Revenue Proposal

Hunter-Central Coast Renewable Energy Zone Network Infrastructure Project

16 May 2025

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Ausgrid

Acknowledgement of Country

The Ausgrid Group acknowledges and pays respect to the people of the Awabakal, Bahtabah, Biraban, Darkinjung, Mindaribba, Wanaruah and Worimi nations, as the Traditional Custodians of the land on which the Hunter-Central Coast REZ will be delivered. We honour all Aboriginal and Torres Strait Islander peoples for their unique ability to care for Country and deep spiritual connection to it. We honour Elders past, present and future, understanding their knowledge and wisdom ensures continuation of culture and traditional practices. We recognise and value the contributions of the Ausgrid Group's First Nations employees for sharing their knowledge and experiences, and for their continued work within the organisation to move us towards our future aspirations.

Contents

Glossary

Term	Description / Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Antiene STSS	Formerly known as Eastern Hub STSS
BSP	Bulk supply point
CAM	Cost Allocation Methodology
Capex	Capital Expenditure
CESS	Capital Expenditure Sharing Scheme
Commitment Deed	The Hunter-Central Coast Renewable Energy Zone REZ Network Infrastructure Commitment Deed executed on 17 December 2024
CPI	Consumer Price Index
Determined Service Payment or DSP	The quarterly payments approved by the AER and paid to Ausgrid by the Scheme Financial Vehicle
DNSP	Distributed Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
EII Act	*Electricity Infrastructure Investment Act 2020*
EII Chapter 6A	The AER is required to assess our Revenue Proposal against a framework modelled on the economic regulation applied to electricity network businesses under the NER. This new framework of rules is referred to as 'EII Chapter 6A'.
EIS	Environmental Impact Statement
EMF	Electromagnetic field
EnergyCo	Energy Corporation of NSW
EP&A Act	*Environmental Protection and Assessment Act 1979*
GW	Gigawatt
HCC	Hunter-Central Coast
HCC LEC	Hunter-Central Coast Local Engagement Committee
HCC REZ Reg Panel	Hunter-Central Coast Renewable Energy Zone Regulatory Panel
HCC RNI	HCC REZ Network Infrastructure Project
HTP	Hunter Transmission Project
Hunter-Central Coast REZ	Hunter-Central Coast Renewable Energy Zone
IAP2	International Association for Public Participation
ISP	Integrated System Plan
JLL	Jones Lang LaSalle

Term	Description / Definition
kV	Kilovolt
MAR	Maximum allowed revenue
MVA	Megavolt-amps
MW	Megawatt
NER	National Electricity Rules
NIS	Network Infrastructure Strategy
NSP	Network Services Provider
Opex	Operational Expenditure
OOS	Out of service
OPGW	Optical fibre ground wire
Panel ToR	Panel Terms of Reference
PTRM	post-tax revenue model
Project Deed	The draft Hunter-Central Coast Renewable Energy Zone REZ Network Infrastructure Project Deed which was attached to the Commitment Deed
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
REF	Review of Environmental Factors
Regulatory Period	1 July 2026 to 30 June 2031
Revenue Determination	The revenue determination made in respect of the HCC RNI Project in response to this Revenue Proposal
Revenue Proposal	This revenue proposal in respect of the HCC RNI Project
REZ	Renewable energy zone
RNI	REZ network infrastructure
Roadmap	The NSW Electricity Infrastructure Roadmap
RoRI	Rate of Return Instrument
SER	Summary Environmental Report
SFV	Scheme Financial Vehicle
Sandy Creek STSS	Formerly known as Muswellbrook STSS
Social Licence Plan	A plan outlining how our social licence investments will be implemented
STS	Subtransmission substation
STSS	Subtransmission switching station
TCD	Transmission Cost Database
TET	Transmission Efficiency Test

Term	Description / Definition
WACC	Weighted average cost of capital
ZS	Zone substation

1 Executive Summary

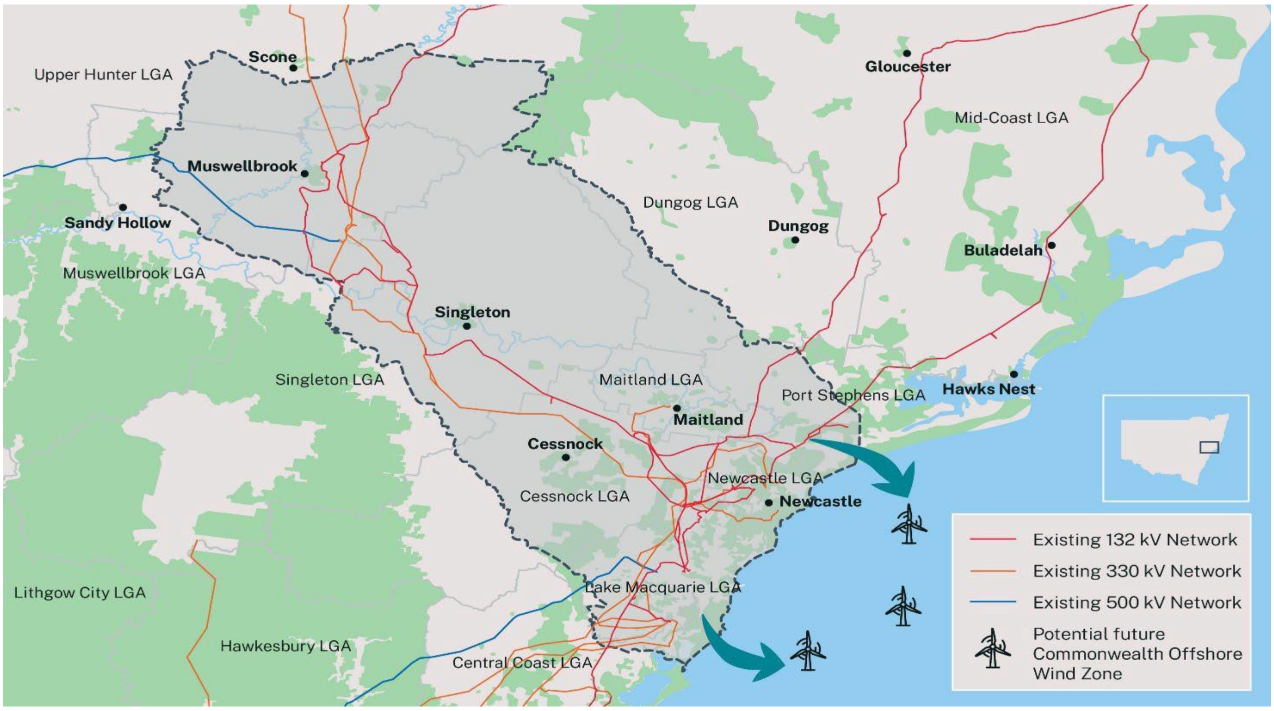
We are pleased to submit our **Revenue Proposal** to the Australian Energy Regulator (**AER**) for the delivery of the Hunter-Central Coast Renewable Energy Zone Network Infrastructure Project (**HCC RNI Project**). This Revenue Proposal covers the initial Regulatory Period from 1 July 2026 to 30 June 2031.

Ausgrid owns and operates a shared distribution grid that stretches from southern Sydney to the Upper Hunter Valley, including the Sydney CBD. More than 4 million Australians rely on our infrastructure to power their homes and businesses every day. Our vision is for our communities to have the power in a resilient, affordable and sustainable future.

1.1 Hunter-Central Coast Renewable Energy Zone

The Hunter-Central Coast Renewable Energy Zone (**Hunter-Central Coast REZ**) covers an area extending from the Upper Hunter to Newcastle and the east coast and has a declared capacity of 1 GW. The HCC RNI Project is Ausgrid's proposed solution to deliver 1 GW of network capacity to support connection of renewable energy generation and storage within the Hunter-Central Coast REZ.

Figure 1: Geographic area of the Hunter-Central Coast REZ



Source: *EnergyCo website*

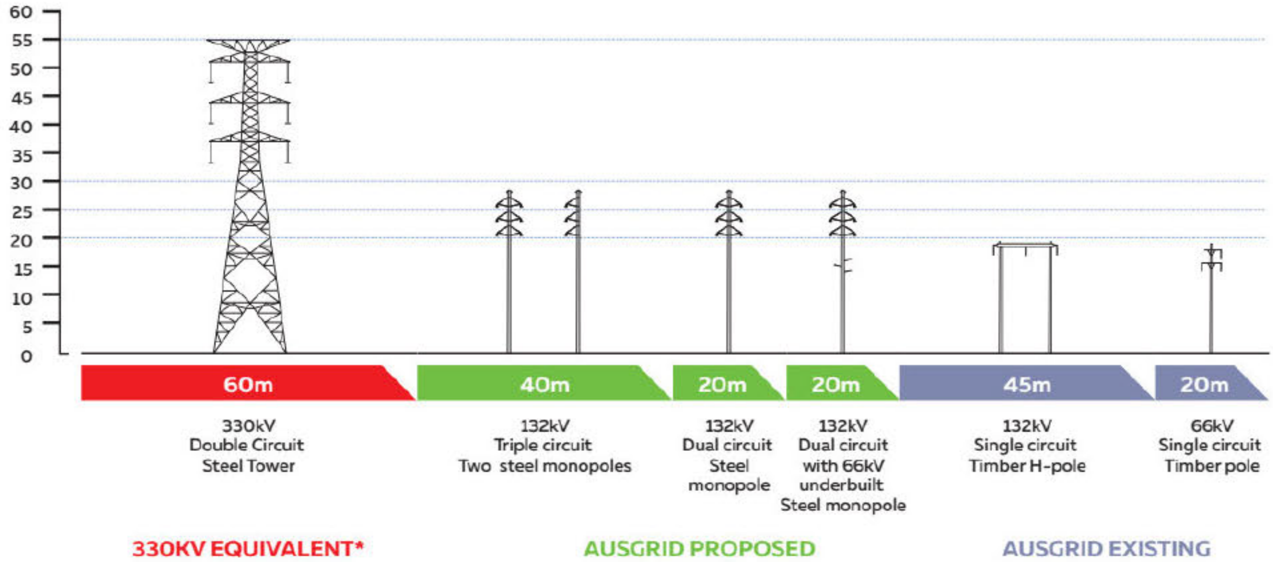
1.2 Cheaper, faster and less disruptive

The HCC RNI Project is the first 'subtransmission' or 'distribution' REZ network infrastructure project authorised under the NSW Government's Electricity Infrastructure Roadmap. This is a major milestone that illustrates how upgrading distribution networks within REZs can increase network capacity and unlock a cheaper, faster and less disruptive energy transition. The HCC RNI achieves this by using smaller network structures than traditional transmission scale investments, and leveraging existing assets and corridors, as outlined in Table 1 and Figure 2.

Table 1: Key elements of the HCC RNI Project

Key element		Description
	1 GW	of additional renewable generation transfer capacity created
	132 kV	solution – enabling smaller structures than any alternate 330 kV solution
	85 km	of existing Ausgrid network corridors to be upgraded with higher capacity lines
	2	new substations to be built
	2	existing substations to be upgraded
	13 km	of new underground fibre
	$591 m	in total capital investment in Ausgrid's network (real, 2025-26)
FINISH	**Mid-2028**	completion date

Figure 2: Comparing the HCC RNI's 132 kV solution to other structures



*Source: Transgrid (6 December 2021) *Environmental Impact Statement - Energy Connect (NSW - Eastern Section) - Technical paper 13 - Electric and magnetic field study*. Available at: https://www.transgrid.com.au/media/0yijlr0d/technical-paper-13-electric-and-magnetic-field.pdf

Ausgrid's proposed solution (shown above in green) builds 132 kV assets in existing corridors.

This solution is more visually appealing than taller 330 kV towers, involves smaller easements and requires little land acquisition – resulting in lower costs, greater certainty of delivery, and better social and environmental outcomes.

1.3 Overview of the regulatory process leading up to this Revenue Proposal

Under the *NSW Electricity Infrastructure Investment Act* 2020 (**EII Act**), the Minister declared the Hunter-Central Coast REZ on 9 December 2022 with an intended network capacity of 1 GW, with the Energy Corporation of NSW (**EnergyCo**) appointed as the Infrastructure Planner.

In 2023, both the Network Infrastructure Strategy (**NIS**)[1] published by EnergyCo and the Infrastructure Investment Objectives Report (**IIO Report**)[2] published by AEMO Services Ltd (**ASL**) (appointed as the Consumer Trustee) identified a need of 1 GW of network transfer capacity in the Hunter-Central Coast REZ with a target a date of 2027.

In October 2023, EnergyCo invited both existing network operators (Ausgrid and Transgrid) to put forward proposals to deliver 1 GW of network transfer capacity with a target date of 2027. In September 2024, after evaluating the two proposals, EnergyCo selected Ausgrid as the recommended Network Operator.

In April 2025, EnergyCo recommended to the Consumer Trustee that Ausgrid should be authorised to carry out the HCC RNI Project. This recommendation included EnergyCo's findings that the HCC RNI Project is expected to provide $270.5 million (real $2024) in net benefits and maintain reliability of supply.[3]

In April 2025, the Consumer Trustee authorised Ausgrid under the EII Act to deliver the HCC RNI Project. The AER is now tasked with setting the revenue allowance that can be recovered in respect of the HCC RNI based on the prudent, efficient and reasonable costs of constructing and operating the Project (the **Revenue Determination**).

1.4 Prudent, efficient and reasonable expenditure

Our forecasts for capital expenditure (**capex**) and operating expenditure (**opex**) were developed over a 12-month process that included a competitive tender administered by EnergyCo. The process of tendering to deliver the HCC RNI Project exerted competitive pressure on Ausgrid to forecast prudent, efficient and reasonable costs. Our forecast has also been subject to Ausgrid's internal governance processes, external independent review and market testing.

The HCC RNI Project will be delivered under a blended model that employs both Ausgrid and external resources. This is ***prudent*** because it leverages Ausgrid's comparative advantages where we have existing resources (e.g. expertise or existing field force) to undertake a task at the most ***efficient*** cost.

1 The NIS is a 20-year strategy for the coordination of NSW network infrastructure to connect new generation, firming and storage in NSW's REZs, which includes the Hunter-Central Coast REZ. The Energy Corporation of NSW, The NSW Network Infrastructure Strategy, May 2023.
2 The IIO Report is published by ASL under section 45 of the EII Act and includes setting out the 20-year development pathway to achieve the infrastructure investment objectives that is in the long-term financial interests of NSW electricity customers. AEMO Services Ltd, 2023 Infrastructure Investment Objectives Report, December 2023.
3 EnergyCo, Hunter-Central Coast Renewable Energy Zone: Summary of EnergyCo's network recommendation, April 2025, page 10

Under this blended model, approximately 70% of our forecast Project capex is subject to market-tested costs derived in accordance with competitive procurement processes.

To further test prudence and efficiency, we engaged GHD to undertake a 'bottom up' review of the unit rates and key inputs into our capex forecast based on a detailed scope of work. GHD concluded that the capex forecast is prudent, efficient and reasonable for carrying out the Project.

1.5 Capital expenditure

Our total forecast capex for the 2026-31 Regulatory Period is $590.8 million (real 2025-26).

Our proposed capex includes a 5-year forecast Regulatory Period and pre-period expenditure that Ausgrid has or will incurred prior to the start of that period. The pre-period expenditure includes project development and 'early works' undertaken by Ausgrid and an Infrastructure Planner Fee which reimburses EnergyCo's costs for undertaking development functions and operations activities in respect of the HCC RNI Project. The EnergyCo component is $92.9 million and is displayed as a single line item below. The Ausgrid component is $69.8 million but is incorporated in the relevant categories of pre-period expenditure shown in Table 2. Further details on the Infrastructure Planner Fee are included in section 5.4.8.

Table 2: Proposed capex split by pre-period and 2026-31 expenditure ($m, real 2025-26)

	Pre-period	2026-31 period	Total
Transmission	80.8	122.2	**203.1**
Substations	28.7	77.5	**106.2**
Land and easements	2.2	21.4	**23.7**
Secondary systems	0.9	3.1	**4.0**
Communications	5.3	2.5	**7.7**
Owner's costs	21.9	32.7	**54.6**
Design, social licence and other	37.0	14.7	**51.8**
Infrastructure Planner Fee (EnergyCo component)	92.9	0.0	**92.9**
Risk costs	13.2	33.7	**46.9**
Total	**283.0**	**307.9**	**590.8**

1.6 Operating expenditure

Our total forecast opex for the 2026-31 Regulatory Period is $15.6 million (real 2025-26). This has been developed based on a bottom-up build, as there is no representative base year from a preceding Regulatory Period to apply a 'base-step-trend' approach. Further, we have forecast an apportionment of our shared business costs (or overheads) based on our updated AER approved cost allocation methodology (**CAM**). There is no 'pre-period' opex that we are seeking to recover in our Revenue Proposal.

Table 3: Proposed opex split by pre-period and 2026-31 expenditure ($m, real 2025-26)

	Pre-period	2026-31 period	Total
Vegetation management	-	0.9	**0.9**

	Pre-period	2026-31 period	Total
Maintenance	-	1.3	**1.3**
Network operations	-	2.8	**2.8**
Overheads	-	10.5	**10.5**
Total	**-**	**15.6**	**15.6**

1.7 Forecast revenue and payment schedule

Our total 2026-31 forecast revenue of $200.3 million (nominal) will fund the delivery and operations of the HCC RNI. Table 4 shows the year-by-year breakdown of our proposed revenue.

Table 4: Maximum allowed revenue over 2026-31 Regulatory Period ($m, nominal)

	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Return on capital	19.8	36.6	41.7	42.3	42.2	**182.5**
Return of capital	2.0	(4.2)	(2.6)	1.2	1.7	**(1.9)**
Operating expenditure	0.3	2.6	4.3	5.5	5.9	**18.6**
Revenue adjustments	0.0	0.0	0.0	0.0	0.0	**0.0**
Corporate income tax	0.3	0.6	0.1	0.0	0.0	**1.0**
Maximum allowed revenue	**22.4**	**35.5**	**43.5**	**49.0**	**49.8**	**200.3**

Ausgrid will recover the maximum allowed revenue (**MAR**) approved by the AER via quarterly payments (**Determined Scheme Payments**) paid by the Scheme Financial Vehicle. Table 5 shows the forecast quarterly payments for the 2026-31 Regulatory Period. The total differs from the MAR calculated in Table 4 due to the timing difference between the quarterly payments and annual revenues. In net present value terms, the MAR and the quarterly payments are the same.

Table 5: Forecast quarterly payments for the 2026-31 Regulatory Period ($m, nominal)

	Quarter 1 (September)	Quarter 2 (December)	Quarter 3 (March)	Quarter 4 (June)	Total
2026-27	5.3	5.4	5.5	5.6	**21.9**
2027-28	8.5	8.6	8.7	8.9	**34.7**
2028-29	10.4	10.5	10.7	10.9	**42.5**
2029-30	11.7	11.9	12.1	12.3	**47.8**
2030-31	11.8	12.0	12.2	12.4	**48.6**
Total					**195.4**

1.8 Community consultation and customer engagement

Our approach to community consultation and engagement for the HCC RNI Project has been transparent, comprehensive and open-minded. We have partnered with our customer representatives and other stakeholders to inform our decision-making and to develop this Revenue Proposal.

Our main engagement for the Revenue Proposal has been through our Hunter-Central Coast Renewable Energy Zone Regulatory Panel (**HCC REZ Reg Panel**). This panel comprises three members, two of whom are part of our ongoing Customer Consultative Committee and one who is part of our ongoing Network Innovation Advisory Committee. Each member was selected to provide a range of economic, engineering, legal, policy and engagement expertise.

In addition to consultation through the HCC REZ Reg Panel, we have undertaken comprehensive stakeholder and community consultation through numerous engagement and communication activities. We have developed a targeted, Project-specific engagement approach with the aim of:

- building trust and confidence
- reaching diverse audiences
- understanding local aspirations and preferences.

1.9 Land requirements and environmental approvals

In keeping with our focus on delivering the HCC RNI in a manner that is efficient and prudent, the proposed infrastructure utilises structures that have a smaller footprint than corresponding 330 kV alternatives, and substantially reuses existing 132 kV transmission line corridors, minimising the requirement for new easements for assets or access paths.

Reuse of existing corridors minimises the need for land acquisition and enables a Review of Environmental Factors (**REF**) planning pathway, significantly streamlining time and costs while maintaining a robust process that ensures environmental impacts are effectively identified, assessed and mitigated.

1.10 Incentive schemes

Incentive schemes are an important part of the regulatory framework. These schemes offer incentives to network businesses (such as Ausgrid) to outperform their AER-approved expenditure allowances so that customers do not pay any more than is necessary for the services they receive.

Table 6 summarises the incentive schemes Ausgrid proposes to apply to the HCC RNI Project.

Table 6: Incentive schemes proposed for HCC RNI Project

Incentive scheme	Description
Efficiency Benefit Sharing Scheme (**EBSS**)	The EBSS incentivises us to pursue continuous opex efficiencies.
Capital Expenditure Sharing Scheme (**CESS**)	The CESS incentivises us to undertake efficient capex.

We propose that the EBSS and CESS apply. We do not propose any amendments to the standard EBSS scheme, however propose two modifications to the CESS:

- to include pre-period expenditure in the capex allowance that is subject to CESS

- to exclude our proposed Social Licence Plan expenditure from the capex allowance that is subject to CESS.

1.11 About us and this Revenue Proposal

Ausgrid owns and operates the network of substations, powerlines, underground cables, and power poles that delivers electricity to communities in large parts of Greater Sydney, the Central Coast and the Hunter.

We build, operate and maintain this distribution network with a focus on providing a safe, reliable and efficient energy supply to over 4 million Australians. Our vision is simple; for our communities to have the power in a resilient, affordable and sustainable future.

The Hunter-Central Coast REZ is part of the NSW Electricity Infrastructure Roadmap. The Roadmap establishes a regulatory and commercial framework for delivering multiple REZs across NSW that are critical to unlocking a more sustainable, net-zero future and maintaining a reliable electricity supply as coal fired power stations approach their scheduled closure. REZs are akin to modern-day power stations that use renewables like solar and wind. They also require medium to high voltage network infrastructure to connect the generation sources to the grid. The HCC RNI Project will deliver 1 GW of network capacity within the Hunter-Central Coast REZ.

The key features of Ausgrid's delivery of the HCC RNI are:

1. **Fast, efficient delivery of 1 GW of transfer capacity**

   We commenced 'early works' on the Project at the start of 2025 and plan to connect generators as early as January 2026, with full 1 GW transfer capacity achieved by July 2028. This follows a multi-stage delivery model where generators connect over three portions, as and when the transfer capacity becomes available.

2. **Leveraging a more economical, first of its kind subtransmission solution**

   The HCC RNI Project is the first 'subtransmission' REZ network infrastructure project authorised under the NSW Electricity Infrastructure Roadmap. By leveraging lower cost 132 kV lines, it will deliver a more economical solution compared to >330 kV 'transmission' solutions that have traditionally been used to increase network transfer capacity.

   Our approach involves using 132 kV feeders to connect the Hunter-Central Coast REZ generators to local loads. This eases pressure on the transmission network by freeing up capacity in the 330 kV grid. Residual generation output that is not utilised by local loads will be carried to existing 330/132 kV main grid exit points. Generators will also incur lower connection costs under our solution as their output does not need to step up to 330 kV.

3. **Putting the community first using an innovative solution and authentic engagement**

   Our solution almost entirely repurposes existing Ausgrid corridors with higher capacity lines. This helps minimise community impacts compared to an option involving completely new lines and easements.

While less disruptive than other solutions, we have still sought to engage with the community by leveraging existing relationships and drawing on our role as the largest network operator in the Hunter-Central Coast region. We have also developed a comprehensive Industry and Aboriginal Participation Plan that builds on Ausgrid's commitment to investing in real, meaningful training pathways and promoting sustainable employment opportunities.

4. **Maximising environmental outcomes to promote a sustainable future**

We have invested prudently in environmental and Aboriginal heritage investigations to ensure the HCC RNI Project can be delivered with minimal impact.

The smaller footprint of our subtransmission assets (132 kV) compared to 330 kV alternatives further minimises environmental impacts, including visual amenity.

1.12 Processes under the NSW Electricity Infrastructure Roadmap

On 17 April 2025, AEMO Services Limited, acting in its capacity as Consumer Trustee, authorised Ausgrid as the network operator for the HCC RNI Project following a recommendation from EnergyCo, as the Infrastructure Planner.

The information below summarises this process by setting out the roles and responsibilities under the NSW Energy Infrastructure Roadmap in respect of REZ network infrastructure (Table 1-1) and how they have applied to the HCC RNI Project (Table 1-2). It shows that these processes include a competitive tender administered by EnergyCo followed by an independent check and authorisation by the Consumer Trustee. The AER's assessment and Revenue Determination is the final step.

Table 1-1: Roles and responsibilities under the NSW Energy Infrastructure Roadmap for non-contestable projects

NSW GOVERNMENT	EnergyCo	• Recommends REZ network infrastructure projects to the Consumer Trustee for authorisation. • Works with communities, investors and industry to coordinate investment in REZ network infrastructure to connect renewable energy generation and storage infrastructure in REZs for the long-term benefit of energy consumers, local communities and industry in NSW.
AEMO SERVICES	Consumer Trustee	• Authorises a network operator to carry out a REZ network infrastructure project taking into consideration the long-term financial interests of NSW electricity consumers. • Consumer Trustee sets the initial Maximum Capital Costs for the prudent, efficient and reasonable development and construction of the REZ network infrastructure that may be determined by the AER in its role. The Consumer Trustee shares its calculation of Maximum Capital Cost with the AER and Minister only.

