Transgrid

A.8 Direct Capex Forecasting Methodology

2026-31 Revenue Proposal for the Enabling Central-West Orana Renewable Energy Zone Network Infrastructure Project (non-contestable)

July 2025

Official

Contents

Acknowledgement of Country

In the spirit of reconciliation, the Transgrid Group acknowledges the Traditional Custodians of the lands where we work, the lands we travel through and the places in which we live.

We pay respect to the people and Elders past and present, and celebrate the diversity of Aboriginal and Torres Strait Islander peoples and their ongoing connections to the lands and waters of NSW and the ACT.

Pokolbin, NSW

Artwork: Yura. Gili. Nanga. the indigenous interpretation of Power. People. Possibilities

1. Purpose, structure and scope of this document

1.1. Context

Transgrid has been engaged by EnergyCo to deliver the Enabling Central-West Orana (CWO) Renewable Energy Zone (REZ) Network Infrastructure Project (referred to herein as the ‘Enabling CWO RNIP’ or the ‘Project’). The Project involves augmenting the existing transmission network to enable the connection of the Main CWO REZ Network Infrastructure Project (‘Main CWO RNIP’), which will be delivered by ACEREZ as the Network Operator.

The Project is the first RNIP to be connected to our existing backbone 500kV transmission network and involves a first-of-its-kind contractual model in NSW. The Enabling CWO RNIP has a unique set of commercial and technical delivery challenges including:

- delivery under a new commercial framework, featuring complex and intertwined contractual arrangements including contracts with EnergyCo, ACEREZ (a consortium consisting of three separate entities), the D&C contractor and third-party equipment suppliers, requiring dedicated resources to ensure effective implementation and compliance
- a combination of brownfield and greenfield works, each presenting distinct delivery challenges and requiring sufficient oversight to balance resourcing and effectively coordinate between different phases
- complex interface management, particularly in areas where existing infrastructure is modified, or where third-party activities intersect with construction (e.g. ACEREZ’s overcrossing of TL79).
- scope interdependencies, technical interfaces and site and program coordination, including with other external bodies to manage outage requirements
- network integration challenges including incorporating new and modified assets that may result in compliance and operational standards risk
- contractual obligations with EnergyCo to deliver the required scope under agreed timelines.

We have taken a thoughtful approach to delivering and operating the Project, focusing on effectively managing these challenges and optimising project outcomes. Drawing from lessons learned from recent and ongoing projects, we have adapted our delivery strategy to ensure we meet the Project’s delivery timeframes.

The timely delivery of the Project is critical to maintaining a safe, reliable, secure and sustainable supply of electricity in NSW following the anticipated closure of the Eraring Power Station in 2027. To meet this timeline, EnergyCo has committed funding for early development activities up to 31 December 2026 under the Project Deed. Under the Project Deed, we are required to reimburse EnergyCo for these early development activity costs.

The EII framework allows us to recover payments required to be made to EnergyCo under the Project Deed in our Revenue Proposal.[1] The AER’s non-contestable Guideline states:

> *(W)here a Network Operator is required to make payments to the Infrastructure Planner under a contractual arrangement as part of a relevant authorisation, we will pass them through as part of our non-*

[1] EII Regulation, cl. 46(1)(b)(ii).

contestable revenue determination. That is, we do not review the efficiency, prudency or reasonableness of these costs but must still include them in our non-contestable revenue determination. [2]

Instead, the Project Deed stipulates that the early development activity costs must be demonstrably prudent, efficient and reasonable and are subject to review and acceptance by EnergyCo. As such, while this methodology document summarises Infrastructure Planner costs as part of total capital expenditure (capex) for the Project, it does not detail the forecasting methodology for these costs as this is not within the scope of the AER's review.

At the time of submitting the Revenue Proposal, the Project's scope does not include the acquisition, energisation and operation of Barigan Creek Switching Station (BCSS). BCSS will be covered by our Consumer Trustee Authorisation only after the Consumer Trustee (as an authorisation provider) approves the transfer and the asset is formally transferred to us. As such, costs associated with the purchase, commissioning, operation and management of BCSS are excluded from our capex and opex forecasts for the Project. Instead, these costs are proposed to be recovered via an adjustment to our allowable revenue, following the transfer of BCSS.

The capex for the Project is broadly categorised as follows:

- pre-period capex, covering development activities related to the establishment of the scope and characteristics of the Project
- payments required to be made to EnergyCo under the Project Deed, including early development activity costs (referred to as Infrastructure Planner costs)
- direct capex, which relates to tendered works and some property, easement and environmental offset costs
- labour and indirect capex, which relates to labour resources to support the delivery phase of the Project, labour-related costs such as travel expenses, training or recruitment and indirect activities such as professional and consulting services, licence fees, legal fees and insurance premiums related to the Project
- equity raising costs, calculated in accordance with the Post-Tax Revenue Model (PTRM).

This document relates to our direct capex forecast and also summarises Infrastructure Planner costs and equity raising costs. Our labour and indirect capex forecast (including pre-period capex) is explained separately in our Labour and Indirect Capex Forecasting Methodology document, also provided as an attachment to the Revenue Proposal.

1.2. Purpose and scope of this document

The purpose of this document is to explain and justify the methodologies we have used in developing our direct capex forecast and explain how we verified and validated actual and forecast direct capex. Our direct capex forecast includes:

- actual costs incurred from 1 July 2021 to 28 February 2025, which includes payments made by EnergyCo for early project development activities (and included in the Revenue Proposal as Infrastructure Planner costs).

[2] AER, Transmission Efficiency Test and revenue determination guideline for NSW non-contestable network infrastructure projects, July 2024, section 5.6.

- forecast costs from 1 March 2025 to 30 June 2031, which includes forecast payments to be made by EnergyCo for early project development activities to 31 December 2026 and our forecast direct capex from 1 July 2026 to 30 June 2031.

As noted above, this document will present Infrastructure Planner costs in the build-up of total capex but does not detail the forecasting methodology for these costs as they are subject to review by EnergyCo and do not form part of the AER's review process.

For clarity, the period in which early development activities will be undertaken extends to 31 December 2026. At the same time, we will begin incurring costs for construction activities from 1 July 2026. Construction activities are not included in the activities that will be paid for by EnergyCo and later reimbursed by us. This means that in 2026-27, costs in our Revenue Proposal will include both Infrastructure Planner costs and construction costs to be paid by Transgrid.

This document should be read in conjunction with our Revenue Proposal, Labour and Indirect Capex Forecasting Methodology and other supporting documents.

Unless otherwise stated, all forecast capex values in this document are presented in real 2025-26 dollars and include real input cost escalation.

Totals presented in tables may not add due to rounding. Zero values in tables are included where the specific units used do not allow for a meaningful representation of the costs (i.e. the costs are less than $0.1 million).

1.3. Document structure

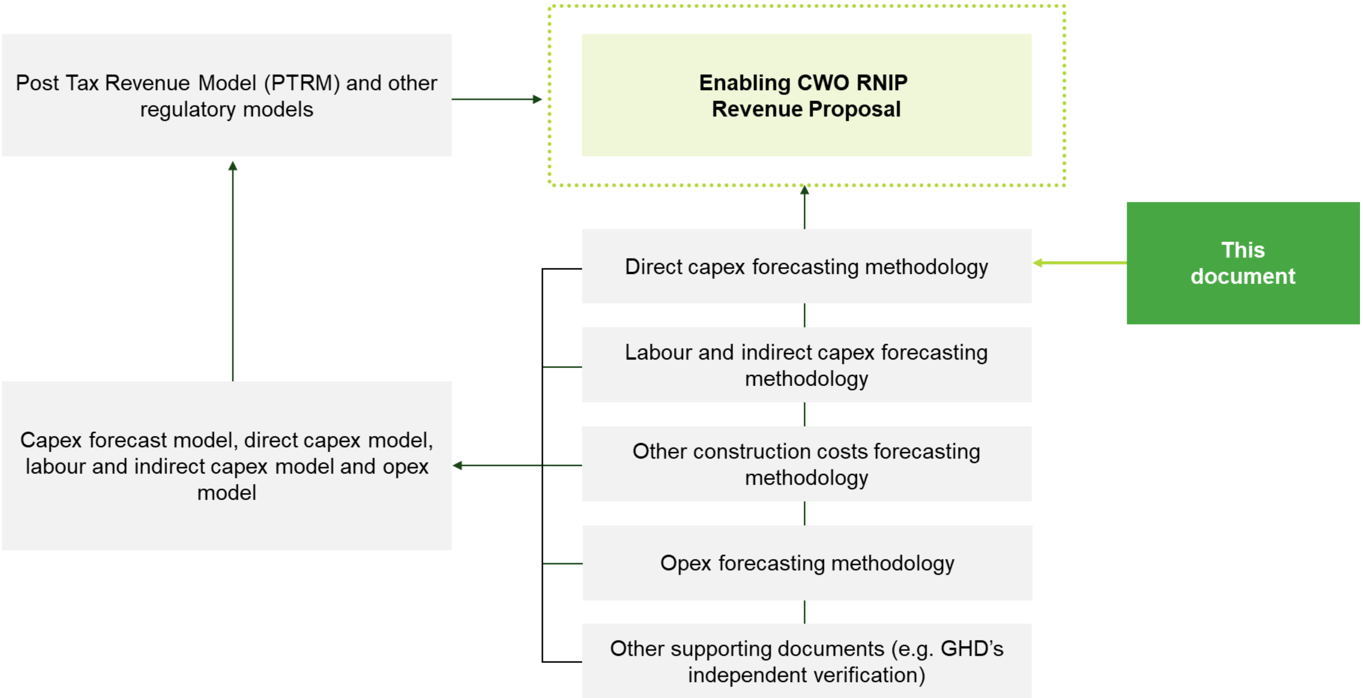
The remainder of this document is structured as follows:

- Chapter 2 summarises our forecast capex
- Chapter 3 outlines the Project scope
- Chapter 4 describes the payments required to be made to EnergyCo under the Project Deed
- Chapter 5 describes our procurement approach for design and construction
- Chapter 6 sets out the forecast capex for design and construction of transmission lines, substations, secondary systems and line transpositions that will be undertaken by our delivery partners
- Chapter 7 sets out our forecast other construction costs and the methodology we used to determine this cost
- Chapter 8 sets out our forecast capex for land and easements and the methodology we used to determine this cost
- Chapter 9 sets out our forecast capex for biodiversity offset costs and the methodology we used to determine this cost
- Chapter 10 sets out labour and indirect costs, with further detail provided in the Labour and Indirect Capex Forecasting Methodology
- Chapter 11 sets out our real input escalators and equity raising costs
- Chapter 12 describes the independent verification process and outcomes.

1.4. Structure of the Revenue Proposal

There are a number of other attachments and models that support, and form part of, our Revenue Proposal for the Project. This document references these attachments, models and other supporting documents for further detail and should be read in conjunction with all other documents comprising our Revenue Proposal. Our Revenue Proposal is structured as illustrated in Figure 1-1 to be as clear and accessible as possible to the AER, customers and other stakeholders.

Figure 1-1 Enabling CWO RNIP Revenue Proposal document structure



Attachments and supporting models comprising our Revenue Proposal are also detailed in Chapter 1 of our Revenue Proposal.

2. Summary of forecast capex for the Project

Our total Enabling CWO RNIP capex is $437.9 million, comprising Infrastructure Planner costs[3], direct, and labour and indirect, capex and equity raising costs (Table 2-1). The Project is anticipated to achieve practical completion date by May 2028, with the majority of expenditure occurring during 2026-27 and 2027-28.

Table 2-1 Total forecast capex for the Project, including pre-period capex ($M, Real 2025-26)

	Pre-period	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Infrastructure Planner costs	152.0	41.5	-	-	-	-	193.5[4]
Pre period costs	8.2	-	-	-	-	-	8.2
Direct costs							
D&C contractor costs	-	74.2	65.9	4.9	-	-	145.0
Easement acquisition	[redacted]						
Biodiversity offset costs	[redacted]						
Other construction costs	-	4.8	5.0	1.9	-	-	11.7
Labour and indirect costs							
Labour costs	-	12.8	25.1	3.2	-	-	41.0
Indirect costs	-	6.9	12.5	1.4	-	-	20.8
Labour escalation and equity raising costs							
Labour escalation	-	0.1	0.2	0.0	-	-	0.3
Equity raising costs	-	1.6	-	-	-	-	1.6
Total (excl. equity raising costs)	160.2	146.4	118.3	11.4	-	-	436.3
Total capex	**160.2**	**148.0**	**118.3**	**11.4**	**-**	**-**	**437.9**

[1] Further details on pre-period, labour and indirect costs are included in the Labour and Indirect Capex Forecasting Methodology.

[2] This is based on the actual early development activity costs up to 28 February 2025 and estimated costs from 1 March 2025 to 31 December 2026. EnergyCo has advised this is the only relevant category of Infrastructure Planner costs to be recovered in the initial Revenue Proposal.

[3] EnergyCo has committed funding (up to a capped amount) for early development activities to 31 December 2026 under the Project Deed. Each month, we submit our actual labour, management and external costs incurred in delivering the milestones agreed with EnergyCo and EnergyCo must then review and pay these costs. Under the Project Deed, these early development activity costs are one of the reimbursable cost categories, for which we must repay EnergyCo. We refer to these reimbursable costs under the Project Deed as Infrastructure Planner costs for the purposes of this Revenue Proposal.

