PEC. It has forward looking capital expenditure of $2,387 million (2022/23 dollars) and delivers PEC by 2026/27. Weighted across the ISP scenarios, Option 4 is estimated to provide $2,389 million in net market benefits on a forward-looking basis. This result indicates that it is materially more beneficial for the NEM for PEC to be delivered and completed under Option 4 than for the project to be abandoned under the base case Option 6.

This result is found to be robust across the various assumptions investigated. It is also shown to continue to be the preferred option across a range of sensitivities (including those relating to the uncertainty of future settlement outcomes under rectification options involving litigation) and the threshold test for the increase in costs.

On the basis of the analysis set out in this Stage 3 NMBA, Transgrid concludes that Option 4 would deliver the highest net market benefits on a forward-looking basis, compared to other options deliver PEC.

Appendix A : Market benefits assessment – key parameters summary

Presented below is a summary of key assumptions that the market modelling exercise draws upon. A more detailed discussion of EY's wholesale market modelling is provided in the separate EY report accompanying this report.

Key drivers input parameters	Step Change	Progressive Change	Green Energy Exports
Underlying consumption	2023 Electricity Statement of Opportunities (ESOO)– Step Change	2023 ESOO – Progressive Change	2023 ESOO – Green Energy Exports
Committed and anticipated generation	Committed and anticipated generators from AEMO's Generation Information July 2024		
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PHES large-scale batteries and hydrogen turbines	2024 IASR Assumptions Workbook – Step Change	2024 IASR Assumptions Workbook – Progressive Change	2024 IASR Assumptions Workbook – Green Energy Exports
New entrant optional build earliest date	1 July 2025		
Retirements of coal-fired power stations	2024 ISP results workbook – Step Change ODP (CDP 14) In line with closure year outcomes, except Eraring which is assumed to retire on 19 August 2027 based on AEMO's Generation Information July 2024	2024 ISP results workbook – Progressive Change ODP (CDP 14) In line with closure year outcomes, except Eraring which is assumed to retire on 19 August 2027 based on AEMO's Generation Information July 2024	2024 ISP results workbook – Green Energy Exports ODP (CDP 14) In line with closure year outcomes, except Eraring which is assumed to retire on 19 August 2027 based on AEMO's Generation Information July 2024
Retirements of other thermal units	Generator retirement dates from AEMO's Generation Information July 2024		
Gas fuel price	2024 IASR Workbook – Step Change	2024 IASR Workbook – Progressive Change	2024 IASR Workbook – Green Energy Exports
Coal fuel price	2024 IASR Workbook – Step Change	2024 IASR Workbook – Progressive Change	2024 IASR Workbook – Green Energy Exports
NEM carbon budget to achieve Federal Government's 2030 emissions reduction target	Budget for 2025-26 to 2029-30 derived from assumptions in 2024 IASR workbook and 2024 ISP outcomes		
	528.1 Mt CO2-e	523.2 Mt CO2-e	540 Mt CO2-e
NEM carbon budget to achieve 2050 temperature-linked emissions levels	Budget for 2025-26 to 2049-50 derived from 2024 outcomes for each scenario		
	555 Mt CO2-e	786 Mt CO2-e	265 Mt CO2-e

Key drivers input parameters	Step Change	Progressive Change	Green Energy Exports
Federal Government Renewable Energy Target	2024 IASR Workbook: 82% share of renewable generation by 2029-30		
Capacity Investment Scheme (CIS) renewable capacity target	2024 IASR Workbook: 18,400 MW CIS eligible capacity by 2029-30, where CIS eligible renewables include new solar PV, onshore wind and offshore wind in the NEM		
Capacity Investment Scheme (CIS) clean dispatchable capacity target	2024 IASR Workbook: 6,125 MW CIS clean dispatchable capacity by 2029-30, where CIS eligible renewables include new solar PV, onshore wind and offshore wind in the NEM		
Victorian Government Targets	2024 IASR Workbook: • Victoria Renewable Energy Target (VRET): 40% by 2025, 65% by 2030 ad 95% by 2035 renewable generation as a percentage of Victorian generation. • Victoria Energy Storage target: 2.6GW by 2030 and 6.3 GW by 2035 • Victoria Offshore Win Target 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040.		
Queensland Renewable Energy Target (QRET)	2024 IASR Workbook: • 50% by 2029-30 • 70% by 2031-32 • 80% by 2034-35 Renewable generation as a percentage of total Queensland demand		
Tasmanian Renewable Energy Target (TRET)	2024 IASR Workbook: 15,750 GWh by 2030 and 21,000 GWh by 2040, inclusive of spill		
NSW Electricity Infrastructure Roadmap	2024 IASR Workbook: • 5,547 TWh of eligible renewable generation in 2024-25 increasing to 33.6 TWh renewable generation in 2029-30 • 2 GW of long duration storage (8 hours or more) by 2029-30		
South Australia Hydrogen Jobs Plan	2024 IASR Workbook: • A 200 MW hydrogen-fuelled generator from 1 December 2025 • A 250 MW electrolyser project included in the hydrogen production forecasts for each scenario		
Victoria SIPS	2024 IASR Workbook: 150 MW import capability in VNI link after Victorian SIPS contract ends 31 March 2032		
Waratah Super Battery SIPS	2024 IASR Workbook: 250 MW increase in export capacity from 1 July 2025 ending July 2030		
Project EnergyConnect	PEC release varies		
Western Renewables Link	2024 IASR Workbook: commissioned by 1 July 2027		
HumeLink	Commissioned by 1 December 2026 as earliest in-service date on instructions from Transgrid		