AUSTRALIAN ENERGY REGULATOR	• Calculates the prudent, efficient and reasonable capital costs for development and construction of REZ network infrastructure, which is referred to as the Transmission Efficiency Test (**TET**). At the outset, this amount cannot exceed the Consumer Trustee's calculation of Maximum Capital Cost. • AER's Revenue Determination must also include an allowance for operating costs and several other matters typical of a reset process under the National Electricity Rules (**NER**).

1.13 How this Revenue Proposal applies the EII regulatory framework

The AER is required to assess our Revenue Proposal and make the Revenue Determination against a framework modelled on the economic regulation applied to electricity network businesses under Chapter 6A of the NER. This new framework of rules is referred to as 'EII Chapter 6A'. While similar to the NER, EII Chapter 6A includes some important differences, as noted in Table 1-2.

Table 1-2: Comparing the regulatory processes under the NER and EII Act

	NER	EII Chapter 6A	Difference
Regulatory review	The AER must accept a forecast that reflects the efficient costs a prudent operator would require in achieving the expenditure objectives.	Network operator is entitled to recover the prudent, efficient and reasonable costs incurred by the network operator for carrying out the infrastructure project.	EII Chapter 6A introduces the concept of recovering 'reasonable' costs. It also requires that the AER evaluate if these costs are reasonable for delivering a specific project, rather than assessing if the costs meet certain expenditure objectives as required under the NER.
Project scope	Network businesses identify potential projects. AER has discretion to set expenditure based on a narrower or different scope or reject the proposed scope of a project in full.	EnergyCo sets project scope with input from Consumer Trustee. EnergyCo negotiates an upper limit on the project capex with the recommended Network operator.	Project scope for HCC RNI is set by contractual framework between Ausgrid and EnergyCo.
Competitive processes	Ausgrid uses market-based mechanisms to source materials and contracted services.	Though not required for a non-contestable project, EnergyCo ran a tender process for the right to deliver HCC RNI. Ausgrid ran competitive tenders for the work it intends to outsource.	EnergyCo tender process exerted competitive pressure on Ausgrid's bid to reflect prudent, efficient and reasonable costs.
Resourcing and delivery	Large programs of work predominately based on Ausgrid's internal unit rates (subject to review against benchmark rates).	Competitive delivery model with substantial outsourcing for the construction of transmission lines, two greenfield subtransmission switching stations, fibre,	Up to 70% of Ausgrid's HCC RNI forecast costs to be externally delivered with costings derived from competitive tender process.

	NER	EII Chapter 6A	Difference
		civil works and greenfield substations.	
Customer perspective	Ausgrid and AER appointed customer representative panels.	Ausgrid and AER appointed panels plus AEMO Services acting as Consumer Trustee.	Independent review by AEMO Services included a customer perspective in its determination of the long-term financial interests of consumers

More broadly, this Revenue Proposal takes into account:

- the EII Act
- the Electricity Infrastructure Investment Regulation 2021 (NSW) (**EII Regulations**)
- AER's TET and Revenue Determination Draft Guideline: NSW non-contestable network infrastructure projects (**AER TET non-contestable Guideline**)
- AER's Better Resets Handbook
- EII Chapter 6A.

1.14 Non-contestable project subject to a competitively tendered process

The HCC RNI Project is a non-contestable project for the purposes of the AER's processes; however, Ausgrid was competing against another proponent when tendering for the Project. This exerted competitive pressure on Ausgrid to forecast prudent, efficient and reasonable costs, which is reflected in the Commitment Deed. Our forecast has also been subject to Ausgrid's internal governance processes, external independent review and market testing.

This Revenue Proposal also addresses:

- the AER's Information Notice
- how we have complied with the Consumer Trustee's authorisation (in section 2.3)
- the contractual arrangements relating to HCC RNI, in particular the Project Deed.

Given the close alignment between EII Chapter 6A and the NER framework we have, where possible, aligned our positions and approaches in this Revenue Proposal with those approved in the AER's 2024-29 Regulatory Determination (made under the NER) for our standard control services.

For example, we have adopted the decisions in the AER's 2024-29 Regulatory Determination for:

- nominated adjustment events
- standard asset lives with the addition of a new asset class for the Infrastructure Planner Fee

As required under the EII Act regulatory framework, we have also adopted the most recent version of the AER's Rate of Return Instrument (**RoRI**) to calculate our return on capital allowance in this Revenue Proposal. The 2022 RoRI was the latest available at the time of preparing this Revenue Proposal.

1.15 Structure of this Revenue Proposal

This Revenue Proposal is structured as follows:

- Executive Summary
- Chapter 1: Introduction to Ausgrid and this Revenue Proposal for the HCC RNI Project
- Chapter 2: Overview of how this Revenue Proposal is consistent with the Consumer Trustee's authorisation and the contractual arrangements with EnergyCo
- Chapter 3: Overview of our engagement approach, activities and what we have heard from our customers and other stakeholders
- Chapter 4: Proposed opex forecast
- Chapter 5: Proposed capex forecast, including 'pre-period' expenditure
- Chapter 6: Details on our proposed revenue
- Chapter 7: Application of the AER's expenditure incentive schemes
- Chapter 8: Proposed adjustment events
- Chapter 9: Other matters including approach to confidential information and the assurance certification we are required to provide, including key assumptions supporting our expenditure forecasts.

Relevant attachments that support this proposal are also referenced throughout.

1.16 Conventions

In this Revenue Proposal, unless otherwise specified:

- all expenditure dollars are forecast and presented in end-year (to 30 June) real 2025-26 dollars unless otherwise specified
- negative figures are presented in brackets
- our revenue building-blocks from the post-tax revenue model (**PTRM**) are presented in end-year (to 30 June) nominal dollars
- totals presented in tables may not add due to rounding
- all figures and tables have been prepared from material sourced by Ausgrid, unless otherwise specified.
- Our forecast expenditure in this Revenue Proposal relates to the HCC RNI Project only (as our first project delivered under the EII Act). The allocation of Ausgrid overhead costs to this project is in accordance with our CAM.

2 About the HCC RNI Project

On 17 April 2025, AEMO Services Limited, acting in its capacity as Consumer Trustee, authorised Ausgrid as the network operator for the HCC RNI.

The Project consists of three portions that will collectively provide 1 GW of network transfer capacity within the Hunter-Central Coast REZ in a manner that minimises disruption to local communities, avoids significant environmental impact and is predominantly confined to landowners who already host electricity infrastructure.

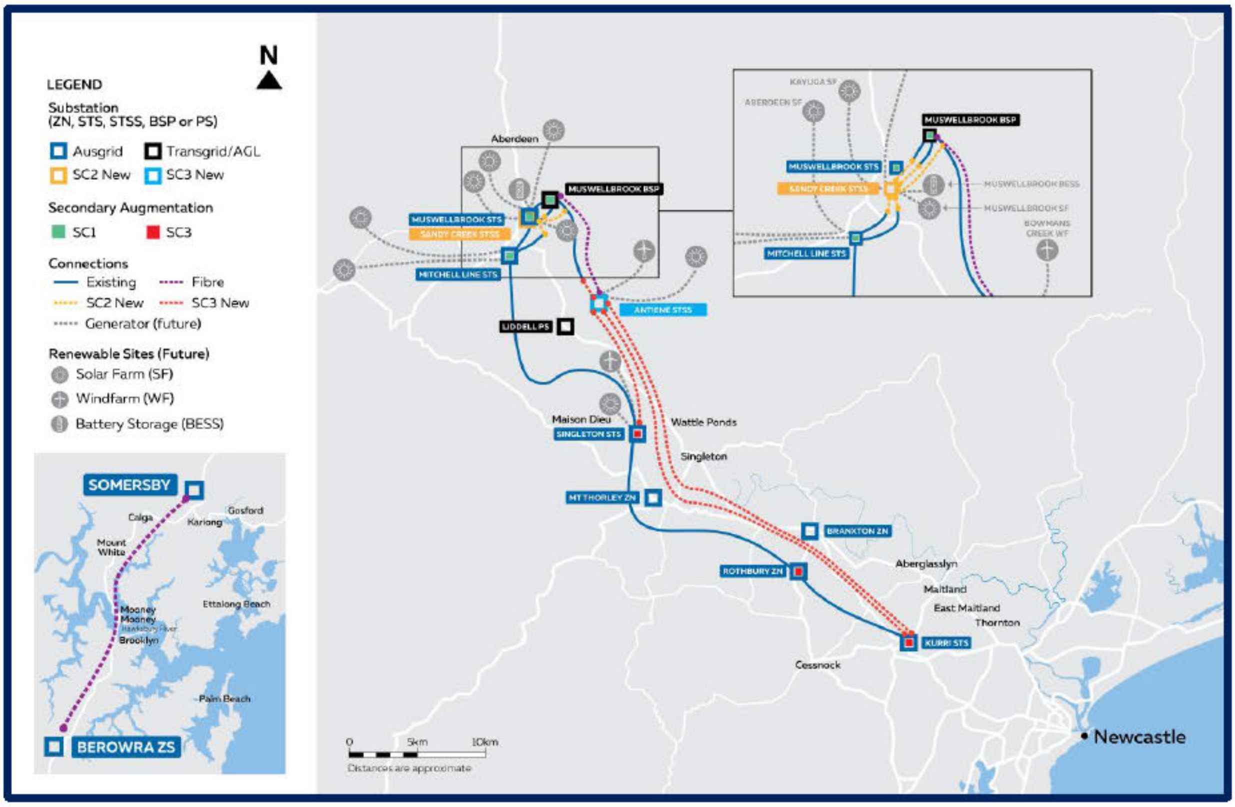
This chapter describes the Project timing, overall Project benefits, and how the proposal meets the requirements of the Consumer Trustee's authorisation.

2.1 Key elements of the Project

The three portions of the HCC RNI Project comprise:

- **Portion 1:** Modernisation of the Upper Hunter secondary systems (providing a total of 350 MW additional network transfer capacity), which is scheduled to complete in December 2025
- **Portion 2:** Construction of a new 132 kV subtransmission switching station (**Sandy Creek STSS**), Muswellbrook network rearrangement, Singleton to Kurri 132 kV link, and installation of a communications link across the Hawkesbury River to provide enhanced security of communications infrastructure (providing a cumulative total of 630 MW of additional network transfer capacity), which is scheduled to complete in June 2028
- **Portion 3:** Construction of a new 132 kV subtransmission switching station (**Antiene STSS**), and Antiene STSS to Singleton 132 kV link (providing a cumulative total of 1 GW of additional network transfer capacity), which is scheduled to complete in July 2028.

Figure 2-1: HCC RNI Project overview



2.2 Project scope

Delivery of the three portions will involve the work described below:

- **Rebuild existing network lines.** Existing lines will be rebuilt with high capacity subtransmission (132 kV) equivalents. Leveraging existing subtransmission corridors will reduce delivery times and minimise community impacts compared to alternative solutions. These will run:
  - from Kurri STS to the new Antiene STSS
  - between the new Sandy Creek STSS and Muswellbrook BSP.
- **Build new switching stations.** Two new STSSs will be built at greenfield sites:
  - The new Sandy Creek STSS will be located adjacent to Ausgrid's existing subtransmission substation (STS) in Muswellbrook, and wholly located within the same property lot. The switching station will consist of an outdoor 132 kV busbar and modular control room and amenities. The connection back to the adjacent substation will be via two underground 132 kV cables.
  - The Antiene STSS will be constructed on a new site adjacent to Lake Liddell and will consist of an outdoor 132 kV busbar and modular control room.
- **Augment existing substations** between Muswellbrook and Kurri. Brownfield augmentations of existing substations will be undertaken to enable an increase in transfer capacity. These include:
  - Muswellbrook STS: demolish existing 132 kV busbar and connect new underground 132 kV cables.
  - Mitchell STS: a single B-phase busbar voltage transformer will be installed on section 1 and section 2 of the Mitchell Line STS 132 kV busbar.
  - Singleton STS: a single B-phase busbar VT will be installed on section 2 of the Singleton STS 132 kV busbar.
  - Rothbury zone substation: new 132 kV feeders to the Antiene STSS, to enable additional impedance through either feeder 95R or 955
  - Kurri STS: two additional 132 kV feeder bays will be constructed by extending the existing 132 kV main busbar to the west.
- **Secondary systems**: Secondary systems to be upgraded including protection upgrades around Muswellbrook
- **Construction of a new communications link** from Somersby Zone Substation to Berowra Zone Substation using an optical fibre ground wire (**OPGW**)

Further details on the delivery strategy for the Project are set out in Attachment 2.2.

A full breakdown of the detailed works scope can be found in **Chapter 5 Capex**.

2.3 Benefits of the Hunter-Central Coast REZ

The HCC RNI Project is expected to result in a net benefit for NSW electricity consumers of $270.5 million (real $2024) over the long term, compared with a scenario in which the HCC RNI Project is not built. The modelled net benefits begin to flow from 2025-26, with the full extent of the modelled benefits expected from 2028-29. [4]

As an integral part of the Hunter-Central Coast REZ, the HCC RNI Project will also contribute to regional growth, generate employment opportunities for Aboriginal and Torres Strait Islander peoples and enable opportunities for local contractors and manufacturing. This will be achieved through Ausgrid's commitments to:

- only using local civil works contractors for substation augmentations
- using all local steel for construction of substations and a large proportion for lines and conductors
- identifying jobs and skills gaps to provide lasting employment opportunities over the life of the HCC RNI Project for workers in adjacent industries, such as mining
- achieving an Aboriginal and Torres Strait Islander participation rate of at least 1.5 per cent throughout the life of the HCC RNI Project, creating opportunities for Aboriginal business and employment opportunities for Aboriginal people.

The HCC RNI Project will allow the Hunter-Central Coast REZ to make a meaningful contribution to the achievement of both the NSW and Commonwealth governments' generation and emissions reductions targets:

- The NSW generation target is for at least 12 GW of generation capacity across the New England REZ, Central-West Orana REZ and other REZ projects. The NSW emission targets require a reduction in greenhouse gas emissions of at least 50 per cent by 2030 (and at least 70 per cent by 2035) compared to 2005 levels, and net zero emissions by 2050.
- The Commonwealth Government has committed to a reduction in greenhouse gas emissions of 43 per cent by 2030 compared to 2005 levels, and net zero emission by 2050. To support the achievement of its 2030 target, the Commonwealth Government has set a target for electricity generation to be 82 per cent renewable by 2030.
- The HCC RNI Project will make a meaningful contribution to the achievement of these targets by facilitating the connection of new renewable energy generation and could realise an emissions savings benefit of approximately $180 million (real $2024) resulting from a reduction of approximately 2 million tonnes of carbon dioxide equivalent over the project life. [5] Most of these emissions savings occur early in the life of the Hunter-Central Coast REZ, as generation and storage projects located in the Hunter-Central Coast REZ displace other, more emissions intensive generators within NSW.

2.4 Consumer Trustee's authorisation and contractual arrangements

Ausgrid confirms that our proposal complies with the Consumer Trustee's authorisation. Table 2-1 provides a guide to where each of the Consumer Trustee's requirements for the scope of the Project has been evidenced in this proposal.

4 EnergyCo, Hunter-Central Coast Renewable Energy Zone: Summary of EnergyCo's network recommendation, April 2025, page 18

5 EnergyCo, Hunter-Central Coast Renewable Energy Zone: Summary of EnergyCo's network recommendation, April 2025, page 22

Ausgrid confirms that our proposal complies with the HCC REZ Network Infrastructure Project Deed. A copy of the Project Deed is included in Attachment 2.1.

Table 2-1: Consumer Trustee's authorisation

Clause	Provision	Evidence of consistency with CT's authorisation
5 (a)	remote end secondary systems works to upgrade protection to duplicated differential line schemes on existing 132 kV lines between Muswellbrook Bulk Supply Point, Muswellbrook Subtransmission Substation and Mitchell Line Subtransmission Substation;	Section 5.4 Capex by expenditure category – Secondary Systems
5 (b)	a new 132 kV subtransmission switching station at Muswellbrook adjacent to the existing Muswellbrook Subtransmission Substation (referred to as Sandy Creek Subtransmission Switching Station);	Section 5.4 Capex by expenditure category – Substations
5 (c)	works to reroute lines 95F and 95H from the Muswellbrook Subtransmission Substation to the Sandy Creek Subtransmission Switching Station;	Section 5.4 Capex by expenditure category – Substations
5 (d)	cut in works at the Sandy Creek Subtransmission Switching Station to reroute line 95M;	Section 5.4 Capex by expenditure category – Substations
5 (e)	new 132 kV lines (referred to as lines 9PF and 9PG) to connect Muswellbrook Subtransmission Substation to the Sandy Creek Subtransmission Switching Station;	Section 5.4 Capex by expenditure category – Transmission Lines
5 (f)	a new 132 kV line (referred to as line 95U(2)) to connect Sandy Creek Subtransmission Switching Station to the existing 95U line, with a tee near Muswellbrook Bulk Supply Point;	Section 5.4 Capex by expenditure category – Transmission Lines
5 (g)	a new dual circuit 132 kV subtransmission line between the Antiene Subtransmission Switching Station and Kurri Subtransmission Substation;	Section 5.4 Capex by expenditure category – Transmission Lines
5 (h)	augmentations to the Kurri Subtransmission Substation;	Section 5.4 Capex by expenditure category – Substations
5 (i)	a new communications link from Somersby Zone Substation to Berowra Zone Substation using an optical fibre ground wire (OPGW) on Feeder 95Z;	Section 5.4 Capex by expenditure category – Communications
5 (j)	a new 132 kV subtransmission switching station along the north-eastern bank of Lake Liddell (referred to as Antiene Subtransmission Switching Station);	Section 5.4 Capex by expenditure category – Substations
5 (k)	augmentations to the Rothbury Zone Substation;	Section 5.4 Capex by expenditure category – Substations
5 (l)	all ancillary plant, equipment or other assets that will be connected to or used by the Network Operator for the purposes of controlling and operating the authorised network infrastructure; and	Section 5.4 Capex by expenditure category – Transmission Lines Section 5.4 Capex by expenditure category – Secondary Systems

Clause	Provision	Evidence of consistency with CT's authorisation
5 (m)	any change, modification or addition to the authorised network infrastructure: (1) required for the Network Operator to comply with its obligations under the National Electricity (NSW) Law or otherwise at law; or (2) made in accordance with the Project Deed, provided that following the relevant change, modification or addition the authorised HCC REZ Network Infrastructure Project will remain consistent with the description in sections 5(a) to 5(l) of this instrument.	N/A
6 (a)	If the Network Operator, having developed and constructed any asset comprising part of the authorised HCC REZ Network Infrastructure Project, ceases to own or lease the relevant asset, that asset will automatically cease to be authorised under this instrument.	N/A
6 (b)	If the Network Operator acquires or leases an asset which: (1) comprises part of an authorised REZ network infrastructure project under another instrument under the Act; and (2) connects to or will be used by the Network Operator in connection with the control or operation of the HCC REZ Network Infrastructure Project, the relevant asset will be deemed to be authorised under this instrument.	N/A
7 (a)	The Network Operator is required to enter into the following contractual arrangements for the purpose of carrying out the HCC REZ Network Infrastructure Project: (a) the Project Deed.	Under the Commitment Deed, Ausgrid and EnergyCo are obliged to enter into the Project Deed once the conditions precedent are satisfied (including obtaining the Revenue Determination)

2.5 Our services

We provide NSW non-contestable services under the EII Act and Regulations (EII services), operating in accordance with, among other things, our licence issued under the Electricity Supply Act 1995 (NSW)[6]. The quality, reliability, and security of supply for the NSW non-contestable services we provide are defined by the EII Act and Regulations, our licences, and customer connection and access agreements. It is important to note that EII services are distinct from transmission services, which are regulated under the NER. As such, EII services are governed by the EII regulatory framework.

6 https://www.ipart.nsw.gov.au/documents/granted-licence/distributors-licence-ausgrid-operator-partnership-7-september-2023

3 What we have heard from stakeholders

In designing how we would engage with our customers for this Revenue Proposal our goal was to adopt an approach that was transparent and open-minded. We did this by partnering with our customer representatives and other stakeholders to inform our decision-making for this regulatory process and to develop this Revenue Proposal.

3.1 Our engagement approach and objectives

Our focus for this Revenue Proposal was to realise better outcomes for customers and community within the Hunter-Central Coast REZ, as we support Australia's transition toward a net zero future. Our main engagement during this Revenue Proposal has been through our HCC REZ Reg Panel.

The HCC REZ Reg Panel members represent residential, business and commercial customers. The Panel comprises three members, two of whom are part of our ongoing Customer Consultative Committee and one who is part of our ongoing Network Innovation Advisory Committee. Each member was selected to provide a range of economic, engineering, legal, policy and engagement expertise.

HCC REZ Reg Panel meetings were chaired by our Head of Regulation. This ensured feedback provided by the Panel could accurately inform the development of this Revenue Proposal and allowed the broad scope of customer concerns to be properly captured.

The HCC REZ Reg Panel met six times between January and April 2025, allowing us to keep abreast of customers' primary points of interest. The HCC REZ Reg Panel also attended some community meetings regarding the Project. The meetings provided a platform to seek views on our approach to the HCC RNI Project and to understand the customer advocates' positions on key elements in this Revenue Proposal. During this process, the Panel challenged Ausgrid on key aspects of our proposal, including:

- the Project risk register and the efficient allocation of risk between Ausgrid, external contractors and customers
- revenue adjustment mechanisms proposed by Ausgrid to comply with its contractual obligations with EnergyCo, and to accommodate the unique procurement arrangements for the Project
- the meaning of 'reasonable' costs in section 38 of the EII Act ('transmission efficiency test') and what this means for our capex forecast
- the program for delivery of the HCC RNI Project and measures undertaken to meet the program.

Our Revenue Proposal has been shaped and significantly improved through the input of our customers and stakeholders. This has been achieved through more than 14 hours of face-to-face or online meetings and a full day site visit to key locations, including Muswellbrook, Singleton and Kurri Kurri.

The AER has attended and, where necessary, participated in our HCC REZ Reg Panel meetings to answer questions and clarify key regulatory processes, leading to improved meeting productivity. These meetings were also attended by an AER appointed Consumer Challenge Panel (**CCP**) representative who will advise the AER regarding the quality of engagement for this process.

We greatly value the feedback in the development of our Revenue Proposal and will continue engaging with the HCC REZ Reg Panel and other stakeholders throughout the subsequent phases of the revenue determination process.

3.2 Our engagement activity and how we have incorporated feedback

Our engagement activities have directly informed the development of this Revenue Proposal. During this process, we have met regularly with the AER, EnergyCo and HCC REZ Reg Panel. With this being our first time participating in a revenue-setting process under the EII Act, we have valued the constructive feedback from all stakeholders, particularly the HCC REZ Reg Panel, in helping shape this Revenue Proposal.

3.2.1 Hunter-Central Coast Renewable Energy Zone Regulatory Panel

The HCC REZ Reg Panel provides a forum for Ausgrid to obtain a customer's perspective in the development of Ausgrid's HCC RNI Revenue Proposal.

The Panel focuses on specific aspects of Ausgrid's regulatory submission, with the understanding that the scope of this panel is constrained by the HCC RNI proposal process.

The involvement of the HCC REZ Reg Panel includes:

- pre-lodgement engagement with the AER and advising on key areas of interest for consumers in accordance with the AER's Better Resets Handbook to the extent possible given the time constraints
- reviewing and providing feedback on elements of Ausgrid's HCC RNI Revenue Proposal to the AER
- considering the allocation of risk between Ausgrid and customers, including contingency and Adjustment Events, which are appropriate for a substantial construction project and required to enable the HCC RNI to be delivered
- demonstrating that the perspectives of consumers have been considered in Ausgrid's approach to the HCC RNI Project.

In addition, the HCC REZ Reg Panel was engaged to provide a short independent report to the AER identifying key issues that the AER should consider when reviewing Ausgrid's Revenue Proposal.

Figure 3-1: HCC REZ Reg Panel members

Mark Grenning

Mark is an experienced energy consultant focusing on larger consumers. His work includes advocacy to energy market bodies, networks and governments covering electricity and gas.

Louise Benjamin

Louise is a commercial and regulatory lawyer with extensive experience in telecommunications and energy regulation. Louise is passionate about exploring strategic outcomes which benefit customers of regulated businesses.

Michael Swanston

Mike is a professional engineer with a passion for energy sustainability and a fair deal for energy customers. Mike has previously worked with utilities, governments and regulators in Australia, Central and South-east Asia and the UAE.

Table 3-2 is a summary of the topics discussed during our meetings with the HCC REZ Reg Panel. Feedback during these meetings informed the proposal development process and has been incorporated into this Revenue Proposal.