[4] This equates to $188.1 million (nominal), taking into account our expected spend profile, and aligns to the capped amount agreed under the Project Deed.

Our capex forecast has been developed to support the timely and cost-effective delivery of the Project, whilst achieving the capital expenditure objectives, outlined in EII Chapter 6A, to:

- meet or manage the expected demand for regulated network services
- comply with all regulatory requirements (as defined in the EII Regulation)
- maintain the safety of the Project through the supply of regulated network services.

Our proposed capex is prudent, efficient and reasonable, and reflects a delivery approach focused on managing the unique and complex challenges of the Project, to optimise outcomes and meet the agreed delivery timeframes.

The scope of works underpinning the forecast is consistent with our Consumer Trustee Authorisation and our contractual obligations under the Project Deed with EnergyCo. These instruments define the required scope, technical specifications and delivery timeframes for the Project. The technical scope of the Project has been independently verified by GHD as appropriate to meet the requirements set out in the Project Deed and Consumer Trustee Authorisation.

To ensure the delivery of the Project results in the best outcomes for consumers, we have prioritised prudent and efficient outcomes when developing our approach to deliver and operate the Project. Our approach has focused on delivering a fit-for-purpose solution, at the lowest sustainable long-term cost to consumers. Examples of actions we have taken to prioritise prudent and efficient outcomes include:

- selecting a transmission line route that minimises impacts on communities and the environment and reduces biodiversity offset liabilities
- undertaking an early contractor involvement process to address key delivery risks and scope uncertainties early in the process, thereby improving cost transparency, reducing unnecessary contractor margins, and achieving cost savings where feasible
- employing cost-efficient design solutions where appropriate – for example, the use of alternate structure types in constrained locations.

Our approach to delivering the Project also ensures optimal resource utilisation. We have appointed a contractor to assist in the design and construction of the Project, leveraging their experience for skill-specific work. Our internal labour resources provide essential project delivery, management, commercial and technical expertise while the selected team structure, stream objectives and scheduled hours is informed by lessons learned from recently completed and in-progress projects to ensure efficiency. For example, our approach to construction management is designed to be proactive and informed, ensuring we are adequately resourced to provide proper oversight to swiftly address issues on site, particularly at third-party interfaces. Similarly, for commercial management, we have established a dedicated team to provide clear oversight and accountability of both upstream and downstream commercial interfaces to ensure compliance with our obligations and to safeguard against avoidable costs, drawing on our experience with the Waratah Super Battery (WSB) project. This approach, combined with the use of professional and consulting services where appropriate ensures resources are adequately skilled, optimally utilised and minimises the risk of labour stranding following the completion of the project.

Our capex forecasting methodology has been tailored to the Project's specific characteristics and delivery model. It draws heavily on competitively sourced, market-tested costs and has been validated through a combination of internal benchmarking and independent expert verification to ensure our proposed costs are prudent, efficient and reasonable. Specifically, our forecasts reflect:

- the outcome of a robust, market-tested procurement process for the design and construction of new and upgraded transmission lines and substations, undertaken in accordance with our strict governance and compliance requirements. The AER accepts that where a suitable, competitive tender process has occurred, it is reasonable to presume that the contract price reflects prudent and efficient costs.[5] Approximately 49.1 per cent of capex (excluding Infrastructure Planner costs) is based on market prices obtained through competitive tender processes.
- cost estimates for specific cost categories provided by service providers (such as our insurance broker) and independent experts (including GHD, who has estimated our likely biodiversity offset liability for the augmentation works). The use of independent cost estimates ensures reliability and transparency in the cost estimation process.
- estimates that utilise rates provided in existing supplier agreements and contracts, ensuring cost estimates reflect prevailing rates in current market conditions.
- a reliance on past actual costs where appropriate, including benchmarking against comparable projects to ensure costs are reasonable taking into account recent market performance.
- review and verification of all Project costs by GHD and E3 Advisory. Independent verification utilises established benchmarks and methodologies to review and validate cost estimates, providing additional validation that cost estimates are prudent, reasonable and efficient.

This framework for cost estimation ensures costs are consistent, transparent, robust and can be adequately justified with supporting information. This evidence-based approach to forecasting ensures consumers are paying no more than they should be for the services they will receive.

Table 2-2 details the total capex required to deliver the Project (as defined in the Consumer Trustee Authorisation) by sub-category of capex. This includes both pre-period costs and Infrastructure Planner costs.

Table 2-2 Enabling CWO RNIP capex by key category ($M, Real 2025-26)

Category of capex	Total capex	Pre-period costs (A)	IP Costs (B)	Forecasts from 1 July 2026 (C)	(C) as % of total capex
Direct costs	**254.1**	**-**	**81.6**	**172.5**	**39.4%**
D&C contractor costs	[redacted]				
Easement acquisition					
Biodiversity offset costs					
Other construction costs	17.1	-	5.4	11.7	2.7%
Labour and indirect costs	**182.0**	**8.2**	**111.9**	**61.9**	**14.1%**
Labour costs	102.9	2.4	59.4	41.0	9.4%
Indirect costs	79.1	5.8	52.5	20.8	4.8%
Labour escalation and equity raising costs	**1.9**	**-**	**0.0**	**1.9**	**0.4%**
Labour escalation	0.3	-	0.0	0.3	0.1%

[5] AER, Expenditure Forecast Assessment Guidelines, final decision, October 2024, p. 7.

Category of capex	Total capex	Pre-period costs (A)	IP Costs (B)	Forecasts from 1 July 2026 (C)	(C) as % of total capex
Equity raising costs	1.6	-	-	1.6	0.4%
Total capex (excluding equity raising costs)	**436.3**	**8.2**	**193.5**	**234.6**	**53.6%**
Total capex	**437.9**	**8.2**	**193.5**	**236.2**	**53.9%**

Table 2-3 details the total capex required to deliver the Project (as defined in the Consumer Trustee Authorisation) by asset class. This includes both pre-period costs and Infrastructure Planner costs.

Table 2-3 Forecast capex by asset class ($M, Real 2025-26)

Asset class	Total capex	Pre-period costs (A)	IP costs (B)	Forecasts from 1 July 2026 (C)	(C) as % of total capex
Transmission lines	271.2	5.2	103.5	162.5	37.1%
Substations	69.0	1.3	31.6	36.2	8.3%
Secondary systems	28.5	0.5	13.2	14.8	3.4%
Land and easements	19.7	0.3	18.6	0.8	0.2%
Biodiversity offsets – Stewardship sites	14.1	0.3	7.9	6.0	1.4%
Biodiversity offsets – direct payments and other costs	33.8	0.6	18.8	14.4	3.3%
Equity raising costs	1.6	-	-	1.6	0.4%
Total capex	**437.9**	**8.2**	**193.5**	**236.2**	**53.9%**

Table 2-4 outlines the total forecast capex (excluding Infrastructure Planner costs), and the basis of the forecast for these various capex components.

Table 2-4 Forecast capex by key category ($M, Real 2025-26)

Category of capex	Value (excluding IP costs)	Market tested or independently estimated	Basis of capex forecast
Direct costs	**172.5**		
D&C contractor costs	145.0	Yes[1]	Outcome of a competitive tender process
Easement acquisition	[redacted]	No	Certified Practising Valuer advice
Biodiversity offset costs	[redacted]	Where possible	Third party estimate for augmentation works and internal desktop assessment for line transposition works
Other construction costs	11.7	No	Detailed probabilistic assessment

Category of capex	Value (excluding IP costs)	Market tested or independently estimated	Basis of capex forecast
Labour and indirect costs	**61.9**		
Labour costs	41.0	No	Internal resource requirements and market labour rates
Indirect costs	20.8	Where possible	Rates from current engagements, available market quotes and recent historical data
Labour escalation and equity raising costs	**1.9**		
Labour escalation	0.3	N/A	The labour escalators for 2026-27 to 2027-28 are as set out in our 2023-28 Revenue Determination. For 2028-29 to 2030-31, the labour escalator is assumed to be equivalent to the average applied in 2026-27 to 2027-28.
Equity raising costs	1.6	N/A	Calculated within the PTRM
Total (excluding equity raising costs)	**234.6**	**N/A**	
Total (including equity raising costs)	**236.2**		

[1] The transpositions scope of work under the D&C contract was unable to be included in the RfT process. Refer to Chapter 5 and 6 for further discussion.

3. Project Scope

The scope of works for the Project aligns with our Consumer Trustee Authorisation for the Project and the Project Deed, as agreed with EnergyCo. The Project is the first RNIP to be connected to our existing backbone 500kV transmission network and represents a first-of-its-kind contractual model in NSW. We are contractually required to deliver the scope within contractually agreed timeframes. To meet this obligation, we have adapted our delivery strategy to ensure timely and efficient delivery.

At the time of submission, the Project excludes the acquisition, commissioning, energisation and operation of BCSS. BCSS will fall under our Consumer Trustee Authorisation following acquisition. As such, costs associated with the purchase, commissioning, energisation, operation, management and maintenance of BCSS will be addressed as an adjustment mechanism for the purposes of this Revenue Proposal. For completeness, the scope of the works associated with BCSS is outlined in Chapter 3.2.

Future works, including two line transpositions, to support the CWO REZ have been identified and will likely be undertaken at a later stage. Studies are also currently underway to determine whether a Special Protection Scheme is required. The delivery model for any future works is currently being determined. These works are not covered by this Revenue Proposal.

3.1. Project scope

Our Consumer Trustee Authorisation describes the scope of the Project as[6]:

- a new 330kV single circuit transmission line between Bayswater and Liddell substations
- a new 330kV single circuit transmission line between Mt Piper and Wallerawang substations
- BCSS cut in works involving Lines 5A3 and 5A5 and connection to Wollar substation and including remote ends works at Bayswater, Mt Piper and Wollar substations
- works to Transgrid's existing 330kV Line 79 to enable the overcrossing of 500 kV transmission lines to be constructed from BCSS to Merotherie Energy Hub for the CWO REZ.

Under the Project Deed, line transpositions for four lines are required to enable transfer of generation from CWO REZ to the NSW transmission network.[7] Detailed network planning for the integration of the Main CWO RNIP, in collaboration with ACEREZ identified the need for these transmission line transpositions on existing Transgrid lines.

Transposition refers to the process of rearranging the relative positions of the conductors along the length of a three-phase transmission line. This assists in minimising voltage imbalances (in line with our requirements under the NER[8]) and reducing energy losses, which is critical for proper system operation and stability. The following line pairs are being transposed:

- 5A4/5A3 Wollar to Bayswater
- 5P1/5P2 Barigan Creek to Mt Piper.

[6] AEMO Services, Statement of Reasons, June 2024, p. 10.

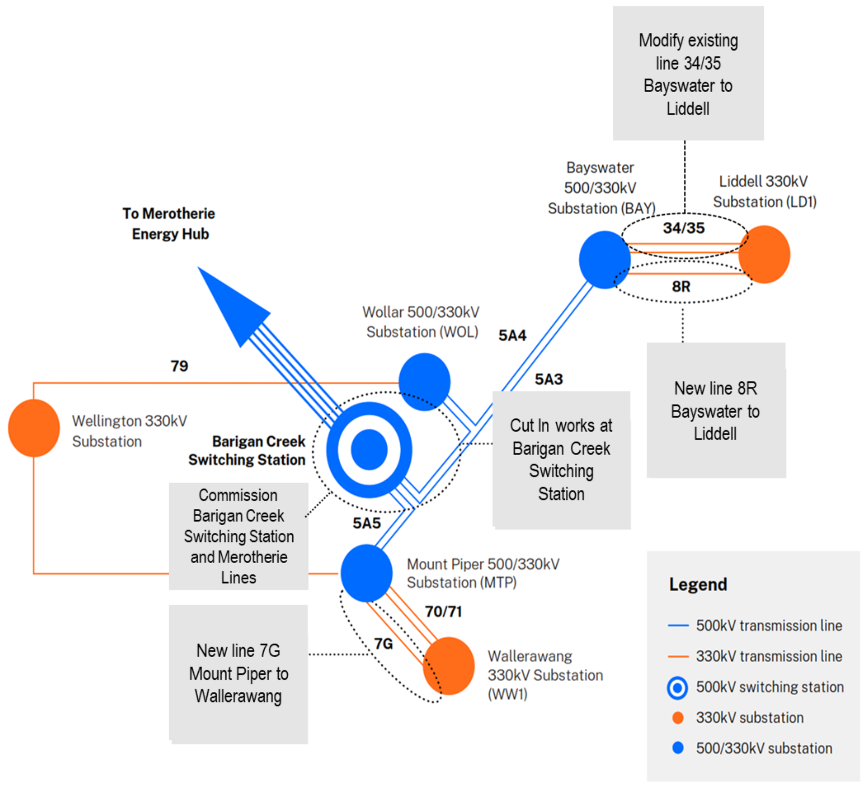
[7] Changes, modifications or additions to the network infrastructure described in the Consumer Trustee Authorisation is permitted if made in accordance with the Project Deed and provided that following the relevant change, modification or addition, the Project remains consistent with the description in the Authorisation. Refer to Clause 5(f)(2) of Transgrid's Consumer Trustee Authorisation for further detail.

