# 2024-29
Revenue Proposal

## Waratah Super Battery Project (non-contestable)

June 2023

Transgrid

People. Power. Possibilities.

# Contents

# Acknowledgement of Country

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

We pay respects to the people and the Elders, past, present and emerging and celebrate the diversity of Aboriginal peoples and their ongoing cultures and connections to the lands and waters of NSW and ACT.

Transgrid

# Executive summary

This is Transgrid's Revenue Proposal for the non-contestable component of the Waratah Super Battery Project (WSB) for the regulatory period commencing 1 July 2024 and ending 30 June 2029 (2024-29).

WSB will be the largest standby network battery in the Southern Hemisphere.[1] It is critical to the affordability, reliability, security and sustainability of electricity supply in NSW given the expected closure of Eraring Power Station in August 2025. WSB comprises contestable and non-contestable components:[2]

- the non-contestable component involves augmentation of our existing transmission network and the installation of the System Integrity Protection Scheme (SIPS) control, and
- the contestable components are the SIPS (battery) and paired generation services.

Australian Energy Market Operator's (AEMO) 2022 Final 2022 Integrated System Plan (2022 ISP) has classified WSB[3] as an Actionable NSW project, which should be progressed urgently.[4] WSB is also part of the New South Wales (NSW) Electricity Infrastructure Roadmap.

On 2 August 2022, the NSW Minister for Energy (Minister) appointed EnergyCo as the Infrastructure Planner for the WSB Project (contestable and non-contestable), which constituted a priority transmission infrastructure project (PTIP) under the Electricity Infrastructure Investment (EII) Act 2020 (NSW). On 14 October 2022, the Minister published an Order directing Transgrid as the Network Operator to carry out the contestable and non-contestable components of WSB.[5]

This Revenue Proposal relates only to the non-contestable work, which is referred to as 'the Project' or 'WSB Project'. Where this Revenue Proposal refers to the entire project, we use the term 'WSB Project (contestable and non-contestable)'.

This is our first non-contestable Revenue Proposal for the WSB Project and the first non-contestable Revenue Proposal under the EII Act. This Revenue Proposal explains our 2024-29 forecast capital expenditure (capex), operating expenditure (opex) and revenue as well as the amount we propose to be paid by the Scheme Financial Vehicle for delivering the Project.

## Customer benefits

The WSB Project will deliver the following benefits to electricity customers:

- unlock the potential capacity of the existing network through the network augmentation thereby allowing more existing generation to be shared, and
- through the SIPS, allow power flows across the network to be monitored and control the operation of the battery energy storage systems (BESS) and paired generators. The SIPS will act as a 'shock absorber' in the event of any sudden power surges, including from bushfires or lightning strikes.[6]

The Project will play an essential role in meeting the needs of electricity customers at the lowest total cost.

1 EnergyCo, Draft Network infrastructure Strategy for NSW, September 2022
2 The Minister directs Transgrid to carry out the WSB Project in accordance with Section 32 of the EII Act
3 Both the contestable and non-contestable components
4 AEMO, 2022 ISP, June 2022 p.70
5 The WSB Delivery Plan is set out in the Ministerial Order
6 EnergyCo, Waratah Super Battery, March 2023

## Customer and stakeholder engagement

Our focus is on delivering better outcomes for electricity customers as Australia transitions to a clean energy future. The Transgrid Advisory Council (TAC), which is our customer consultative committee, has been our primary forum for engagement on this Revenue Proposal. TAC members represent consumer and business advocates, renewables generators and large customers. Our TAC meetings are facilitated by our Executive and Leadership team to ensure customer and other stakeholders' views are shared broadly across our business.

The TAC has met monthly from February to June 2023, allowing us to seek members' views and positions on the WSB Project, the EII regulatory framework and key positions and proposals in this Revenue Proposal. The TAC has been generally supportive of our proposed approach. Where we have received specific feedback from the TAC, we have reflected it in this Revenue Proposal. The Australian Energy Regulator (AER) attended and participated in our TAC meetings, and so responded directly to TAC members' questions, where relevant.

We have also met regularly with the AER and the Energy Corporation of NSW (EnergyCo) in preparing this Revenue Proposal. Feedback from the AER and EnergyCo has informed the content and structure of this Revenue Proposal and supporting documentation.

We welcome the constructive and positive approach adopted by all stakeholders and appreciate the input and views received, noting that this is a new revenue-setting process for all parties. We welcome feedback on this Revenue Proposal as we maintain our on-going engagement with the TAC and other stakeholders in the next phases of the revenue determination process.

## Our approach to this Revenue Proposal

The EII Chapter 6A[7] substantially replicates Chapter 6A of the National Electricity Rules (NER or Rules). To greatest extent possible, we have therefore aligned our positions and approaches in this Revenue Proposal with those approved in the AER's 2023-28 Revenue Determination (made under the NER) for our prescribed transmission services.[8] For example, we have adopted the decisions in the AER's 2023-28 Revenue Determination for:

- labour and materials escalation rates[9]
- nominated pass through events
- standard asset lives with two exceptions, being to add new asset classes for SIPS control and financeability
- straight-line depreciation method for all asset classes, except for 'Financeability Asset', where we propose to accelerate depreciation to ensure that the project is financeable
- debt raising cost unit rate (as a placeholder), and
- equity raising cost parameters.

7 The Economic regulation of NSW non-contestable revenue determinations under Part 5 of the EII Act 2020, as set out in Appendix A of the AER's TET and Revenue Determination Guideline for NSW non-contestable network infrastructure projects - Final, April 2023

8 AER, Final Decision Transgrid Transmission Determination, 1 July 2023 to 30 June 2028, 28 April 2023.

9 Given that the AER's 2023-28 Determination does cover 2028-29, we have extrapolated the forecast by setting the 2028-29 real labour escalator equal to the average of that adopted by the AER for 2023-24 to 2027-28.

As required under the EII regulatory framework, we have also adopted the most recent version of the AER's Rate of Return Instrument (RoRI) to determine the rate of return that applies to the Project. We have therefore used the 2022 RoRI to calculate our return on capital allowance in this Revenue Proposal.