Table 3-2: Summary of engagement with the HCC REZ Reg Panel

Date	Discussion Topic	Content Overview
January	NER vs Electricity Infrastructure Investment Act (EII Act)	• Roles and responsibilities of Ausgrid, EnergyCo, AER and the Consumer Trustee under the EII Act • Ausgrid's contractual framework under the EII Act • Timeline and overview of the HCC RNI proposal process • Revenue mechanisms
	Expectations of panel role	• Panel Terms of Reference (**ToR**) • What successful customer engagement looks like • Likely areas of key engagement
	Project overview	• HCC RNI objectives • Solution overview including project staging, key deliverables and a project timeline • Advantages of our 132 kV solution • Delivery strategy including a breakdown of internal and external delivery activities • Procurement and governance
	What we've heard so far	• A summary of discussions between the AER and Ausgrid including any feedback provided by the AER
Early February	Regulatory process mud map	• NSW Electricity Infrastructure Roadmap • Regulatory process for the HCC RNI including the roles of EnergyCo, Consumer Trustee, AER and Ausgrid

Date	Discussion Topic	Content Overview
	Expenditure summary	• Summary of our capex and opex proposal
	Overview of risk mechanisms	• Our approach to risk and contingency • Simplified framework for risk allocation • Revenue adjustment events
Late February	Regulatory process mud map (continued)	• EII Act cost recovery and financial flows
	Issues Register	• Main issues we need to prioritise • What a prudent, efficient and reasonable proposal should look like
	Risk allocation	• Contractual risk allocation negotiated with EnergyCo • Overview of our risk allocation framework
March	EnergyCo Q&A	• Project timeline: 2023 IIO Report vs. Commitment Deed with EnergyCo • AEMO Services calculation of Maximum Capital Cost • Justification and breakdown of the Infrastructure Planner Fee • Implications of the HCC RNI on Roadmap costs
	Capex outline	• Breakdown of capex for transmission lines, switching stations and Owner's costs • Annual opex breakdown by category • Allocation of shared costs based on proposed CAM
	Calculation of Revenue	• Breakdown of 'as commissioned' expenditure • Indicative annual payments • Financeability test
Late March (additional risk allocation meeting requested by panel)	Escalation	• Calculation of project escalation
	Estimate Class	• Changes in cost class between now and final submission • Justification of cost classes
	Owner's costs	• Breakdown of Owner's cost by category and financial year
	Contingency	• Breakdown of contingency by capex category • Cost class vs. contingency accuracy • Detail of risks covered by contingency
	Early works and liquidated damages	• Consideration of consumer risk in $70m Early Works funding • Mitigation measures to prevent liquidated damages
	Decommissioned assets	• Residual value, treatment and depreciation of decommissioned assets • Customer impact.

Date	Discussion Topic	Content Overview
April	Feedback on draft proposal	Provided in HCC REZ panel report

3.2.2 Pre-lodgement engagement with the AER

Throughout preparation for this Revenue Proposal, we have maintained regular contact with the AER. We have also sought feedback on matters such as our regulatory models and interpretation of the regulatory framework, and discussed the nature and scope of our engagement activity with the HCC REZ Reg Panel, noting the following challenges:

- The timeframes for pre- and post-lodgement engagement for this regulatory process were ~80% and ~70%, respectively, shorter than what was available for the 2024-29 Revenue Proposal. These tight timelines meant that our engagement approach had to be refined to achieve efficient and productive outcomes.
- Our existing CAM required amendment to reflect our updated organisational structure and incorporate HCC RNI activities as a new service.
- This is our first non-contestable Revenue Proposal under the NSW regulatory framework.

3.2.3 Pre-lodgement engagement with EnergyCo

Prior to lodging this Revenue Proposal, we provided a draft to EnergyCo (as required under the Commitment Deed). EnergyCo had the opportunity to provide comments on the Revenue Proposal, and all material comments have been addressed.

3.3 Pre-lodgement engagement with customer and community stakeholders

In addition to consultation through the HCC REZ Reg panel, an engagement program was carried out with affected communities and customers. This program was used to raise awareness about the HCC RNI Project and understand stakeholders' primary views and concerns. The consultation sought comments, feedback and suggestions on several Project elements. It was used to identify potentially affected residents and stakeholders and build a comprehensive database of community members with interest in, or concern about, the Project. Our engagement program included opportunities for general stakeholder participation as well as more targeted consultation with landowners, government agencies and First Nation group representatives.

The customers and communities impacted by the Project represent a range of cultural, social and economic backgrounds. We identified that a two-way feedback process would be key to building trust and understanding the needs of stakeholders directly impacted by the Project. This two-way feedback approach involved engaging early and often to foster strong relationships with identified stakeholders.

During this process, we have been guided by the principles outlined in internal and external engagement guidelines, including:

- Ausgrid's Community Engagement handbook
- International Association for Public Participation (**IAP2**) standards
- 2024-29 Regulatory Proposal Engagement Framework

- Ausgrid's NS174C Environmental Handbook for Construction and Maintenance

We developed a targeted, Project-specific engagement approach with the aim of:

- building trust and confidence
- reaching diverse audiences
- understanding local aspirations and preferences

Our broad approach has increased Project awareness, allowing stakeholders and the community to share productive feedback on key areas of interest. Throughout this process, we have balanced community feedback with other project considerations including our obligations to EnergyCo under the Commitment Deed and draft Project Deed.

3.3.1 Why we engaged with the community

Ausgrid's commitment to extensive and meaningful engagement for the Hunter Central Coast RNI Project stems from the recognition that social licence is a critical factor for the success of electricity network projects. By actively engaging with stakeholders and the community, Ausgrid aims to build trust and support, which is essential for mitigating risks and ensuring the project is delivered on time and within budget. This proactive approach not only addresses potential concerns but also demonstrates Ausgrid's dedication to transparency and collaboration. Furthermore, such engagement helps differentiate the Hunter Central Coast project from other infrastructure initiatives by showcasing a strong commitment to community involvement and sustainable development.

3.3.2 Opportunities for engagement

Ausgrid has undertaken a range of activities to ensure community members are aware of the proposed activities and had an opportunity to provide feedback on the Project. We have briefed key stakeholders including:

- Members of Parliament (Federal and State)
- government departments and agencies (Federal and State)
- local government
- Traditional Custodian groups
- industry and interest groups
- landholders
- surrounding communities.

Table 3-3 summarises the variety of consultation tools used during this engagement program. An online survey was also set up to gather community feedback and gauge sentiment towards the Project. Most stakeholders expressed a willingness to participate in our engagement activities and emphasised their desire to remain informed and engaged as the HCC RNI Project progresses.

Throughout the engagement process, we updated our social media pages to advertise community drop-in sessions, highlight online resources and share Project updates. The focus of the posts has been to increase general awareness of the Project and highlight opportunities for stakeholders to engage with Ausgrid.

Table 3-3 Summary of community and customer stakeholder engagement tools

Number	Engagement tool
2	Community information sessions
6	Landowner information sessions
25	Individual landowner meetings
1	Pop-up session
2	Webinars
26	Emails sent to stakeholders
278	Emails and phone calls received from stakeholders
2316	Visits to our HCC REZ Your Say web page
10	Council and industry stakeholder briefings
2	Print advertisements for community information sessions
1	Local radio station campaign

3.4 How our engagement influenced this proposal

Our engagement with the HCC REZ Reg Panel, the AER and EnergyCo has influenced multiple aspects of this Revenue Proposal. A high-level summary of how we have taken feedback into account from these stakeholders is set out in Table 3-4.

Table 3-4: Summary of how our engagement influenced this proposal

Topic	How our proposal has been influenced	More information
Efficient allocation of risk	Our conceptual framework for the efficient allocation of risk was robustly challenged, resulting in more detailed articulation of how and why each category of contingency and adjustment mechanisms provide the best outcome for customers	Section 5.2
Reasonable costs	How we interpret 'reasonable' costs in the EII Act ('transmission efficiency test') and what this means for our capex forecast	Section 5.2
Escalation	Feedback from the HCC REZ Reg Panel prompted Ausgrid to clearly disaggregate escalation in our capex presentation	Section 5.2

Topic	How our proposal has been influenced	More information
Customer lens	Each capex driver includes a 'customer lens' summary that was reviewed by the HCC REZ Reg Panel for feedback	Section 5.4
Modified CESS	We took on feedback from the HCC REZ Reg Panel which ultimately led to a decision to not propose a modification of the CESS sharing thresholds	Section 7.2
Social licence	We have provided more information about the governance measures that will support the prudence of the $5.3m in social licence expenditure that will be guided by the community	Attachment 5.7
Adjustment mechanisms	We have undertaken a thorough review to ensure there is no double counting between our proposed expenditure and adjustment mechanisms	Attachment 8.1

Further detail on our engagement with Regulatory stakeholders is set out in Attachment 3.1 – Regulatory stakeholder engagement approach.

4 Forecast opex

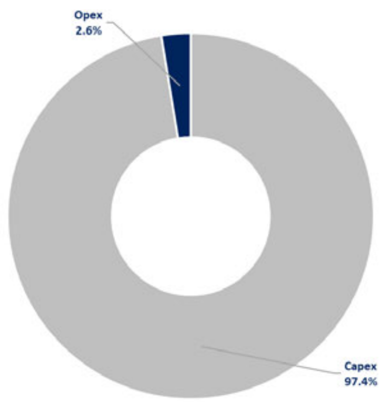
This chapter sets out the total 2026-31 forecast opex for the HCC RNI Project. The opex model is included as Attachment 4.1.

In developing this forecast, we have applied our approved CAM to allocate costs between 'EII Act services' and 'other services' (including Distribution Services), which are subject to regulation under the NER.

4.1 Overview of our forecasting approach

Our total forecast opex for the 2026-31 Regulatory Period is $15.6 million (real 2025-26), excluding debt raising costs. We have used a bottom-up-build approach to determine our forecast opex, which comprises the following categories of opex:

- **Vegetation management:** proactive vegetation cutting to maintain safety clearances and provide unobstructed access to our assets
- **Maintenance:** inspections, conditioning monitoring and preventative maintenance tasks aimed at preserving asset functionality and condition integrity, as well as corrective and breakdown maintenance
- **Operations:** operating and providing grid planning support to HCC RNI
- **Regulatory costs:** incremental regulatory expenditure associated with HCC RNI that is not recovered through the CAM allocation
- **Overheads (CAM allocation):** the allocation of shared costs to the HCC RNI activities using the CAM approved by the AER on 14 March 2025.

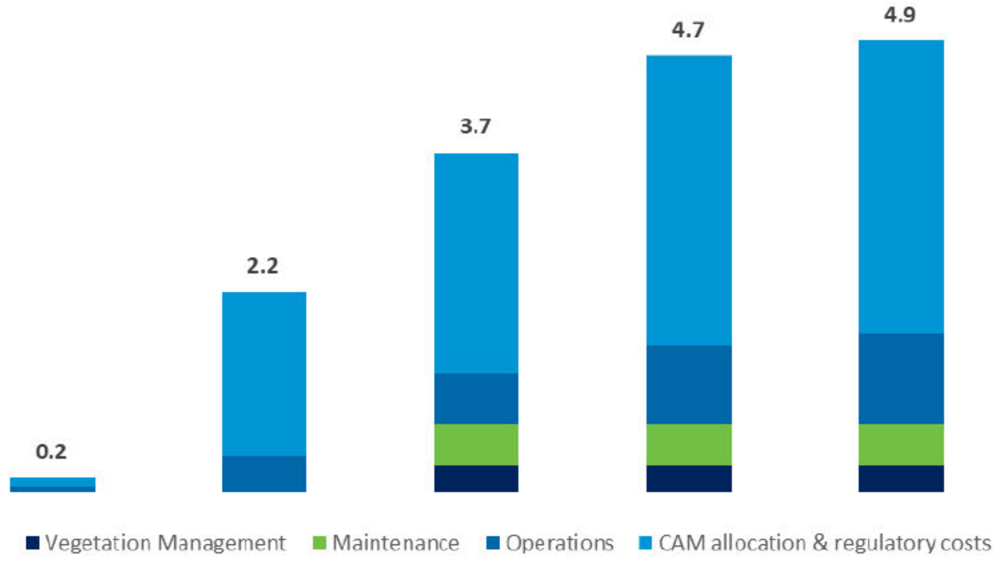


The delivery model adopted for our operating and maintenance requirements for HCC RNI depends on the type of assets involved. Internal resources will generally deal with substation equipment (e.g. switchgear, transformers, secondary systems), while external contractors will manage pole and line inspections, vegetation management, fire systems and property activities.

To forecast direct opex (excluding CAM), we have adopted an approach based on unit costs and forecast quantities. The unit costs have been derived based on a review of existing contracts or costings from Ausgrid's similar assets. Market testing of these unit costs supports their prudence, efficiency and reasonableness in line with the AER's expenditure assessment framework.

The components of our forecast opex (excluding debt raising costs) are presented in Figure 4-1.

Figure 4-1: Proposed opex for HCC RNI ($m, real 2025-26)



The average forecast of $3.1 million opex per annum (real 2025-26) for the 5-year period represents 2.6 per cent of the Project's total forecast expenditure (real 2025-26). The forecast costs are required to manage the network and comply with associated regulations under the EII Act.

4.2 Key assumptions

Table 4-1 sets out the key assumptions underpinning our opex forecast. The reasonableness of these assumptions has been certified by our Directors in accordance with clause S6A.1.2(6) of the EII Chapter 6A.

Table 4-1: HCC RNI key assumptions ($m, real 2025-26)

Key assumptions	
Legislative and regulatory obligations	Current legislative and regulatory obligations, our licence requirements, the Consumer Trustee's authorisation, and contractual arrangements relating to the HCC RNI Project remain in place over the 2026-31 Regulatory Period.
Adjustment events	The AER approves our proposed adjustment events for the 2026-31 Regulatory Period.
Access scheme	The Minister will not declare an access scheme for the Hunter Central Coast RNI
Project scope and timing	Project scope and timing will be as per the draft Project Deed and the Consumer Trustee's authorisation for the RNI project.
Contractual arrangements	Project Deed and major subcontracts will be executed no later than 31 December 2025.

4.3 Vegetation management

Vegetation management includes identifying, scoping and undertaking proactive vegetation cutting to maintain safety clearances and provide unobstructed access to our assets. This activity also manages the risks associated with bushfires and public safety, and is therefore carried out routinely.

The expenditure for vegetation management is a marginal cost additional to existing vegetation management along the corridor. The additional cost accounts for a wider clearance and a small amount of additional conductor that is not currently subject to vegetation management. The cost was developed using unit rates from existing contracts for Ausgrid's standard control services. The forecast assumes that the additional vegetation management cost will begin in 2028-29, after commissioning of the final portion of the HCC RNI.

The forecast vegetation management expenditure is presented in Table 4-2. Vegetation management is considered a variable cost because it may change depending on the length of corridor required to be maintained.

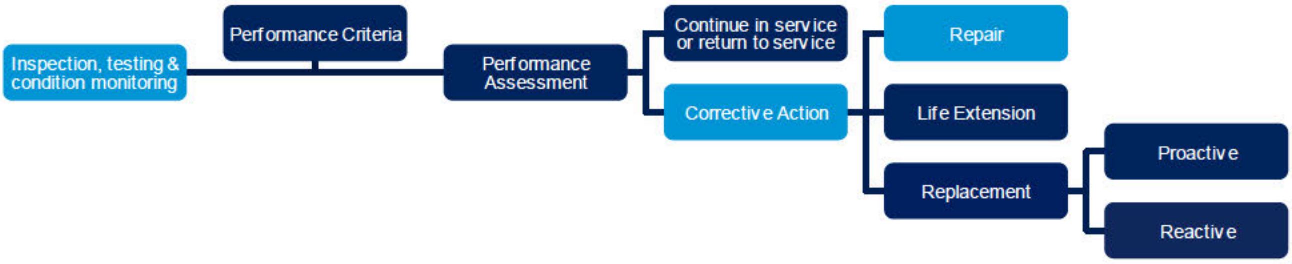
Table 4-2: Proposed vegetation management expenditure for HCC RNI ($m, real 2025-26)

Direct expenditure	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Vegetation management	0.0	0.0	0.3	0.3	0.3	0.9

4.4 Maintenance

As part of our planned maintenance program, Ausgrid undertakes inspection, testing and condition monitoring of our assets to ensure they are performing correctly, and to identify any potential defects that may require rectification. We also perform preventative maintenance tasks aimed at preserving asset functionality and condition integrity. For the HCC RNI, we propose using the Condition Based Maintenance (**CBM**) program, in line with the approach utilised for our broader network assets. The CBM approach is illustrated in Figure 4-2. Maintenance expenditure is considered to be a variable cost because it may change depending on the volume assets being maintained.

Figure 4-2: Overview of our planned CBM approach to HCC RNI



If an asset meets the performance criteria, it continues in service or is returned to service. However, if the asset fails the performance criteria, we may choose to:

- take corrective action, which could involve repairs (maintenance opex)
- undertake asset life extension or replacement (capex)
- elect not to undertake any planned maintenance tasks and instead allow the asset to run to 'end-of-life' and take corrective action under fault and emergency conditions (reactive).

Fault and emergency maintenance activities are generally only required where preventative maintenance is inefficient (limited value given the risk) or ineffective (unable to detect an imminent failure).

Where practicable, preventative inspection, testing and condition monitoring is calculated based on asset quantity, the cycle required for each asset and historical internal labour costs or contract prices. This expenditure may be quite variable so it has been averaged to determine a typical annual cost. For example, inspections of electrical equipment in 132 kV switching stations may occur 6 monthly, inspections of 132 kV poles may occur once every 5 years, while inspections of kiosks may occur every 12 years.

Repairs and breakdowns are based on a top-down analysis of Ausgrid's latest 5 years of experience of similar assets.

'Lifecycle expenditure' refers to the total cost of owning, operating, maintaining and ultimately replacing assets over their entire lifespan. This approach ensures optimal long-term performance and cost efficiency by considering all stages of an asset's lifecycle, including design, procurement, operation, maintenance and disposal. Proper lifecycle expenditure planning can optimise costs by balancing capex on new assets with opex for maintaining existing assets. Efficient management can reduce long-term costs. As a result, a portion of the costs associated with planning and managing our lifecycle approach has been allocated to the HCC RNI Project. The profile for the lifecycle expenditure in Table 4-3 aligns with the maintenance expenditure, starting in 2027-28.

Table 4-3: Proposed maintenance expenditure for HCC RNI ($m, real 2025-26)

Direct expenditure	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Substation	0.0	0.0	0.1	0.1	0.1	**0.3**
Lines and cables	0.0	0.0	0.1	0.1	0.1	**0.3**
Secondary systems	0.0	0.0	0.0	0.0	0.0	**0.0**
Lifecycle	0.0	0.0	0.2	0.2	0.3	**0.7**
Total	**0.0**	**0.0**	**0.4**	**0.4**	**0.5**	**1.3**

4.5 Grid planning and operations

This expenditure relates to the incremental activities required for operating and providing grid planning support to the HCC RNI.

Operations/control room expenditure relates to remote monitoring of the site for critical failures. It also includes time for local high voltage (**HV**) operators for site inspections, switching and on-call hours.

Planning activities involve monitoring the thermal rating and sagging of the subtransmission lines, and also includes time from grid planners involved in the connections to the network. These are marginal costs on top of existing control room and grid planning support for Ausgrid's broader network. These costs are considered semi-fixed costs as they do not vary materially based on the size of the network, unless there is a large step change to the size of the network.

Table 4-4: Proposed grid planning and operations expenditure for HCC RNI ($m, real 2025-26)

Direct expenditure	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Operations/control room	0.0	0.3	0.5	0.7	0.8	**2.4**
Grid planning support	0.0	0.1	0.1	0.1	0.2	**0.5**
Total	**0.1**	**0.4**	**0.6**	**0.9**	**1.0**	**2.8**

4.6 Incremental regulatory costs

The incremental regulatory costs included in our proposed opex relate to the additional costs associated with regulatory compliance and development activities for the 2032-37 HCC RNI Regulatory Proposal. These costs are additional to the regulatory costs allocated to the Project through the CAM allocation (see section 4.9 below). These costs are considered fixed costs because the majority of costs do not vary with the size of the network.

Table 4-5: Proposed regulatory costs for HCC RNI ($m, real 2025-26)

Expenditure	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Regulatory costs	0.1	0.3	0.3	0.1	0.1	**0.8**

The incremental regulatory costs are intended to cover expenditure relating to data audits, dealing with adjustment events, communication with the AER and consultancy services in preparation for the next Revenue Proposal.

4.7 Overheads

The allocation of shared costs (or overheads) to HCC RNI activities is based on the Weighted Average Revenue (**WAR**) cost method. This allocation aligns with Ausgrid's updated CAM approved by the AER in March 2025 and included as Attachment 6.4. The updated CAM includes reference to HCC RNI as a new regulated activity under the EII Act. The updated CAM will take effect from 1 July 2025.

The purpose of the CAM is to outline Ausgrid's approach to attributing or allocating shared costs to the distribution services it provides under the NER, regulated activities under the EII Act, and unregulated services.

Figure 4-3: Allocation of costs under Ausgrid's approved CAM

Wherever possible, costs are directly attributed to the relevant service category. Once all directly attributable costs have been allocated to the relevant service category, the remaining unallocated costs (or shared costs) are allocated based on the WAR cost allocator. Depending on the nature of the shared costs, we apply one of the two following allocators:

- WAR *excluding* revenue earned from providing unregulated services to other parties is used to allocate shared costs that only support the regulated (SCS, ACS and EII services) part of the business
- WAR *including* revenue earned from providing unregulated services to other parties is used to allocate shared costs that support the entire business (e.g. legal, finance and insurance costs).

This approach is summarised in Figure 4-4. Our proposed shared costs allocated to the HCC RNI are set out in Table 4-6. These costs are considered fixed costs because Ausgrid's overheads are relatively fixed, therefore the allocation remains relatively stable once the revenue is stable.

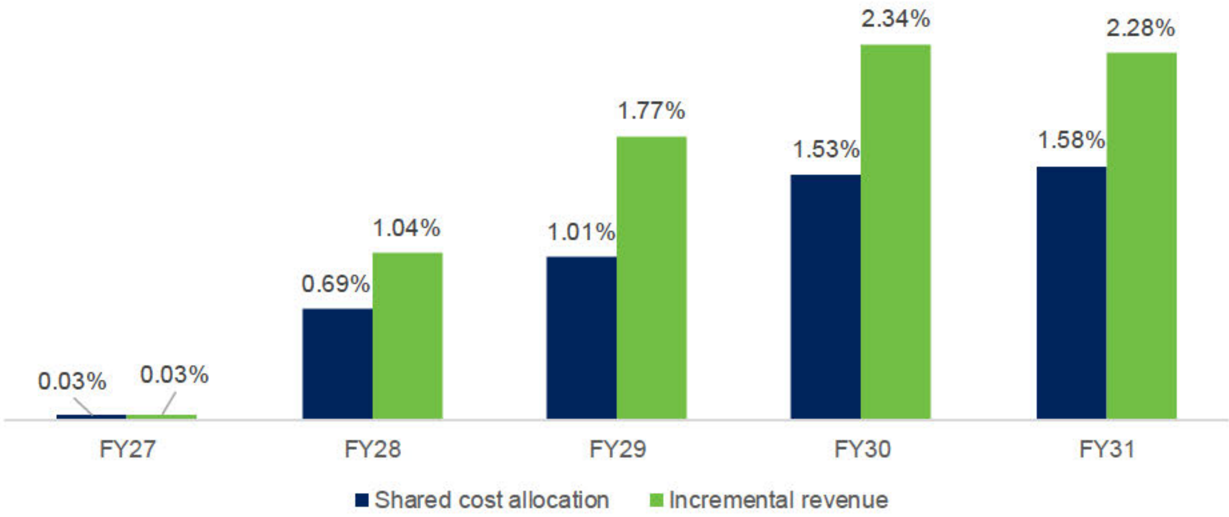
Figure 4-4: Shared cost allocation under Ausgrid's approved CAM

Table 4-6: Proposed CAM allocation expenditure for HCC RNI ($m, real 2025-26)

Expenditure	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Overheads (based on CAM allocation)	0.1	1.5	2.1	3.1	3.1	**9.8**

As shown in Figure 4-5, our proposed CAM allocation does not exceed the proposed incremental revenue associated with the HCC RNI. This is given that the shared cost allocation (**dark blue** column) is less than the incremental revenue associated with the HCC RNI Project (**green** column).

Figure 4-5: CAM allocation and incremental HCC RNI revenue



4.8 Real labour price growth escalation

Aligned with standard practice in NER determinations, we have applied forecast Wage Price Indices (WPI) to our base opex cost estimates throughout the forecast period.

In selecting the appropriate WPI forecasts for this escalation, we have adopted the indices that the AER approved in Ausgrid's 2024-29 regulatory decision.[7] For the two years not covered by that determination, we used a rolling average of the previous three years.

The WPI forecasts used for our proposed opex are presented in Table 4-7.

Table 4-7: Proposed wage price growth forecasts for HCC RNI ($m, real 2025-26)

Real escalation	2026-27	2027-28	2028-29	2029-30*	2030-31*
	AER decision	AER decision	AER decision	Estimated	Estimated
WPI	0.91%	0.80%	0.92%	0.88%	0.87%
Note: * Estimated values based on rolling average of the last three years.					

We have not included any real materials escalation in the opex forecast.

4.9 Interaction between CAM allocation for HCC RNI and SCS

For all opex expenditure except CAM allocation, we have included incremental costs above the existing costs we incur, where applicable, or new costs if there are no existing costs. CAM allocation is an exception to this and is based on forecast CAM allocations across Ausgrid's lines of business including HCC RNI. This is to most closely align with expected opex that will be allocated to HCC RNI.

This methodology means that some shared costs approved in Ausgrid's 2024-29 Regulatory Proposal for distribution services will be diverted from SCS to the HCC RNI Project. All else being

7 AER – Final Decision Ausgrid distribution determination 2024-29 - Opex model - April 2024.

equal, this would result in an EBSS reward for SCS opex over the 2024-29 period due to a reallocation of expenditure rather than an efficiency saving. We propose to manage this by excluding the amount allocated to shared opex costs in the HCC RNI from the opex allowance used to calculate the EBSS reward in 2026-27, 2027-28 and 2028-29 of the SCS Regulatory Period. The new base year opex for the following Regulatory Period will reset at the lower amount excluding HCC RNI shared costs and no further adjustment will be necessary.