[8] NER, clause S5.1a.

As outlined above, an additional two line transpositions will be delivered at a later stage.

The five key packages of works are illustrated in Figure 3-1 and described in Table 3-1. A diagram of the initial transpositions is provided in Figure 3-2.

Figure 3-1 Enabling CWO RNIP work packages



Source: Transgrid (adapted from AEMO Services, 2024).

Figure 3-2 Transmission line transpositions

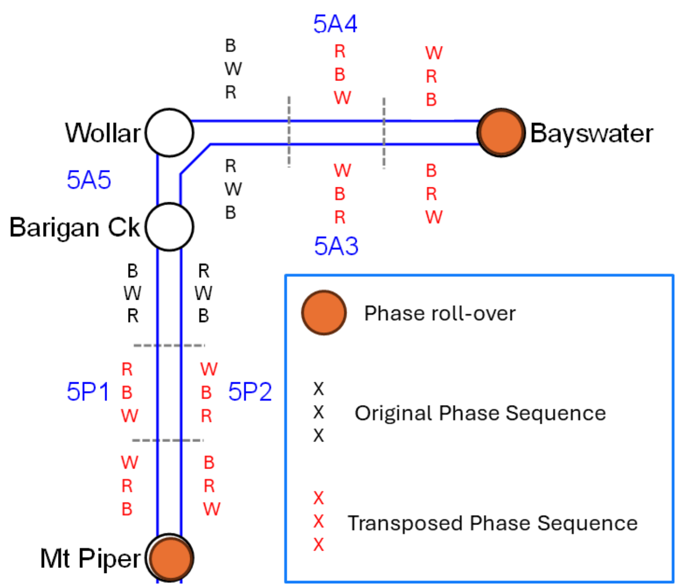


Table 3-1 Work package descriptions

Package	Scope of Work	Date for Practical Completion
Bayswater to Liddell Upgrade Works	Establish an additional 330kV transmission line between Bayswater Substation and Liddell Substation, involving line modification works to utilise an existing 330kV transmission line and asset replacements at substations. Works include: • Transmission Line Works - Establishment of 330kV transmission line foundations for new lattice towers and poles - Relocation of Line 33 and Line 34, including removal of redundant Line 73/74 timber poles and tower structures in the vicinity of Bayswater, construction of three new lattice towers and stringing of spans including optical ground wire. - Loop-in-loop-out (LILO) of the existing 330kV Line 81 (to create a new 330kV transmission line between Bayswater and Liddell, to be called Line 8R) including removal of existing steel tower structure, construction of a new lattice tower and two 3 pole tension structures and stringing of spans including optical ground wire. • Substation Works - Demolition of two redundant bays comprising of landing structures and footings to allow for the construction of two new switchbays. - Construction of two new switchbays at Bayswater including pole landing structures in redundant eastern bays to enable re-routing of Lines 33 and 34. - Minor HV plant and equipment upgrades, augmented to facilitate connection of Lines 81 and 8R. - Secondary systems works including new protection, control and communications equipment (including cabling and panels) at Bayswater. - Remote end works at Liddell and Newcastle limited to protect setting changes and nomenclature changes.	[redacted]
Mount Piper to Wallerawang Upgrade Works	Establish a new 330kV transmission line between Transgrid's existing Mt Piper 330kV substation and existing Wallerawang 330kV substation and augment substations to include additional lines. Works include: • Transmission Line Works: - Installation of new structure foundations - Establishment of new 330kV transmission line between Mt Piper and Wallerawang, to be named Line 7G. - Demolition of 132kV Line 94E section to make way for new double circuit 330kV structures. - Establishment of new double circuit structures between Cox River and existing Lines 70 and 71, including stringing of spans	[redacted]

Package	Scope of Work	Date for Practical Completion
	and rearrangement of Lines 70/71 and new 7G to minimise under-crossings. • Substation Works: - Footing construction, support structures modifications and gantry works, as required. - Installation of new 330kV line feeder bay 7G at Mt Piper including strung bus and interplant bus upgrades. - Upgrade and modification of HV plant and equipment in Wallerawang feeder bay 7G. - New secondary system panels for protection and control for new feeder bays at Mt Piper and Wallerawang. - Installation of new communication panels and equipment at Mt Piper to Wallerawang.	
Transposition Works	Perform line transpositions for four lines; Mt Piper to Barigan Creek and Barigan Creek to Bayswater to enable transfer of generation from CWO REZ to the NSW transmission network. Works include: • Design and construction of transmission line foundations and new steel poles • Transpose four transmission lines (5A4/5A3, 5P1/5P2) at intervals corresponding to one-third and two-thirds of their lengths.	[redacted]
Cut in to BCSS	Modification of the existing 500kV line 5A5 (Mt Piper to Wollar) and 5A3 (Mt Piper to Bayswater) to loop-in-loop out of BCSS. Works include: • Transmission Line Works - Establishment of foundations for new transmission towers - Establishment of 5 new tension towers - Stringing of spans, excluding supply and installation of the landing spans to the Barigan Creek gantry structure • Substation Works - Augmentation of 500kV Lines 5A3 and 5A5, which will be cut-into BCSS and create new 500kV Lines 5P1 and 5P2, requiring remote end protection schemes to be upgraded. - Commencement of remote end secondary system works at Wollar, Mt Piper and Bayswater substations. - Installation, testing and commissioning of remote end secondary system works within Transgrid's network to facilitate BCSS cut-in.	[redacted]
Facilitation of TL79 Over-crossing	Facilitate management of Transgrid's TL79 assets including facilitating outages during construction by ACEREZ of the new transmission line that crosses over TL79.	[redacted]

[9] Note that the transposition construction works are occurring concurrently with the main works, however the phase roll cannot be undertaken for lines 5A3/5A4 and 5P1/5P2 until the BCSS cut-in and commissioning is complete.

3.2. Acquisition and energisation of BCSS

BCSS will be constructed by ACEREZ as part of the Main CWO RNIP and is the key connection point from CWO REZ into Transgrid's NSW transmission network. Following construction, ACEREZ will transfer ownership of BCSS to us and we will pay EnergyCo the relevant purchase price.

At the time of the transfer, BCSS will then fall within our Consumer Trustee Authorisation. We will commission the asset into our existing transmission network, to be used in connection with the control and operation of the Enabling CWO RNIP. Relevant works, as specified under the Project Deed, are:

- provision of loop-in-loop-out landing spans to the BCSS gantry structures for line 5A5 (Mt Piper – Wollar)
- connection of line 5A3 (Mt Piper – Bayswater) and line 5A5 (Mt Piper – Wollar) to BCSS
- commissioning and energisation of remaining Merotherie line bays
- commissioning and energisation of Merotherie lines 5M1, 5M2, 5M3 and 5M4
- performing asset acceptance, testing and commissioning to energise BCSS into the NSW transmission network.

Acquisition of BCSS is expected to occur in [redacted] Energisation and commissioning of BCSS will then occur from [redacted]

3.3. Project timeline

We are contractually required to deliver the scope within agreed timeframes under the Project Deed with EnergyCo, in line with the dates outlined in Table 3-2.

Table 3-2 Project timeline

Work package	Date
BCSS commissioning	[redacted]
BCSS cut in	[redacted]
Bayswater to Liddell upgrade works	[redacted]
Mt Piper to Wallerawang upgrade works	[redacted]
Merotherie lines connection	[redacted]
Line transpositions	[redacted]

[10] Note that the transposition construction works are occurring concurrently with the main works, however the phase roll cannot be undertaken for lines 5A3/5A4 and 5P1/5P2 until the BCSS cut-in and commissioning is complete.

To meet these delivery milestones, we have adapted our delivery strategy to ensure timely and efficient execution. In particular, we:

- engaged early with delivery partners through an Early Contractor Involvement process to address delivery risks and enable timely mobilisation
- utilised separable portions under the D&C contract, eliminating the risk of the contractor claiming a single delay or variation that has a consequential impact on other scopes of work
- adopted a proactive project, construction, and commercial management model to ensure strong oversight, early resolution of site issues, and prompt management of disputes
- intend to purchase key long lead equipment which will be free-issued to the contractor, minimising the chance of equipment-related delays (due to our greater market power and ability to reprioritise equipment across the network)
- adopted a design strategy where we undertook more of the design work in key areas, ensuring this could be completed prior to contract award, and in parallel to procurement.
- will complete the commissioning works of the assets constructed, following experiences on recent projects where external contractors held this responsibility and delays occurred.

These measures are designed to provide flexibility and ensure we are able to meet the Project's timeframes, whilst reducing the risk of any cost overruns.

4. Infrastructure Planner costs

Clause 46(1)(b)(ii) of the EII Regulation allows us to recover costs for any payments required to be made to EnergyCo under contractual arrangements entered into pursuant to the Consumer Trustee Authorisation. The Project Deed was entered into pursuant to clause 7 of our Consumer Trustee Authorisation and therefore, payments made in accordance with the Project Deed are permitted to be recovered by us.

The Project Deed requires us to make payments to EnergyCo for a range of costs EnergyCo may incur in respect of the Project (Infrastructure Planner costs), including:

- costs relating to biodiversity offsets (excluding any biodiversity offsets for which Transgrid is responsible for obtaining)
- payments made by EnergyCo for early project development activities

[redacted]

- the costs of variations to be borne by EnergyCo.

Under the Project Deed, EnergyCo must provide us with actual and budgeted Infrastructure Planner costs. These costs must be included in the Revenue Proposal and are payable by us to EnergyCo by 29 January 2027 (or 20 business days after we are notified that such costs are approved by the AER). We supported EnergyCo in the determination of the amount for inclusion in the Revenue Proposal, noting that at the time of submission, actual and expected reimbursable costs only related to early development activities (the costs for which are driven by the activities we intend to undertake in this period). This amount is included in the proposed base expenditure and is detailed in Table 4-1 below.

Table 4-1 Summary of Infrastructure Planner costs by activity ($M, Real 2025-26)

Capex category	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	Total
D&C contractor costs	[redacted]						
Equipment	-	-	-	-	4.8	-	4.8
Easement acquisition	[redacted]						
Biodiversity offset costs	[redacted]						
Other construction costs	-	-	-	-	0.6	4.8	5.4
Labour costs	2.6	3.2	9.1	15.1	19.4	10.0	59.5
Indirect costs	6.1	1.9	3.8	16.3	18.7	5.7	52.5
Total	**8.7**	**5.1**	**12.8**	**39.7**	**85.7**	**41.5**	**193.5**

Table 4-2 summarises Infrastructure Planner costs by asset class.

Table 4-2 Summary of Infrastructure Planner costs by asset class ($M, Real 2025-26)

Asset class	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Transmission lines	5.5	3.2	8.1	23.4	34.7	28.5	103.5
Substations	1.4	0.8	2.0	6.7	13.5	7.2	31.6
Secondary systems	0.6	0.3	0.8	3.0	5.3	3.0	13.2
Land and easements	0.3	0.2	0.4	6.6	10.9	0.3	18.6
Biodiversity offsets – stewardship sites	0.3	0.2	0.4	-	6.3	0.7	7.9
Biodiversity offsets – direct payments and other costs	0.7	0.4	1.0	-	15.0	1.7	18.8
Total	**8.7**	**5.1**	**12.8**	**39.7**	**85.7**	**41.5**	**193.5**

As outlined above, Clause 46(1)(b)(ii) of the EII Regulation allows us to recover the costs for any payments required to be made to EnergyCo under contractual arrangements entered into pursuant to the Consumer Trustee Authorisation. The Project Deed stipulates that the early development activity costs must be demonstrably prudent, efficient and reasonable and are subject to review and acceptance by EnergyCo. The AER will then pass these costs through as part of the Revenue Determination.[11]

The actual payments made by us to EnergyCo may be higher or lower than this estimated amount. This could be due to:

- a variance between actual costs incurred and the budgeted amount included in the Revenue Proposal (either higher or lower), and/or
- a cost arising that was not certain or initially foreseen at the time of submission (e.g. [redacted] a contractual variation).

To account for this, the Project Deed requires us to propose an adjustment mechanism to allow for adjustments to the Infrastructure Planner costs recovered by Transgrid. Accordingly, we have proposed a non-automatic adjustment mechanism to reflect increases or decreases in Infrastructure Planner costs (see Chapter 9 of the Revenue Proposal for further discussion).

[11] AER, Transmission Efficiency Test and revenue determination guideline for NSW non-contestable network infrastructure projects, July 2024, section 5.6.

5. Our procurement approach

5.1. Overview

The Project's procurement process focused on the following components that are required for the Project:

- design and construction for the network augmentation and upgrade works, and
- high voltage (HV) plant and equipment.

We used two broad models to procure the above components:

- **Design and construct (D&C) contract** – implemented for the design and construction of new and upgraded transmission lines and substations for the augmentation works; alongside the design and construction of the transposition works
- **Directly procured assets** – procuring high voltage (HV) plant, equipment and secondary systems utilising our existing panel arrangements. Some items will be provided as free issue items to the D&C contractor for the augmentation and connection works.

All Transgrid-supplied equipment for the Project (including HV and secondary systems) is being purchased prior to 31 December 2026 and forms part of early development activity costs funded by EnergyCo and repaid by us. This is reflected in the Infrastructure Planner costs included in the Revenue Proposal. As such, only the procurement model for the design and construction of the transmission lines, substations and line transpositions is explained below.