As discussed with the AER, to ensure the Project is financeable, we have calculated depreciation on the basis of 'as-incurred' capex rather than 'as commissioned' capex. We have also added a new 'Financeability Asset' asset class and have accelerated the depreciation of this asset over the 2024-29 period to ensure that the Project is financeable in each year of the regulatory period. This approach is consistent with the Energy Networks Australia's (ENA) Rule Change Proposal, Ensuring the Financeability of Actional ISP Projects.[10]

We have adopted the AER's existing TNSP PTRM with minimal adjustments to calculate our 2024-29 revenue. Where we have made changes to the PTRM, we have aligned with the AER's PTRM guidance note.[11]

## Operating expenditure

Our total forecast opex for the 2024-29 regulatory period is $24.9 million (including debt raising costs). This has been determined using a bottom-up-build because no representative base year is available from a preceding regulatory period, which means that we are not able to apply the base-step-trend approach. Our forecast opex comprises:

- maintenance costs, which are estimated based on the routine inspection and maintenance regimes for substations, transmission lines and SIPS control
- operating costs, which reflect the labour costs needed to meet our obligations under the Network Operator Deed (NOD), SIPS service agreement and Paired Generation service agreement, and
- insurance expenses, [redacted] for the WSB assets once they are commissioned.

## Capital expenditure

Our total forecast capex for the 2024-29 regulatory period is $254.7 million (excluding equity raising costs).[12, 13] To ensure that customers are paying no more than they should be for the services that they will receive we have forecast capex using:

- detailed scopes of work, which have been independently assessed by GHD, and
- to the greatest extent possible, market-tested costs from our competitive procurement process, which has been undertaken in accordance with our compliance and governance requirements.

We expect that at least 70.8 per cent of the capex for the Project will be based on market prices obtained through competitive tender processes. Our forecast capex for the 2024-29 period comprises:

- $69.8 million for the transmission line network augmentation works, which comprises the uprating of transmission line 39 Bannaby to Sydney West and lines 3L/4 and 5 Yass to Marulan

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[10] ENA, Ensuring the financeability of actionable ISP Projects – Proposal to change the National Electricity Rules, 9 June 2023

[11] AER, Final Guidance note – Amendments to NER PTRM for determinations under the Electricity Infrastructure Investment Act and Regulations (AER EII Act PTRM Guidance Note), June 2023.

[12] Total forecast capex including equity raising costs of $0.7 million is $225.5 million.

[13] This is development and construction capex and includes pre-period capex incurred prior to 1 July 2024

- $108.4 million for the substation augmentation works, which comprises the uprating of equipment across 22 substations located in north and south NSW
- $19.3 million for the SIPS control works, which involves design, installation and commissioning works. It also includes the costs of future rounds of paired generation being integrated into the scheme[14]
- $57.2 million for our labour and indirect costs, which comprises project management required to establish and manage the Project, project support roles and other labour and indirect costs, such as stakeholder and community engagement and insurance costs.

The delivery of the Project is required to meet the strict delivery milestones set out in the Ministerial Order:

- deliver SIPS control and complete the first portion of network augmentations by 1 November 2024, and
- complete all network augmentation by 1 August 2025.

GHD has independently verified that the scope of the Project is reasonable and realistic to meet the requirements in the Ministerial Order and considers that the forecast capex for the Project is prudent, efficient and reasonable and likely to sit within a reasonable level of accuracy.

## Incentive schemes

A key feature of incentive regulation is that the AER's incentive schemes are intended to promote efficient cost and service performance over time. We support incentive regulation where it will be effective, given the particular circumstances of the project.

For this Project, the AER's non-contestable Guideline explains that the AER intends to:

- apply the same expenditure incentive schemes, being the Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) that currently apply under the NER
- develop an EII-specific Service Target Performance Incentive Scheme (STPIS), which would apply only from the second regulatory control period, and
- not apply either the NER small-scale incentive scheme or the demand management innovation allowance mechanism.

We agree with the AER's position, with the exception of the proposed application of the EBSS and the CESS. We do not support the application of the EBSS and CESS to the NSW Roadmap or AEMO's ISP projects. This is because, in an inflationary and uncertain operating environment with high value, complex and specialised projects, these incentive schemes introduce an asymmetric risk.

A key driver of this asymmetric risk is that design and construct (D&C) contractors are currently not willing to provide fixed price contracts. To safeguard against potential losses (i.e., risk costs) caused by labour shortages, increasing materials costs and supply chain disruption, D&C contractors require some cost components in their contracts to be variable. This allows them to offer a lower contract price than they otherwise would if they were forced to price in the risk costs though a fixed price contract. By way of example for the WSB Project, the D&C contract cost of $166.0 million included in this Revenue Proposal for transmission lines and substations reflects a variable contract cost.[15] If, however, the contractor was required to offer a fixed price contract, then the D&C contract cost is expected to increase by around

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[14] We will deliver the SIPS control using internal resources due to the highly complex and highly specialised nature of the SIPS control design, installation and commissions works. These costs are included in our SIPS control cost category.

[15] The $166.0 million comprises $68.3 million for transmission lines and $97.7 million for substations.

$30 million or 20 per cent. The variable contract cost in this Revenue Proposal therefore provides consumers with a higher probability of a lower price outcome.

A variable contract price means, however, that Transgrid is holding the residual risk costs, which have not been fully priced into our Revenue Proposal. Accordingly, the probability of overspending the AER's capex allowance is greater than the probability of underspending it. If the CESS applies with a variable contract price as proposed, these projects would generate less than the benchmark rate of return. Investors may therefore not be willing to commit capital to these projects, which is not in the long-term interest of consumers, because these projects are critical to:

- the urgent energy transition, which in turn will drive down energy prices
- support the Australian and NSW Government's commitment to a net-zero future, and
- ensure consumers continue to receive reliable and secure electricity.

It would therefore not be in the long-term interest of consumers to apply penalties or rewards for differences between actual and forecast expenditure where these differences are driven by factors other than true efficiency savings or losses.

## Forecast revenue, payment schedule

Our total 2024-29 forecast revenue of $137.7 million (nominal) will fund the delivery of the Project in accordance with the Ministerial Order to ensure the continued reliable secure and sustainable supply of electricity supply in NSW. The table below shows in nominal dollars the year-by-year breakdown of the forecast.