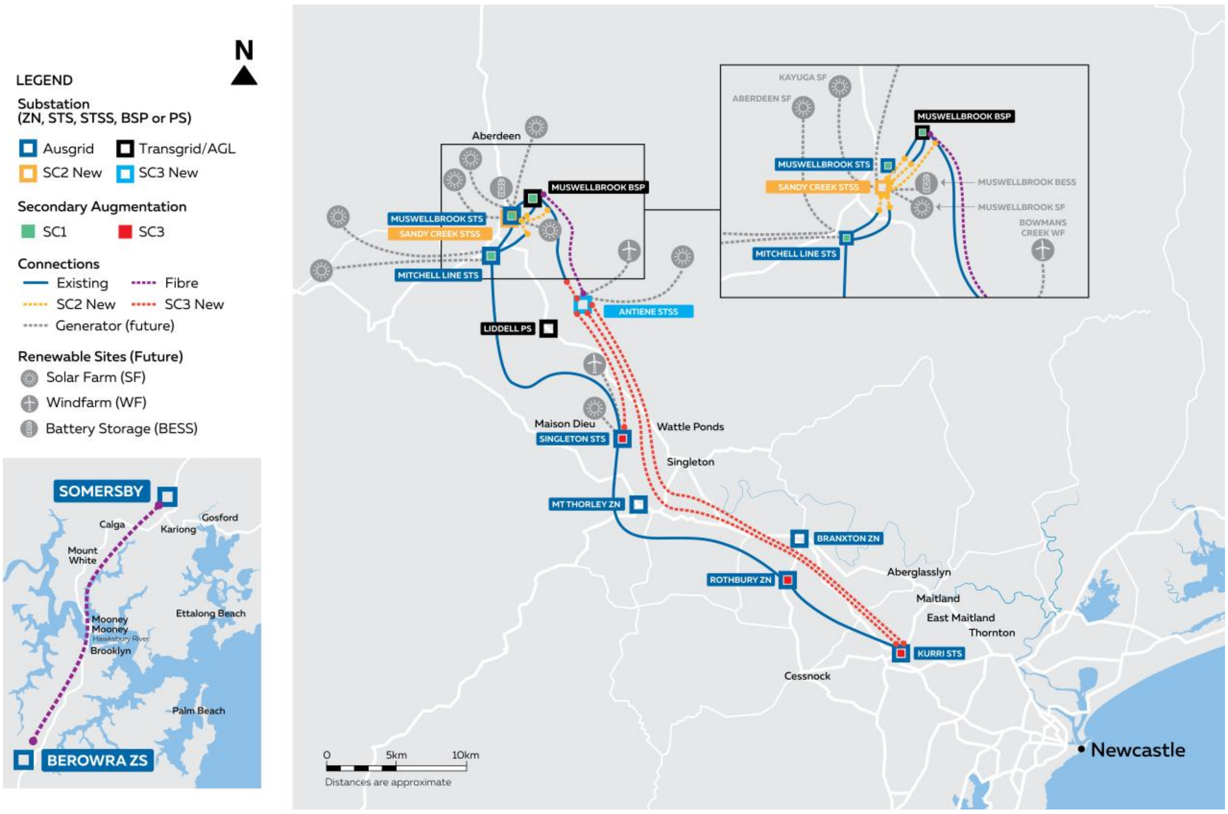
5 Forecast capex

Capex refers to the investments Ausgrid needs to make towards the construction and commissioning of the HCC RNI. This chapter sets out the direct and indirect capex associated with the Project. The capex model is included as Attachment 5.1.

5.1 Overview of HCC RNI capex

The HCC RNI will enable an additional 1 GW of transfer capacity through removing and rebuilding 85 km of existing subtransmission lines in existing corridors. It also includes investment in substations, which house transformers, and switching stations that operate, without transformers, at a single voltage level. Additional fibre communications links will also be built to provide enhanced security of communications infrastructure. Figure 5-1 sets out the RNI corridor that forms the basis of our capex forecast.

Figure 5-1: HCC RNI corridor



Our total proposed capex to deliver the HCC RNI Project is $590.8 million. This includes $283.0 million in expenditure incurred before 1 July 2026, known as 'pre-period expenditure', and $307.9 million in forecast capex in the 2026-31 Regulatory Period.

The breakdown of this expenditure by project asset category is outlined in Table 5-1. The total capex includes base capex to be expended by Ausgrid, risk costs which allow a reasonable contingency and the Infrastructure Planner Fee.

The Infrastructure Planner Fee is a payment Ausgrid is required to make to EnergyCo, which reimburses EnergyCo's costs for undertaking development functions and operations activities in respect of the HCC RNI and Ausgrid's costs for early (pre-Project Deed) works. The EnergyCo component is $92.9 million and is displayed as a single line item below. The Ausgrid component is

$69.8 million but is incorporated in the relevant categories of pre-period expenditure shown in Table 5-1.[8]

Table 5-1: Proposed HCC RNI capex ($m, real 2025-26)

	Pre-period	Regulatory Period					Total
	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	
Transmission lines	80.8	99.9	22.4	-	-	-	**203.1**
Substations	28.7	62.6	14.7	0.2	-	-	**106.2**
Land and easements	2.2	19.3	2.1	-	-	-	**23.7**
Secondary systems	0.9	1.3	1.7	0.1	-	-	**4.0**
Communications	5.3	2.5	-	-	-	-	**7.7**
Owner's costs	21.9	15.1	13.3	4.3	-	-	**54.6**
Design, social licence and other	37.0	10.0	4.4	0.3	-	-	**51.8**
Infrastructure Planner Fee (EnergyCo component)	92.9	-	-	-	-	-	**92.9**
Risk costs	13.2	25.9	7.2	0.6			**46.9**
Total	**283.0**	**236.7**	**65.8**	**5.4**	**-**	**-**	**590.8**

Delivery of the HCC RNI will require the following scope of work:

- **Rebuild existing network lines.** Existing lines will be rebuilt with high capacity subtransmission (132 kV) equivalents. These will run from Kurri STS to the new Antiene STSS, and between the new Sandy Creek STSS and Muswellbrook BSP. Leveraging existing subtransmission corridors will reduce delivery times and minimise community impacts compared to alternative solutions.
- **Build new switching stations.** Two new STSSs will be built at greenfield sites, Sandy Creek and Antiene. The new Sandy Creek STSS will be located adjacent to Ausgrid's existing STS in Muswellbrook, and wholly located within the same property lot. The switching station will consist of an outdoor 132 kV busbar and modular control room and amenities. The connection back to the adjacent substation will be via two underground 132 kV cables. The Antiene SSTS will be constructed on a new site adjacent to Lake Liddell and will consist of an outdoor 132 kV busbar and modular control room.
- **Augment existing substations** between Muswellbrook and Kurri. Brownfield augmentations of existing substations will be undertaken to enable an increase in transfer capacity. These include:
    - *Muswellbrook STS*: demolish existing 132 kV busbar and connect new underground 132 kV cables

8 Our capex forecast reflects the capital expenditure objectives, criteria and factors as set out in EII Chapter 6A clauses 6A.6.7(a), 6A.6.7(c) and 6A.6.7(e), respectively

- *Mitchell Line STS*: a single B-phase busbar voltage transformer will be installed on section 1 and section 2 of the Mitchell Line STS 132 kV busbar
- *Singleton STS*: a single B-phase busbar VT will be installed on section 2 of the Singleton STS 132 kV busbar
- *Rothbury zone substation*: new 132 kV feeders to the Antiene STSS, to enable additional impedance through either feeder 95R or 955
- *Kurri STS*: two additional 132 kV feeder bays will be constructed by extending the existing 132 kV main busbar to the west.

- **Secondary systems:** Secondary systems to be upgraded including protection upgrades around Muswellbrook
- **Construction of a new communications link** from Somersby Zone Substation to Berowra Zone Substation using an optical fibre ground wire (**OPGW**)

This scope of work and associated costs is required to meet the CT authorisation and comply with associated regulations under the EII Act.

5.1.1 Pre-period capex

We commenced work on the HCC RNI Project in 2024-25, with an objective to meet the commissioning targets outlined in the Network Infrastructure Strategy[9]. We will continue to incur costs before commencement of the 2026-31 Regulatory Period, referred to as ‘pre-period expenditure’. This expenditure relates to the following activities:

- Assessing the feasibility of the augmentation and upgrade works
- Undertaking procurement processes for the delivery of the Project
- Procuring equipment
- Detailed design work, including testing
- Early construction works.

We are also obliged to pay the Infrastructure Planner Fee as part of ‘pre-period expenditure’.

We have included the pre-period capex within our proposed opening asset base, to be recovered over subsequent Regulatory Periods. In doing so, we have established a new asset category called ‘Infrastructure Planner Fee’.[10] Where other pre-period capex is directly attributable to an asset class, such as transmission lines, we have attributed the relevant pre-period capex directly to that asset class. Where pre-period capex is not directly attributable to a single asset class, such as for labour or overhead costs and other indirect costs, we have allocated this pre-period capex across asset classes in proportion to the total capex for the Project.

9 EnergyCo, NSW Network Infrastructure Strategy, May 2023, page 39

10 The asset class for Infrastructure Planner fee is the EnergyCo component of the Infrastructure Planner fee, which includes all expenditure incurred by EnergyCo for the development and operations phases of the Project. The Ausgrid components of the Infrastructure Planner fee are included within the appropriate respective capex categories.

5.1.2 Key assumptions

Table 5-2 sets out the key assumptions underpinning our capex forecast. The reasonableness of these assumptions has been certified by our Directors in accordance with clause S6A.1.1(5) of the EII Chapter 6A.

Table 5-2: Key assumptions underpinning our capex proposal

Key assumptions	
Legislative and regulatory obligations	Current legislative and regulatory obligations, our licence requirements, the Consumer Trustee's authorisation, and contractual arrangements relating to the HCC RNI remain in place over the 2026-31 Regulatory Period
Adjustment events	The AER approves our proposed adjustment events for the 2026-31 Regulatory Period
Access scheme	The Minister will not declare an access scheme for the HCC RNI.
Project scope and timing	Project scope and timing will be as per the draft Project Deed and the Consumer Trustee's authorisation for the RNI project.
Contractual arrangements	Project Deed and major subcontracts will be executed no later than 31 December 2025.

5.2 Our forecast is prudent, efficient and reasonable

Under section 38 of the EII Act, the AER is responsible for 'calculating the prudent, efficient and reasonable capital costs for development and construction of the network infrastructure project'. In this section we step through why our proposed capex of $590.8 million (real 2025-26) satisfies each element of this assessment criterion, known as the 'transmission efficiency test' or 'TET'.

5.2.1 Prudence of our proposed capex

The prudence of our proposed capex is supported by the additional oversight that exists under the EII framework, particularly from the Infrastructure Planner and Consumer Trustee.

In the AER TET non-contestable Guideline the AER recognises that there are differences between the EII Act and NER regime. It states that this 'reflect[s] that the scope of [the AER's] assessment under the EII Act is narrower than the scope of the assessment of a transmission network service provider's revenue proposal under the NER'.[11] Prudent expenditure under the NER requires an assessment of the 'best course of action considering the available alternatives'.[12] Under the EII framework, the only option available for consideration is the option the Infrastructure Planner has selected.

Working within this regime, we have developed a capex proposal that is prudent because it aligns to the investment needed to deliver the technical specifications set by the Infrastructure Planner. This involves delivery of three portions, which have been designed to release additional capacity as soon as possible:

11 AER, TET and Revenue Guideline for NSW Non-contestable Network Infrastructure Projects, 2023, p.8
12 AER, Forecast expenditure assessment guideline for transmission, 2013, p. 9

- **Portion 1:** Modernisation of the Upper Hunter secondary systems (providing a total of 350 MW additional network capacity)
- **Portion 2:** Construction of the new Sandy Creek STSS, Muswellbrook network rearrangement, Singleton to Kurri 132 kV link, and installation of a communications link across the Hawkesbury River to provide enhanced security of communications infrastructure (providing a cumulative total of 630 MW of additional network capacity)
- **Portion 3:** Construction of the new Antiene STSS, and Antiene to Singleton 132 kV link (providing a cumulative total of 1 GW of additional network capacity).

The prudence of our proposed capex is further supported by the competitive tension that applied in the selection of Ausgrid as the Network Operator for the HCC RNI Project. EnergyCo selected Ausgrid as the Network Operator following a select tender process between Ausgrid and Transgrid.[13]

We engaged extensively with the HCC REZ Reg Panel about the EII framework. The Panel's report to the AER provides recommendations and feedback on how the EII regime can be improved. We welcome this feedback and look forward to continued dialogue with customer advocates and other groups on this topic. For the purposes of our Revenue Proposal, we are confident that the additional oversight under the EII framework supports a finding that the capex required for the HCC RNI Project is prudent.

Our proposal aligns with the technical solution and capex estimate authorised by the Consumer Trustee on the recommendation of the Infrastructure Planner. Reaching this point involved an extensive 18-month process, with review and challenge by independent authorities, like the Consumer Trustee, with legislative responsibilities to make authorisation decisions in the long-term financial interest of NSW energy customers.

The next limb of the TET requires Ausgrid to establish that our forecast reflects the efficient costs to meet the prudent option selected by the Infrastructure Planner.

5.2.2 Efficiency of our proposed capex

Our proposed capex reflects the efficient level of investment needed to deliver the HCC RNI Project.

We have adopted a blended delivery model that uses both internal and external resources. This leverages Ausgrid's comparative advantages where we have existing resources, such as:

- internal expert design, network modelling, property, community engagement and governance teams
- an available internal workforce, to undertake tasks at the most efficient cost
- procurement of equipment which is then free issued to subcontractors, allowing Ausgrid to leverage its purchasing power and avoid subcontractor margins.

All other tasks are delivered through external resources procured through competitive tender.

Our forecasting approach is based on:

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13 EnergyCo, Hunter-Central Coast Renewable Energy Zone: Summary of EnergyCo's network recommendation, April 2025, page 14

- agreed pricing from competitively sourced external contracts (approximately 70% of our proposed capex)
- forecasting methods aligned with those used for Ausgrid's other regulatory determinations for expenditure that has not been competitively sourced
- real escalation on labour and materials above CPI, which totals $3.8m or 1% of the total capex estimate.

Table 5-3 sets out the forecasting method we have used for each element of our capex forecast. The 'market price' column refers to areas of our forecast that have been built up from pricing agreed with suppliers and subcontractors following competitive procurement processes. Further detail on our procurement strategy is included in Attachment 5.3.

The 'established method' column refers to areas of our forecast where we have adopted costings approved in our 2024-29 NER determination or applied an established AER practice or tool for forecasting an expenditure category. Further detail on Ausgrid labour and labour related costs is included in Attachment 5.5. The labour model is included as Attachment 5.6.

Table 5-3: Ausgrid's forecasting method for each category of investment ($m, real 2025-26)

		Market price	Established method	Capex ($m)	% of total capex
Transmission lines	Contracted services	✓		[redacted]	[redacted]
	Materials	✓		[redacted]	[redacted]
	Ausgrid Labour		✓	5.5	1%
	Other	✓	✓	5.3	1%
	Subtotal			**203.1**	**34%**
Substations	Contracted services	✓		[redacted]	[redacted]
	Materials	✓		[redacted]	[redacted]
	Ausgrid Labour		✓	2.6	0%
	Other		✓	1.0	0%
	Subtotal			**106.2**	**18%**
Land and easements	**Subtotal**	✓	✓	**23.7**	**4%**
Secondary systems	**Subtotal**	✓	✓	**4.0**	**1%**
Communications	**Subtotal**	✓	✓	**7.7**	**1%**
Owner's costs	Contracted services	✓		2.7	0%
	Ausgrid Labour		✓	49.8	8%
	Other		✓	2.1	1%
	Subtotal			**54.6**	**9%**
Design, social licence and other	**Subtotal**	✓	✓	**51.8**	**9%**

		Market price	Established method	Capex ($m)	% of total capex
Infrastructure Planner Fee	**Subtotal**		✓	**92.9**	**16%**
Risk costs	**Subtotal**		✓	**46.9**	**8%**
Total				**590.8**	**100%**

We engaged GHD to undertake an independent review of our cost estimates for the HCC RNI Project. This is a prudent measure to introduce an element of independence to assessing the efficiency of our forecast. GHD's report is provided in Attachment 5.2.

GHD concluded that:

- the capex forecast is prudent, efficient and reasonable for carrying out the Project
- as a Class 2 / 3 estimate, the capex forecast represents the best available estimate at this stage of the Project's development
- the base capex forecast is free of any generalised risk provisioning and the approach and separate quantification of risk provisioning is prudent.

GHD considered benchmarking the HCC RNI Project cost estimate against AEMO's Transmission Cost Database (**TCD**) tool. However, the TCD tool does not yet have relevant standardised unit costs for predominately distribution network solutions, such as the HCC RNI Project.

GHD was able to benchmark a select portion of our scope which was the greenfield and brownfield substation works. The benchmarking concluded our capex forecast was within 3% of the estimated cost from the TCD tool output.

In the absence of appropriate benchmarking for the HCC RNI as a whole project, GHD's review therefore primarily focused on verifying the efficiency of our capex estimate by:

- reviewing the outcomes of competitive tendering procurement processes and third party contracts
- inspecting procurement supply contracts and quotes for pricing free-issued equipment
- reviewing reports from independent specialists to support cost estimation (e.g. land valuation, risk costs)
- assessing our forecasting approach for internal labour forecasts and the reasonableness of the resourcing profile in the context of the project scope.

5.2.3 Reasonableness of our proposed capex

Our proposed capex is reasonable because it is based on an estimate that Ausgrid has developed using good industry practice within the accelerated timeframes that apply under the EII Act.

The term 'reasonable capital costs' is a feature of the EII framework that does not apply under the NER regime. We engaged with our HCC REZ Reg Panel on the meaning of this term and its interaction with the prudence and efficiency limbs in the TET.

Our view is that ‘reasonable’ requires a tailored assessment of whether good industry practice has been employed in the circumstances under which a cost estimate has been developed. In the case of the HCC RNI Project, this requires a holistic assessment of the following considerations:

- NSW Government policy requiring HCC RNI to provide 1 GW of transfer capacity within a highly constrained timeframe
- limits on the amount of funding available for project development activity. The activities that were limited to available funding included detailed design development, detailed site investigations and sampling, environmental assessment and reports, and developing detailed project staging plans
- restrictions on joint planning with Transgrid and on engaging with a wide range of relevant stakeholders, including directly impacted landholders, broader community, Transport for NSW, councils, MPs, and other government agencies before January 2025
- the timing of Ausgrid’s formal engagement as the HCC REZ Network Operator, which did not occur until mid-December 2024.

Despite these limitations we have employed good industry practice in developing our cost estimates. This involved:

- engaging expert cost consultants, Turner & Townsend, to augment our internal estimation capability and develop of our cost model
- best practice procurement processes including competitive tenders for major subcontracts, seeking improved pricing for bulk purchases from Ausgrid’s existing equipment supplies, obtaining fixed prices for known scope
- undertaking bottom-up builds of those items not yet able to be fully market tested.

5.3 Efficient allocation of risk

Our proposed capex reflects the expected prudent and efficient cost of delivering the required transmission assets within the specified timeframe set by the Infrastructure Planner for the HCC RNI Project.

This section sets out our approach to the allocation of Project risks and explains why this results in efficient outcomes for consumers, by allocating risks to the party that is best placed to bear and/or manage that risk. Our approach is to first assess the risk characteristics of each capex category and to allocate them to one of the following three groups:

- **Group A** – capex costs with a high degree of forecast certainty
- **Group B** – capex costs that are uncertain, but the event risk and/or consequences are somewhat under the control of Ausgrid or our contractors and can be reasonably estimated, and so the risk is best borne by Ausgrid or our contractors
- **Group C** – capex costs that are uncertain and beyond the control of Ausgrid or its contractors, and where the event risk and/or consequences of the event cannot be reasonably estimated by Ausgrid, so the risk is best borne by consumers.

This grouping of capex costs ensures that Ausgrid:

- appropriately allocates the risk to the party that is best placed to bear and/or manage that risk

- avoids double counting of any risk, by ensuring that risk events cannot be included as both a contingent cost allowance and as an adjustment event
- allows Ausgrid to set a contingent cost allowance which is reasonable and proportionate for the Project.

To reflect these capex groupings, we report capex as either:

- **Base capex** – costs that have a high certainty of being incurred by Ausgrid; or
- **Risk (contingency) costs** – the expected cost of risks that are reasonably foreseeable to be encountered and where Ausgrid, or its contractors, are best placed to manage these risks; or
- **Revenue adjustment events** – which addresses risks that are less foreseeable, uncertain risks that are not under the control of Ausgrid or its contractors, or uncertain risks where the impact of the risk cannot be reasonably estimated, and so the positive and negative impacts of these events are best borne by consumers.

Table 5-4: Treatment of capex costs and risks

Capex grouping	Base capex	Risk (contingency) costs	Revenue adjustment events
Group A	Expected cost of the capex category based on: • Contracts procured competitively • Forecast internal costs • Infrastructure Planner Fee	None	None
Group B	The certain costs of the capex category	Expected cost of the risk event	None
Group C	Best estimate or provisional sum for the capex category	None	Ex-post adjustments (no allowance unless a defined event occurs)

Our capex proposal includes both base capex and risk (contingency) costs and are discussed in greater detail below in section 5.4 below. Chapter 8 sets out our proposed revenue adjustment events.

The remainder of this section sets out how capex costs and risks have been allocated.

5.3.1 Base capex

Expenditure included in our base capex allowance includes costs where there is a high degree of confidence that they will be incurred in the delivery of the HCC RNI Project.

Base capex is the sum of:

- The expected cost of capex categories for which there is no contingency allowance or revenue adjustment event (**Group A**). For example, if the capex category is forecast to have a 50 per cent chance of costing $10 million and a 50 per cent chance of cost $11 million, then Base capex would include the expected cost of $10.5 million.

- Certain costs of those capex categories for which there is a contingency allowance (**Group B**). For example, transmission line stringing can be done using a helicopter or by traditional methods at a [redacted] cost premium. From our survey of the route, we know that [redacted] of lines will need to be strung using traditional methods; however, the requirement to use traditional stringing may impact a higher percentage of the route and in some foreseeable scenarios could be [redacted]. Base capex assumes that [redacted] of the lines will be strung using traditional methods (with [redacted] of stringing done by helicopter), and a contingency risk allowance is included to cover the risk that a higher proportion of traditional stringing will be required.
- The best estimate of, or provisional sum for, the cost of those capex categories for which there is a revenue adjustment event (**Group C**). For example, our best estimate of the EnergyCo portion of the Infrastructure Planner Fee is $92.9 million, which is included in Base capex. However, the Infrastructure Planner Fee Adjustment Event allows for a variation (either positive or negative) in our revenue, if the fee determined by EnergyCo changes. In some cases, the provisional sum will be zero (e.g. there is no estimate or provisional sum for a terrorism event).

5.3.2 Risk (contingency) costs

Risk (contingency) costs set out the expected cost of risks that are reasonably foreseeable and where Ausgrid, or its contractors, are best placed to manage these risks.

We note that the AER has stated that it expects that network operators should 'demonstrate how its risk assessment represents reasonable and realistic expectations of risks that could be realistically encountered'.[14]

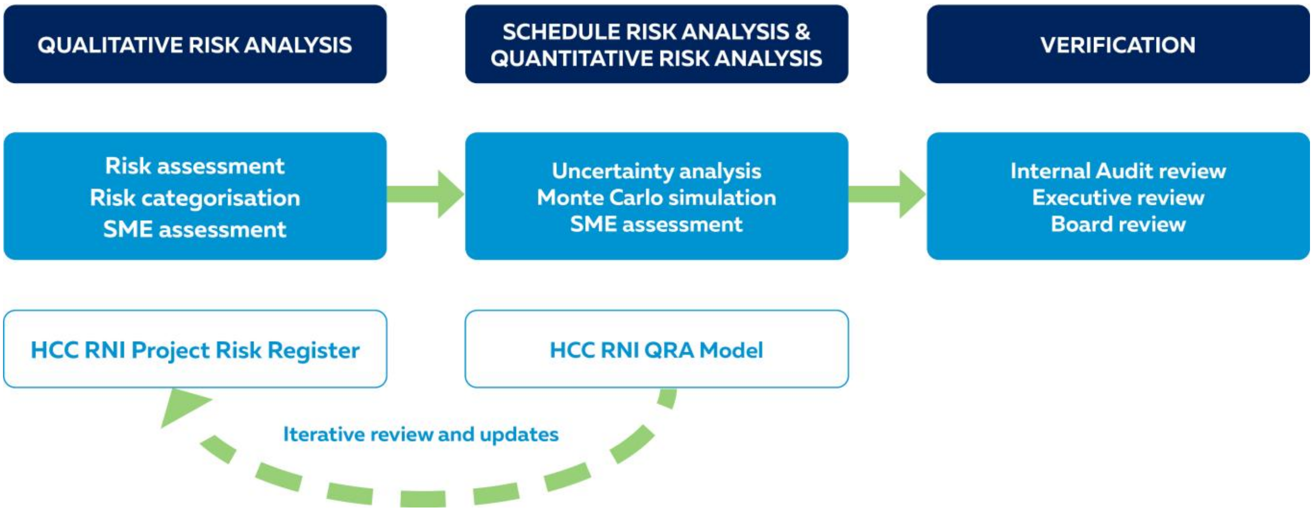
We interpret this to mean that:

- risks proposed should reflect those that could be realistically encountered, and should not include risks that are hypothetical or which rarely occur
- proposed likelihoods and consequences should reflect reasonable assumptions and be supported by available evidence.