5.2. Design and construction for transmission lines, substations and line transpositions

To ensure we deliver the Project at the lowest sustainable, whole-of-lifecycle cost to maximise benefits to consumers, we undertook a competitive procurement process for the design and construction of new and upgraded transmission lines and substations. This process was undertaken in accordance with our strict governance and compliance requirements. The AER accepts that where a suitable, competitive tender process has occurred, it is reasonable to presume that the contract price reflects prudent and efficient costs.[12]

Overall, our procurement process was characterised by three key phases which progressively reduced risk and increased confidence in the award of a suitable contractor to complete the design and construction works. Figure 5-1 summarises at a high-level the three phases of the procurement process, ahead of awarding the contract.

[12] AER, Expenditure Forecast Assessment Guidelines, final decision, October 2024, p. 7.

Figure 5-1 Transmission line and substations procurement process

Each of these procurement phases is explained in further detail below.

5.2.1. Expression of Interest (EOI)

In April 2023, we issued an EOI to the following eight contractors:

[redacted]

- Zinfra Pty Ltd (Zinfra)

[redacted]

Four contractors responded with their withdrawal from the EOI event:

[redacted]

[redacted]

Subsequently, [redacted] Zinfra, [redacted]

Based on the technical and commercial evaluations conducted on the submissions, we selected three contractors to proceed to the next stage (Early Contractor Involvement Stage). They were [redacted] Zinfra and [redacted]

5.2.2. Early Contractor Involvement (ECI)

An ECI model is a collaborative procurement process to assist in developing a tender for the construction phase of a project. Generally, this process allows for:

- innovation and construction efficiencies, as a result of early collaboration between the tenderer and contractors
- the opportunity to understand project drivers and what constitutes a successful outcome
- a better understanding of the broader project risks, leading to a more effective allocation of risks in the delivery phase.[13]

To optimise the procurement process, we engaged the three contractors – [redacted] Zinfra [redacted] – in a reimbursed ECI phase. This provided them with an opportunity to undertake site inspections (including identifying construction lay-down areas and assessing existing foundations for possible re-use), develop constructability reports for Transgrid's review and review and refine commercial arrangements, prior to the Request for Tender (RfT) phase.

The intent was to identify risks and opportunities for inclusion in the RfT technical specification. Additionally, it was intended to expedite the tender period as the delivery partners would have a good understanding of the project sites and Transgrid's requirements.

This phase maximised the opportunity for Transgrid and delivery partners to:

- collaboratively assess the constructability of the designs
- validate the existing tower designs, propose new ideas for foundation design to reduce cost, duration and ground disturbance and consider ways to optimise outage requirements and reduce recall time
- address key project challenges and opportunities (including critical resourcing, site access and planning approval requirements)
- identify opportunities for acceleration of the allocated scope at various stages of the project lifecycle
- negotiate commercial and contractual items with respect to the new delivery contract prior to finalisation.

5.2.3. Request for Tender (RfT)

Our Procurement and Contracting Strategy involved tendering for a single D&C contract with six separable portions. This approach was preferred as:

- a single contract reduces resourcing issues and future variation risks and ensures efficient contract management, providing a single point of accountability
- market attractiveness and appetite was higher for a single contract with separable portions, rather than awarding sub-projects, ensuring a competitive outcome
- the use of separable portions eliminates the risk of the contractor claiming a single delay or variation has a consequential impact on other scope of work. Delays to the works will be isolated to separable portions and any potential delay claims are limited, reducing risk exposure to claims and costs.

[13] Australian Department of Infrastructure and Regional Development, National Alliance Contracting Guidelines, guidance note 6, September 2015, p. 27.

The D&C contract is a fixed-price lump sum contract (with specific limited adjustment items). This allows for key risks to be transferred to the contractor and provides cost certainty, reducing the risk of cost overruns in delivery. This model was suited to the Project, as the scope was relatively certain and the ECI process provided sufficient information for bidders to provide an informed price. In these particular circumstances, the contractual model is also less administratively burdensome and reduces the risk of disputes, compared to an integrated target cost model. The presence of specific, limited adjustments in the contractual model ensures that the tendered price remains efficient, and does not include unwarranted premiums for items which are highly variable and that the contractor has minimal control over. These items will be addressed on an open book basis, to ensure transparency in pricing.

Pursuant to our Procurement and Contracting Strategy and the RfT Plan, we invited the following contractors to participate in the competitive tender process: Zinfra, [redacted][14].

On 31 May 2024, we received submissions from two tenderers: Zinfra [redacted] chose not to bid due to capacity issues in their organisations. We assessed these offers based on our standard evaluation criteria as well as compliance with the social procurement requirements to determine the preferred contractor. The evaluation criteria included both technical and commercial components and was assessed by an appropriately qualified Transgrid evaluation committee. Further details of the evaluation criteria and process are set out in our RfT Evaluation Plan, provided as an Attachment to this Revenue Proposal.

To assist with the tender evaluation, we held four external and 25 internal workshops to clarify departures, assumptions and exclusions in evaluating value for money to the consumer.

As part of the tender evaluation process, we engaged [redacted], an infrastructure advisory firm, to complete a Value for Money assessment of the tenderers' pricing. The assessment focused on three key areas:

- review of the two tender submissions and associated tender clarifications and departures
- comparison of the two tender submissions against [redacted] previous estimate of the Project, with a specific focus on activities where there was a large cost variance between [redacted] estimate and tender submissions, and
- recommendations to assist with ongoing tender clarifications.

The assessment concluded that:

- the Enabling CWO RNIP has a complex scope of work comprised of both brownfield and greenfield works that are heavily reliant on specialist power system capability with a more challenging risk profile, and
- where large cost variances were identified by [redacted], Transgrid should continue to clarify the cost build up with tenderers, which was done in subsequent tender evaluation sessions.

A preferred tenderer was identified through this process.

[14] [redacted] was invited to submit a tender despite not participating in the ECI process in order to increase competitive tension in the process and maximise the chance of multiple tenders being submitted.

5.2.4. Contract Award

The tender process identified Zinfra as the preferred tenderer to deliver the full scope of works for the Project. The benefit of a single D&C contract is that it enables efficient management whilst maximising market appetite and minimising Transgrid and consumers' exposure to changes in schedule and costs.

The D&C contract was awarded to Zinfra on 21 March 2025.

5.2.5. Deed of Amendment for line transposition works

The line transposition works were identified as a scope requirement, following detailed network planning for the integration of the Main CWO RNIP, in collaboration with ACEREZ, into the existing Transgrid network. As this occurred post the commencement of the RfT process, it was not possible to include the transposition scope of work without delaying the award of the remainder of the works and impacting the commissioning date.

Following the award of the contract, we asked Zinfra to price the scope of works to complete the required transmission line transpositions. The response from Zinfra forms the basis of the cost forecast. We are in the process of awarding the transposition scope of work through a Deed of Amendment to Zinfra's existing contract. The costs estimated by Zinfra have been compared against our internal estimate for the proposed scope which had been independently reviewed by [redacted] (a consultancy firm with expertise in cost estimation of major transmission projects). This review by [redacted] identified that the estimate was reasonable, given the early stage of development for the project.

6. Design and construction

6.1. Overview

The D&C contract with Zinfra has been broken down into seven separable portions, with only the first separable portion awarded at the time of submission. These separable portions are:

- **D&C Separable Portion 1** – Detailed design and management plans
- **D&C Separable Portion 2** – BCSS cut-in works
- **D&C Separable Portion 3** – Transmission Line Bayswater and Liddell
- **D&C Separable Portion 4** – Substation Works Bayswater and Liddell
- **D&C Separable Portion 5** – Transmission Line Mt Piper and Wallerawang
- **D&C Separable Portion 6** – Substation Works Mt Piper and Wallerawang
- **D&C Separable Portion 7** – Transpositions

This breakdown for Separable Portions 1 to 6 was developed during the ECI period, described in Chapter 5.2.2. As part of this process, we worked through with the participants how best to minimise risk to both parties by including separable portions.

The line transposition works were only identified as a scope requirement, following detailed network planning for the integration of the Main CWO RNIP into the existing Transgrid network. As this occurred post the commencement of the RfT process, it was not possible to include the transposition scope of work without delaying the award of the remainder of the works and impacting the commissioning date. Given this, Separable Portion 7 is being included in the D&C contract with Zinfra in accordance with the process described in Chapter 5.2.5 of this document.

Table 6-1 sets out our forecast capex for design and construction. The capex forecast reflects the detailed final contract price agreed with Zinfra following the detailed procurement and evaluation process outlined in Chapter 5. The costs for the initial transmission line transpositions are based on the price provided by Zinfra, following the award of the D&C contract.

Table 6-1 Design and construction capex for the Project for the 2026-31 regulatory period[1] ($M, Real 2025-26)

Capex category	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Transmission lines	[redacted]	[redacted]	[redacted]	-	-	[redacted]
Substations	[redacted]	[redacted]	[redacted]	-	-	[redacted]
Secondary systems	[redacted]	[redacted]	[redacted]	-	-	[redacted]
Transpositions	[redacted]	[redacted]	[redacted]	-	-	[redacted]
Total	**74.2**	**65.9**	**4.9**	**-**	**-**	**145.0**

[1] This cost breakdown excludes Infrastructure Planner costs.

We provide further detail of the capex forecast for transmission lines, substations and secondary systems and transpositions below, with reference to the pricing for each separable portion as provided by Zinfra. Separable Portion 1 relates to design, management plan development, investigations and other pre-construction activities to support the construction of the remainder of the separable portions. The costs associated with this separable portion have been apportioned to the capex categories listed above (except Separable Portion 7) based on the pre-construction effort associated with each category.

6.2. Transmission lines capex

The transmission lines scope of work set out in the Consumer Trustee Authorisation requires us to construct new 330 kV transmission lines between Mt Piper and Wallerawang and between Bayswater and Lidell, alongside 500kV line cut in works at BCSS. The selection of the transmission line route between Mt Piper and Wallerawang was informed by our community and stakeholder engagement, with a focus on minimising impacts on communities, the environment and reduces biodiversity offset liabilities.

Table 6-2 sets out the relevant transmission lines scope of each separable portion.

These works are being completed under Separable Portions 2, 3 and 5 of the D&C contract.

Table 6-2 Transmission lines detailed scope of work

Relevant separable portion	Scope
D&C Separable Portion 2 – BCSS cut-in works	• Modify existing TL5A3/5A5 to LILO of Barigan Creek Switchyard.
D&C Separable Portion 3 – Transmission Line Bayswater and Liddell	• Removal of redundant TL73/74 timber poles and conductors in the vicinity of Bayswater to make way for line modifications and utilize existing switch bays. • Loop-in-loop-out (LILO) of the existing 330kV line 81, which runs between Liddell and Newcastle, in the vicinity of existing structure 81-688A at Bayswater Substation, to modify the network to become Line 81 between Newcastle and Bayswater. • The remaining section of Line 81 will be utilised to create the new 330kV transmission line between Bayswater and Liddell, to be called Line 8R. • Relocation of Line 33 and Line 34 to the spare Line 74 and Line 73 switch bays at Bayswater.
D&C Separable Portion 5 – Transmission Line Mt Piper and Wallerawang	• Establishment of a new Twin Olive 330kV transmission line between Transgrid's existing Mt Piper substation and Wallerawang substation. • Removal and disposal of TL94E between Str 13 to 33.

Table 6-3 outlines key dates for the delivery of the transmission lines scope of work.

Table 6-3 Expected timing for transmission lines capex scope of work

Activity	Expected date
Procurement of towers	[redacted] (post prototype and load testing)
Completion of detailed design (by Transgrid)	[redacted]
Construction commencement for Separable Portion 2	
Construction commencement for Separable Portion 5	
Construction commencement for Separable Portion 3	

Activity	Expected date
Tower erection and stringing for Separable Portion 3	[redacted]
Tower erection and stringing for Separable Portion 5	
Commissioning for Separable Portion 3	
Separable Portion 2 cut-in/commissioning	
Commissioning for Separable Portion 5	

6.3. Substations capex

The substation scope of work set out in the Consumer Trustee Authorisation requires us to augment the existing Wollar, Bayswater, Liddell, Mt Piper and Wallerawang substations where the works shall be coordinated with the relevant Transmission Line works. Table 6-4 sets out the relevant substations scope of each Separable Portion.

These works are being completed under Separable Portions 2, 4 and 6 of the D&C contract.

Table 6-4 Substations scope of work

D&C contract Separable Portion	Scope
D&C Separable Portion 4 – Substation Works Bayswater and Liddell	• Demolition of two redundant bays comprising of landing structures and footings • Construction of two new switchbays at Bayswater including pole landing structures in redundant eastern bays to enable re-routing of TL33/34 • Minor HV plant and equipment upgrades in 330kV bays which will be augmented to facilitate connection of TL81/8R.
D&C Separable Portion 6 – Substation Works Mt Piper and Wallerawang	• Construction of new 330kV line feeder bay 7G at Mt Piper including strung bus and interplant bus upgrades. • Upgrade and modification of HV Plant and equipment in Wallerawang redundant generator feeder bay to be connected to line 7G • Communications Upgrades at Mt Piper and Wallerawang

Table 6-5 outlines key dates for the delivery of the substation scope of work.