Maximum allowed revenue over the 2024–29 regulatory period - Detailed breakdown ($M, Nominal)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Return on capital | 7.4 | 16.5 | 17.0 | 16.6 | 16.2 | **73.7** |
| Return of capital | 8.0 | 6.4 | 5.8 | 5.8 | 5.7 | **31.6** |
| Operating expenditure | 3.9 | 5.2 | 5.8 | 6.5 | 5.9 | **27.2** |
| Revenue adjustment | 3.5 | - | - | - | - | **3.5** |
| Corporate income tax | 1.0 | 0.1 | 0.1 | 0.2 | 0.3 | **1.7** |
| **Maximum allowed revenue** | **23.7** | **28.2** | **28.7** | **29.1** | **28.1** | **137.7** |
| NPV (as at 30 June 2024) | | | | | | **113.0** |

We have calculated a schedule of quarterly payments that we propose to be paid by the Scheme Financial Vehicle for delivering the Project based on our forecast MAR for the 2024-29 regulatory period. We have done so by converting our MAR into quarterly payments.[16] The table below shows the forecast quarterly payments for the 2024-29 regulatory period. The total revenue differs slightly from the table above due to the impact of the NPV conversion.

16 The net present value (NPV) of the schedule of payments matches the NPV of MAR

Forecast quarterly payments for the 2024-29 regulatory period ($M, Nominal)

| Year | Quarter 1 (September) | Quarter 2 (December) | Quarter 3 (March) | Quarter 4 (June) | Total |
|---|---|---|---|---|---|
| 2024-25 | 5.6 | 5.7 | 5.8 | 5.9 | 23.2 |
| 2025-26 | 6.7 | 6.8 | 6.9 | 7.0 | 27.5 |
| 2026-27 | 6.8 | 6.9 | 7.1 | 7.2 | 28.0 |
| 2027-28 | 6.9 | 7.0 | 7.1 | 7.3 | 28.4 |
| 2028-29 | 6.7 | 6.8 | 6.9 | 7.0 | 27.4 |
| **Total** | **32.8** | **33.3** | **33.9** | **34.4** | **134.3** |
| NPV (as at 30 June 2024) | | | | | 113.0 |

The EII regulatory framework allows us to include symmetrical adjustment mechanisms to update our payment schedule for certain pre-defined events that are beyond our control. These events can change our expenditure within a regulatory period and the cost impact may be positive or negative.[17] We propose:

- automatic adjustments to address annual updates to revenue for actual inflation, the return of debt update to the allowed rate of return (consistent with the NER and our 2023-28 Revenue Determinations) and any additional contractual payments to EnergyCo,[18] and
- 'non-automatic' adjustments for changes in paired generation cost, unavoidable contract variations and contractor force majeure events. In relation to these adjustments, the AER would be required to review or remake its revenue determination.

In addition to these defined events,[19] we have proposed nominated pass-through events consistent with the AER's 2023-28 Revenue Determination for our prescribed transmission services.

[17] Clause 51 of the EII Regulations and AER, AER non-contestable Guideline, April 2023, Section 5.5.
[18] While no future contractual payments to EnergyCo are forecast, we have included an automatic adjustment should this arise in the future.
[19] In accordance with EII Chapter 6A rule 6A.6.9(a)


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# About us and this Revenue Proposal

# 1. About us and this Revenue Proposal

## 1.1. About us, the project and this Revenue Proposal

Transgrid operates the high voltage transmission network in NSW and the Australian Capital Territory (ACT), which services about four million customers. Our transmission network supplies higher peak loads and transmits more energy annually than any other transmission network in Australia. We are also a network operator for the purposes of the EII Act.[20]

WSB project is part of the NSW Electricity Infrastructure Roadmap. It is critical to the affordability, reliability, security and sustainability of electricity supply in NSW, given the planned closure of Eraring Power Station, which will reduce the supply of electricity generated within the Sydney-Newcastle-Wollongong region. WSB will be the largest standby network battery in the Southern Hemisphere[21] and will:

- provide a short-term solution until the Sydney Ring transmission project, particularly the Hunter Transmission project, is operational, and
- operate as part of a System Integrity Protection Scheme (SIPS) to address an expected breach of the NSW Energy Security Target in 2025–26, by increasing power transfer capacity on transmission lines that connect generation in the northern and southern regions of NSW to Sydney, Newcastle and Wollongong.

WSB comprises contestable and non-contestable components:

- the non-contestable component involves augmentation of our existing transmission network (transmission lines and substations) and the installation of a SIPS control and communications systems, and
- the contestable components comprises:
  - SIPS services to be provided by a BESS with minimum capacity of 700 megawatts (MW) / 1,400 megawatt hours (MWh). This will be undertaken by a service provider competitively procured by EnergyCo. This is the subject of a separate contestable Revenue Determination process, which concluded on 14 December 2022 with the publication of the AER's Final Revenue Determination,[22] and
  - Paired Generation Services to be undertaken by a portfolio of generators competitively procured by EnergyCo (contestable). This is the subject of a separate contestable Revenue Determination process, which is currently underway. Transgrid will submit its Revenue Proposal to the AER following the conclusion of the contestable process.

This Revenue Proposal relates only to the non-contestable work, which is referred to as 'the Project' or 'WSB Project'. Where this Revenue Proposal refers to the entire project, we use the term 'WSB Project (contestable and non-contestable)'.

The WSB Project involves increasing the thermal ratings of specific transmission lines, allowing existing generation to transmit more energy to meet demand in the Sydney, Newcastle, Wollongong region. The Project will form an integral part of our existing transmission network once operational and involves:

[20] Electricity Infrastructure Investment (EII) Act 2020 (NSW)
[21] EnergyCo NSW Network infrastructure Strategy, May 2023
[22] AER, Revenue Determination (contestable) Transgrid, Waratah Super Battery – SIPS component, December 2022

- uprating existing transmission lines and substations. This involves:
  - uprating transmission lines 3L, 4 and 5 to operate at 85°C and line 39 to operate at 120°C. This requires the installation of new structures, modification of insulator arrangements and tower strengthening activities to ensure appropriate ground clearances are maintained, and
  - uprating equipment at 22 substations from Dumaresq, near the Queensland border, down to Upper Tumut in the Snowy Mountains, near the Victorian border, to unlock the potential capacity of the existing network. This requires the replacement of HV terminal equipment and modification of secondary systems.[23]
- designing, installing, commissioning and operating the SIPS control. The SIPS control will monitor the transmission lines for overload conditions and, subject to any overload, engage the SIPS (battery) and paired generation services.[24] The SIPS control will be one of the most complex schemes of its type installed in the NEM and will be critical to the reliability and security of the NSW power system into the future.