Key drivers input parameters	Step Change	Progressive Change	Green Energy Exports
New-England REZ Transmission	Earliest in-service date advised by proponent • New England REZ infrastructure Project Part 1 commissioned by June 2031 2024 ISP outcome – Step Change: • New England Infrastructure Project Part 2 commissioned by July 2034	Earliest in-service date advised by proponent • New England REZ infrastructure Project Part 1 commissioned by June 2031 2024 ISP outcome – Progressive Change: • New England Infrastructure Project Part 2 commissioned by July 2041	Earliest in-service date advised by proponent • New England REZ infrastructure Project Part 1 commissioned by June 2031 2024 ISP outcome – Green Energy Exports: • New England Infrastructure Project Part 2 commissioned by July 2034
Central-West Orana REZ Transmission Link	2024 ISP outcome – Step Change: commissioned by August 2028	2024 ISP outcome – Progressive Change: commissioned by August 2028	2024 ISP outcome – Green Energy Exports: commissioned by August 2028
Project Marinus Stage 1	Earliest in-service date advised by proponent: commissioned by 1 December 2030		
Project Marinus Stage 2	2024 ISP outcome – Step Change: commissioned by 1 July 2037	2024 ISP outcome – Progressive Change: commissioned by 1 July 2036	2024 ISP outcome – Green Energy Exports: commissioned by 1 December 2032
Queensland-New South Wales Interconnector (QNI) Connect	2024 ISP outcome – Step Change: commissioned by 1 July 2034	2024 ISP outcome – Progressive Change: commissioned by 1 July 2034	2024 ISP outcome – Green Energy Exports: commissioned by 1 July 2034
CopperString 2032	2024 ISP outcome: commissioned by July 2029		
Victoria-New South Wales Interconnector	Earliest in-service date advised by proponent: commissioned by 1 December 2029	2024 ISP outcome – Progressive Change: commissioned by 1 July 2034	2024 ISP outcome – Green Energy Exports: commissioned by 1 July 2030
Mid North South Australian REZ Expansion	2024 ISP outcome – Step Change: commissioned by 1 July 2029	2024 ISP outcome – Progressive Change: commissioned by 1 July 2030	2024 ISP outcome – Green Energy Exports: commissioned by 1 July 2029
Snowy 2.0	Generation Information July 2024: Commissioned by December 2028		
Discount rate	2024 IASR workbook: 7% real, pre-tax		
Modelling period	2025-26 to 2049-50		
Modelling temporal resolution (dispatch interval duration)	1 hour	1 hour	2 hour

Appendix B : Total project assessment and net present value results

The forward-looking NMBA presented previously is the relevant basis on which to identify which of the eight options is the best way forward. The forward-looking NMBA identifies Option 4 (new contract with revised fixed price) as the option that provides the greatest net market benefit across all ISP scenarios and on a weighted basis. The next best option (Option 1 – Mutually agreed descope) provides approximately 20 per cent less weighted net market benefits compared to Option 4. Additionally, Option 4 having a positive net market benefit demonstrates that it is pursuant to the NEO for PEC to be completed (it is better than the base case Option 6 in which PEC is abandoned).

For completeness, Transgrid has also undertaken a complementary assessment quantifying PEC's overall net benefit to the market on a total project basis (taking into account actual past costs as well as the future costs of the project). This assessment is analogous to the forward-looking assessment that was carried out in the earlier RIT-T, in that it assesses the overall net benefit of PEC on a total project basis, compared to a base case in which it is assumed that PEC does not exist.

The total project assessment is presented for Option 4 only (i.e., the preferred option identified under the forward-looking analysis), and makes use of updated market modelling to quantify the impact of PEC to date on the wholesale market as well as its forecast impact in the future (as opposed to relying on market benefit estimates from the time of the initial RIT-T in 2019).