Table 6-5 Expected timing for substation capex scope of work

Activity	Expected date
Commencement of HV equipment procurement	[redacted]
Completion of detailed design (by Zinfra)	
Construction commencement for Separable Portion 4	
Construction commencement for Separable Portion 6	
Commissioning for Separable Portion 4	
Commissioning for Separable Portion 6	

Activity	Expected date
Separable Portion 2 cut-in/commissioning 5A5	[redacted]
Separable Portion 2 cut-in/commissioning 5A3	

6.4. Secondary systems capex

The secondary systems scope of work set out in the Consumer Trustee authorisation requires us to augment or replace the existing secondary systems at Wollar, Bayswater, Liddell, Mt Piper and Wallerawang substations where the works shall be coordinated with the relevant Substation and Transmission Line works. Table 6-6 sets out the relevant secondary systems scope of each Separable Portion. These works are being completed under Separable Portions 2, 4 and 6 of the D&C contract.

Table 6-6 Secondary Systems Scope of Work

D&C Contract Separable Portion	Scope
D&C Separable Portion 2 – BCSS cut-in	• Remote End Works – 500kV Wollar 5A5 – Secondary Systems and Communications upgrades • Remote End Works – 500kV Bayswater 5A3 Secondary System Upgrades • Remote End Works – 500kV Mt. Piper 5A3 and 5A5 Secondary System Upgrades
D&C Separable Portion 4 – Substation Works Bayswater and Liddell	• New secondary systems including new control and protection panels for relocated Line 33 and Line 34 switch bays at Bayswater • New control and protection panels and secondary system upgrades for existing Line 33 and Line 34 bays being converted to Line 81 and Line 8R • Secondary system setting changes at remote ends Newcastle and Liddell to address the network modifications • Communication upgrades at Bayswater
D&C Separable Portion 6 – Substation Works Mt Piper and Wallerawang	• Upgrading secondary systems including new control and protection panels for new Line 7G at Mt Piper and Wallerawang substations • Communication upgrades at Mt Piper and Wallerawang substations

The secondary systems equipment will be supplied by Transgrid. Table 6-7 outlines key dates for the delivery of the secondary systems scope of work.

Table 6-7 Expected timing for secondary systems capex scope of work

Activity	Expected date
Completion of detailed design SP2 (by Transgrid)	[redacted]
Completion of detailed design SP4 (by Transgrid)	
Completion of detailed design SP6 (by Transgrid)	
Construction commencement for Separable Portion 2 (remote ends)	

6.5. Line transposition works

The line transposition works (Separable Portion 7) involve two key components:

- transmission line poles trial
- design and construction works.

The line transposition works are at an early stage of development with only a high-level concept design completed. Limited environmental and geotechnical studies have been conducted to date with more studies planned during 2025 and 2026.

6.5.1. Transmission line poles trial capex

This is the first time we have performed line transpositions on our 500kV network. To ensure the success of the design, we will engage our D&C contractor to conduct a trial of the transposition design and approach. This trial will ensure the design is safe and meets the requirements of the network.

The trial will be completed on an existing Transgrid property in Armidale, during the development phase of the project. The scope of the trial includes the design, procurement and supply of poles and associated equipment alongside a number of tests which need to be done to confirm the approach.

6.5.2. Design and construction works

Following the completion of the transmission line poles trial, detailed design will commence for line transposition works. The transposition scope of works includes:

- detailed design of transpositions, following the outcomes of the trial
- procurement of steel poles
- site establishment and access track upgrade
- foundations development
- construction of the transpositions towers
- stringing of conductor, and
- commissioning and handover.

The delivery schedule for the line transposition works is still under development based on feedback from our D&C contractor however, at a high level, we expect:

- detailed design to be completed in [redacted]
- construction to commence in [redacted], and
- commissioning to occur in [redacted].

The forecast capex for the design and construction costs is based upon a detailed bottom up build provided by our D&C contractor which will be the basis for the variation to their contract. This detailed bottom-up build has been reviewed by Transgrid against independent estimates produced for the scope of work to confirm the cost effectiveness of the D&C contractor's pricing.

7. Project risks

7.1. Overview

The Enabling CWO RNIP is the first non-contestable REZ network infrastructure project to be delivered under the NSW EII framework. It presents a unique set of delivery challenges largely driven by the delivery program required under the contractual arrangements with EnergyCo and the novel interfaces and complexities associated with ensuring the successful integration of the Main CWO RNIP into the NSW transmission network.

To reduce Project uncertainty, we have sought to undertake activities that assist in the identification and understanding of risks faced. This has included reducing Project uncertainty by:

- undertaking early development activities, including undertaking geotechnical investigations and environmental activities (such as spring survey and Environmental Impact Statement (EIS) development), and
- engaging multiple contractors in an ECI phase, to allow them to assess constructability of the designs and resourcing, site access and planning approval requirements.

Following this, we have comprehensively and transparently identified and assessed the key risks for Project, including our ability to efficiently manage, prevent or mitigate these risks (including through insurance) and the magnitude and likelihood of the risk.

We consider that there are a range of risks that are best managed by us as part of our usual risk practices / controls when delivering a transmission project of this size and scope. Additionally, we consider that some of these risks are related to unpredictable events that are outside of our control and cannot be reasonably mitigated or prevented. For these risks, it is not appropriate to include an allowance in our proposed base expenditure due to the difficulties in accurately quantifying these costs. For these specific risks, we have proposed adjustment mechanisms (as outlined in Chapter 9 of our Revenue Proposal) in accordance with clause 51 of the EII Regulation and clause 6A.6.9 of EII Chapter 6A.

However, there are also a number of residual risks that will affect the cost of the project and cannot be efficiently transferred, avoided or mitigated (or included as adjustment mechanisms). For these risks, we consider it is most appropriate to include an allowance in our base expenditure to adequately address these risks. This risk allowance is referred to as 'other construction costs'.

Our forecast other construction costs for the Enabling CWO RNIP is $11.7 million over the 2026-31 regulatory period, representing 2.7 per cent of the total capex.

Table 7-1 Other construction costs ($M, Real 2025-26)

Capex category	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Other construction costs	4.8	5.0	1.9	-	-	**11.7**

We have adopted a bottom-up approach to the quantification of this allowance, including:

- establishing consequence estimates that represent reasonable estimates of the efficient and prudent costs that may be incurred
- estimating realistic likelihoods of the consequential cost being incurred

- accounting for the presence of any controls or mitigations, and
- accounting for the Project specific contractual risk allocations adopted.

Throughout this process, we have engaged extensively with the Transgrid Advisory Council (TAC) to ensure alignment with consumer interests and regulatory expectations. Consultation with the TAC focused on preferred approaches to risk allocation, including the appropriate balance between upfront allowances and adjustment mechanisms. Feedback from the TAC has informed both the forecast other construction costs and the adjustment mechanisms proposed.

When forming our position on the application of incentive schemes (such as CESS) and the calculation of our allowance, we have assumed that our proposed adjustment mechanisms are accepted. Where the AER adopts an alternate view of appropriate adjustment mechanisms is appropriate, we will need to also reconsider our positions on these aspects of our Revenue Proposal.

This chapter outlines our approach to project risk cost allowance and should be read in conjunction with the Other Construction Costs Forecasting Methodology, provided as an attachment to the Revenue Proposal.

7.2. AER's risk framework

Under EII Chapter 6A, our annual revenue requirement is to be determined using a building blocks approach. Under clause 6A.5.4 of EII Chapter 6A, our revenue can include compensation for risks that the AER considers are necessary to compensate a Network Operator for risks that are not otherwise compensated for in the return on capital.

While the Project is being delivered under the EII framework, we note that the AER's application of EII Chapter 6A is intended to be consistent with the NER, except where there are compelling reasons to deviate from that approach.[15] For this reason, we have considered the AER's guidance note on the regulation of actionable ISP projects[16] and in particular, its guidance on the AER's expectations on the treatment of risks. The AER can accept the inclusion of a risk allowance in the capex forecast for a project where:[17]

- residual risks have been identified, and
- the associated cost estimates of the residual risk are efficient i.e. the consequential cost is adjusted to reflect the likelihood of occurrence.

To inform its assessment, the AER requires a comprehensive and transparent explanation of how the risks have been identified and costed, including:[18]

- risk identification – clearly identifying the risk events, and
- risk cost assessment – estimating the potential cost impacts, the likelihood of occurrence, the consequential costs and any mitigation/management strategies.

[15] AER, Transmission Efficiency Test and revenue determination guideline for non-contestable network infrastructure projects guideline, July 2024, p. 2.
[16] AER, Regulation of actionable ISP projects, Guidance note, March 2021.
[17] AER, Regulation of actionable ISP projects, Guidance note, March 2021, pp. 16-17.
[18] AER, Regulation of actionable ISP projects, Guidance note, March 2021, p. 17

In the recent HumeLink determination, the AER also indicated that it considers a P50 confidence level is most appropriate when forecasting a risk allowance, as it is the point at which risks are shared equally between Transgrid and consumers.[19]

7.3. Capex forecasting method and assumptions

We have undertaken a thorough assessment of our residual risks. We have adopted an integrated Cost and Schedule Quantitative Risk Analysis (QCSRA) probabilistic approach to estimating our risk allowance. We have utilised a hybrid approach, combining the top-down Risk Factor coupled with the top-down First Principles Risk Analysis (FPRA) technique, which accounts for both inherent uncertainties and contingent risk.

Our risk management framework and project risk management procedure are well developed and align with AS ISO 31000:2018 Risk Management Guidelines. The key steps in our risk approach involve:

- understand and establish the context for the potential risk events that could arise
- identify expected risks and establish a risk register
- analyse and evaluate potential risks, and mitigate/manage potential risks
- assess potential cost impacts of risks, to determine appropriate 'other construction costs' allowance.

Chapter 7.3.1 to 7.3.3 overviews our approach to identifying, quantifying and modelling risks associated with the delivery of the Enabling CWO RNIP. Our approach is explained in further detail in our Other Construction Costs Forecasting Methodology document, provided as an attachment to this Revenue Proposal.

7.3.1. Risk context

There is an inherent complexity to delivering large infrastructure projects. Common infrastructure project complexities include adjacent project interfaces, latent conditions, force majeure events (including COVID-19), social licence, environmental risks, cost escalation and contractor delivery. Examples of recent projects that have faced significant commercial challenges as a result of these risks include the M6 Project, Sydney Metro City and South-West, Inland Rail, WestConnex and Sydney Lightrail.

The Enabling CWO REZ RNIP has a unique set of delivery challenges including:

- complex and intertwined contractual arrangements including contracts with EnergyCo, ACEREZ, the D&C contractor and third-party equipment suppliers
- a combination of brownfield and greenfield works, each presenting distinct delivery challenges
- intricate technical and commercial interfaces
- network integration challenges, and
- delivery under a novel regulatory framework.

Each of these factors contribute to the overall risk profile of the Project, and our ability to efficiently manage, mitigate or prevent these risks from occurring.

The Enabling CWO RNIP D&C contract has been selected as a lump-sum fixed price model (with specific, limited adjustment items). This type of contract achieves cost certainty upfront and reduces the risk of cost escalation, which would be inherent in a cost plus, construct only, or incentivised target cost model. We

[19] AER, AER Determination Transgrid's HumeLink Stage 2 Delivery Contingent Project Application, 2 August 2024, p. 38.

used competitive pressure throughout our tendering approach to ensure that contract pricing was efficient. The D&C fixed price model also enables the risk to be allocated to the party best able to manage and control it which in the case of the Project is often the D&C contractor.

7.3.1.1. Identify risks and establish a risk register

Once we understood the risk context, we proceeded to identifying potential risks that were likely to present themselves within the specific Project context in order to develop our risk register.

This process included thoroughly examining both the upstream contract with EnergyCo and the downstream contract with the D&C contractor to identify risks that are expected to impact the Project's delivery cost or schedule. We assigned each risk a 'risk owner' who is responsible for developing and maintaining the risk treatment plan for each individual risk.

Risks identified fall into one of the following categories:

- inherent uncertainty (i.e. inherent quantity and productivity risks) with time or cost impacts – these risks are associated with the uncertainty of the cost item estimated or the duration of an activity in the schedule, i.e. the risk does not arise due to a specific 'event'.
- inclement weather impacts, including from rain, heat, fire and wind delays – informed by the use of an inclement weather analysis tool.
- contingent risk events (i.e. discrete risks) with time or cost impacts – relating to specific events that may or may not occur.
- prolongation – related to the indirect costs incurred if the project extends beyond the budgeted timeframe.

7.3.2. Analysing and evaluating Project risks

Once we established a comprehensive list of risks, we reviewed and qualified these risks through a series of risk workshops which were attended by internal and independent subject matter experts (SMEs) and risk specialists from different disciplines related to the Project.

For each risk, we undertook a qualitative assessment to determine the following:

- potential causes
- consequences and scenarios
- mitigation measures and controls,
- treatments, and
- residual risk rating.

These risks were included in our risk register which is maintained in our central database.

We periodically review our risk register and update as new risks are identified and existing risks are treated or closed. We continually monitor and review changes to our risk positions arising from updated information or changes in circumstances and will continue to do so on an ongoing basis until the Project is complete.