This is our first non-contestable Revenue Proposal for the WSB Project and the first non-contestable Revenue Proposal under EII Act. This Revenue Proposal explains our 2024-29 forecast capex, opex and revenue as well as the amount we propose to be paid by the Scheme Financial Vehicle delivering the Project during the 2024-29 period.

## 1.2. A PTIP

A PTIP is defined as a transmission infrastructure project that is located in NSW and forms part of an infrastructure project identified in the latest ISP published by AEMO.

The WSB Project (contestable and non-contestable) was declared a PTIP for the purposes of the EII Act because the WSB Project is located in NSW and was identified in the most recently published ISP, being the 2022 ISP, as an Actionable NSW Project.[25]

A key market development, which led AEMO to classify the WSB Project (contestable and non-contestable) as NSW Actionable Project, was the announcement by Origin Energy in February 2022 that the Eraring power station is expected to close August 2025, which is seven years earlier than previously expected. In May 2022, in response to this announcement and the associated change in market circumstances, AEMO in its role as the Energy Security Target Monitor, identified a breach in the target in 2025–26, with this breach expected to extend through to 2030–31.

On 30 June 2022, AEMO published its 2022 ISP, which:

- identified the Sydney Ring (a project designed to reinforce electricity supply to Sydney, Newcastle and Wollongong) as an Actionable NSW project, to be progressed urgently and with a latest date for delivery of July 2027,[26] and
- recommended a combination of delivery options, including the WSB project as part of a staged delivery of the Sydney Ring project.[27] The 2022 ISP states:

[23] This will remove constraints on 20 transmission lines increasing the ability to transmit energy over the network.
[24] EnergyCo, Waratah Super Battery, March 2023
[25] AEMO, 2022 ISP, June 2022
[26] AEMO, 2022 ISP, p.70
[27] Ibid, at page 71

*The northern part of this project is named the Hunter Transmission Project and may include the Waratah Super Battery and related upgrades. As an actionable New South Wales project, this project will progress under the Electricity Infrastructure Investment Act 2020 (NSW) rather than the ISP framework. It is also identified as a REZ-critical project in the 2021 Infrastructure Investment Objectives (IIO) report[65] published by AEMO Services' (as the New South Wales' Consumer Trustee).*

## 1.3. Ministerial Order

On 14 October 2022, the Minister published an Order directing Transgrid as the Network Operator to carry out the WSB Project, which comprises:[28]

- the contestable components comprising the SIPS (battery) and paired generation services, and
- the non-contestable component, which involves augmentation of our existing transmission network, and the installation of the SIPS control.

We must comply with the WSB Delivery Plan detailed in the Order in carrying out the project. Section 2.3 of the Revenue Proposal sets out how we have complied with the Minister's direction in preparing this Revenue Proposal.

## 1.4. Our services

We provide NSW non-contestable services under the EII Act and Regulations (EII services), relying on, amongst other things, our licence that is issued under the Electricity Supply Act 1995 (NSW).

The quality, reliability and security of supply of the NSW non-contestable services we provide are established in the EII Act and Regulations, our licences as well as in customer connection and access agreements.

Importantly, EII services are not transmission services, which are subject to regulation under the National Electricity Rules (NER or Rules). Accordingly, EII services are regulated under the EII regulatory framework. As explained in the AER's Explanatory Statement, the EII regulatory framework currently does not differentiate EII services and transmission services and the AER is working with the Office of Energy and Climate Change (OECC) to clarify this either by derogation or an amendment to the existing EII regulations change[29]:

*At the time of publishing this Guideline we were aware that the EII framework does not differentiate services under the EII framework from prescribed transmission or prescribed distribution services under the NER. This potentially means that Network Operators are subject to two regulatory regimes (the NER and the EII framework).*

*We expect the issue to be resolved before the end of this year. Should resolution of this issue require an amendment to this Guideline, we will make it in accordance with the amendment process described in the Guideline.*

Our forecast expenditure in this Revenue Proposal relates only to non-contestable EII services. The allocation of costs to these services is in accordance with our Cost Allocation Methodology (CAM).[30]

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[28] The Minister directs Transgrid to carry out the WSB project in accordance with Section 32 of the EII Act

[29] AER, Explanatory Statement: TET and revenue determination guideline for NSW non-contestable network projects (AER Guideline Explanatory Statement), April 2023, p. 3

[30] Transgrid, Cost Allocation Methodology, May 2023.

Expenditure has been allocated to capex and opex in accordance with our Expenditure Capitalisation Standard. A copy of this standard is provided as an attachment to this Revenue Proposal.[31]

## 1.5. Basis for this Revenue Proposal

This Revenue Proposal relates to EII services and adopts the NSW Regulatory framework in full. The NSW regulatory framework comprises:

- The EII Act
- The Electricity Infrastructure Investment Regulation 2021 (NSW) (EII Regulations)[32]
- AER Transmission Efficiency Test (TET) and Revenue Determination Draft Guideline: NSW non-contestable network infrastructure projects (AER non-contestable Guideline),[33] and
- EII Chapter 6A[34]

This Revenue Proposal also addresses:

- the AER's Information Notice (see WSB non-contestable Information Notice Compliance checklist),[35] and
- how we have complied with the Minister's direction relating to the network infrastructure project and the contractual arrangement relating to WSB, in particular the Network Operator Deed (NOD).

Given that the EII Chapter 6A[36] substantially replicates Chapter 6A of the NER, we have to the greatest extent possible aligned our positions and approaches in this Revenue Proposal with those approved by the AER's 2023-28 Revenue Determination (made under the NER) for our prescribed transmission services.[37] For example, we have adopted the decisions in the AER's 2023-28 Revenue Determination for:

- labour and materials escalation rates[38]
- nominated pass through events
- standard asset lives with two exceptions, being to add new asset classes for SIPS control and financeabiltiy
- the debt raising cost unit rate (as a placeholder), and
- equity raising cost parameters.