Further, our risk allowances consider the controls or mitigations adopted by Ausgrid consistent with good industry practice.[15] Our capex proposal then reflects the best estimate of risk (contingency) costs, given reasonable and realistic expectations of the likelihood and consequence of each identified risk (i.e. the expected cost of the risk). This approach is summarised in Figure 5-2.

14 AER, Guidance Note | Regulation of actionable ISP projects, 2021, pp. 17-18.
15 AER, Guidance Note | Regulation of actionable ISP projects, March 2021, p 18.

Figure 5-2: Ausgrid risk management process for the HCC RNI



Our approach is in line with ISO31000 and is necessary to address a range of project uncertainties arising from the underlying characteristics of the technical specifications and timetable set by the Infrastructure Planner, including:

- potential difficulties in accessing easements
- unknown geotechnical conditions on the route for new transmission lines
- unforeseen artifacts, native title claims and site contamination
- inclement weather over and above a reasonable threshold that delays and increases the cost of the Project
- third party unrest resulting in delays.

5.3.3 Revenue adjustment events

Revenue adjustment events allow Ausgrid to apply to the AER, in predefined circumstances, to amend our allowed revenues to account for changes in our HCC RNI costs.

In addition to the adjustment events prescribed in EII Chapter 6A[16], we are proposing 18 nominated cost adjustment events, which fall into three broad categories:

- **Standard events,** which are adjustment events for AER distribution and transmission determinations that are commonly approved by the AER
- **EnergyCo contractual compliance events**, which are events that are either required to be included under the contractual arrangements with EnergyCo or are necessary to reflect those contractual arrangements
- **Procurement induced cost uncertainty events,** which reflect that the unique procurement process for the HCC RNI has resulted in a higher than usual degree of uncertainty around certain cost items at the current stage of the process.

16 EII Chapter 6A, 6A.7.3(a1).

These revenue adjustment events are not designed to completely de-risk the HCC RNI Project. Rather, revenue adjustment events are an important part of the incentive framework, as they allow for price adjustments to be made in response to large, unexpected and uncontrollable events that result in cost changes. Without adjustment events, Ausgrid would likely hold higher levels of contingency to manage the impact of such events on the Project, which may not be efficient or in the interests of customers. Adjustment events are symmetrical (where possible) so allow Ausgrid to return cost savings to customers where certain costs turn out to be lower than expected.

We outline our proposed adjustment events in more detail in **Chapter 8** and Attachment 8.1 of this Revenue Proposal. These events are balanced so that Ausgrid is not unfairly penalised when unlikely but foreseeable events that are outside our control occur. Equally, revenue adjustment events ensure that customers pay no more than necessary for the Project.

5.4 Capex by expenditure category

Our total proposed capex for the HCC RNI Project is $590.8 million including pre-period expenditure, EnergyCo's component of the Infrastructure Planner Fee, and the forecast expenditure needed to deliver 1 GW of transfer capacity as per the Consumer Trustee's authorisation of the Project.

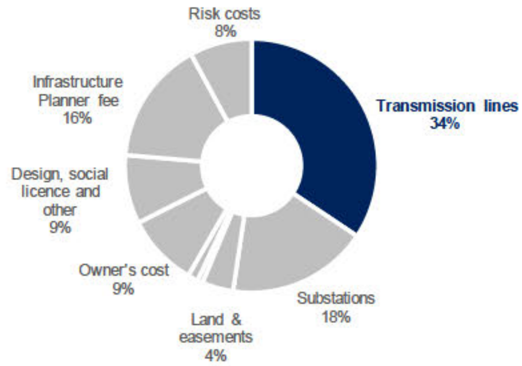
This section of our proposal addresses the prudence and efficiency of the components of our capex proposal. It describes the expenditure and scope of each major capex category. We also explain why our proposal is reasonable given the circumstances under which we have developed our forecast to meet NSW government policy.

5.4.1 Transmission lines

We propose $203.1 million in capex to build 'transmission lines' connecting new generation with load in the Hunter-Central Coast REZ and existing exit points to the main grid. Transmission lines make up the largest single share of our total capex, at 34%.

Unlocking value for customers

Our 132 kV lines are more cost efficient than traditional transmission and make prudent use of approximately 100 km of existing overhead line corridors.



Our appointment as the network operator for the HCC RNI Project incorporated a competitive process that resulted in our proposed 132 kV solution for 'transmission lines' being considered more prudent than traditional transmission. Technically speaking, our solution is a 'subtransmission' option that falls within the voltage levels offered by distribution networks.

We will upgrade existing feeders to connect local loads and carry the residual output to existing 330/132 kV main grid exit points. This is more efficient than building 330 kV lines to carry the full required transfer capacity into the main grid. By connecting generation to local loads at the 132 kV level, our technical solution frees up capacity in the 330 kV grid. This can defer investment on the main grid by easing emerging transmission constraints.

Australia's first Distribution Renewable Energy Zones

The Hunter-Central Coast REZ will be Australia's first distribution REZ or 'DREZ'.

The DREZ model leverages existing capacity and network corridors to co-locate generation and loads in a way that eases pressure on the transmission network. It is a model that can connect transfer capacity for new generation in a way that is cheaper, faster and less disruptive on the community than traditional transmission scale investments.

Figure 5-3 Photomontage of existing and proposed transmission lines


Existing


Example proposed

Prudent, efficient and reasonable costs

Our delivery model for transmission lines is prudent, efficient and reflective of reasonable costs.

Table 5-5 shows that 94% of our proposed transmission lines capex is based on external resources. This delivery model will unlock savings for customers by leveraging competitive tension between bidders seeking to supply contracted services ([redacted] of costs) and materials ([redacted] of costs). Ausgrid will purchase materials through proven suppliers, with no contractor margin or 'on cost' being passed to consumers. Our forecast also implements an efficient allocation of risk between Ausgrid, suppliers and our customers (see section 5.3 above).

Table 5-5: Proposed transmission lines capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Contracted services	[redacted]	[redacted]	External	• Market tested prices
Materials	[redacted]	[redacted]	External	• Market tested prices • Alignment with industry standards e.g. AS7000
Labour (internal)	5.5	3%	Internal	• Labour rates based on internal sources • Efficiency benchmarked against AER approved labour rates

	Proposal	%	Delivery	Forecasting method
Other	5.3	3%	Blended	• Market tested prices • Benchmark efficient internal labour rates
Total	**203.1**	**100%**		

The prudence and efficiency of our forecast is further supported by our engineering analysis. Ausgrid has completed substantial modelling along subtransmission routes to determine the optimal pole heights, constructions, span lengths and conductor tensions. Steel poles have been chosen as the primary pole type, due to their strength capabilities, low weight, lower visual impact and ease of installation.

Scope of work

The subtransmission line works comprise the rebuilding of existing Ausgrid network with increased capacity subtransmission lines. This will take place:

- between Kurri STS and the new Antiene STSS
- between the new Sandy Creek STSS and the Muswellbrook BSP.

The construction will occur within Ausgrid existing subtransmission corridors with some expansion into public and private land.

With the exception of replacement timber poles on a single feeder (Feeder 95Z) and the two underground feeders connecting Muswellbrook STS and Sandy Creek STSS, all new circuits will be constructed using steel poles with embedded foundations.

STS	**Subtransmission substation** contains transformers that step up/down voltages
STSS	**Subtransmission switching station** connect and disconnect lines at the same voltage (i.e. no transformers)
BSP	**Bulk supply point** is a substation or switching station that connects transmission to both individual customers and distribution networks
ZS	**Zone substation** receives high voltage electricity from subtransmission network and converts it to lower voltages for distribution

The subtransmission scope will be undertaken in stages to ensure minimal imposition on the live network. More detailed information about the scope of work is set out in Table 5-6.

Table 5-6: More detailed overview of scope – Transmission lines

Component	Detail
132 kV Circuits Kurri STS to Antiene STSS	• Two new 132 kV circuits will be built between Kurri STS and Antiene STSS and will comprise two direct 600 MVA circuits. • The specific route section design includes: o Kurri STS to Branxton Tee: ▪ 24 km – remove 66 kV feeder (KU12) and replace it with a single pole line 132 kV dual circuit construction o Branxton Tee to ABS34272:

Component	Detail
	▪ 20 km – rebuild 66 kV feeder (KU12) with single pole line 132 kV dual circuit construction, with 66 kV under-built. o ABS34272 to Mt Thorley ZS: ▪ 1.1 km – build a single pole line 132 kV dual circuit twin construction ▪ 3.1 km – rebuild existing 66 kV out of service (OOS) line to single pole line 132 kV dual circuit, with 66 kV under-built. o Mt Thorley ZS to Singleton STS: ▪ 3.3 km – rebuild 66 kV Feeder (6019) to single pole line 132 kV dual circuit with 66 kV under-built. ▪ 7.7 km – remove 132 kV feeder (955) and build two new pole lines along existing corridor o Singleton STS to Antiene STSS: ▪ 23 km – remove 132 kV feeder (95U) and build two new pole lines along existing corridor
132 kV Circuit Transgrid Muswellbrook BSP to Sandy Creek STSS (teed)	• One new 132 kV network segment will be built comprising: o Sandy Creek STSS to tee 300 MVA – Feeder 95U(2) o 4 km rebuild of existing 132 kV feeder (95M) as a 132 kV dual circuit 300 MVA single conductor single pole line (Feeders 95M, 95U(2)).
132 kV Circuits Muswellbrook STS to Muswellbrook STSS	• Two new 132 kV circuits feeders (9PF and 9PG) will be constructed • Scope includes rerouting of 132 kV feeder connections to terminate at Muswellbrook STSS rather than the existing STS. This will require the re-alignment of an existing 66 kV feeder (6022) to allow construction of the new STSS and feeder connections.

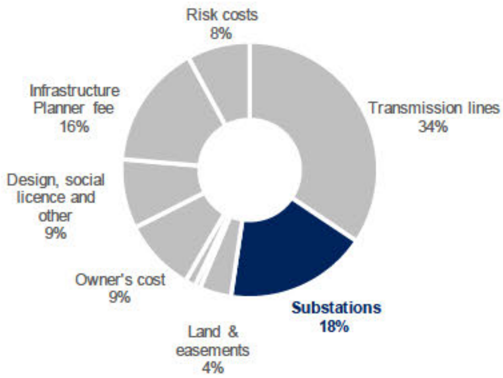
5.4.2 Substations

We propose $106.2 million in capex to build two new 132 kV subtransmission switching stations (Sandy Creek STSS and Antiene STSS), to augment existing subtransmission substations (Kurri, Mitchell Line, Singleton and Muswellbrook) and to install a 'series reactor' at 132/11 kV zone substation in Rothbury.

Unlocking value for customers

Approximately 97% of our forecast expenditure to deliver greenfield switching stations is based competitive tendered priced contracts.

Figure 5-4: Substations capex %



Prudent, efficient and reasonable costs

Approximately 97% of forecast expenditure for substations and switching is based on external delivery, as outlined in Table 5-7. This approach leverages competitive tender processes to deliver costs that are prudent, efficient and reasonable for the scope of work determined by EnergyCo in its role as Infrastructure Planner for the HCC RNI.

Table 5-7: Proposed substations and switching stations capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Contracted services	[redacted]	[redacted]	External	• Market tested prices
Materials	[redacted]	[redacted]	External	• Market tested prices • Alignment with industry standards e.g. AS7000
Labour (internal)	2.6	2%	Internal	• Labour rates based on internal sources • Efficiency benchmarked against AER approved labour rates
Other	1.0	1%	Blended	• Market tested prices • Benchmark efficient internal labour rates
Total	**106.2**	**100%**		

Scope of work

To facilitate the connection of new generators we will build two new 132 kV subtransmission switching stations, Sandy Creek STSS and Antiene STSS. Both sites have been selected to ensure that they can be built as 'greenfield' constructions with minimal impact on existing network operations and the surrounding community.

To link the new switching stations into the broader 132 kV network, 'brownfield' busbar augmentation work will be required at Ausgrid's existing Kurri and Muswellbrook subtransmission substations. To improve load sharing under contingent conditions across the new 132 kV feeders, a series reactor will be installed in Ausgrid's existing Rothbury 132/11kV Zone Substation.

Explanation of technical terms

- **Brownfield busbar augmentation** involves extending components (busbar) at an existing substation to enable connection of additional equipment or electricity feeders.
- **Series reactor installation** involves the connection of electrical equipment (a reactor) to an electricity feeder to control power flow in that feeder.
- **An electricity feeder** is a power line that carries electricity from a substation or switching station to distribution points, such as homes. Feeders have unique identifiers e.g. "95F".

Table 5-8: More detailed overview of scope – Substations and switching

Component	Detail
Antiene STSS	• The Antiene STSS will comprise an outdoor 132 kV busbar and modular control room with amenities. • Switchyard to follow Ausgrid's standard arrangements while the control room will comprise a modular building fabricated off-site.
Sandy Creek STSS	• The Sandy Creek substation will comprise an outdoor 132 kV busbar and modular control room and amenities located adjacent to Ausgrid's existing Muswellbrook 132/33kV STS • The connection back to the adjacent Muswellbrook STS will be via underground 132 kV cable with appropriate thermally stabilised bedding as required. • The switchyard has the main 2500A rated high level busbar running east–west and the low-level feeder connections running north–south.
Muswellbrook STS	• Once Antiene STSS is constructed, two overhead feeders (95F and 95H) will be redirected to the STSS in a staged fashion. • To maintain supply to Muswellbrook STS, two new underground 132 kV feeders (9PF and 9PG) will be installed from the STSS to the STS. The two new feeders will bypass the existing Muswellbrook STS 132 kV busbar and supply two transformers (T1 and T3).
Kurri STS	• Two additional 132 kV feeder bays to be added at Kurri STS with the augmentation works required to increase transfer capacity through to Transgrid's Newcastle BSP. A third bay could be added in the future. • Design of switchyard extensions based on Ausgrid's standard arrangements with bay spacings allowing suitable and safe access to all components for installation, operation, testing and replacement.
Rothbury ZS	• The installation of a series reactor to improve load sharing under contingent conditions across the new 132 kV feeders to the Eastern Hub STSS through additional within one of two feeders (95R or 955). • The required extension is complicated by the need to keep a feeder (955) available for service throughout the equipping phase of works.

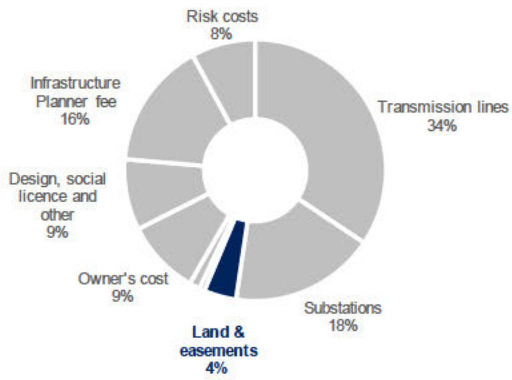
5.4.3 Land and easements

We propose $23.7 million in capex to acquire around [redacted] hectares of property interests from Crown land and private landholders. The total cost includes land acquisition costs as well as market valuation of land and associated professional fees incurred through the acquisition process.

Unlocking value for customers

Ausgrid's solution minimises land acquisition and impact on landowners by leveraging existing Ausgrid properties and easements, ensuring efficient and cost-effective project delivery.

Figure 5-5: Land and easements capex %



Given the scale and complexity of the HCC RNI Project, there are significant implications for the land and property requirements along the proposed route.

To manage these risks, our solution leverages existing Ausgrid landholdings and property interests within the REZ. In addition to a number of freehold properties, Ausgrid has significant easements and corridors in place that contain existing electricity infrastructure. Ausgrid will be able to utilise or augment (widen or extend) these existing easements where required to accommodate the RNI infrastructure, thereby limiting the impact on surrounding landowners.

Through the design optimisation process, Ausgrid has been able to deviate the proposed route around items of significance, utilising existing rail and road corridors to further minimise the impacts on surrounding landowners.

As a result, the proposed design requires only around [redacted] hectares of property interests to be acquired from Crown land and private landholders. Ausgrid appointed Jones Lang LaSalle (**JLL**) as an independent valuer to provide preliminary desktop advice in relation to the estimated compensations payable to respective landowners of the land required for the HCC RNI and estimates for professional fees payable to support land acquisition (e.g. legal, conveyancing, valuation). The JLL report is included as Attachment 5.4.

Table 5-9: Proposed Land and easement capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Contracted services	[redacted]	[redacted]	External	Market price from independent expert (JLL)
Other	[redacted]	[redacted]	External	Land acquisition, market valuation from independent expert (JLL)
Total	**23.7**	**100%**		

17 The amount of [redacted] is the provisional sum which is subject to the Land Acquisition adjustment event

5.4.4 Secondary systems

We propose $4.0 million in capex to modernise secondary systems in the Upper Hunter to comply with NER standards and enable bi-directional power flow, including upgrading protection on 132 kV lines. Additionally, Transgrid will perform minor enabling works to facilitate connection to the NSW transmission network.

Unlocking value for customers

Ausgrid will undertake this work as it can efficiently leverage our strength in delivering secondary system remote end protection upgrades, which are regularly performed on existing Ausgrid substations.

Figure 5-6: Secondary systems capex %

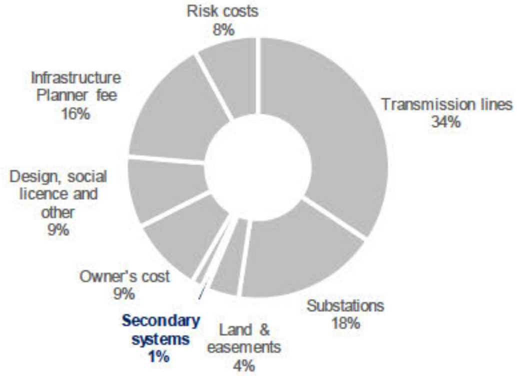


Table 5-10: Proposed secondary systems and ancillary works capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Labour (internal)	[redacted]	[redacted]	Internal	• Labour rates based on internal sources • Efficiency benchmarked against AER approved labour rates
Contracted Services	[redacted]	[redacted]	External	• Ausgrid estimate based on prior Transgrid capital works
Materials	[redacted]	[redacted]	Internal	• Market tested prices • Alignment with industry standards e.g. AS7000
Total	**4.0**	**100%**		

Secondary Systems

Ausgrid will undertake secondary systems modernisation to bring secondary systems in the Upper Hunter into compliance with current NER standards and enable bi-directional power flow. This includes remote end secondary systems works to upgrade protection to duplicated differential line schemes on existing 132 kV lines between Muswellbrook BSP, Muswellbrook STS and Mitchell Line STS. These works and procurement of equipment will be performed directly by Ausgrid.

Ancillary Works

Ausgrid has specifically designed our solution to minimise ancillary works that would need to be completed by another Network Operator. Some small components of ancillary works are required

18 The amount of [redacted] (which comprises [redacted] and Ausgrid labour to support [redacted] work) is the provisional sum which is subject to the [redacted] adjustment event

to be provided by Transgrid, consistent with work that Ausgrid and Transgrid would typically coordinate with each other as business-as-usual.

The HCC RNI Project mostly involves a series of augmentations to existing distribution (subtransmission) infrastructure in the Hunter-Central Coast REZ. The additional network transfer capacity will flow into the existing NSW electricity network at multiple points in the Hunter-Central Coast REZ.

Transgrid will be required to complete a number of minor enabling works to facilitate connection to the NSW transmission network. These enabling works will include:

- Enabling use and crossing of Transgrid easements for fibre works and feeder crossings;
- Installation of communications equipment on Transgrid property at Muswellbrook 330 kV BSP; and
- Upgrade and recommissioning of protection systems at both Muswellbrook and Newcastle BSPs.

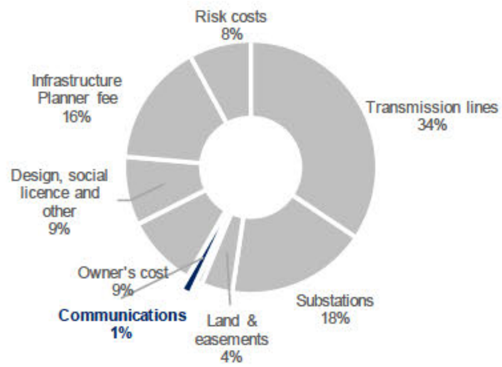
5.4.5 Communications

We propose $7.7 million in capex to install a secure fibre communications link between the Hunter-Central Coast REZ and Sydney to enhance redundancy and security for the electricity network so that the HCC RNI can be operated in a safe and secure manner.

Unlocking value for customers

Approximately 91% of the forecast expenditure will be managed through an external delivery model, leveraging competitive tender processes to ensure cost efficiency and prudence.

Figure 5-7: Communications capex %



Ausgrid will install a communications link across the Hawkesbury River that will complete a secure fibre communications link between the Hunter-Central Coast RNI and Sydney. This includes 30 km of OPGW and 2 km all dielectric self-supporting fibre installation. To facilitate this work, we will need to replace a small proportion of timber poles along the feeder.

The new link will run from Somersby to Berowra using an OPGW on Feeder 95Z. This will provide communications redundancy and enhanced security of communications infrastructure between the Hunter-Central Coast RNI and Sydney. This will ensure the electricity network in the RNI can be operated in a safe and secure manner during critical events.

It is prudent for this capability to be developed, given the impact a loss of communications could have on the operation of the NSW electricity system when generation levels in the Hunter-Central Coast REZ are high, as is expected to be the case following completion of the HCC RNI and associated generation facilities.

Approximately 91% of forecast expenditure is based on an external delivery model, as outlined in Table 5-11. This approach leverages competitive tender processes to deliver costs that are prudent, efficient and reasonable for the scope of work determined by EnergyCo in its role as Infrastructure Planner for the Hunter-Central Coast REZ.

Table 5-11: Proposed communications capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Contracted Services	[redacted]	[redacted]	External	• Market tested prices
Labour (internal)	[redacted]	[redacted]	Internal	• Labour rates based on internal sources • Efficiency benchmarked against AER approved labour rates
Total	**7.7**	**100%**		

5.4.6 Owner's costs

Owner's costs refer to the project management expenses that Ausgrid, as the project owner, incurs in delivery of the HCC RNI Project. In this Revenue Proposal it is distinguished from other costs which are undertaken by Ausgrid which are typically undertaken by an external construction contractor (eg design or construction work which is being undertaken by Ausgrid internal teams).

We propose $54.6 million in Owner's costs, which is predominantly Ausgrid labour, for the management and delivery of the HCC RNI Project. Owner's costs make up 9 per cent of our total capex and reflect the prudent delivery model Ausgrid has put in place to subcontract specific parts of the project and retain certain functions within Ausgrid to leverage key internal capabilities.

Unlocking value for customers

Our labour rates are in line with, or outperform, the benchmark efficient ANS labour rates that the AER approved for our 2024-29 determination under the NER.

Figure 5-8: Owner's costs capex %

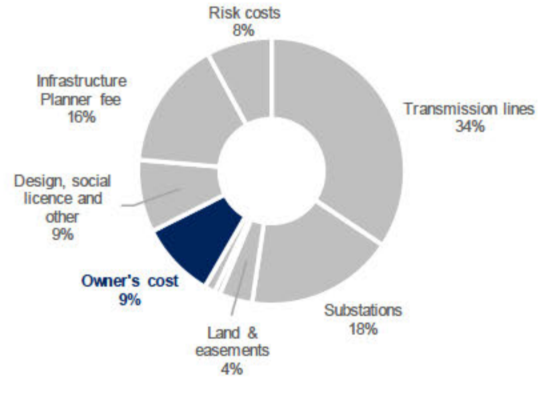


Table 5-12: Proposed Owner's costs capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Contracted services	2.7	5%	External	Market tested prices
Materials	n/a	n/a	-	n/a
Labour (internal)	49.8	91%	Internal	Labour rates based on internal sources Efficiency benchmarked against ANS labour rates
Other	2.1	4%	Internal	Market tested prices (staff training budget tested against publicly available course fees)
Total	**54.6**	**100%**		

Prudent, efficient and reasonable costs

Our proposed capex uses both internal and external resources. This is a prudent approach because it leverages Ausgrid's existing field workforce and other internal capabilities. It also promotes efficiency by using external resources when they offer the lowest cost option.

To enable a blend of internal and external resources, Ausgrid will project manage the overall Project and program. This includes managing external contracts, procuring all equipment for the construction of HCC RNI assets and managing how each component of the Project interface with each other. Owner's costs also include review of design related works, the implementation of property acquisitions and completion of environmental approvals.

Table 5-13: Benchmark rates vs Ausgrid actual

AER benchmark rate ($per hour)			Ausgrid rate	Difference
Technical specialist	198.81	Business support officer	[redacted]	[redacted]
		Safety advisor	[redacted]	[redacted]
Field worker	204.17	Electrical contract inspector	[redacted]	[redacted]
		Civil contract inspector	[redacted]	[redacted]
		Line inspector	[redacted]	[redacted]
Engineer	258.87	Project controller	[redacted]	[redacted]
		Project engineer	[redacted]	[redacted]
		Project manager	[redacted]	[redacted]
		Category manager	[redacted]	[redacted]
Senior engineer	309.10	Senior contractor administrator	[redacted]	[redacted]
		Project manager	[redacted]	[redacted]
		Project engineer	[redacted]	[redacted]
		Design	[redacted]	[redacted]
		Procurement	[redacted]	[redacted]

AER benchmark rate ($per hour)			Ausgrid rate	Difference
Engineering manager	357.58	Commercial director	[redacted]	[redacted]
		Head of planning and connections	[redacted]	[redacted]
		Asset investment planning manager	[redacted]	[redacted]
		Design	[redacted]	[redacted]

Scope of work

Our Owner's costs proposal consists of six main activities, which are outlined in Table 5-14.