7.3.3. Quantifying other construction costs

In alignment with industry standards, and our internal processes and procedures, we have undertaken an integrated probabilistic Quantitative Cost and Schedule Risk Analysis (QCSRA) to estimate both time and cost risk consequences. The specific QCSRA methodology adopted was a hybrid combination of the 'top-down' Risk Factor, coupled with the First Principles Risk Analysis (FPRA) technique[20].

The QCSRA process is summarised below:

- **Data collection and verification**, acquiring the latest master schedule and cost estimate after being subjected to health check and rectification process as required
- **Cost and time related risks revision and identification**, identifying risks with a time or cost impact based on the existing risk register
- **Risk analysis workshops**[21], conducting iterative workshops with the respective Project Team leads to establish the following inputs:
- **Inherent uncertainty** in base estimate costs and schedule durations, including uncertainty in time lost as a result of inclement weather within the schedule;
- **Contingent risk events** with cost and time impacts that may or may not happen;
- **Prolongation (delay) costs** incurred if the project extends beyond the budgeted timeframe, based on the Risk Adjusted Schedule results.
- **Schedule Risk Analysis (SRA) modelling**, removing any wet weather and contingency allowances in the schedule and establishing the schedule risk analysis model in the schedule risk analysis software, Acumen Risk
- **Cost Risk Analysis (CRA) modelling**, removing any existing project allowances and contingencies from the cost estimate and establishing the cost risk analysis model in the cost risk modelling software, @Risk[22]
- **Model Integration**, calculating prolongation periods based on the SRA model
- **Allocate Risk Costs**, allocating risk costs based on proposed risk allocations for the Revenue Proposal
- **Draft results**, running the risk model to produce draft risk results.

Further information is available in the Risk Report, provided as an attachment to the Revenue Proposal.

7.3.3.1. Assessing likelihood of occurrence and expected impact

Individual risk owners and specialists have quantified each risk by assessing the likelihood of occurrence as well as the expected time or cost impact. In doing so, they have drawn on a range of available information including experience from similar projects, SME experience, independent estimates, supplier, contract, design and program information.

[20] Methodology applied based on: Australian Government, Supplementary Guidance Note 3A – Probabilistic contingency estimation, version 2, November 2023 and Risk Engineering Society and Engineers Australia, Contingency Guideline, 2nd edition, February 2019.

[21] Methodology applied based on: Australian Government, Supplementary Guidance Note 3A – Probabilistic contingency estimation, version 2, November 2023 and Risk Engineering Society and Engineers Australia, Contingency Guideline, 2nd edition, February 2019.

[22] Industry standard software sold by Lumivero.

The potential variability in time and cost was assessed with respect to the:

- best case outcome
- worst case outcome, and
- most likely outcome.

Each possible risk cost outcome is based on supporting evidence. This approach is often referred to as a 'three-point estimate' of the cost impact and is a well-accepted and robust industry method. The simplest way to describe a three-point estimate is to use a triangular distribution. This means that the best case and worst case are the absolute extremes, i.e., there is no possibility outside this range.

Specifically, our analysis has utilised a 'trigen' distribution that considers the best and worst cases as a 1 in 10 type of outcome i.e. if we performed the project many times, then:

- one in ten would have an outcome as good as the best case, and
- one in ten would have an outcome as bad as the worst case.

We have adopted trigen distribution for the three-point estimates to remove distortion of distribution driven by extreme events (absolute best and worst cases). As a result, during the workshops and discussions to determine the uncertainty data for each risk, we considered a 1 in 10 plausible best case and 1 in 10 plausible worst case. These results are then reflected in the modelling.

7.3.3.2. Model simulation

The quantitative analysis includes a comprehensive schedule risk analysis (SRA) and cost risk analysis (CRA) to identify the key uncertainties and risks.

Once all time-based inputs were established, the SRA risk model was run and a probabilistic time-based histogram of completion dates produced for each Separable Portion of the Project.

The histogram reflects the number of 'hits' or simulation iterations t`hat returned a given completion date. The number of hits before a certain date on the histogram is sometimes referred to as a 'confidence interval' which indicates the level of confidence (or P-value) that a completion date can be achieved. For example, 500 hits before date x in a 1000 iteration simulation would indicate a 50 per cent confidence (P50) that date x can be achieved.

Following the SRA simulation, P-value dates from P0 to P100 for all Separable Portion completions were imported to the CRA model to be applied as a probabilistic prolongation period. Once all cost-based inputs were established, and SRA prolongation periods imported, the CRA probabilistic model was run and a probabilistic cost-based histogram of risk costs produced for the Project.

While a range of P-values (P0 – P100) are produced as part of the probabilistic analysis, for the purposes of this Report, only P50 cost values have been reported (in line with the AER's preference for risk allowances to be developed at the P50 level). We can also determine other values with different confidence intervals. The P-Value chosen is determined by the organisation's risk appetite. It is common for organisations to use P90 risk contingency as it provides shareholders with the greatest confidence. This practice is in line with industry good practice and guidelines.

7.3.3.3. Outcomes of our analysis

As a result of our analysis, we have identified risk costs that are likely to be incurred to deliver the Project on time and within budget. These risk costs from part of the overall cost of the Project and reflect the probability-weighted calculation of 'expected costs'.

Table 7-2 details the key risk costs which comprises $11.7 million or 2.7 per cent of the total forecast capex.

Table 7-2 Identified other construction costs ($M, Real 2025-26)

Other construction cost	Description	Forecast capex
Planning and environmental process approval uncertainty	Intensity of planning and environmental approvals processes may increase as a result of additional submissions requiring additional resourcing to respond in order to meet delivery timelines.	3.7
Supplier delays	Delays to supply of Transgrid supplied equipment and secondary systems due to unanticipated global supply chain delays affecting overseas manufacturing and shipping timeframes.	3.1
Extended Inclement Weather	Project delays caused by inclement weather such as heavy rainfall or heat (over and above contracted allowance) which prevents the safe and effective completion of works.	1.9
Property valuation uncertainty	Uncertainty in property valuation and compensation processes may require additional resourcing, increased legal costs for negotiations or result in variances to final compensation amounts.	[redacted]
Third party interface risk	Large number of third-party interfaces for the project, including interfaces with other projects requires additional stakeholder management or changes to construction methodology.	0.8
Equipment failures	Failures from existing Transgrid equipment or equipment supplied to the D&C contractor results in delays to the Project	0.3
Top 6 other construction costs		[redacted]
Other minor risks (combined)		
Total other construction costs		**11.7**

8. Easement acquisition

8.1. Overview

This chapter explains our forecast capex for acquiring the easements required for delivering the Enabling CWO RNIP. [redacted] These costs are therefore included in the Infrastructure Planner cost. The forecast capex for line transposition easement acquisitions post 1 January 2027 is [redacted] million.

This chapter outlines:

- our easement acquisition obligations
- our methodology for estimating the forecast capex relating to easement acquisition, expected to be incurred from 1 January 2027.

8.2. Our easement acquisition obligations

Our property acquisition process is guided by the *Land Acquisition (Just Terms Compensation) Act 1991* (NSW) (JTC Act). Under the JTC Act, acquisition can be by agreement or compulsory acquisition. The acquisition process must be a fair and transparent process with appropriate engagement and negotiation undertaken, before compulsory acquisition can be considered as a last resort.

Figure 8-1 provides an overview of the process for acquisition by agreement with landowners.

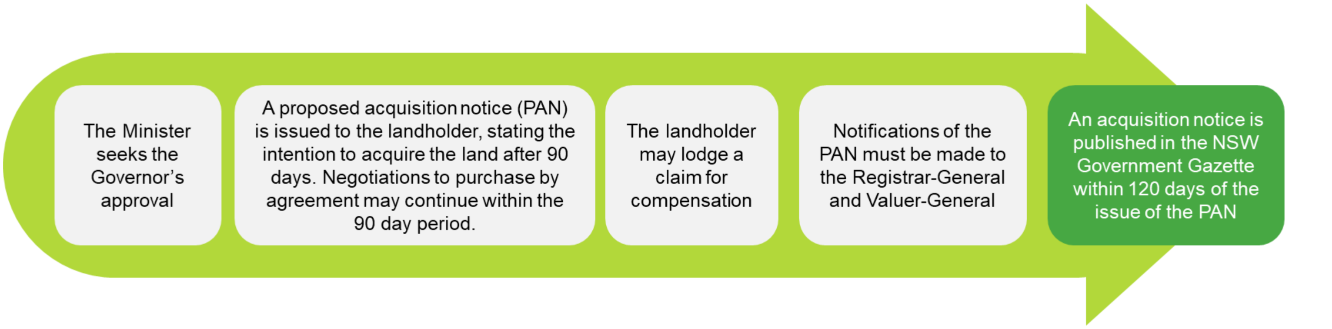
Figure 8-1 Process for acquisition by agreement

To align the timing of funding approval and construction site access, we will seek to negotiate and enter into property option agreements with landholders, where possible. These conditional contracts are an agreement for us to acquire an easement over the land at a pre-agreed value at a future date. This approach will deliver greater certainty of the costs of the Project and will reduce the time to access the site once the construction phase commences. At the time of preparing the Revenue Proposal, no option agreements have been entered into. Where appropriate, we will seek immediate acquisitions if requested by the landholder.

If an agreement cannot be reached after at least six months of negotiation, we have the option to undertake compulsory acquisition under the JTC Act with the approval of the Minister. The JTC Act sets out a process to be followed in these circumstances. Figure 8-2 provides an overview of the process for compulsory acquisition.

The processes of acquisition by agreement or by compulsory acquisition will be undertaken concurrently to meet Project deadlines. Both processes take approximately 24 months to complete, hence both processes are undertaken at the same time to ensure deadlines are met.

Figure 8-2 Compulsory acquisition process



8.3. Approach to estimating easement acquisition costs for line transposition works

The transpositions for four transmission lines from Mt Piper to Barigan Creek and Barigan Creek to Bayswater requires:

- permanent transmission line easements from four landholders
- access easements from six landholders, and
- a temporary construction easement from one landholder.

In total, seven separate landholders are impacted by this scope of work (with some landholders impacted by multiple interests).

The line transposition works are at an early stage of development with only high-level concept design completed. Greater certainty of the easement acquisition costs will be known closer to possession of site, currently expected to occur in early 2027.

As the transposition scope of works is not well developed, it is also difficult to assess which costs will be realised prior to 31 December 2026. Based on NSW property acquisition data from 2023-24, 93.7 per cent of property acquisitions were settled by agreement.[23] Noting this, we currently expect to incur a significant portion of the relevant acquisition costs prior to 31 December 2026. However, the minimum timeframe for concluding property acquisition processes is two years. It is also expected that we will likely continue to negotiate with certain landholders up to the date that a compulsory property acquisition notice is published

[23] NSW Centre for Property Acquisition, Summary of acquisition – financial year 2023-24, NSW Government.

in the NSW Government Gazette (currently anticipated in late 2026 or early 2027). [redacted]owever, where there is a significant timing delay in incurring these costs, we may seek to adjust our revenue to recategorise easement acquisition costs from Infrastructure Planner costs to capital expenditure incurred in the regulatory period (see Chapter 9 of the Revenue Proposal for further discussion).

The total forecast capex for the acquisition of the required easements for the transposition scope of works is [redacted], with [redacted] expected to be incurred prior to 31 December 2026 as an early development activity and [redacted] during the 2026-31 regulatory period. The costs relate to the following activities:

- compensation payments to landholders
- option fees, payable upon execution of an option for easement
- transfer duty on land acquisition costs
- compulsory acquisition costs
- Transgrid's legal costs
- disturbance costs being the payment of fees incurred by landholders for professional advice, such as legal and valuation fees
- statutory fees, valuations and legal costs.

The forecast capex for easement acquisition for the line transposition works is summarised in Table 8-1.

Table 8-1 Forecast easement acquisition capex ($M, Real 2025-26)

Activity	Total Project capex
Landholder compensation	[redacted]
Option fees	[redacted]
Legal Fees	[redacted]
Landholder disturbance costs	[redacted]
Valuation fees	[redacted]
Minor interest disturbance costs	[redacted]
Compulsory acquisition costs	[redacted]
Other (transfer duty and survey fees)[1]	[redacted]
Total	[redacted]

[1] Other costs sum to approximately [redacted] and do not appear in the table due to the larger units adopted.

Each of these cost categories are explained in further detail below.

8.3.1. Landholder compensation

The easement acquisition process for the line transposition works is currently in its early stages, with detailed valuations expected to be undertaken in June 2025.

The total forecast capex for landholder compensation is based on an internal desktop valuation undertaken by a Certified Practising Valuer with significant valuation experience. To provide further confidence in this estimate, this forecast has been endorsed by Transgrid's Senior Property Manager who is also a Certified Practising Valuer.

Our experience with prior projects is that to reach agreements with private landholders through commercial negotiations, a premium above the initial valuation is paid. This variance is due to a range of factors, including:

- not all individual impacts of the project or compensable impacts on the landholder's property are known at the time of initial valuation,
- landholders are also entitled to seek their own independent valuation reports which may be higher than the initial valuation report (as a result of differing expert valuation opinions), resulting in an increased negotiated compensation amount
- changes to the easement corridor between the valuation and agreed compensation dates, and
- increases in real estate market conditions over the negotiation period.