As required under the EII regulatory framework, we have also adopted the most recent version of the AER's RoRI to determine the rate of return that applies to the WSB Project. At the time of preparing this Revenue Proposal, the 2022 RoRI was the latest available. We have therefore used the 2022 RORI to calculate our return on capital allowance in this Revenue Proposal.

[31] Transgrid, Expenditure Capitalisation Standard, November 2021.
[32] Electricity Infrastructure Investment (EII) Regulation (NSW) 2021 made under the EII Act.
[33] AER, TET and Revenue Determination guideline for non-contestable network infrastructure projects (AER non-contestable Guideline), April 2023.
[34] The Economic regulation of NSW non-contestable revenue determinations under Part 5 of the EII Act 2020, as set out in Appendix A of the AER's TET and Revenue Determination Guideline for NSW non-contestable network infrastructure projects – Final EII Regulatory Framework, April 2023
[35] AER, Information Notice issued to Transgrid for the Waratah super Battery Project (non-contestable), May 2023.
[36] The EII Regulatory Framework
[37] AER, Final Decision Transgrid Transmission Determination, 1 July 2023 to 30 June 2028, 28 April 2023.
[38] Given that the AER's 2023-28 Determination does cover 2028-29, we have extrapolated the forecast by setting the 2028-29 real labour escalator equal to the average of that adopted by the AER for 2023-24 to 2027-28.

We have also adopted the AER's existing TNSP PTRM with minimal adjustments to calculate our 2024-29 revenue. Where we have made changes to the PTRM, we have aligned with the AER's PTRM guidance note.[39]

We look forward to participating in the development by the AER of an EII-specific STPIS. The AER has indicated this will be developed in the second half of 2023 given that this scheme would apply to non-contestable determinations from the second regulatory control period onwards. There will be no STPIS applied to the WSB Project the 2024-29 period.

As noted above, the contestable components of the WSB Project are subject to separate Revenue Proposals:

- on 17 October 2022, we submitted our Revenue Proposal on the SIPS services
- the AER published its Final Decision on 14 December 2022, and
- we expect to submit our Revenue Proposal for paired generation services to the AER post July 2023[40]

## 1.6. Structure of this Revenue Proposal

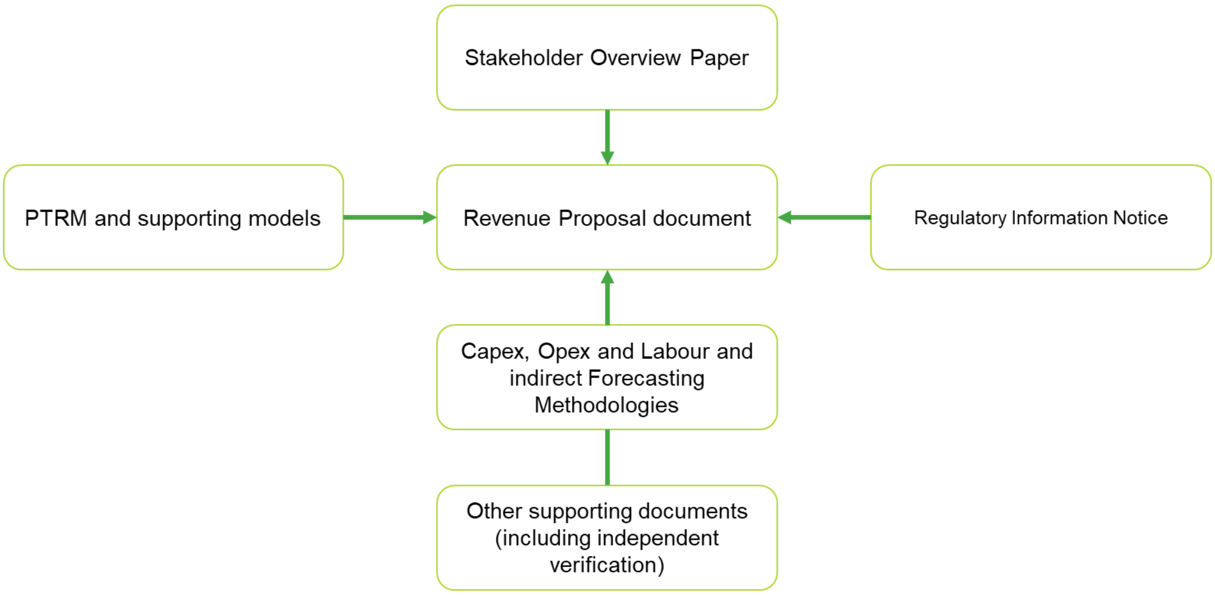
This Revenue Proposal is structured as follows:

- Chapter 2 provides an overview of how this Revenue Proposal is consistent with the NSW Minister's direction and the contractual arrangement relating to the WSB Project and the benefits expected to be delivered from undertaking the Project
- Chapter 3 provides an overview of our engagement approach, activities and what we have heard from our customers and other stakeholders
- Chapter 4 details our opex forecast
- Chapter 5 details our revised capex forecast
- Chapter 6 details our revised RAB and our depreciation forecast
- Chapter 7 details our estimated rate of return, forecast inflation, and debt and equity raising costs
- Chapter 8 details our estimated cost of corporate income tax
- Chapter 9 details our revised proposals on the application of the AER's expenditure incentive schemes
- Chapter 10 details our proposals on our nominated cost pass through events
- Chapter 11 details our forecast maximum allowed revenue
- Chapter 12 details our proposed payment schedule and revenue adjustments
- Chapter 13 details other matters - provides information on our approach to confidential information and the assurance and certification we must provide, including the key assumptions supporting our expenditure forecasts.

This Revenue Proposal comprises the attachments and models illustrated in Figure 1-1 as well as other supporting documents. This Revenue Proposal references these attachments, models and other supporting documents and should be read in conjunction with them.

[39] AER, EII Act PTRM Guidance Note, June 2023
[40] Under the AER's Revenue Determination Guideline for NSW contestable network projects, the AER has 42 business days to make a determination from the date it receives a Revenue Proposal.