Table 5-14: Owner's costs scope of works

Component	Detail
Project management	• Overall project management of program and delivery, including managing all interfaces between subcontractors • Project controls and assurance
Contract administration	• Upstream contract management with EnergyCo • Subcontractor management
Property acquisition	• Property condition or dilapidation surveys • Compulsory acquisition of Crown Land • Negotiations with Wanaruah Local Aboriginal Land Council • Easement or right of carriageway acquisitions
Environmental approvals	• Environmental studies and other work being undertaken by the internal Ausgrid Environmental Services team • The Project makes use of existing Ausgrid easements for a significant portion of the feeder routes, and will be assessed under Part 5 of the EP&A Act via an REF. Therefore, the Project does not trigger the requirements of the Biodiversity Offset Scheme.
Design	• Owner's design management and review throughout project
Procurement	• All procurement activities will be undertaken by Ausgrid • Free-issue equipment to subcontractors

5.4.7 Design, social licence and other

We propose $51.8 million in design, social licence and other activities, which include externally sourced design works, community and social, environmental planning, legal, regulatory and insurance. This category makes up 9 per cent of our total capex.

Unlocking value for customers

We have applied a blended delivery model to leverage Ausgrid's design capabilities and strengths in community and stakeholder management, with external expert support procured through competitive tender processes.

Figure 5-9: Design, social licence and other capex %

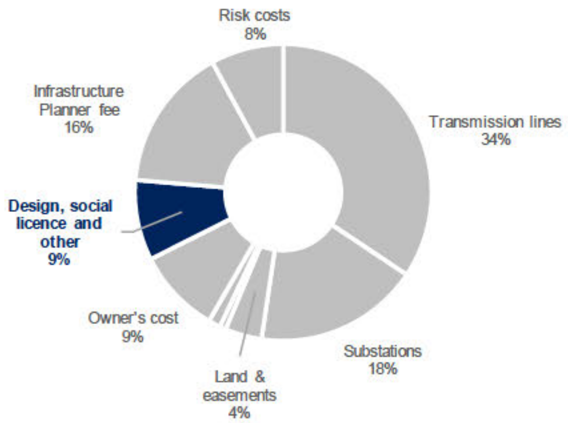


Table 5-15: Proposed Design, social licence and other capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Community and social licence	24.1	46%	Refer to section below	
Design works	9.7	19%	Refer to section below	
Insurance	[redacted]	[redacted]	Refer to section below	
Legal	[redacted]	[redacted]	Refer to section below	
Environment & Planning	2.5	5%	Refer to section below	
Regulatory	1.2	2%	Refer to section below	
Total	**51.8**	**100%**		

Community and social licence

We propose $24.1 million capex for community and social licence, with more detail set out in our Social Licence Proposal (Attachment 5.7).

We know that there is no 'one-size-fits-all' approach to earning community trust, and that early engagement and leveraging existing relationships are key to gaining and maintaining this trust. We have a well-considered, location specific social licence strategy for the Project, drawing on our existing active role in the Hunter and Central Coast, to ensure the community is at the centre of decision-making about social investment.

We have also developed a comprehensive Industry and Aboriginal Participation Plan that builds on Ausgrid's commitment to investing in real, meaningful training pathways and promoting sustainable employment opportunities, aligned with the EII Act and the Renewable Energy Sector Board Plan.

Our community engagement team includes property coordinators, acquisition managers, and land and property access managers. More than 150 property access agreements with individual landowners will be needed through the construction phase of the Project, to interact with landholders and coordinate access through their property. The team will also be delivering the Land and Property Acquisition Plan (see section 5.4.3 on Land and Easements).

Our Social Licence Proposal involves a cost allowance of $5.3 million which will enable Ausgrid to address identified impacts and deliver social outcomes and benefits for local communities within the HCC RNI Project footprint. The objectives of the Social Licence Plan are to mitigate and ultimately enhance potential impacts of the Project by fostering socioeconomic growth and advantages for the communities affected, and to direct the allocation of resources towards maximising community benefits throughout the Project's design and construction stages.

The cost allowance of $5.3 million, which represents approximately 1 per cent of the expected AER approved project cost, was estimated through benchmarking against similar projects. This funding level is reflective of prudent, efficient and reasonable costs for securing the social licence needed to build, operate and maintain the HCC RNI Project. An additional $0.3 million is allocated to Ausgrid's internal costs to administer the Social Licence Plan.

Ausgrid proposes to establish a new customer panel called the Hunter-Central Coast Local Engagement Committee (**HCC LEC**) which will be responsible for reviewing and selecting successful initiatives for funding. The HCC LEC will be made up of council representatives; regional representative from business, Aboriginal and environment sectors; and community members or group representatives. We intend to hold up to five workshops with the HCC LEC throughout the planning and construction phases of the Project. The outcomes from the workshops will drive how we invest in building social licence.

Table 5-16: Proposed community and social licence capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Labour (internal)	17.7	74%	Internal	• Labour rates based on internal sources • Efficiency benchmarked against ANS labour rates
Contracted services	1.1	4%	External	• Market tested prices
Social Licence Plan	5.3	22%	Internal	• Industry benchmarking performed by cost consultant
Total	**24.1**	**100%**		

Design works

For the HCC RNI Project, Ausgrid has made the decision to supplement our 150-strong internal design team with a design consultant to provide additional capacity to meet the Project program.

Ausgrid has partnered with AECOM, a multi-national engineering consultant with extensive experience in both transmission and distribution engineering. AECOM is an Ausgrid engineering panel member and is familiar with working to Ausgrid design standards.

Complexity and volume considerations have determined whether design packages will be self-performed by Ausgrid or contracted to the engineering consultant. This has led us to outsource the greenfield substation designs to AECOM and retain the brownfield substation packages internally. The modifications to the brownfield substations at Kurri STS and Rothbury ZS, as well as the existing Muswellbrook STS, require more complex interfaces and micro-staging, so have been retained within the Ausgrid design team.

Ausgrid will also undertake the full transmission line design, enabling distribution relocation designs, telecommunications network augmentations, and other remote end control and protection works internally. These teams possess the technical expertise and resource availability to meet the Project timeframes.

Table 5-17: Proposed design works capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Labour (internal)	5.2	54%	Internal	• Labour rates based on internal sources • Efficiency benchmarked against ANS labour rates
Contracted services	[redacted]	[redacted]	External	Market tested prices
Others	[redacted]	[redacted]	External	Market tested prices
Total	**9.7**	**100%**		

Insurance

The insurance costs cover the estimated amount required to put in place appropriate insurance for the delivery phase of the Project. In an early draft of the Project Deed, EnergyCo set out a suite of insurances it would require to be put in place to support the Hunter-Central Coast RNI Project. Ausgrid sought the advice of an expert insurance broker, Marsh, who advised on refinements to the insurance package which reduced premium costs without significantly reducing cover. EnergyCo reviewed and agreed to Ausgrid's proposal and Marsh has provided an estimate of the cost of placing that insurance. The Marsh report is included as Attachment 5.8. Note that insurance will not be placed until the Project Deed is signed, so the amount is an estimate at this point.

Once the Project is operational, it will be covered by Ausgrid's group insurance policies. An allocation for the costs of these policies is addressed in opex.

Table 5-18: Proposed insurance capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Other	[redacted]	100%	External	Market tested prices
Total	[redacted]	**100%**		

Legal

Legal costs encompass the external legal support required to develop and execute the Commitment Deed and Project Deed with EnergyCo, and to enter into appropriate agreements with downstream subcontractors. Legal costs also include ongoing contract management costs for the delivery phase of the Project.

Table 5-19: Proposed legal capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Contracted services	[redacted]	100%	External	Market tested prices
Total	[redacted]	**100%**		

Environmental Planning

The environmental planning costs are predominantly external specialist consultants to perform environmental assessments (e.g. cultural heritage, noise and ecology assessments) and support the delivery of the Environmental Impact Statement (**EIS**) and Summary Environmental Report (**SER**).

We also propose $[redacted] million of capex to support biodiversity planting and $[redacted] million capex for archaeology treatments to known artefacts.

Table 5-20: Proposed environmental planning capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Contracted services	2.5[19]	100%	External	Market tested prices
Total	**2.5**	**100%**		

Regulatory

The regulatory costs are predominantly labour costs for the regulation staff to manage and prepare the Revenue Proposal and manage the regulatory panel and consultants.

Table 5-21: Proposed Regulatory capex ($m, real 2025-26)

	Proposal	%	Delivery	Forecasting method
Labour (internal)	0.8	64%	Internal	Labour rates based on internal sources
Contracted services	0.3	28%	External	Market tested prices
Regulatory panel	0.1	7%	External	Market tested prices
Total	**1.2**	**100%**		

Consultant costs relate to modelling assistance, expert regulatory assistance, document drafting and the detailed engineering cost review undertaken by GHD.

5.4.8 Infrastructure Planner Fee

Our capex forecast includes the Infrastructure Planner Fee which is an amount to reimburse EnergyCo for costs incurred in respect of the HCC RNI Project and for Ausgrid's costs expended prior to reaching financial close (which occurs when the Revenue Determination is made and the Project Deed is signed). Infrastructure Planner Fee, totalling $162.7 million, will be paid prior to the first year of the Regulatory Period. The Infrastructure Planner Fee has three components:

- the amount notified by EnergyCo which reflects its project development costs, being $81.7million (this amount makes up 14 per cent of our total capex);

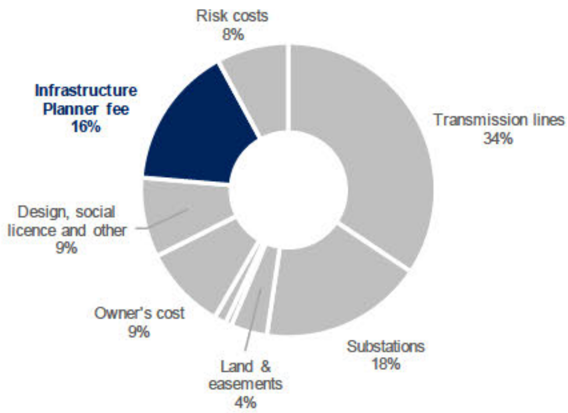
19 The amount of [redacted] (i.e. excluding the amounts reserved for biodiversity planting and archaeology treatments to known artefacts) is the provisional sum which is subject to the Planning Costs adjustment event.

- the amount notified by EnergyCo which reflects its operations costs, being $11.2 million (this amount makes up 2 per cent of our total capex); and
- the amount which Ausgrid expects to incur on project development, planning and early works prior to reaching financial close, being $69.8 million (this is incorporated in the relevant categories of pre-period expenditure shown in this chapter).

Unlocking value for customers

The HCC RNI Project will be aligned to a prudent scope determined by an independent Infrastructure Planner, EnergyCo.

Figure 5-10: Infrastructure Planner Free capex %



5.4.9 Risk costs

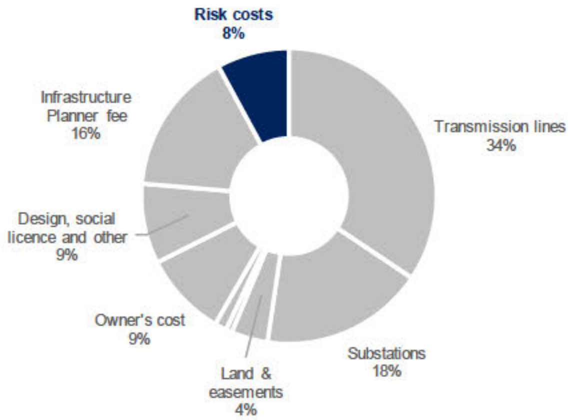
We propose $46.9 million in risk costs totalling 8 per cent of our total capex forecast.

Our approach to the efficient allocation of risk is set out in more detail in section 5.3 above. A detailed analysis of our risk costs, and description of risks which build up to $46.9 million, is set out in the Risk & Contingency Report at Attachment 5.9. The Risk & Contingency Report demonstrates that the proposed amount for risk costs aligns to a value which is at or less than the P50 value from the outputs of risk modelling and Monte Carlo analysis.

Protecting customers

We have taken significant steps to protect customers from funding inefficient risk allocation (see section 5.3 above).

Figure 5-11: Risk costs capex %

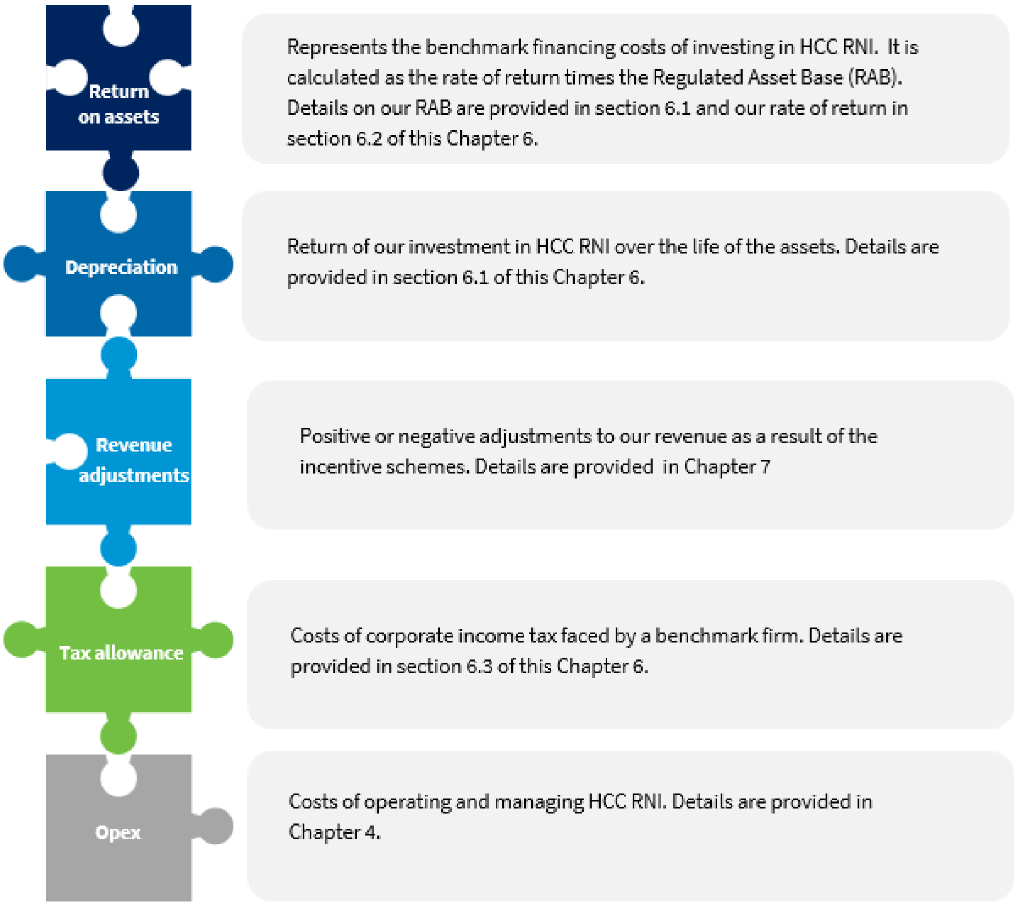


6 Proposed Revenue

This chapter explains how the proposed revenue has been calculated using the revenue building block components shown in Figure 6-1. The revenue building blocks for HCC RNI include the creation of a new Regulatory Asset Base (**RAB**), the forecast return of and return on capital, revenue adjustments (covered in Chapter 8), the tax allowance, and opex (covered in Chapter 4).

For the 2026-31 Regulatory Period, we are proposing a total nominal revenue of $200.3 million. The EII PTRM used to derive this revenue is included as Attachment 6.1 and the rate of return model is included as Attachment 6.2.

Figure 6-1: Revenue building blocks



6.1 Regulatory asset base

This section discusses the creation of a new RAB for HCC RNI and the forecast return of capital.

The RAB represents the total unrecovered value of the assets that Ausgrid uses to provide regulated services. The RAB for each year is rolled forward from the previous year by:

- adding efficient new capex net of disposals, as it is incurred or commissioned
- adding forecast inflation
- deducting depreciation.

The RAB value is used to calculate the revenue required to recover our efficient costs associated with the return on capital and depreciation.

The difference between "as incurred" capex and "as commissioned" capex lies in the timing of the forecast expenditure. "As incurred" capex recognises capital expenditure at the time when the expenditure is actually made by the Network Operator. Under this approach the expenditure starts earning a return on capital and return of capital from the year it is incurred, whether or not the physical assets are operational. "As commissioned" capex aligns with when the assets are commissioned or in operational service. The "as commissioned" capex triggers the commencement of the return of capital. Further details on our approach to estimating the "as commissioned" capex for the HCC REZ RNI project are provided in Section 6.1.3 (Depreciation).

In accordance with clause 6A.6.1 of EII Chapter 6A, a new RAB has been developed for HCC RNI to determine the forecast revenue for the Project during the 5 years of the 2026-31 Regulatory Period.

The capex in the RAB is depreciated based on standard economic lives. Short life assets, such as communications assets, have a 10-year life; long-life assets such as 132 kV concrete and steel poles have a 55-year life. These asset lives align with those used in the AER's 2024-29 Regulatory Determination for Ausgrid. In addition, because this project is being delivered under the EII Act, we have introduced a new asset class for Infrastructure Planner Fee, which has a standard asset life of 25 years. Table 6-1 lists the asset classes comprising the RAB for HCC RNI and their standard asset lives.

Table 6-1: PTRM asset classes and asset lives

Asset class name	Standard life
Communications (digital)	10 years
132 kV concrete & steel pole lines	55 years
Transmission substation equipment 132/66 kV	45 years
Transmission and zone land & easements	n/a
Ancillary substation equipment	15 years
Infrastructure Planner Fee	25 years

Being a new asset class, we had to estimate the standard life of the Infrastructure Planner Fee. We propose a 25 year standard life to align with the default term of the Project Deed. Pre-development costs, if capitalised, are typically depreciated over the project life.

6.1.1 Pre-period and in-period capital expenditure

The opening balance of the RAB for HCC RNI at the start of the 2026-31 Regulatory Period is $291.3 million on an 'as-incurred' basis and $289.4 million on an 'as-commissioned' basis. The RAB reflects the roll forward of pre-period expenditure as it is incurred or commissioned, escalated by a half-year pre-period nominal weighted average cost of capital (**WACC**).

Pre-period 'as incurred' expenditure, excluding WACC escalation, is $283.0 million (real 2025-26) inclusive of $162.7 million in fees for the pre-development work, procurement and monitoring of the Project prior to the first year of the Regulatory Period. The expenditure, undertaken by the Infrastructure Planner and known as the Infrastructure Planner Fee, covers the following functions:

- investigate, plan, coordinate and carry out planning, design, construction and operation of storage and network infrastructure[20]
- assess and make recommendations to the Consumer Trustee about the REZ network infrastructure projects required for the REZ[21]
- assess and make recommendations about contractual arrangements that a Network Operator may be required to enter into to carry out a REZ project under an authorisation.[22]

The Infrastructure Planner Fee is not subject to the AER's oversight. However, Ausgrid has included details of the portion relating to pre-development work undertaken by Ausgrid in relevant asset categories in Chapter 5.

The Infrastructure Planner Fee has been included as pre-period expenditure as it is expected to have been incurred before the start of the Regulatory Period.

We have escalated the pre-period expenditure to the opening RAB value in 2026-27 using the placeholder nominal WACC equivalent to the FY26 WACC determined for our SCS revenue. We propose to replace the placeholder WACC with the fixed real time varying nominal vanilla WACC and true-up the pre-period expenditure once actual inflation for 2025-26 is available. This will be done as part of the annual adjustment update outlined in Section 6.2.2 and Attachment 8.1.

During the Regulatory Period, new capex is added to the RAB from 1 July 2026 to 30 June 2029, which is the date by which the Project is expected to be completed.

6.1.2 Indexation of the RAB

The primary purpose of indexing the RAB is to maintain its real value over time. This approach prevents the erosion of the value of the asset base due to inflation. Forecast regulatory inflation is used to index the RAB in the Revenue Determination, and is updated with actual inflation throughout the Regulatory Period. Further details on the forecast regulatory inflation are provided in Section 6.2.2 and Attachment 6.3.

6.1.3 Depreciation

Depreciation is the mechanism through which we recover our expenditure on our network investments over the economic life of the assets. We propose depreciation on 'as commissioned' basis except for the Infrastructure Planner Fee. Given that it is not possible to identify specific assets that will be commissioned over the Regulatory Period, we have forecast the 'as commissioned' capex based on the capacity being made available. As a result, the capex for each PTRM asset class has been apportioned as shown in Table 6-2.

Table 6-2: 'As commissioned' approach to estimate depreciation

	Pre-period	Regulatory period				
Year	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31
Portion	1	N/A	2	3	N/A	N/A

20 EII Act, s63(4)
21 EII Act, s30.
22 EII Regulation, cl 43(1)(e).

	Pre-period	Regulatory period				
Capacity available (MW)	350	0	280	370	0	0
As commissioned apportionment	35%	0%	28%	37%	0%	0%

Depreciation is calculated in the AER's PTRM on a straight line basis based on the capex and standard lives of each asset class.

We propose to recognise the Infrastructure Planner Fee in full on an 'as incurred' basis, coinciding with the early stages of the project, rather than deferring its recognition until the first portion of the project is commissioned. The Infrastructure Planner Fee, introduced as a new asset class within the EII PTRM, is distinct from existing asset categories. We consider its unique role as significant, upfront, and enabling expenditure, that is outside the control of Ausgrid, means that it can be considered ' commissioned' from day one, We note that, in cases where the 'as incurred' value of an asset class in the first year is lower than the 'as commissioned' value, we have used the 'as incurred' value.

Our calculation of the nominal depreciation follows the straight-line depreciation method. To prevent double compensation for inflation—given the application of a nominal WACC in the revenue calculation process—the regulatory depreciation calculation adjusts nominal straight-line depreciation by removing the forecast indexation on the opening RAB.

6.1.4 Value of the RAB

Table 6-3 sets out our proposed RAB at the commencement of the 2026-31 Regulatory Period and the proposed capex entering the RAB over the five-year period. Additions to the RAB from net capex and the Infrastructure Planner Fee includes the gross-up for half-nominal WACC to account for the timing difference between expenditure and inclusion in the RAB.[23]

Table 6-3: Proposed RAB for HCC RNI

	Pre-period	In period				
$m, nominal	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**
Opening RAB		291.3	538.3	613.2	621.7	620.5
Net capex	123.8	249.0	70.6	6.0	-	-
Infrastructure Planner Fee	167.5					
Indexation		7.6	14.0	15.9	16.2	16.1
Depreciation		(9.5)	(9.8)	(13.4)	(17.4)	(17.8)
Closing RAB	291.3	538.3	613.2	621.7	620.5	618.8

23 As noted in Section 6.1.1, the opening RAB value has been escalated using the placeholder half-year nominal WACC.

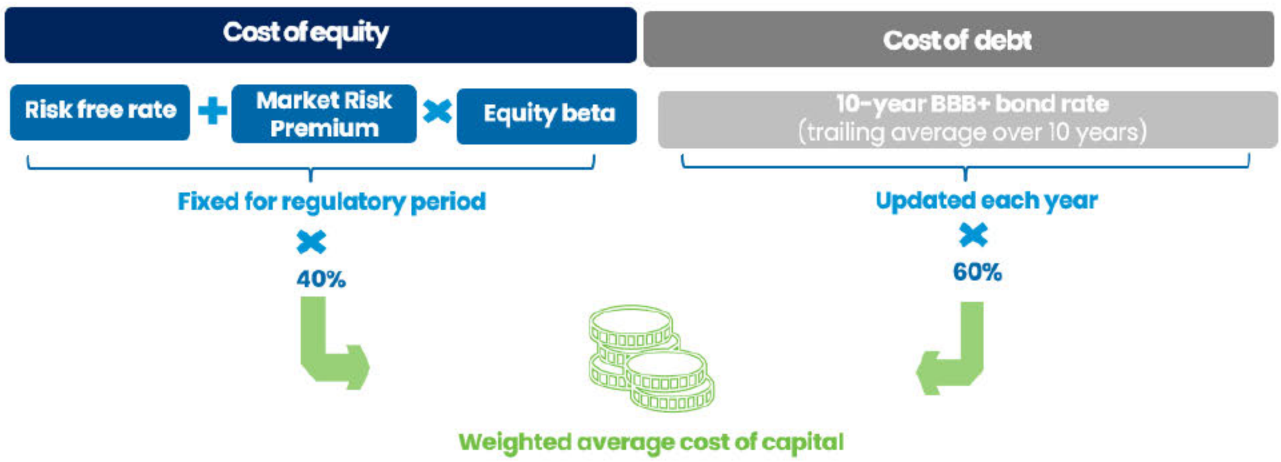
6.2 Rate of Return

The rate of return, or WACC, represents the weighted average cost of both debt and equity that an efficient network would incur to raise funds from a diverse group of investors and capital markets. The WACC is an estimate of the benchmark financing costs required to fund investments in our network. Essentially, the WACC represents the return required by both debt and equity investors on the invested capital, which is the RAB. It serves as compensation for the risks and opportunity costs that these investors bear when they commit their capital to the business.

The AER sets how the WACC will be calculated for all network determinations through a separate process. Under Division 1B of the National Electricity Law, calculation of the rate of return is determined by the Rate of Return Instrument (**RoRI**), updated every 4 years by the AER. The EII Chapter 6A sets out that the rate of return should be applied to EII projects in accordance with the NER.

The WACC is calculated by taking into account the proportion of debt and equity in an efficient firm's capital structure, the cost of debt, and the cost of equity (Figure 6-2).