Although this total project assessment is purely theoretical and does not influence decision making around the best way forward for PEC, it does offer insight into whether consumers would have been better off without PEC instead of Option 4.

This section describes the total project base case used for the assessment, and the total costs and benefits for Option 4, before presenting the net present value results for the total project assessment. Amounts provided in this section are expressed in 2022/23 present value terms, unless otherwise stated.

The NPV results for the total project assessment show that Option 4 is the highest-ranking option and is expected to deliver approximately $964 million (PV, 2022/23 dollars) in net market benefits on a weighted basis.

Total project base case

This total project assessment assumes that in the base case there is 'no PEC' (i.e., both PEC SP1 and SP2 are assumed to be absent). This base case therefore excludes actual capital costs that have been incurred for PEC, as well as expected future costs to complete PEC. Additionally, the total project base case does not include any 'abandonment costs' for PEC.

The total project base case continues to assume that VNI West will still be built in the absence of PEC. The only costs that are included under the total project base case are therefore the capital costs for the portion of PEC that is shared with VNI West (i.e., Line 5 between Dinawan and Wagga Wagga), as this portion is assumed to still be built as part of VNI West. Specifically, Line 5 is assumed to be built by 2027 in the total project base case, costing $880 million (2022/23 dollars).

Total project cost

Total capital expenditure for Option 4 on a total project basis is $4,611 million (2022/23 dollars). This is equal to the forward-looking capital expenditure (i.e., $2,387 million) plus the actual capital expenditure incurred to date (i.e., $2,225 million). Total capital expenditure includes ElectraNet costs of $535 million for the South Australian portion of PEC, and the cost of Line 5, which is included at the same cost as in the total project base case and so nets off in the assessment and has no impact on the outcome.

The treatment of residual asset values, risk allowances and contingency is unchanged from the forward looking assessment (see section 2.5). External funding under Option 4 continues to be assumed in the total project assessment, as the delivery of that option still occurs under the same rectification approach.

Annual operating expenditure for all eight rectification options is again assumed to be 0.8 per cent of capex relating to lines and substations (i.e., excluding land and biodiversity offset costs).

Total project benefits

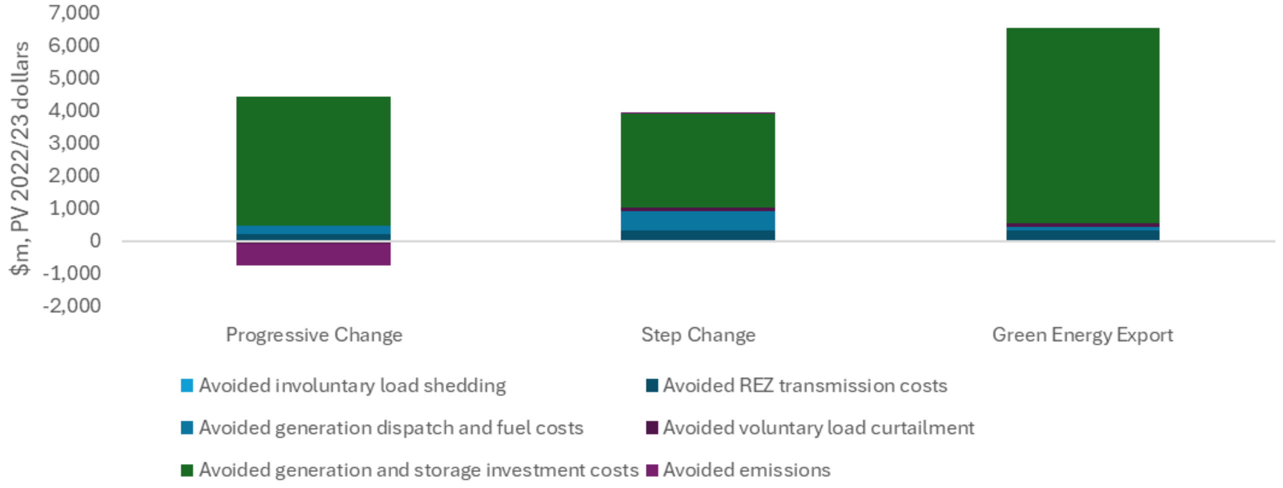
EY has modelled the market benefits on a total project basis, i.e., in a base case where PEC is assumed not to exist, and under Option 4, where PEC is in place by 2026/27.[36] As for the forward-looking assessment, EY has undertaken this modelling under each of the three 2024 ISP scenarios: Progressive Change, Step Change, and Green Energy Exports.

For each scenario, EY has estimated benefits (or disbenefits) from avoided involuntary and voluntary load shedding, avoided generation dispatch and fuel costs, avoided generation and storage investment costs, avoided REZ transmission costs, and changes to greenhouse gas emissions. The gross market benefits provided by Option 4 under the total project basis range between $3,682 million (Progressive Change scenario) and $6,504 million (Green Energy Exports scenario).