Given these circumstances, applying a premium to initial valuation estimates is standard industry practice. This approach also assists in reducing the number of compulsory acquisitions required, whereby the authority has limited control over internal and external disturbance costs.

To reflect this premium, we have examined the correlation between the initial valuation offers to the agreed compensation amount for our most recent major project, HumeLink (to best reflect current market conditions). Actual compensation paid for property required to deliver HumeLink was [redacted] higher than Transgrid's initial instructed valuation report. This has been calculated based on the 163 initial valuation offers, compared to the final agreed compensation amount, and is considered conservative as the premium has increased since the calculation date. Therefore, we have applied a premium of [redacted] per cent to the value of Transgrid's valuation reports.

8.3.2. Option fees

To ensure site access as soon as possible, we need to establish early option agreements to secure future acquisitions. An option agreement is a legal deed which provides Transgrid with the necessary property rights to build the project and dictates the requirements of the landholder during the construction phase.

Seven entities along the selected route are eligible to enter into an Option Deed with Transgrid. An independent expert, JLL estimated a standard option fee allowance for private landholders of [redacted] for our recent Victoria to New South Wales (VNI)-West Stage 1 Contingent Project Application.

Adopting this standard option fee allowance, our forecast capex for option fees is [redacted] calculated as follows:

[redacted]

8.3.3. Legal fees

We will incur professional fees for property and compulsory acquisition legal services in connection with the easement acquisition. These services will include initial due diligence and existing easement terms review, legal documentation preparation and any legal advice required throughout the negotiation and/or compulsory acquisition processes. Our capex forecast of [redacted] million is based on a fee estimate compiled by [redacted]

8.3.4. Landholder disturbance costs

We are required under the JTC Act to compensate landholders for their legal and valuation costs, referred to as 'landholder disturbance costs'. Under section 55(d) of the Act, landholders are entitled to compensation for professional costs reasonably incurred in connection to the acquisition.

The seven relevant landholders are therefore entitled to landholder disturbance costs. Our total capex forecast for landholder disturbance costs is [redacted] million. This includes:

- [redacted] for landholder legal costs, and
- for landholder valuation costs.

8.3.4.1. Landholder legal costs

Our forecast of [redacted] for landholder legal costs is based on a quotation provided by [redacted]. We have estimated the forecast landholder legal costs by identifying the particular services that are relevant to a landholder's legal representation rights, as quoted by [redacted] The actual legal costs incurred by the landholders in connection to the acquisition must be paid in accordance with the Act.

Our total capex forecast for landholder legal costs includes:

- [redacted] for easement acquisitions (by agreement) – these costs relate to the preparation of the necessary legal documents for the landholders that reach a negotiated agreement with Transgrid for the property interests
- [redacted] for compensation entitlement and negotiations – these costs relate to the landholders' legal advice in connection to the compulsory acquisition process which is separate to the negotiated agreement process but occurs concurrently
- [redacted] for novation deeds – these costs relate to an allowance per landholder if a novation to the agreed legal documents needs to occur
- [redacted] for disbursements – these costs relate to disbursement costs that the landholders' solicitors may incur.

8.3.4.2. Landholder valuation costs

Our forecast of [redacted] for landholder valuation costs is based on a fee estimate from [redacted]. The landholders are entitled to attain valuation advice under the JTC Act and the cost must be reimbursed by Transgrid. As the anticipated landholder valuation cost is not yet available due to the infancy of the scope of work, we have relied upon the quote provided to Transgrid for its valuation advice.

8.3.5. Valuation fees

Valuation fees must be incurred as a requirement of the JTC Act for an independent and equitable compensation amount to be offered to the landholders.

We have been provided with a fee estimate from [redacted] for [redacted] to prepare valuation reports and assist with negotiations. The quote is based on a standard fee per landholder for the valuation report and an allowance for negotiation and explanation of the valuation.

8.3.6. Minor interest disturbance costs

A minor interest holder is any entity which holds a registered or unregistered interest in the land. Under the JTC Act, a minor interest holder must be notified, and is entitled to, the same disturbance fees as a landholder.

There are nine minor interest holders that are entitled to legal advice and valuation advice under the JTC Act. At the time of preparing the Revenue Proposal, minor interest holders have not been notified of the transposition scope of works (due to its early stage) and therefore it is difficult to estimate the applicable disturbance costs. Our forecast costs are estimated from Transgrid's valuation quote from [redacted] for seven landholders to arrive at an average cost per landholder. The calculation is:

[redacted]

The calculation per interest holder is then multiplied by the number of minor interest holders:

[redacted]

We have not allowed for minor interest holder legal disturbance costs as not all landholders will require valuation advice. Typically, minor interest holders attain legal or valuation advice, not both.

8.3.6.1. Compulsory acquisition costs

We engage the Department of Climate Change Energy Environment & Water (DCCEEW) to review and approve each of the proposed compulsory acquired properties prior to the issuance of proposed acquisition notices (PANs). This is a requirement under the JTC Act and must occur prior to Ministerial execution.

To inform our forecast, DCCEEW provided set costs per employee per quarter. We estimate a Grade 7/8 and Grade 5/6 position will be required for two quarters to provide the review services required for Ministerial execution.

Table 8-2 summarises the relevant costs.

Table 8-2 DCCEEW review costs ($, Real 2025-26)

Position	Quarter incurred	Cost / quarter
Grade 7/8	2nd	[redacted]
Grade 5/6	2nd	
Grade 7/8	4th	
Grade 5/6	4th	
Total		

8.3.7. Other costs (survey fees and land transfer duties)

The following section itemises administrative fees relating to the Project.

8.3.7.1. Survey fees

Land Registry Services (LRS) survey fees will be incurred to register our newly acquired easement rights on land title with the Land and Registry Services.

The two fees payable per survey are a pre-examination fee and a lodgement for examination fee.

We estimate fifteen survey plans will be required to be undertaken. The fifteen survey plans are required based on our survey team's review of the cadastral system and the location of the anticipated easements required.

Our forecast capex is calculated as follows:

[redacted]

8.3.7.2. Land transfer duties

Land transfer duty is payable on easement compensation, prior to registration of the acquired easements.

Our forecast capex cost of [redacted] for land transfer duty was calculated using Revenue NSW's online transfer duty calculator[24] (for the [redacted] assessed easement acquisition total compensation amount).

[24] Revenue NSW, Transfer of land or business calculator.

9. Biodiversity offset costs

9.1. Overview

This chapter explains our forecast capex required for biodiversity offset costs for delivering the Enabling CWO RNIP. We expect to incur biodiversity offset costs related to the following scopes of work:

- augmentation works from Bayswater to Lidell and Mount Piper to Wallerawang, and
- four transmission tower line transpositions for two circuits from Bayswater to Barigan Creek and Barigan Creek to Mt Piper.

The augmentation and transposition works described in our Revenue Proposal are subject to different environmental approval pathways. This means that a different set of cost assumptions are applicable for each scope of work, particularly with regards to the likelihood of the costs occurring, and when costs are likely to become payable.

Table 9-1 provides a summary of the biodiversity offset costs for the Project over the regulatory period.

Table 9-1 Biodiversity offset costs ($M, Real 2025-26)

Capex category	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Augmentations	[redacted]					
Line transposition						
Total						

A changing regulatory environment (combined with the required timing for submission of the Revenue Proposal) means our estimates for biodiversity offset costs are currently contingent on several external factors that are not yet confirmed. Changes in these positions could materially affect costs and timing. These factors include:

- The biodiversity offset cost estimate for the Mt Piper to Wallerawang portion of the project depends on utilising offset sites to minimise cost payable. These sites cannot be confirmed prior to submission of the Revenue Proposal.
- Biodiversity offset costs are currently calculated assuming that consent for deferral of offset liability is provided and a full clearing model will apply to the Project. Each of these assumptions may not apply, resulting in changes to the biodiversity offset cost payable.
- Options available for offset acquittal may change, based on the recently introduced *Biodiversity Conservation Amendment (Biodiversity Offset Scheme) Act 2024* (NSW).
- Desktop studies were required to inform our estimate for offset costs associated with line transposition works, as site access is not possible until later in 2025.

Given these uncertainties, we consider it is appropriate to ‘true up’ our biodiversity offset cost forecast at the time the Project’s biodiversity offset liability, and relevant cost implications, are known. We have proposed an adjustment mechanism to reflect this. The proposed adjustment, and the relevant factors that necessitate this approach, are outlined further in Chapter 9.4.4.3 of our Revenue Proposal.

This chapter outlines:

- our biodiversity offset obligations, and
- our methodology for forecasting our proposed biodiversity offset costs.

9.2. Our biodiversity offset obligations

Biodiversity offsets are conservation measures intended to compensate for residual impacts on biodiversity caused by projects, to ensure there is no net loss of biodiversity arising from the activities that occur during and after construction.

The Mt Piper to Wallerawang portion of the Project has been declared by the NSW Minister for Planning and Public Spaces as Critical State Significant Infrastructure (CSSI), meaning it is essential for NSW for economic, environmental and social reasons. We also submitted a referral under the *Environment Protection and Biodiversity Conservation Act 1999* (Cth) (EPBC Act) for the Project, which has been determined as a 'controlled action' requiring Commonwealth approval.

All CSSI project applications must be accompanied by an Environmental Impact Statement (EIS). The EIS in turn requires a comprehensive assessment of biodiversity impacts from the construction and operation of the Project. The Project's planning approvals, impact mitigations and biodiversity offset obligations are required in accordance with:

- the Environmental Planning and Assessment Act 1979 (NSW) (EP&A Act)
- the Biodiversity Conservation Act 2016 (NSW) (BC Act)
- the EPBC Act

Under the BC Act, we are required to:

- avoid biodiversity impacts in the first instance
- minimise the extent of the biodiversity impacts, where impacts cannot be avoided, and
- offset the residual impacts, once avoidance or minimisation steps are exhausted.

Determining the degree to which avoidance and minimisation approaches are applied requires careful consideration of the trade-offs between biodiversity impacts and other social and economic objectives.

The resultant residual biodiversity impacts give rise to a biodiversity credit liability. There are various approaches by which credit liabilities can be satisfied or "acquitted". These include:

- establishing biodiversity stewardship sites using Biodiversity Stewardship Agreements (BSAs). BSA establishment forms the lowest-cost acquittal pathway, however, takes between two to three years to deliver, because it requires:
  - identification, landholder consultation (or land purchase) and assessment of appropriate land with the relevant flora and fauna, and
  - review and approval of the BSA applications.
- purchasing and retiring existing credits from the market (generally an intermediate cost option, however, also limited by supply)
- payment to the Biodiversity Conservation Fund (BCF), which forms the highest-cost acquittal option.

Additional measures, such as 'prescribed biodiversity conservation measures', have recently been established under the *Biodiversity Conservation (Biodiversity Offset Scheme) Amendment Act 2024* (BC Amendment Act). These are likely to provide an acquittal option similar in price to market purchase, however, the regulations establishing these mechanisms are yet to be released.

The environmental approvals process and resultant impact on biodiversity offset obligations are different for the Project's augmentation and transposition scopes of work as set out below.

9.2.1. Biodiversity offset obligations for augmentation works

The augmentation works are subject to the NSW Biodiversity Offset Scheme, which requires a Biodiversity Development Assessment Report (BDAR) to be prepared in accordance with the Biodiversity Assessment Method (BAM), including:

- an assessment of the biodiversity values of the land subject to the proposal
- an assessment of the impact of the proposal on the biodiversity values of the land, in accordance with the BAM
- measures that the proponent proposes to take to avoid and minimise the impact of the proposal
- the number and type of biodiversity credits needed to offset residual impacts of the proposal.

Consistent with our approach for Project Energy Connect and HumeLink, we have applied for consent conditions deferring the delivery of the Project offset liabilities which must be approved by the Minister for Planning with concurrence from the Minister for Environment. The outcome of our application for deferred offsets will materially impact the timing and amount of biodiversity offset costs for the augmentation works. Rejection of our deferral application will require us to acquit our liability prior to impacts to biodiversity occurring through higher-cost acquittal mechanisms, including payment into the BCF. Approval of our application will allow us sufficient time to acquit our liability at a lower cost, primarily via the establishment of BSAs. At the time of submission, we have not received a decision on this issue. Whilst we would ordinarily expect to have received an approval for offsets deferral at this stage of the process, the deferral of offsets is currently under consideration by NSW Department of Climate Change, Energy, the Environment and Water. Transgrid (and our industry partners) are currently advocating to NSW Government to retain a deferral option for CSSI projects.

9.2.2. Biodiversity offset obligations for transposition works

The transposition scope of works is separate to the Mt Piper to Wallerawang transmission line works and is therefore not deemed to be CSSI and does not require an EIS.

Under the *Electricity Network Assets (Authorised Transactions) Act 2015* (NSW), Transgrid is deemed to be an Authorised Network Operator (ANO) and can self-assess and self-determine the environmental impact of the transposition scope of works.