Figure 1-1: Revenue Proposal document structure



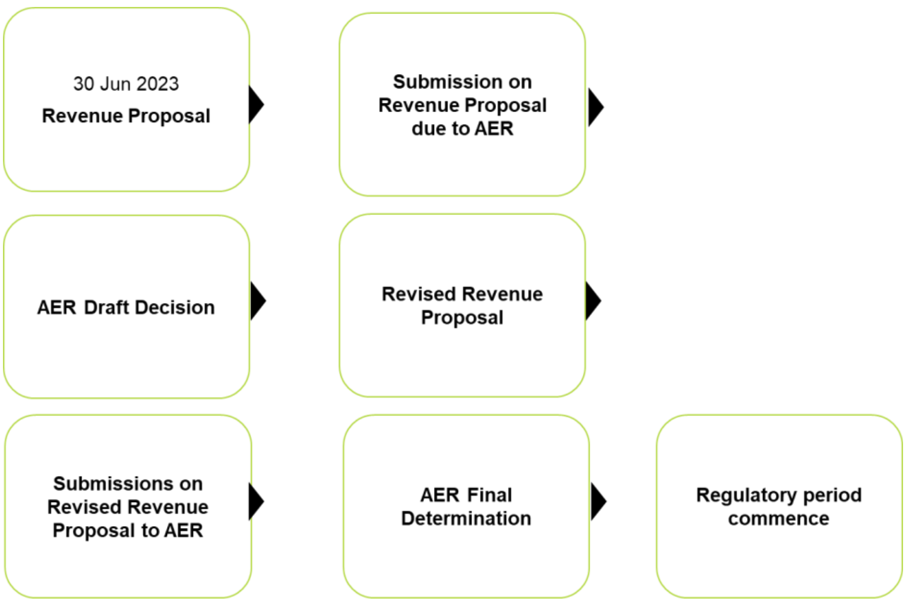

## 1.7. How to provide feedback

We welcome the views of customers and other stakeholders on this Revenue Proposal. Please share your feedback with us by:

- email at: revenue.reset@transgrid.com.au
- phone on: 02 9284 3431

The AER's review process and the next steps are shown in the figure below. This Revenue Proposal will be submitted by 30 June 2023 to enable the AER to make a Final Decision by 22 December 2023. The new regulatory period will commence on 1 July 2024.

Figure 1-2: AER's review process and next steps



The AER will invite submissions on our Revenue Proposal until 20 July 2023. We will continue to engage with our customers and other stakeholders on our Revenue Proposal up to and after this date, including through the TAC.

## 1.8. Conventions

In this Revenue Proposal, unless otherwise specified:

- historical and forecast expenditure is presented in end-year (to 30 June) real 2023-24 dollars
- all dollars for regulatory years:
    - up to and including March 2023 are actuals
    - March 2023 to 30 June 2024 are estimates, and
    - 2024-25 onwards are forecasts.
- negative figures are presented in brackets, and
- 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 us, unless otherwise specified.

Our forecast expenditure in this Revenue Proposal relates to EII services only. The allocation of costs to these services is in accordance with our Cost Allocation Methodology (CAM).[41]

[41] Transgrid, Cost Allocation Methodology, May 2023.

# 2

# About the WSB Project

# 2. About the WSB Project

## 2.1. Project description and timing

On 14 October, the NSW Government gazetted the *Priority Transmission Infrastructure Project Direction (Waratah Super Battery Project) Order 2022 (Order)* and the NSW Minister directed Transgrid as the Network Operator to carry out the WSB project (contestable and non-contestable).[42] The Order sets out the scope of the contestable and non-contestable elements of the Project.

As discussed in Section 1.1, this Revenue Proposal only relates to the non-contestable component and therefore, all references to WSB or the Project in this document relate to the non-contestable component of the project.

Schedule 2 and Schedule 3 of the NOD[43] detail the scope of the WSB Project, which involves:

- planning and design of the network augmentation works, being the feasibility assessment, augmentation and delivery of the Northern Works and Southern Works, and
- planning, design, coding, installation, delivery, commissioning and operation of the SIPS control and communications systems and interface.

The WSB Project has two delivery stages (otherwise known as commissioning dates):

1. deliver SIPS control and complete first portion of network augmentations by 1 November 2024, and
2. complete all network augmentations by 1 August 2025.

Table 2-1 provides further details on the non-contestable works and the milestone dates.

Table 2-1: Scope and timing of the Project

| Work element | Definition of the works | Milestone date | Category of capex |
|---|---|---|---|
| Network Augmentations – Northern Works | Feasibility assessment, augmentation and delivery of substation works associated with:<br>• Line 81 Liddell to Newcastle<br>• Line 82 Liddell to Tomago<br>• Line 83 Liddell to Muswellbrook<br>• Line 84 Liddell to Tamworth<br>• Line 85 Armidale to Tamworth<br>• Line 86 Armidale to Tamworth<br>• Line 88 Tamworth to Muswellbrook<br>• Line 8C Dumaresq to Armidale<br>• Line 8E Sapphire to Armidale<br>• Line 8J Dumaresq to Sapphire | 1 November 2024 | Substations – refer to Section 5.7 |
| Network Augmentations – Southern Works | Feasibility assessment, augmentation and delivery of transmission lines and substations works associated with: | Line 39 – 1 November 2024 | Transmission Lines – refer to Section 5.6 |

42 NSW Government Gazette No 473, 14 October 2022
43 Network Operator Deed – Waratah Super Battery Project, 17 October 2022

| Work element | Definition of the works | Milestone date | Category of capex |
|---|---|---|---|
| | • Line 39 Bannaby to Sydney West<br>• Line 3L/4 Yass to Marulan<br>• Line 5 Yass to Marulan | Lines 3L/4 and 5 – 1 August 2025 | |
| | Feasibility assessment, augmentation and delivery of substation works associated with other southern transmission lines. | 1 August 2025 | Substations – refer to Section 5.7 |
| SIPS Control | Planning, design, coding, installation, delivery, commissioning and operation of the SIPS control and communications systems and interfaces. | 1 November 2024 | SIPS control – refer to Section 5.8 |

## 2.2. Benefits of the WSB Project

The successful on-time delivery of the Project is critical to the continued reliable, secure, sustainable and safe supply of electricity in NSW following the anticipated closure of the Eraring Power Station in 2025. The Project will form an integral part of our existing transmission network once operational and will:

- unlock the potential capacity of the existing network through the network augmentation works allowing more existing generation to be shared, and
- through the SIPS, allow power flows across the network to be monitored and control the operation of the BESS and paired generators, allowing the WSB project to operate. The SIPS will act as a 'shock absorber' in the event of any sudden power surges, including from bush fires or lightning strikes.[44]

## 2.3. Consistency with the Minister's direction and our contractual arrangements

This Revenue Proposal is consistent with the Minister's direction and our contractual arrangement relating to the WSB Project, in particular the NOD.[45] Table 2-2 sets out how this Revenue Proposal is compliant with the relevant sections of the Minister's direction.