The figure below illustrates that most of the benefits from PEC are provided by avoided generation and storage investment costs under each of the scenarios. However, under the Progressive Change scenario, emissions and voluntary load curtailment increase compared to the base case and therefore impose costs of $749 million.

[36] In contrast, in modelling forward-looking market benefits EY has assumed PEC SP1 is included the base case, and that both PEC SP1 and SP2 are included in the option case.

Figure 15: Gross market benefits under each scenario on a total project basis



In undertaking this modelling, EY draws on AEMO's 2024 ISP Inputs and Assumptions, latest information on generation commissioning timing published by AEMO, and timing for other ISP projects as set out in the 2024 ISP. The results of the market benefit assessment on a total project basis are discussed in the separate EY report.

General NPV modelling parameters

The updated PEC assessment presented in this report adopts general NPV modelling parameters set out in Table 13 below.

Table 13: General NPV modelling parameters

General parameter	Total assessment
Assessment period	32 years
First year of assessment	2018/2019
Market modelling period	25 years
Discount rate	7 per cent
Base year for inputs	2022/23 dollars

An assessment period of 32 years for the total assessment has been adopted to accommodate actual capital expenditures having been incurred from 2018/19, and the wholesale market modelling period ending in 2049/50, which is consistent with the final modelling year for the 2024 ISP.

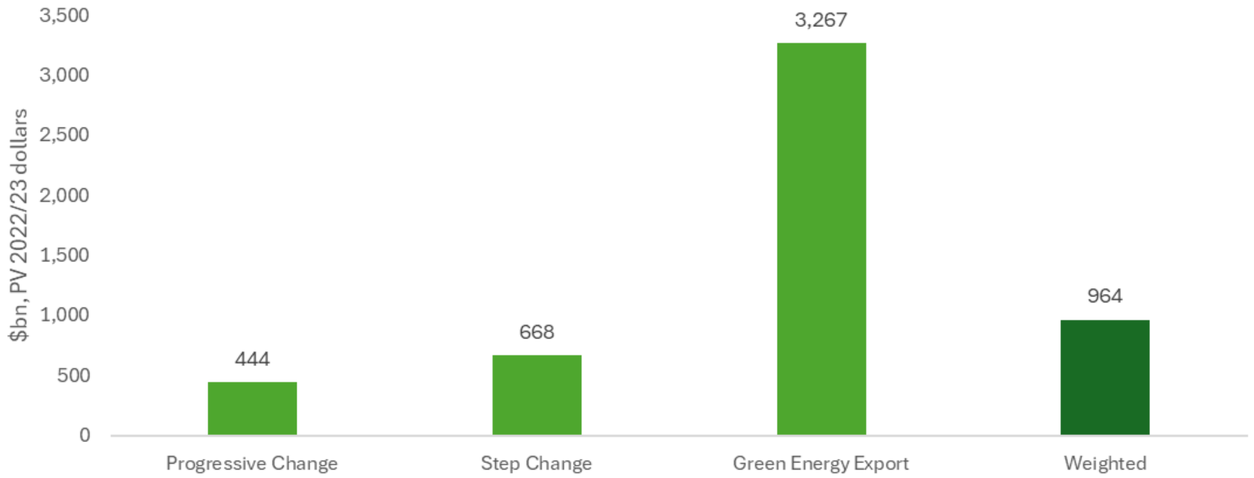
A real, pre-tax discount rate of 7 per cent has been adopted for this analysis to align with AEMO's 2023 Inputs, Assumptions and Scenarios Consultation report.[37] For the purposes of this report, all figures are expressed in 2022/23 dollars, unless otherwise stated.

[37] AEMO '*2023 Inputs, Assumptions and Scenarios Report*', July 2023, p 123.

Weighted total project net market benefits

Figure 16 shows the estimated total project net market benefits for Option 4 under each scenario and weighted across the three ISP scenarios. The weights used are the same as those used forward-looking assessment. Option 4 is expected to deliver approximately $964 million in net market benefits (weighted) on a total project basis.

Figure 16: Summary of the estimated total project net market benefits for Option 4, weighted across the three scenarios on a total project basis



Under the total project assessment, PEC provides positive net market benefits under the Step Change scenario (albeit very modest) and Green Energy Exports scenario, and on a weighted basis. Marginal net costs are exhibited for the Progressive Change scenario.

Figure 17 provides a breakdown of costs and benefits for each option under the Step Change scenario.

Figure 17: Breakdown of net market benefits for Option 4 under each scenario and the weighted outcome on a total project basis