As no field assessment has been possible to assess the environmental impact of the transposition scope of works, it is currently uncertain whether biodiversity offset costs will apply for this portion of the Project. Field assessment of the transposition works is currently scheduled to commence in mid-2025. Greater certainty regarding any requirement for biodiversity offsets resulting from the transposition scope will be available later in 2025. If offsets are likely to be required for any of the transposition works, surveys may run from mid-late 2025 to August 2026, and the offset estimate will be refined in late 2026. Works are scheduled to commence in March 2027. If a significant biodiversity impact is identified, and the transposition works must be assessed under the NSW Biodiversity Offset Scheme, the offset liability must be acquitted prior to impacts to biodiversity occurring. The transposition works would not be eligible for consent conditions that allow offsets deferral as this portion of the Project is not designated as CSSI.

For the purposes of our Project capex forecast, we have undertaken conservative rapid desktop assessments to estimate any potential offset liability that may be required for the transposition works. These assessments assume likely significant impacts to threatened biota at all sites and that all offsets are secured through payment into the BCF. For this reason, we have proposed a biodiversity offset costs 'true-up' adjustment mechanism to ensure that consumers pay no more than necessary for biodiversity offsets, given the existing uncertainty around the total quantum of costs payable.

9.3. Capex forecast method and assumptions for offsets for augmentation works

We have based our biodiversity offset capex forecast for the augmentation scope of works on an independent cost estimation report prepared by GHD, provided as an attachment to the Revenue Proposal. GHD's cost estimate report includes forecast capex for two scenarios:

- A 'High Case' scenario that aligns with the required approach for the BAM credit calculations at this stage of the assessment and approval process and assumes all offsets are being secured through BCF payments. The High case scenario estimate is [redacted] and comprises approximately:

[redacted]

- An 'Expected Case' scenario, which adjusts the High Case scenario based on consideration of less conservative assumptions relating to assumed presence of threatened flora and fauna species; an assumption that new BSA establishment will form the primary basis for offset acquittal; that 20 per cent of ecosystem credits cannot be generated at BSAs and will be retired via payment to the BCF; and an assumption that species credits will be primarily acquitted via payment to the BCF, due to uncertainty regarding their presence at new offset sites. The Expected Case scenario is [redacted] and comprises approximately:

[redacted]

Table 9-2 summarises the High and Expected Case scenario cost estimates, prepared by GHD.

Table 9-2 GHD High and expected case scenarios ($M, Real 2025-26)

Category	High Case	Expected Case
Ecosystem credits	[redacted]	[redacted]
Species Credits		
Impact contingency		
Assessment contingency		
Credit price indexation		
Total		

To identify the likely biodiversity offset costs, GHD used the results of the survey and assessment tasks completed to date to confirm impacts upon:

- 103.37 hectares of native vegetation
- six Plant Community Types (PCTs)
- seven threatened flora species
- Habitat of nine threatened fauna species.

In determining the disturbance area, the following was assumed:

- the construction and operational footprint includes a 60 metre wide easement, three construction compounds, access tracks and brake and winch sites, and
- the footprint would be fully cleared.

The total forecast capex for biodiversity offset costs is [redacted], based [redacted] Approximately [redacted] of this cost is expected to be incurred during the development phase and will be included in our Infrastructure Planner costs. The remaining [redacted] will be incurred post 31 December 2026.

9.4. Capex forecast method and assumptions for offsets for transposition works

Biodiversity offsets would only be required for the transposition works if they are likely to significantly affect biodiversity values (and are thus required to be assessed under the NSW Biodiversity Offset Scheme). As it has not been possible to conduct field assessments at the time of submission preparation, it is currently not known whether offsets will be required. At present, our expected capex forecast is based on a high-level desktop assessment of conservative biodiversity offset cost scenarios for the transposition works.

Our capex forecast for biodiversity offset costs for the transposition scope of works conservatively assumes:

- the presence of particular PCTs and habitat within each proposal area
- PCTs / habitat are based upon desktop assessments and are subject to the limits of input data sources and interpretation of aerial photography
- the presence of threatened flora species (for those sites where presence is considered likely based upon assumed habitat)
- a significant impact on those threatened species assumed to occur
- acquittal of any offset liability via payment to the BCF.

To identify forecast biodiversity offset costs, we undertook a desktop assessment as follows:

- **Ecosystem credit generation**: the area of each PCT / Offset Trading Group (OTG) occurring within each transposition site was determined via application of the NSW State Vegetation Type Map (SVTM) to each of the transposition impact footprints with the use of GIS software. Aerial imagery was used to categorise vegetation condition states (as high, medium or low) within each OTG, and an assumed per-hectare credit generation rate applied per condition state (based upon rates indicated in recent Transgrid BDARs).

- **Species credit generation**: given the relatively small area of impact for each transposition site, it was assumed that there is no significant impact to any threatened fauna species, and thus no offset liability. Candidate threatened flora species were assessed as those species with:
  - known records within one kilometre of the impact site, and / or
  - known habitat formed by a PCT indicated as occurring within the impact footprint.
- For flora species identified as having potential habitat within the footprint, the impact area was assumed to be the total potential habitat within which the impact is occurring. Credit generation for each identified flora species was determined in accordance with the BAM and considered:
  - assumed vegetation condition
  - the type of species credit (i.e. area or count)
  - for count species, an assumed number of individuals (10)
  - the biodiversity risk weighting for each species (default value applied by the BAM).
- **Credit price**: Credit pricing assumed payment of any future transposition offset liability to the BCF and was based upon quoted prices reported in the BCF Charge Report Version 7 (December 2024). Where a directly equivalent price for the OTG and region was available, this was applied. Where a direct equivalent was not available, a nearest proxy was applied (e.g. average of prices across regions for a single OTG, or nearest higher-threat OTG within the same region).

Our assessment assumed each footprint includes:

- a permanent easement area (totalling 100 metres by 60 metres expanded area)
- construction disturbance areas
- access tracks 8 metres in width

The total forecast capex for biodiversity offset costs for transposition works is [redacted]. Approximately [redacted] of this cost is expected to be incurred during the development phase and will be included in our Infrastructure Planner costs. The remaining [redacted] will be incurred post 31 December 2026.

Table 9-3 summarises the results of these desktop assessments.

Table 9-3 Rapid desktop assessment results ($M, Real 2025-26)

Site	Ecosystem Credits	Species Credits	Total
[redacted]			
Total	[redacted]		

Field assessment of the transposition works is currently scheduled to commence in mid-2025. Greater certainty regarding any requirement for biodiversity offsets resulting from the transposition scope of works will be available later in 2025. For this reason, we have proposed a biodiversity offset costs 'true-up' adjustment mechanism to ensure that consumers pay no more than necessary for biodiversity offsets, given the existing uncertainty around the total quantum of costs payable.

9.5. E3 review of our biodiversity offset cost estimate

We engaged E3 Advisory to undertake an independent verification and assessment of our biodiversity offset capex forecast for both the augmentation and transposition scope of works (noting that GHD has prepared both the biodiversity offset cost estimate for the augmentation works and the independent cost verification report).

E3 considered that the design envelope used to determine the area of disturbed land that may require biodiversity offsets was appropriate for the construction activities and the approach and calculation of the biodiversity offsets was well documented, prudent and efficient. E3's report is provided as an attachment to the Revenue Proposal.

10. Labour and indirect costs

We forecast a total of $70.0 million in capex for labour, labour-related and indirect costs to support the safe, efficient and timely delivery of the Project across its development, construction and commissioning phases. This includes:

- $8.2 million in pre-period project expenditure, and
- $61.9 million in forecast capex over the 2026-31 regulatory period.

This forecast is essential to securing the skilled workforce, professional services and supporting infrastructure needed to meet the Project's scope, schedule and compliance obligations.

Key components of forecast include:

- **Direct internal labour costs** which cover project development, project delivery management, community and stakeholder engagement, land and environmental activities and other support and corporate activities
- **Direct labour-related costs** which cover travel expenses, training, recruitment and IT hardware costs, and
- **Indirect costs** which primarily cover professional and consulting services, including support for environmental management, and a share of capitalised labour and related costs.

Table 10-1 sets out our annual forecasts over the 2026-31 regulatory period. Our approach to calculating these costs and a detailed explanation of the cost breakdown and assumptions are provided in our Labour and Indirect Capex Forecasting Methodology, provided as an attachment to our Revenue Proposal.

Table 10-1 Total labour and indirect forecast capex for the Project, including pre-period capex ($M, Real 2025-26)

	Pre-period	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Pre-period costs	8.2	-	-	-	-	-	8.2
Augmentation forecast capex from 1 January 2027							
Direct labour	-	11.5	21.9	3.2	-	-	36.5
Direct labour-related	-	1.3	3.1	-	-	-	4.5
Indirect	-	6.9	12.5	1.4	-	-	20.8
Total	**8.2**	**19.7**	**37.6**	**4.6**	**-**	**-**	**70.0**

Note: This does not include Infrastructure Planner costs. Infrastructure Planner costs are discussed in Chapter 4.

The labour and indirect capex forecast reflects the Project's unique and complex delivery environment, which drives the scope, timing, and scale of labour requirements across the regulatory period. We need to coordinate a major infrastructure delivery project involving greenfield and brownfield works, multiple delivery partners, and tight regulatory and environmental constraints. In particular:

- The Project involves interdependent contractual arrangements with EnergyCo, ACEREZ and the D&C contractor that require active coordination to mitigate delivery and compliance risks.
- We must deliver both brownfield and greenfield works, with existing asset upgrades needed before energising the new BCSS.
- Delivery interfaces with ACEREZ must be closely managed, particularly under shared environmental, design and commissioning responsibilities.
- As the licensed Transmission Network Service Provider for NSW, we must ensure the safe and efficient integration of new infrastructure into the broader transmission network, while enabling the connection of renewable generation.

To meet these delivery requirements, a stable, skilled and flexible workforce is essential, supported by expert services and enabling processes and systems.

In addition, we are committed to delivering this Project at the lowest sustainable cost, while meeting our contractual delivery, regulatory and community obligations. To support this objective, our forecasting approach has been designed to ensure costs are well-justified and aligned with efficient delivery, including:

- a bottom-up build for internally derived cost categories, including labour and labour-related costs, based on forecast roles and activity schedules.
- use of supplier estimates and market-based benchmarks for indirect services, such as environmental consultants and commercial advisors.
- independent assurance review by our external advisor, GHD, which reviewed and validated the scope of works and associated cost forecasts.

These measures demonstrate that the forecasts are prudent, efficient and reasonable, and in line with the requirements of the EII Act, EII Regulations and EII Chapter 6A.

Further detail on our assumptions and forecasting method is provided in the Labour and Indirect Methodology attachment to this Revenue Proposal.

11. Escalators and equity raising costs

11.1. Real labour input escalation

Our labour costs were prepared in real 2025-26 dollars and labour escalation need to be applied from 2026-27. Where possible, we have adopted the labour escalators in the AER's 2023-28 Revenue Determination. Given that the AER's determination only includes forecasts out to 2027-28, we have extrapolated the forecast by setting the 2028-29, 2029-30 and 2030-31 real labour escalators equal to the average of that adopted by the AER for 2026-27 to 2027-28.

Table 11-1 Real labour escalation forecast for the 2026-31 regulatory period

Component	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Real labour escalation (%)	0.43%	0.30%	0.37%	0.37%	0.37%	N/A
Real labour escalation ($M, Real 2025-26)	**0.1**	**0.2**	**0.0**	**-**	**-**	**0.3**

11.2. Equity raising costs

Equity raising costs are estimated in two steps:

1. The PTRM calculates the share of earnings paid out and then reinvested and the uses these values – along with forecast cash flows – to determine how much additional equity is needed to maintain a 60 per cent leverage ratio
2. The PTRM calculates the costs of the various funding sources, namely retained earnings, reinvested dividends, and equity offerings.

To apply this method, we propose adopting the parameters that the AER adopted for the 2023-28 Revenue Determination for our prescribed transmission services as placeholders for determining the regulated revenues for this Project:

- imputation payout ratio (or earnings payout ratio) – of 87.87 per cent per dollar of income generated
- dividend reinvestment plan take up – of 30 per cent of each dollar paid out as dividends
- subsequent equity raising cost – of 3 per cent per dollar of equity raised in a subsequent equity raising, and
- dividend reinvestment plan cost – of 1 per cent per dollar of equity reinvested.

Applying this approach and assumptions gives the equity raising cost forecasts set out in Table 11-2.

Table 11-2 Forecast equity raising costs ($M, Real 2025-26)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Equity raising costs	1.6	-	-	-	-	1.6
Total	**1.6**	**-**	**-**	**-**	**-**	**1.6**

12. Independent external validation

We engaged GHD to undertake an independent verification and assessment of our capex forecast for the Project. GHD independently verified and assessed:

- whether the scope of the Project is appropriate to meet the requirements of the Consumer Trustee Authorisation and the Project Deed
- whether the capex forecast includes any payments required to be made by us to the Infrastructure Planner under any contractual arrangement
- the accuracy and supportability of the capex forecast at this stage of the Project using a range of assurance techniques. These include validation against tender results, benchmarking against comparative projects, selection testing, recalculation, and alignment with industry practice
- whether capex costs for development and construction for the network infrastructure project are prudent, efficient, and reasonable.

Overall, GHD concluded that our development and construction capex is prudent, efficient and reasonable. GHD's independent review therefore supports the consistency of our forecast capex with that which would be incurred by a prudent, efficient and reasonable business.

GHD's report is provided as an attachment to this Revenue Proposal.