Table 2-2: Consistency of the Revenue Proposal with the Minster's direction

| Minister's Direction<br><br>Clause | Provision | Evidence of consistency between Minster's direction and this Revenue Proposal |
|---|---|---|
| 5 | Transgrid must, taking all reasonable steps, complete the planning, design and construction stages of the Waratah Super Battery Project by the relevant dates specified in the Transgrid WSB Delivery Plan. | This Revenue Proposal forms part of, and enables the completion, design and construction stages of the Waratah Super Battery Project by the relevant dates in the Minister's direction. |

[44] EnergyCo, Waratah Super Battery, March 2023
[45] In accordance with Section 4.2.1(a) of AER's WSB non-contestable information notice.

| Minister's Direction Clause | Provision | Evidence of consistency between Minster's direction and this Revenue Proposal |
|---|---|---|
| 6 | Transgrid must carry out the Waratah Super Battery Project in accordance with this Order, including:<br>(a) the specifications set out at Schedule 1 of this Order,<br>(b) the Transgrid WSB Delivery Plan, and<br>(c) the conditions set out at Schedule 3 of this Order. | This Revenue Proposal is consistent with<br>• the specifications set out at Schedule 1 of this Order (see the two rows below),<br>• the relevant milestones in Schedule 2 WSB Delivery Plan (see the last row below and Section 2.1 of this Revenue Proposal), and<br>• the conditions set out at Schedule 3 of this Order. |
| Schedule 1 clause 2 | In carrying out the Waratah Super Battery Project, Transgrid must comply with the Transgrid WSB Delivery Plan in accordance with the contractual arrangements detailed in clause 3 of this Schedule 1. | This Revenue Proposal is compliant with the Transgrid WSB Delivery Plan set out in Schedule 2 (see last row below) in accordance with the contractual arrangements in the NOD. Compliance with the NOD is set out in Table 2-3. |
| Schedule 1 clause 3 | Transgrid is required to enter into contractual arrangements to carry out the Waratah Super Battery (including the development and construction of the infrastructure project), including the types if contractual arrangements set out below<br>(d) A 'network operator deed' setting out the rights and responsibilities of the WSB Infrastructure Planner and Transgrid in respect of the carrying out of the Waratah super Battery Project (NOD) | The NOD is the key contract relevant to this Revenue Proposal. The NOD was executed on 17 October 2022. |
| Schedule 2 | • Transgrid to lodge non-contestable regulatory determination application with the Regulator by 31 March 2023.<br>• Transgrid to deliver SIPS control and first portion of network augmentation by the later of 1 November 2024 and the date on which the SIPS Service Provider must commence providing the interim SIPS Service.<br>• Transgrid to complete all network augmentation by 1 August 2025. | Milestone dates as set out in the Transgrid WSB Delivery Plan. The NOD was amended on 13 April 2023 to change the date by which we are required to submit our non-contestable Revenue Proposal (this Revenue Proposal) to the AER from 31 March 2023 to 30 June 2023. On 30 June 2023, we submitted this Revenue Proposal to the AER in accordance with the NOD amendment.<br>• This Revenue Proposal is based on the 1 November 2024 delivery date for the SIPS control and first portion of network augmentation. See Section 2.1 of this Revenue Proposal.<br>• This Revenue Proposal is based on the 1 August 2025 delivery date for all |

| Minister's Direction Clause | Provision | Evidence of consistency between Minster's direction and this Revenue Proposal |
|---|---|---|
| | | remaining network augmentation. See Section 2.1 of this Revenue Proposal |

Table 2-3 sets out how this Revenue Proposal is compliant with the relevant sections of the NOD.

Table 2-3: Consistency of the Revenue Proposal with the NOD

| NOD Clause | Provision | Evidence of consistency between NOD and this Revenue Proposal |
|---|---|---|
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |

[46] The $3.0M (nominal) payment made in 2022-23 translates to $3.1 million when adjusted for inflation.

| NOD Clause | Provision | Evidence of consistency between NOD and this Revenue Proposal |
|---|---|---|
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | |

| NOD Clause | Provision | Evidence of consistency between NOD and this Revenue Proposal |
|---|---|---|
| | [redacted] | |
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] |

# 3

# What we have heard from out customers and other stakeholders

# 3. What we have heard from our customers and other stakeholders

This chapter provides an overview of our engagement approach and activities as well as what we have heard from our customers and other stakeholders and how we have responded to their feedback in preparing this Revenue Proposal.

## 3.1. Our engagement approach and objectives

The TAC has been the primary forum for engagement on the development of this Revenue Proposal. The TAC is our executive level stakeholder forum with members representing consumer and business advocates, renewables generators and large customers. The feedback and input we receive from TAC members on major projects and strategic policy issues helps to ensure that customer and industry needs and perspectives are addressed in the decisions we make.

Following feedback from the TAC on our 2023-28 Revenue Proposal engagement, we have refined and improved our engagement approach on major projects, including ISP and NSW Electricity Infrastructure Roadmap projects. We have made several changes to our engagement approach to enhance customer outcomes and better meet stakeholder needs and expectations. In particular, we have:

- reviewed the TAC membership and governance arrangements to ensure it remains representative and fit for purpose
- consolidated the TAC to one group and scheduled monthly, rather than quarterly, meetings to allow adequate time and opportunity for feedback to be considered and addressed in our projects
- co-designed meeting agendas for each TAC
- improved the timeliness of providing briefing materials to the TAC ahead of each TAC meeting, and
- sought input and views from the TAC on key positions and proposals and invited the TAC to participate in decision making processes, where appropriate.