Figure 6-2: AER's approach to calculating the rate of return



In this Revenue Proposal, we apply a placeholder WACC of 6.80 per cent (nominal vanilla). The breakdown of this placeholder WACC is shown in Table 6-4.

Table 6-4: Placeholder WACC

Component	Definition	Values
Risk free rate (placeholder)	Return that is available to investors on an investment that is free of risk – based on 10 year Commonwealth government bonds.	4.50%
Market Risk Premium	Premium over the risk free rate for the whole market.	6.20%
Equity beta	Reflects the level of risk or volatility of network businesses in relation to the overall market.	0.6
Return on equity (placeholder)	Return to investors to compensate for the risk of holding its equity.	8.22%

Component	Definition	Values
Return on debt[24] (placeholder)	Return that lenders expect for providing debt financing to the company.	5.85%
Nominal vanilla rate of return (placeholder)	Rate of return without adjusting for inflation and tax.	6.80%

6.2.1 Averaging periods

The 2022 RoRI stipulates that Ausgrid must nominate an averaging period for return on debt and the risk free rate applicable to return on equity for the 2026-31 Regulatory Period.

This following section states Ausgrid's nominated averaging periods.

6.2.1.1 Return on debt

Clause 24 of the 2022 RoRI states that the nominated debt average period must:

- be over a period of 10 or more consecutive business days, up to a maximum of 12 months
- start no earlier than 16 months prior to the commencement of a regulatory year
- finish no later than 4 months prior to the commencement of a regulatory year
- be specified for each regulatory year within the Regulatory Period
- not overlap for each different regulatory year
- be nominated both:
  - prior to the start of the return on debt averaging period
  - no later than the lodgement date of the Revenue Proposal for the Regulatory Period.

Table 6-5 shows Ausgrid's nominated debt averaging periods for the 2026-31 Regulatory Period, in compliance with the above requirements.

Table 6-5: Proposed averaging periods for cost of debt

Regulatory year	Start date	End date
1 July 2026 – 30 June 2027	[redacted]	[redacted]
1 July 2027 – 30 June 2028	[redacted]	[redacted]
1 July 2028 – 30 June 2029	[redacted]	[redacted]
1 July 2029 – 30 June 2030	[redacted]	[redacted]
1 July 2030 – 30 June 2031	[redacted]	[redacted]

24 First year estimate. Debt is updated annually, each year of the regulatory period.

6.2.1.2 Risk free rate

Clause 8 of the 2022 RoRI states that the nominated averaging period for the risk free rate must:

- be over a period of 20 or more business days up to a maximum of 60 business days
- start no earlier than 7 months prior to the commencement of the Regulatory Period
- finish no later than 3 months prior to the commencement of the Regulatory Period
- be nominated both:
  - prior to the start of the risk free rate averaging period
  - no later than the date of lodgement of the Revenue Proposal for the Regulatory Period.

In accordance with the above requirements, Ausgrid nominates an averaging period of [redacted] to calculate the risk free rate applicable to return on equity. This period also meets the requirements of the 2022 RoRI.

6.2.1.3 Placeholder rate of return averaging periods

In its Guidance Note on Amendments to NER PTRM for EII Determinations (**Guidance Note**), the AER recognises that the timeframes set out in the RORI have been developed for standard NER determinations. The shorter revenue determination process under the EII framework may result in the return on equity and debt not being known for the first regulatory year at the time when the AER makes its final determination for a REZ project. The Guidance note provides a mechanism whereby the DNSP can nominate placeholder averaging periods for the cost of equity and debt, which will be amended to reflect the actual nominated averaging periods prior to the start of the regulatory period.[25]

The placeholder averaging periods for our cost of equity and debt for the first year of the 2026-31 Regulatory Period are set out in Table 6-6.

Table 6-6: Proposed placeholders for cost of debt and equity

Regulatory year	Cost type	Start date	End date	Rate
1 July 2026 – 30 June 2027	Cost of debt	15 January 2025	17 March 2025	5.85%
1 July 2026 – 30 June 2031	Cost of equity	8 January 2025	12 February 2025	8.22%

6.2.2 Inflation

Forecast inflation is used to calculate the depreciation building block in the EII PTRM and to convert real dollar values to nominal dollar values.

We have calculated forecast inflation based on the AER's final decision on the treatment of expected inflation.[26] This is based on applying a linear glide path from one or two years of forecast inflation published by the Reserve Bank of Australia (**RBA**) in its most recent Statement on Monetary Policy (published in February 2025), to the midpoint of the RBA's inflation target of 2.5 per cent.

25 AER, Guidance note – Amendments to NER PTRM for EII determinations, November 2024.
26 AER, Final Decision on Regulatory Treatment of Inflation, December 2020.

Our estimate of expected inflation is 2.60 per cent, which we derived from the geometric average of the inflation forecast from 2026-27 to 2030-31, as presented in Table 6-7.

Table 6-7: Inflation forecast

	2026-27	2027-28	2028-29	2029-30	2030-31
Inflation forecast	2.70%	2.65%	2.60%	2.55%	2.50%

The Regulatory Forecast Inflation model in Attachment 6.3 sets out the detailed calculations of our proposed forecast inflation.

6.2.3 Equity and debt raising costs

6.2.3.1 Equity raising costs

Equity raising cost is defined as costs that must be paid by an entity when it raises capital. These costs are paid to equity arrangers for services such as structuring the issue, preparing and distributing information and undertaking presentations to prospective investors'.[27]

Equity raising costs are calculated as at the start of the Regulatory Period, similar to a standard NER Revenue Proposal. The equity raising cost amount for HCC RNI is calculated in the EII PTRM in line with the AER's Guidance Note on the PTRM for determinations under the EII Act and Regulations.[28]

Equity raising costs are calculated by applying a rate of 3 per cent to the equity requirements for a REZ project over the five-year period, net of retained cashflows. It then adds the equity raising cost as lump sum amount (in real $ value) to the RAB in the first year of the Regulatory Period.

For this Revenue Proposal, the equity raising costs are estimated to be $1.2 million (real 2025-26).

6.2.3.2 Debt raising costs

Debt raising costs refer to the expenses incurred by network businesses when they issue new debt or refinance existing debt. These costs are recognised and compensated by the AER to ensure that network businesses can recover the efficient costs associated with debt financing their operations.

These costs are calculated by multiplying the opening RAB value for each year by a debt raising cost benchmark. Our placeholder benchmark of 0.083 per cent is consistent with Ausgrid's most recent Regulatory Determination under the NER.

For this Revenue Proposal, the debt raising costs are estimated to be $1.3 million (real 2025-26).

6.3 Estimated cost of corporate income tax

The 'taxation' building block is an allowance to meet income tax liabilities, taking into account the benefit that shareholders receive from imputation credits.

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27 ACCC, South Australian Transmission Network Revenue Cap, 11 December 2002.

28 AER, Guidance note – Amendments to NER PTRM for determinations under the Electricity Infrastructure Investment Act and Regulations, November 2024.

Our proposed income tax allowance for HCC RNI has been calculated using the AER's approach in accordance with the NER.

6.3.1 Forecast income tax allowance

In accordance with clause 6A.6.4 of EII Chapter 6A, the forecast income tax allowance for any given year is calculated using the statutory corporate tax rate of 30 per cent adjusted for imputation credits based on the 2022 RoRI value for gamma of 0.57. Figure 6-3 shows the calculation for the forecast income tax allowance.

Figure 6-3: Tax allowance calculation

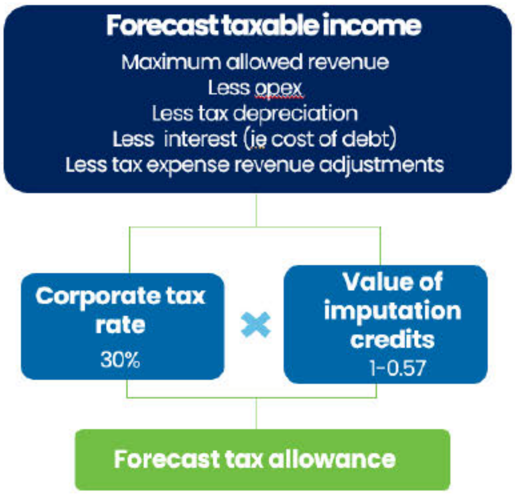


Table 6-8 shows the various elements of the forecast income tax allowance calculations for the 2026-31 Regulatory Period.

Table 6-8: Forecast income tax allowance ($m, nominal)

Components	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Revenue for tax	22.4	35.5	43.5	49.0	49.8	**200.3**
Opex	0.3	2.6	4.3	5.5	5.9	**18.6**
Tax depreciation	9.3	9.6	16.7	24.1	23.2	**82.9**
Interest	10.2	18.9	21.5	21.8	21.8	**94.2**
Tax expense revenue adjustments	0.0	0.0	0.0	0.0	0.0	**0.0**
Total tax expenses	19.9	31.0	42.5	51.5	50.9	**195.7**
Corporate tax rate	30.00%	30.00%	30.00%	30.00%	30.00%	
Taxable income	2.5	4.5	1.1	(2.4)	(3.5)	**2.1**
Tax payable	0.8	1.4	0.3	0.0	0.0	**2.4**
Imputation credits	(0.4)	(0.8)	(0.2)	0.0	0.0	**(1.4)**
Net tax allowance	0.3	0.6	0.1	0.0	0.0	**1.0**

6.3.2 Forecast tax depreciation

Tax depreciation is a component of the calculation of the forecast taxable income. In accordance with the EII PTRM, we applied the diminishing value method to depreciate as commissioned capex (excluding equity raising costs) and straight line depreciation method to the opening tax asset base. We have rolled forward an opening tax asset value, based on pre-period as-commissioned capex, which is the capex relevant for taxation purposes. This is similar to rolling forward the opening RAB value on as-commissioned basis, except that we have excluded the escalation component for pre-period nominal WACC, which is not a relevant component for taxation. We used the straight line method to depreciate equity raising costs for tax.

Ausgrid does not propose to immediately expense any capex over the 2026-31 Regulatory Period. Immediate expensing is reserved for Ausgrid's costs that are capitalised for accounting purposes but immediately deductable for tax purposes. In line with our NER submission, Ausgrid has to date only immediately expensed costs related to site decommissioning and remediation of land in accordance with the relevant provisions of the Income Tax Assessment Act 1997.[29] This includes activities such as the removal of Polychlorinated Biphenyls (PCBs) and asbestos. In relation to the HCC RNI project, the anticipated expenditure for removing old equipment and control systems, which may contain small amounts of asbestos, is expected to be minimal. Consequently, the impact of these specific costs on our overall tax deductions will be negligible. Furthermore, as discussed in section 6.7 (Value and treatment of decommissioned assets), we do not propose to remove the value of the decommissioned assets from our NER RAB. In line with this approach, it would not be appropriate for HCC RNI to immediately expense any costs associated with the decommissioning of these assets.

6.3.3 Tax asset lives

The depreciation approach for the 2026-31 Regulatory Period is based on the tax standard lives of the asset classes outlined in the EII PTRM. The asset classes and associated tax standard lives match the AER's 2024-29 Regulatory Determination for Ausgrid's dual function asset services.

Table 6-9: Tax asset classes and asset lives

Asset class	Depreciation method	Tax Standard Life
Communications (digital)	Diminishing value	10 years
132 kV concrete & steel pole lines	Diminishing value	48 years
Transmission substation equipment 132/66 kV	Diminishing value	40 years
Transmission & zone land and easements	n/a	n/a
Ancillary substation equipment	Diminishing value	15 years
Infrastructure Planner Fee	Diminishing value	25 years

29 Section 40-755 concerning deductions for environmental protection activities and section 40-190(2)(b) regarding costs associated with balancing adjustment events like decommissioning.

As noted in section 6.1, a new asset category for Infrastructure Planner Fee was created for the HCC RNI Project. We propose to adopt the same life as the Standard Life, which in turn aligns with the default term of the project Deed. This reflects the provisions set out in 40-I of Income Tax Assessment Act 1997 (ITAA 1997). This subdivision provides mechanisms for deducting capital expenditures that may not fall under standard depreciation rules for tangible assets. Specifically, section 40-830 allows certain capital costs directly connected with a project ('project amounts') to be deducted over the 'project life' (as defined in section 40-845).

The Infrastructure Planner Fee represents expenditure connected to establishing the HCC RNI Project. Its nature is comparable to costs explicitly mentioned in section 40-840(d)(d) as potential project amounts, specifically:

- an amount incurred for feasibility studies for the project (40-840(2)(d)(iii))
- an amount incurred for environmental assessments for the project (40-840(2)(d)(iv))
- an amount incurred to obtain information associated with the project (40-840(2)(d)(v)).

Therefore, treating this fee as a project amount under section 40-840, deductible over the project life, is appropriate. We interpret the relevant 'project life' as the 25-year term outlined in the Project Deed.

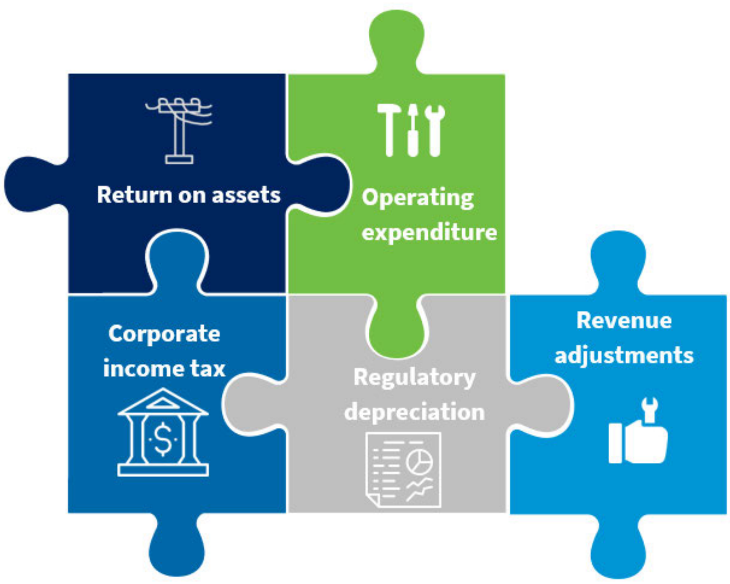
Consequently, aligning the tax effective life of the Infrastructure Planner Fee with the 25-year Project Deed term represents a well-founded approach under Subdivision 40-I. This duration is also consistent with the anticipated operational lifespan of the typical Renewable Energy Zone (REZ) generating assets expected to connect to our network as a result of the HCC RNI project.

6.4 Maximum allowed revenue

This section sets out our total annual maximum allowed revenue (**MAR**) for the 2026-31 Regulatory Period calculated using a building block approach.

The MAR for the HCC RNI is the sum of the forecast efficient costs that Ausgrid will incur to implement the Project. The MAR consists of various 'building blocks', presented in Figure 6-4.

Figure 6-4: Annual revenue requirement for HCC RNI



The MAR comprises the following components:

- **Return on assets** – benchmark financing costs of investing in HCC RNI. It is calculated as a rate of return multiplied by the RAB (section 6.2).
- **Regulatory depreciation** – the payback on Ausgrid's investment in HCC RNI (section 6.1.3).
- **Revenue adjustments** – the adjustments (increase or decrease) relating to the incentive schemes (chapter 7).
- **Corporate income tax** – the costs of corporate income tax faced by a benchmark REZ firm (section 6.3).
- **Operating expenditure** – the costs of operating and managing HCC RNI (this is discussed in Chapter 4).

Our proposed revenue is presented in Table 6-10.

Table 6-10: Maximum allowed revenue ($m, nominal)

Building block	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Return on capital	19.8	36.6	41.7	42.3	42.2	**182.5**
Regulatory depreciation	2.0	(4.2)	(2.6)	1.2	1.7	**(1.9)**
Opex	0.3	2.6	4.3	5.5	5.9	**18.6**
Revenue adjustment	0.0	0.0	0.0	0.0	0.0	**0.0**
Income tax	0.3	0.6	0.1	0.0	0.0	**1.0**
Total revenue	**22.4**	**35.5**	**43.5**	**49.0**	**49.8**	**200.3**

6.5 Payments and adjustments

This section outlines Ausgrid's proposed schedule of quarterly payments for the HCC RNI Project that will be paid over the 2026-31 Regulatory Period by the Scheme Financial Vehicle (**SFV**) administered by the Financial Trustee.

6.5.1 Indicative schedule of payments

Chapter 6A of the EII Act requires Ausgrid to calculate a schedule of quarterly payments that we propose to invoice the SFV for the delivery of HCC RNI. To do this, we have used the EII PTRM, which converts the MAR into quarterly amounts in a manner that is NPV neutral.

Table 6-11 provides the proposed quarterly payments for the 2026-31 period.

Table 6-11: Proposed quarterly payments for HCC RNI ($m, nominal)

Year	Quarter 1 (September)	Quarter 2 (December)	Quarter 3 (March)	Quarter 4 (June)	Total
2026-27	5.3	5.4	5.5	5.6	**21.9**
2027-28	8.5	8.6	8.7	8.9	**34.7**
2028-29	10.4	10.5	10.7	10.9	**42.5**

Year	Quarter 1 (September)	Quarter 2 (December)	Quarter 3 (March)	Quarter 4 (June)	Total
2029-30	11.7	11.9	12.1	12.3	**47.8**
2030-31	11.8	12.0	12.2	12.4	**48.6**
Total					**195.4**

The total MAR differs from the sum of the quarterly payments because of the timing differences between quarterly and annual revenues. In net present value terms, the MAR and the quarterly payments are the same.

The quarterly payments presented in Table 6-11 are expected to be adjusted in accordance with the mechanism set out in the following section.

6.5.2 Adjustments

We propose to adjust the MAR and associated quarterly payments following a number of 'mechanistic' adjustments, namely:

- Replacement of the placeholder return on debt and return on equity which are the result of the misalignment between the nominated averaging period for the first year of the revenue period resulting from the timing of the Revenue Proposal and the AER's Final Decision, if required
- Annual update of the return on debt to the allowed rate of return in accordance with the 2022 RoRI
- Annual update of actual inflation through the annual adjustment mechanism.

Other 'non-automatic' adjustments may also impact the forecast quarterly payments in Table 6-11 above. These adjustments are detailed in Chapter 8.

The formula used to calculate the adjusted quarterly payments is set out below:

$$\sum_{n=1}^{4} NPV(QP_n) = NPV(AR_t(Adjusted) + NAA_t + PTC_t)$$

Where:

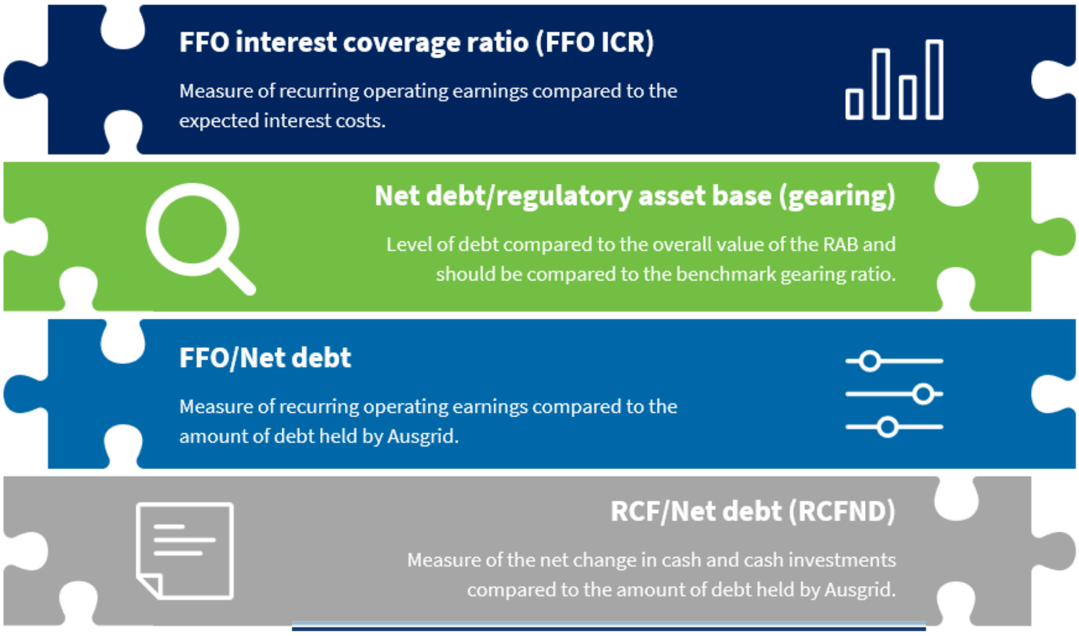
- **NPV(QP_n)** is the net present value of each quarterly payment in the year t, calculated by applying the updated rate of return
- **AR_t(Adjusted)** is the annual revenue requirement of year t, calculated using the PTRM, adjusted for actual inflation, updated rate of return and contractual payments to EnergyCo.
- **Actual inflation** is the percentage change in the ABS' CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1
- **Updated rate of return** is the applicable rate of return calculated for year t, updated for the return on debt calculated for year t, in accordance with the 2022 RoRI and using the averaging periods approved by the AER
- **NAA_t** is the AER's approved adjustments for year t, which may be positive or negative
- **PTC_t** is the AER's approved adjustment cost for year t.

6.6 Financeability test

Financeability is defined as a Network Service Provider's (**NSP**) ability to meet its financing obligations and to efficiently raise any new capital requirements needed to undertake the forecast investments in the network and maintain financial sustainability while undertaking large-scale infrastructure projects, particularly those identified in the Integrated System Plan (**ISP**). Financeability is closely tied to a NSP's ability to maintain its investment-grade credit rating of BBB+ at the benchmark level of gearing (60 per cent). This involves assessing whether regulated revenue streams provide sufficient cash flows to cover financial obligations at that level of gearing.

The AER employs a financeability test for actionable ISP projects to evaluate a NSP's financial position using four key metrics, as shown in Figure 6-5.

Figure 6-5: AER's financeability test metrics



We have assessed the financeability position of Ausgrid including the HCC RNI expenditure. We have done this in line with the AER's financeability guideline for actionable ISP projects, published in November 2024, and have used the AER's financeability guideline model to assess the four key metrics shown in Figure 6-5.

The financeability guideline model calculates and compares the overall weighted numeric result from the four metrics under a base case without the ISP project, and the position with the ISP project included. This overall weighted numeric score is the measure of the financeability position and is calculated based on Moody's rating methodology for regulated electric and gas networks. The model assesses if there is a financeability issue with reference to a financeability threshold, which is the numeric score associated with the benchmark credit rating of Baa1 or the equivalent BBB+ used to estimate the return on debt component in the RoRI.

If compared to the base case, the overall weighted numeric score deteriorates and the deteriorated position is below the financeability threshold, then that indicates there is a financeability issue with the inclusion of the Project.

Our base case position under the financeability assessment is our prevailing SCS Determination PTRMs. We assessed our financeability position with the HCC RNI Project included by adding the expenditure for the Project to our base case. Our assessment did not indicate a financeability issue for Ausgrid from the inclusion of the forecast HCC RNI expenditure. As a result, we are not proposing any financeability adjustment in the EII PTRM for HCC RNI, nor therefore in our revenue proposal.

6.7 Value and treatment of decommissioned assets

As noted in Chapter 2, Ausgrid plans to upgrade certain existing assets with new 132 kV overhead lines along established easements. These upgrades will involve replacing 132 kV concrete and steel pole lines, and transmission 132/66 kV substation equipment. As of 30 June 2026, the residual value of the decommissioned assets is estimated to be $6.9 million (nominal). Due to its immateriality, Ausgrid intends to retain these assets in its NER RAB and continue depreciating them over their remaining life. This decision is expected to have a negligible effect on customer bills with an estimated 16 cents per year for residential customers on a flat tariff, and an estimated 30 cents per year for small businesses on a flat tariff.

7 Incentive schemes

This chapter outlines Ausgrid's preferred approach to the incentive schemes applicable to the HCC RNI Project over the 2026-31 Regulatory Period.

The incentive schemes are an important part of the regulatory framework. These schemes provide incentives for network businesses like Ausgrid to outperform their expenditure allowances approved by the AER, so that customers do not pay any more than is necessary for the services they receive. We propose that the CESS and EBSS apply to the HCC RNI Project.

Table 7-1 summarises the incentive schemes which will be applicable to Ausgrid with regards to the HCC RNI Project.

Table 7-1: Incentive scheme for HCC RNI Project

Incentive scheme	Description
EBSS	The EBSS incentivises us to pursue continuous opex efficiencies
CESS	The CESS incentivises us to undertake efficient capex

7.1 Efficiency Benefits Sharing Scheme

The EBSS provides incentives to continuously reduce our operating costs and give customers a share of any savings that we achieve as a result of the scheme. The current approach used for the EBSS is set out in the AER's Efficiency Benefit Sharing Guideline.[30] In applying the scheme, the AER must have regard to:

- the need to provide DNSPs with a continuous incentive to reduce opex
- the desirability of both rewarding for efficiency gains and penalising for efficiency losses
- any incentives that DNSPs may have to capitalise expenditure
- the benefits to electricity consumers likely to result from the scheme.

Ausgrid proposes that the EBSS be applied to HCC RNI for the 2026-31 Regulatory Period. In line with our NER 2024-29, we also propose to exclude debt raising costs from the EBSS for the HCC RNI Project. Table 7-2 shows the opex values proposed to be subject to the EBSS.

Table 7-2: Proposed opex subject to EBSS ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Total opex	0.2	2.2	3.7	4.7	4.9	**15.6**
Less debt raising costs	(0.1)	(0.3)	(0.3)	(0.3)	(0.3)	**(1.3)**
Opex subject to EBSS	0.0	1.9	3.4	4.5	4.6	**14.3**

30 AER, Better Regulation, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013.

7.2 Capital Expenditure Sharing Scheme

The CESS allows Ausgrid's customers to benefit from improved efficiencies in our capex over a regulatory control period by providing financial rewards and penalties for efficiency gains and losses. Efficiency gains and losses are derived by calculating the difference between the AER's capex allowance and our actual capex. A proportion of the efficiency gains and losses are shared with our customers.

The AER's guidelines state that application of the CESS to a particular Revenue Determination will be decided on a case-by-case basis. In any determination under the EII Act, the AER may decide to either: (a) not apply a CESS at all; (b) apply the CESS as per its NER guideline; or (c) apply the CESS in a modified way:

> *"In its revenue proposal a Network Operator may propose to modify the application of a guideline, incentive scheme or model but must provide reasons for doing so. Depending on the circumstances and the reasoning, we may be willing to consider modifying our current incentive schemes and we would do this on a case-by-case basis."* (AER Guideline, section 3.3)

Ausgrid does not propose any adjustments to the sharing ratios in the standard CESS applicable to the HCC RNI Project. We propose that the standard CESS ratios as outlined in Capital Expenditure Incentive Guideline applies to our capex:[31]

- A 30 per cent sharing ratio for any underspend up to 10 per cent of the forecast capital expenditure allowance
- A 20 per cent sharing ratio for any underspend that exceeds 10 per cent of the forecast capital expenditure allowance
- A 30 per cent sharing ratio for any overspend of the forecast capital expenditure allowance.

7.2.1 Modifications to CESS

Due to the regulatory and contractual timings of this project, we are in an unusual position where a significant proportion of capex is forecast to be incurred before the start of the regulatory period. If the CESS only applied to capex within the regulatory period, a significant amount of capex would not be subject to the CESS. Further, there would be a perverse incentive to overspend in the pre-period in order to underspend in the regulatory period and receive a CESS reward.

To avoid this sub-optimal outcome, we propose that pre-period expenditure is included in the allowance that is subject to CESS. Ausgrid's view is that this would best align with the intent of the scheme to incentivise efficient capex without creating incentives to change the timing of capex. It also aligns with the CESS principle that network operators should be rewarded or penalised for improvements or declines in efficiency of capital expenditure. This should apply to the whole project expenditure, not a portion that is removed due to when project and regulatory scheduling arbitrarily delineates the 'pre-period'.

Further, we propose to exclude from the CESS the expenditure allocated to our social licence initiatives for HCC RNI. The specific allocation of these funds will be guided by consultations with community and stakeholders. As this expenditure is determined by community needs rather than

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31 AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, July 2024.

capital efficiency, any unspent portion should not be classified as an efficiency gain under the CESS. We believe the core CESS objective of incentivising efficient capital investments is not applicable to social licence expenditure which is an allowance that may or may not be spent in full. Table 7-3 shows the capex values proposed to be subject to the CESS. We have given effect to including (or excluding) all pre-period expenditure in the CESS allowance by adding (subtracting) it to 2026-27 expenditure.

Table 7-3: Proposed capex subject to CESS ($m, real 2025-26)

Year	2026-27	2027-28	2028-29	2029-30	2030-31	Total
Total capex	519.6	65.8	5.4	0.0	0.0	**590.8**
Less social licence costs	(5.3)					**(5.3)**
Capex subject to CESS	514.3	65.8	5.4	0.0	0.0	**585.6**

8 Adjustment mechanisms

Under the EII Act, a revenue determination may include provisions for the adjustment of any amount included in the revenue determination, whether or not the amount relates to a capital cost.[32]

This chapter sets out Ausgrid's proposed adjustment events. It includes the 'predetermined' set of adjustments in EII Chapter 6A and adjustments that are commonly approved pass-through events in NER determinations. We also nominate additional adjustment events to allow Ausgrid to comply with contractual arrangements with EnergyCo and to manage uncertainty associated with the unique procurement processes related to the HCC RNI Project.

8.1 Prudent, efficient and reasonable

The availability of adjustment mechanisms is an important part of the incentive-based regulatory framework. They promote prudent, efficient and reasonable cost recovery by dealing with highly uncertain events on an *ex post* basis (i.e. after the event has occurred). This provides Ausgrid with a reasonable opportunity of recovering our costs while also protecting customers, as outlined below.

Prudently managing bill outcomes and protecting customers against the risk of paying twice

The approval of an adjustment mechanism:

- promotes improved bill outcomes for customers by offsetting (lowering) the level of contingency included in our *ex ante* expenditure forecast (i.e. our proposed 2026-31 capex and opex)
- does not put customers at risk of paying twice for an event since the AER will only approve revenue adjustments for costs that are incremental to our *ex ante* forecast
- allows for benefits of lower costs to be passed to consumers as adjustment events are symmetrical wherever possible.

In the absence of adjustment mechanisms, Ausgrid would likely hold higher levels of contingency for large, unexpected and uncontrollable events. This would be an inefficient way to manage bill outcomes for customers as it would lead to a higher *ex ante* expenditure allowance and therefore asking customers to pay for large, uncontrollable events that may not occur.

We engaged extensively with our HCC REZ Reg Panel on this topic. The Panel challenged Ausgrid to make sure that there was no overlap between our *ex ante* expenditure forecast and our proposed adjustment events. We confirm that there is no 'double counting'.

AER oversight will also protect customers. In all cases, a revenue adjustment will only be approved to the extent Ausgrid can demonstrate that the relevant costs are not already provided for under the Revenue Determination, and can only be claimed under one adjustment event category.

32 EII Regulations, cl 51.

There is consequently no risk of customers 'paying twice' for events or other occurrences. The AER will only allow prudent, efficient and reasonable costs to be approved via adjustment events, that are incremental to our *ex ante* allowance.

Key assumption

Our proposed capex and opex for the 2026-31 Regulatory Period assume that the adjustment events that we have proposed will be approved by the AER. The reasonableness of this assumption has been certified by our Directors in accordance with clause S6A.1.1(5) and S6A.1.2(6) of the EII Chapter 6A.

Should the AER not approve any of our proposed adjustment events, then a key assumption underpinning our forecast of capex and opex would have failed to eventuate. This would have direct implications for what Ausgrid considers to be the prudent, efficient and reasonable expenditure needed to deliver the HCC RNI Project.

Ausgrid has not quantified the increase in risk costs that would be required if particular adjustment events were not approved. Each of the adjustment events could be assessed to have a broad range of potential risk cost values due to the uncertainty of the impact of the events. Furthermore, pricing individual adjustment events would lead to a higher dollar amount for risk costs as compared to the preferred method (which involves determination of a total dollar amount which is at or less than the P50 value from outputs of risk modelling and Monte Carlo analysis for a range of events – see Attachment 5.9). The inherent uncertainty around the adjustment events, where the event risk and/or consequences of the event cannot be reasonably estimated by Ausgrid, is the reason why these events have been proposed as adjustment events rather than considered in risk costs.

To promote prudent, efficient and reasonable cost recovery, Ausgrid supports a balanced adjustment mechanism framework. If a positive change event occurs, Ausgrid should be able to seek the approval of the AER to recover a positive adjustment amount.[33] Equally, if a negative change event occurs, Ausgrid should return the savings as determined by the AER.[34] In both cases, Ausgrid must present evidence to the AER of the change event and the AER will make a determination as to the adjustment amount and how it should be addressed in revenue.

8.2 Our proposed adjustment categories

Our proposed adjustment events fit into five broad categories:

- **predetermined events,** which reflect adjustment events specified in EII Chapter 6A
- **automatic adjustment mechanisms,** which reflect a one-off update to the cost of equity to reflect the actual risk free rate and annual updates for actual inflation and return on debt
- Nominated cost adjustment events:

33 EII Chapter 6A, cl 6A.7.3(a).
34 EII Chapter 6A, cl 6A.7.3(b).

- **standard events,** which are adjustment events for AER distribution and transmission determinations that are commonly approved by the AER
- **EnergyCo contractual compliance events**, which are events that are either required to be included under the contractual arrangements with EnergyCo or are necessary to reflect those contractual arrangements
- **procurement induced cost uncertainty events,** which reflect that the unique procurement process for the HCC RNI Project has resulted in a higher than usual degree of uncertainty around certain cost items at the current stage of the process.

The remainder of this chapter discusses each event at a high level, with more detailed information set out in Attachment 8.1 Adjustment mechanisms.

8.3 Predetermined events, automatic adjustment mechanisms and standard events

In addition to the predetermined events and automatic adjustment mechanisms under EII Chapter 6A, Ausgrid proposes that the standard suite of nominated adjustment events the AER commonly accepts in NER distribution and transmission determinations will apply.

8.3.1 Pre-determined EII Chapter 6A events

EII Chapter 6A specifies six predetermined adjustment events for a non-contestable network infrastructure project.[35] These are:

a. a regulatory requirement as defined in section 46(3) of the EII Regulation
b. a service standard event
c. a tax change event
d. an insurance event
e. an inertia shortfall event[36]
f. a fault level shortfall event.[37]

Ausgrid proposes that the first four of these events apply as adjustment events for the HCC RNI Project.

Table 8-1 summarises our proposed pre-determined events, with terms defined in the Commitment Deed (Attachment 2.3). More detailed information is set out in Attachment 8.1.

Table 8-1: Pre-determined events

Event	Definition
Regulatory requirements	An increase or decrease in the revenue the Proponent may recover to accommodate additional prudent, efficient, and reasonable costs the Proponent incurs in complying with: 1. a regulatory requirement, as defined in s46(3) of the EII Regulations…

35 EII Chapter 6A, cl 6A.7.3(a1).
36 While EII Chapter 6A includes the inertia shortfall event, this event is now removed from NER Chapter 6A following the improving security frameworks for the energy transition rule change (known as the ISF Rule).
37 While EII Chapter 6A includes the fault level shortfall event, this event is now removed from NER Chapter 6A following the efficient management of system strength (EMSS) on the power system rule change.

Event	Definition
Service standard event	An increase or decrease in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs from a service standard event, as defined in NER Chapter 10 (Service Standard Event).
Tax change event	An increase or decrease in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs from a tax change event, as defined in NER Chapter 10 (Tax Change Event).
Insurance event	An increase or decrease in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs from an insurance event, as defined in NER Chapter 10 (Insurance Event).

8.3.2 Automatic adjustment mechanisms

We propose to make a one-off update to the cost of equity to reflect the actual risk free rate and annual updates to the revenue and quarterly payments to reflect actual inflation and return on debt. These updates do not require the AER to review or remake the Revenue Determination.

8.3.2.1 Risk free rate update

In Chapter 6, we noted that the timeframes outlined under the EII revenue determination process would warrant the adoption of a placeholder averaging period for the risk free rate, which is a component of the cost of equity. The AER's Guidance Note allows for a true-up of the placeholder return on equity with the actual cost of equity once it is known.[38]

8.3.2.2 Annual inflation update

The AER's guidance note on Amendments to NER PTRM for Determinations under the EII Act and Regulations sets out that the calculation of quarterly payments should also include the ability to remove forecast inflation and apply actual inflation outcomes on an annual basis, consistent with the annual pricing process under the NER framework. Using the EII PTRM we propose to make the CPI adjustments to update the nominal vanilla WACC from forecast to actual.

Once the actual 2025-26 CPI is known, we also propose to make a one-off adjustment to the half-yearly fixed real time varying nominal vanilla WACC used in the EII PTRM on the pre-period expenditure to derive the opening RAB value.

8.3.2.3 Update to the cost of debt

The 2022 RoRI includes provisions requiring annual updates to the cost of debt component.

8.3.2.4 Proposed process for the automatic adjustments

The EII Chapter 6A sets out that when adjusting payments a Network Operator must provide:[39]

1. a description of the components to be adjusted

38 See: AER, Guidance note – Amendments to NER PTRM for determinations under the Electricity Infrastructure Investment Act and Regulations, November 2024, p 15.
39 AER, Appendix A (EII Chapter 6A): Transmission Efficiency Test and Revenue Determination guideline for NSW non-contestable network infrastructure projects, S6A.1.3(14).

2. the timing of the adjustment for each component, or relevant trigger event
3. a detailed explanation of the proposed method of indexation, escalation or adjustment
4. identification of the authoritative source (or sources) of indices or data to be used for any indexation, escalation or adjustment.

We propose to follow the process set out in Attachment 8.1 to make adjustments to our revenue and quarterly payments.

Table 8-2 summarises our proposed automatic adjustment events, with terms in the 'annual update for actual inflation' and 'return on debt update' defined in the Commitment Deed (Attachment 2.3). More detailed information is set out in Attachment 8.1.

Table 8-2: Automatic adjustment events

Event	Definition
Risk free rate update	Following the AER's EII PTRM Guidance Note, we propose to make a one-off update to the cost of equity to reflect the actual cost of equity once the nominated averaging period has passed.
Annual update for actual inflation	An annual update to revenue for the actual rate of inflation. The actual inflation is the percentage change in the relevant price index used for the escalation of costs in the revenue determination, as published by the Australian Bureau of Statistics' (ABS), from December in year t-1 to December in year t-2.
Return on debt update	Return on debt update to the allowed rate of return. Updated rate of return is the applicable rate of return calculated for year t, updated for the return on debt calculated for year t, in accordance with the 2022 RORI and using the averaging periods approved by the Regulator.

8.3.3 Standard events

We also propose that the nominated pass-through events that are commonly approved in NER distribution and transmission determinations should be approved for HCC RNI Project. These nominated pass-through events are:

a) an insurance coverage event
b) an insurer's credit risk event
c) a natural disaster event
d) a terrorism event.

These events align with pass-through events accepted by the AER in Ausgrid's 2024-2029 Regulatory Determination and other recent determinations under the NER.[40]

Table 8-3 summarises our proposed standard events, with terms defined in the Commitment Deed (Attachment 2.3). More detailed information is set out in Attachment 8.1.

40 See for example: AER, Final decision | Ausgrid electricity distribution determination 2024 to 2029 | Attachment 15 pass-through events, April 2024, p 1 and table 15.1; and AER, Final decision | TasNetworks electricity distribution and transmission determination 2024 to 2029 | Overview, April 2024, pp 46, 49-50.

Table 8-3: Standard adjustment events

Event	Definition
Insurance coverage event	An increase or decrease in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs following an insurance coverage event: An insurance coverage event occurs if: 1. the Proponent: a) makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies; or b) would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances; and 2. the Proponent incurs costs: a) beyond a relevant policy limit for that policy or set of insurance policies; or b) that are unrecoverable under that policy or set of insurance policies due to changed circumstances; and 3. the costs referred to in paragraph 2 above materially increase the costs to the Proponent in providing direct control services. For the purposes of this insurance coverage event: • 'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of the Proponent, where those movements mean that it is no longer possible for the Proponent to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies; • 'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had: o the limit not been exhausted; or o those costs not been unrecoverable due to changed circumstances; • a relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the regulatory control period or a previous Description regulatory control period in which the Proponent was regulated; • the Proponent will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of the Proponent in relation to any aspect of the Proponent's network or business; and • the Proponent will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of the Proponent in relation to any aspect of the Proponent 's network or business. Note for the avoidance of doubt, in assessing an insurance coverage event through application under rule 6.6.1(j), the Regulator will have regard to: i) the relevant insurance policy or set of insurance policies for the event; ii) the level of insurance that an efficient and prudent Distribution Network Service Provider would obtain, or would have sought to obtain, in respect of the event;

Event	Definition
	iii) any information provided by the Proponent to the Regulator about the Proponent's actions and processes; and iv) any guidance published by the Regulator on matters the Regulator will likely have regard to in assessing any insurance coverage event that occurs.
Insurer's credit risk event	An increase or decrease in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs following an insurer's credit risk event. An insurer credit risk event occurs if an insurer of the Proponent becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, the Proponent: a) is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or b) incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer. Note: in assessing an insurer credit risk event pass through application, the Regulator will have regard to, amongst other things: i) the Proponent's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation; and ii) in the event that a claim would have been covered by the insolvent insurer's policy, whether the Proponent had reasonable opportunity to insure the risk with a different provider.
Natural disaster event	An increase or decrease in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs following a natural disaster event. Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the regulatory period that changes the costs to the Proponent in carrying out the RNI Project.
Terrorism event	An increase or decrease in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs following a terrorism event. Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which: 1. from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear); and 2. changes the costs to the Proponent in carrying out the RNI Project. Note: In assessing a terrorism event pass through application, the Regulator will have regard to, amongst other things: i) whether the Proponent has insurance against the event; ii) the level of insurance that an efficient and prudent network operator would obtain in respect of the event; and iii) whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

8.4 EnergyCo contractual compliance events

EII Chapter 6A allows a proponent to put forward additional adjustment events.[41]

We propose seven events that fall within the EnergyCo contractual compliance category. These events are either required to be included under the contractual arrangements with EnergyCo or are necessary to reflect those contractual arrangements.

Table 8-4 summarises our proposed EnergyCo contractual compliance events, with terms defined in the Commitment Deed (Attachment 2.3). More detailed information is set out in Attachment 8.1.

Table 8-4 : EnergyCo contractual compliance events

Event	Definition
Regulatory requirements	An increase or decrease in the revenue the Proponent may recover to accommodate additional prudent, efficient, and reasonable costs the Proponent incurs in complying with: … 2. a Change in Law or NSW Government Policies (as those terms are defined in the Project Deed).
[redacted]	[redacted]
DSP Delay Adjustment	A decrease in the revenue the Proponent may recover where it has an obligation to pay liquidated damages to the Infrastructure Planner for a failure to achieve Practical Completion of all RNI Separable Portions by the Last Date for Practical Completion under the Project Deed. The reduction in revenue will be an amount equal to the liquidated damages paid by the Proponent to the Infrastructure Planner in accordance with clause 14.3A (*Delay Damages*) of the Project Deed.
DSP IP Fee Adjustment	An increase or decrease in the revenue the Proponent may recover to reflect a change to the amount of Infrastructure Planner Fees that the Proponent is required to pay the Infrastructure Planner under the Project Deed.
Reduction in IP Fee due to reduced Technical Services Payments	An increase in the revenue the Proponent may recover where the amount of the Infrastructure Planner Fees that the Proponent is required to pay is reduced under clause 18.1(d) of the Project Deed due to reduced Technical Service Payments (as defined under the Project Deed). The increase in revenue will be equal to the amount of the reduction in Technical Service Payments. This adjustment will only be made where there is a corresponding downward DSP IP Fee Adjustment reflecting the reduced Infrastructure Planner Fee.
Force Majeure Event under contractual arrangements with the Infrastructure Planner	An increase or decrease in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs or cost savings the Proponent achieves following a Force Majeure Event (as defined in the Project

41 EII Chapter 6A, cl 6A.7.3(a1)(5).

Event	Definition
	Deed), to the extent that such an event does not fall within the definition of any other DSP Adjustment Event. Note that in assessing the additional costs or cost savings as a result of a Force Majeure Event, the Regulator will have regard to, amongst other things, whether the additional costs or cost savings are prudent, efficient and reasonable.
Actions by the Infrastructure Planner	An increase in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs as a result of: 1. a fraudulent, reckless, unlawful or malicious act or omission of the Infrastructure Planner in connection with the RNI Project; 2. a breach by the Infrastructure Planner of its obligations under this deed or the Project Deed; 3. an act or omission of the Infrastructure Planner, not being an act or omission which is: (a) expressly permitted or allowed under this deed or the Project Deed; and (b) within the timeframe permitted or allowed by this deed or the Project Deed; or 4. complying with a direction given by the Infrastructure Planner, to the extent not given in connection with a breach of the Project Deed by the Proponent, and to the extent not already provided for under the Revenue Determination, to the extent such actions do not fall within the definition of any other DSP Adjustment Event. This excludes payments or additional costs the Proponent can avoid or mitigate.

8.5 Procurement induced cost uncertainty events

The nominated adjustment events proposed by Ausgrid under this category reflect the unique procurement process for the HCC RNI Project, which has resulted in a higher than usual degree of uncertainty around certain cost items at the current stage of the process.

Ordinarily, Ausgrid would have been able to complete more detailed cost estimation processes prior to submitting its expenditure forecasts. However, due to tight confidentiality restrictions outside our control Ausgrid had been unable to conduct many of the usual community engagement and due diligence activities until announcement of Ausgrid as recommended Network Operator in December 2024.

It is therefore necessary to include adjustment provisions to reflect [redacted], [redacted] and [redacted] that may occur in the process of finalising Project documents and cost estimations.

The seven adjustment provisions that Ausgrid proposes to apply to the HCC RNI Project under the procurement induced cost uncertainty adjustments category are set out in Table 8-5, with terms defined in the Commitment Deed (Attachment 2.3). More detailed information is set out in Attachment 8.1.

Table 8-5: Procurement induced cost uncertainty events

Event	Definition
[redacted]	[redacted]
Contractor Force Majeure	An increase or decrease in the revenue the Proponent may recover to accommodate the additional costs the Proponent incurs from a contractor force majeure event. The Contractor Force Majeure adjustment mechanism accounts for efficient, prudent, and reasonable additional construction costs incurred by the Proponent: i) during the construction phase; ii) as a result of an unforeseen force majeure event impacting the contractor; iii) where the costs are not covered by an existing insurance policy or adjustment mechanism; iv) the Proponent has informed the Infrastructure Planner of the Force Majeure Event consistent with the requirements of the Project Deed; v) the Force Majeure Event is declared in accordance with the terms of the construction contract; and vi) where the additional costs are not covered by any other DSP Adjustment Event.
[redacted]	[redacted]
[redacted]	[redacted]

Event	Definition
	[redacted]
Land Acquisition and Planning Costs	An increase or decrease in the revenue the Proponent may recover to account for: i) actual land acquisition or planning costs for the RNI Project being higher or lower than the forecast amount accepted by the Regulator in the Revenue Determination; or ii) additional costs arising (including in connection with project delay) as a result of a Legal Challenge (as defined in the Project Deed) to planning approvals or the Proponent's Review of Environmental Factors (REF) for the RNI Project; or iii) additional costs arising (including in connection with project delay) as a result of an Environmental Notice (as defined in the Project Deed) being issued in connection with the RNI Project.
Unforeseen Artefacts, Native Title Claims or Contamination	An increase or decrease in the revenue the Proponent may recover to account for a change in prudent, efficient, and reasonable design and construction costs to the Proponent from the following trigger events: i) Native Title Claims (as defined in the Project Deed) which could not reasonably have been anticipated as at the date of the Project Deed by a prudent, competent and experienced person engaged in the same or similar type of undertaking as the Proponent and its Subcontractors (as defined in the Project Deed), as the case may be, under the same or similar circumstances as the delivery of the RNI Project (as defined in the Project Deed) that had examined the Project Site (as defined in the Project Deed) and its surroundings (to the extent access to the Project Site and landowners was available), examined all information available (or made available) to the Proponent and performed such other reasonable due diligence as was able to be performed; ii) the discovery and impacts of Excluded Contamination (including compliance by the Network Operator with any related Environmental Notice) on, in, over or under or about the Project Site (each as defined in the Project Deed); or iii) discovery, treatment, protection and removal of Artefacts on the Project Site (each as defined in the Project Deed) located on land that was not owned or controlled by the Proponent as at the date of the Project Deed, that could not reasonably have been anticipated at the date of the Project Deed by a prudent, competent and experienced person engaged in the same or similar type of undertaking as the Proponent and its Subcontractors (as defined in the Project Deed), as the case may be under the same or similar circumstances as the delivery of the RNI Project (as defined in the Project Deed) that had examined the Project Site (as defined in the Project Deed) and its surroundings (to the extent access to the Project Site and landowners was available), examined all information available (or made available) to the Proponent and performed such other reasonable due diligence as was able to be performed.
[redacted]	[redacted]

9 Other Matters

9.1 Confidential Information

In accordance with clause 6A.10.1 (f)(2) of the EII Chapter 6A and the AER's Draft Confidentiality Guideline, we have completed a confidentiality template in Attachment 9.5 to this Revenue Proposal that details the matters for which we are claiming confidentiality.

9.2 Certifications

9.2.1 Certification statement

Schedules 6A.1.1(5) and 6A.1.2(6) and of the EII chapter 6A require our Directors to certify the key assumptions that underlie our capex and opex forecasts. Our key assumptions for opex are set out in Section 4, and for capex in Section 5.

Our certification statement is provided as Attachment 1.2 to this Revenue Proposal.

9.2.2 Statutory declaration by Chief Executive

The AER's Information Notice requires an officer of Ausgrid to make a statutory declaration attesting to the information provided in response to that notice.

In summary, the statutory declaration specifies actual information must be true and accurate and the forecasts and historical estimates are the best forecasts and estimates able to be provided. These standards are intended to deliver the highest quality information to the AER, to ensure it is able to make decisions that are required under the EII Act.

The statutory declaration made by our Chief Executive Officer is provided as Attachment 9.4.

9.3 RIN compliance

Ausgrid confirms that our proposal complies with the Regulatory Information Notice (**RIN**) issued by the AER on 2 May 2025. We have also considered the requirements of the Electricity Infrastructure Investment 2020 (NSW) (EII Act), EII Chapter 6A, and the TET Guidelines. As the RIN incorporates these same compliance and information requirements, our adherence to the RIN ensures that our proposal meets all necessary obligations.

9.4 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Table 9-1: Supporting documents list

Supporting document	
Attachment 9.1	RIN Response
Attachment 9.2	Regulatory Information Notice compliance checklist
Attachment 9.3	Material assumptions
Attachment 9.4	Revenue Proposal Statutory Declaration
Attachment 9.5	Confidentiality claims