These changes promote a more transparent and inclusive engagement approach and more closely reflect our engagement principles, which are:

- **Genuine** – we will engage early and often, ensuring time for feedback to be considered and integrated into our projects and decision-making processes
- **Inclusive** – we will provide ongoing engagement opportunities, using various methods, to facilitate meaningful involvement in issues and projects
- **Accessible** – we will ensure our communication materials are clear, concise and easy to understand, and we will provide information materials in a timely manner
- **Responsive** – we will work with TAC members to regularly review and refine our engagement approach and processes
- **Transparent** – we will engage openly, honestly and transparently and we will demonstrate how we have considered feedback, the decisions we make and why.

## 3.2. Our engagement requirements

The AER's non-contestable Guideline sets out its expectation about how we should engage with our stakeholders on the preparation of our EII Revenue Proposals. This explains that:

> *Network Operator will use its best endeavours to engage with stakeholders ahead of submitting its revenue proposal to us. This may include, but is not limited to, consulting stakeholders on the*

> *nature of the project through to the costs that it proposes to incur to meet the requirements of the Consumer Trustee's authorisation or the Minister's authorisation or direction. We acknowledge that a non-contestable infrastructure project may have interlinkages with a contestable project that is based on extensive commercially sensitive information. We appreciate that this may constrain the ability of the Network Operator's stakeholder engagement.*

The AER also acknowledges that the timing between the Minister's authorisation or direction of a project and the due date for a Revenue Proposal is unknown and may vary between non-contestable determinations. This timing constraint, combined with constrains that may arise due to interlinkages with a contestable components of these projects, may have implications for the nature and scope of consultation that can be undertaken prior to the submission of a Revenue Proposal under the EII regulatory framework. The AER therefore acknowledges that a network operator should seek to address the engagement principles in its Better Resets Handbook on a best endeavours basis.

The AER's Better Resets Handbook sets out engagement principles covering:

- the nature of engagement
- the breadth and depth of engagement, and
- clearly evidenced impact of this engagement.

We have used these principles to measure the outcomes of our engagement as referenced in Table 3-1.

Table 3-1 Reference to Better Resets Handbook engagement outcomes

| | AER principles | Our self-assessment |
|---|---|---|
| Nature of engagement | Sincerity of engagement:<br>• High level 'buy-in' from network businesses extending from Board level<br>• Openness to new ideas and a willingness to change, and<br>• Ongoing conversation with customers about outcomes that matter to them, which allows customers to 'set the agenda'. | • Our Executive General Manager (EGM) of Corporate and Stakeholder Affairs chairs the TAC.<br>• Our CEO and other members of our Executive Leadership Team (ELT) regularly attend the TAC, at least quarterly.<br>• Our CEO and ELT facilitate an important feedback loop between the TAC, our wider ELT and Board.<br>• The TAC is an established vehicle for customer engagement that has been in place since 2016.<br>• We consulted with the TAC on the 2023 TAC Engagement Strategy.<br>• We continue to work collaboratively with TAC members on the TAC meeting program and to set monthly meeting agendas, to ensure we address issues of interest and concern.<br>• We remain open to modifying and further refining our engagement approach based on feedback from the TAC. |

| | AER principles | Our self-assessment |
|---|---|---|
| Breadth and depth of engagement | Accessible, clear and transparent engagement:<br>• Set out plans and objectives, topics, areas of influence. | Based on feedback from the TAC in 2022 about the areas for improvement in our engagement we:<br>• revised our engagement objectives<br>• increased the frequency of TAC meetings from quarterly to monthly<br>• revisited our TAC membership to ensure it properly represents customers<br>• co-designed the 2023 TAC engagement plan and remain open to changes based on feedback from the TAC, and<br>• adopted the practice of circulating materials in advance of meetings to allow time for discussion of issues following presentations. |
| Clearly evidenced impact of engagement | Consultation on outputs, then inputs:<br>• customers should be seen to guide the development of proposals i.e. consumers are consulted on what they want and how they want businesses to engage, and<br>• customers guide consultation on individual components of a proposal. | We have:<br>• identified issues that are not within our control, such as the need (driver), scope and timing of the project. These are determined by the Ministerial Order.<br>• to the greatest extent possible, aligned our positions and approaches with those approved by the AER's 2023-28 Revenue Determination, which was published on 28 April 2023. |
| | Proposal links to customer preferences:<br>• Independent customer support for the proposal. | |

## 3.3. Our engagement activity and feedback and how we have responded

### 3.3.1. Transgrid Advisory Council

As noted above, our TAC is the primary forum for engagement on our WSB Revenue Proposal. Since February 2023, we have held monthly meetings with the TAC, where members were invited to discuss and provide their views, input and perspectives on the following matters:

- the NSW regulatory framework, in particular EII Chapter 6A
- the need (driver), scope and timing for the WSB Project
- our approach to determining prudent, efficient and reasonable forecast capex, and
- our proposals and positions on key elements of this Revenue Proposal.

#### NSW regulatory framework

We discussed with the TAC that the EII Chapter 6A substantially replicates Chapter 6A of the NER and that, given the close alignment between them for most elements of this Revenue Proposal, we have aligned our positions and approaches with those approved by the AER in its 2023-28 Revenue Determination, which was published on 28 April 2023.

The TAC was generally supportive of this approach and expressed its overall support for the Revenue Determination process, which is similar to the process under the NER, notwithstanding that the timeframes are truncated. Similar to the NER process, it:

- invites stakeholder submission on our initial Revenue Proposal
- involves an AER Draft Decision on our initial Revenue Proposal
- involves us submitting a Revised Revenue Proposal, and
- requires the AER to publish its Final Decision.

The TAC acknowledged that the development of the EII Chapter 6A is led by the NSW Office of Energy and Climate Change (OECC) and is therefore outside of our control. As a result, there is little opportunity for collaboration or influence with the TAC on the nature of the regulatory framework.

Our engagement with the TAC on the regulatory framework therefore focused on informing rather than involving or collaborating.

### Need, scope and timing for the Project

We discussed with the TAC that the need (i.e., driver), scope and timing of the Project is determined by the Ministerial Order. The TAC acknowledged that, given this, decisions on these matters are outside of our control and, as a result, there is little opportunity for collaboration or influence with the TAC on these matters. Our engagement with the TAC on need, scope and timing for the Project, therefore, focused on informing rather than involving or collaborating.

### Forecast capex

We discussed with the TAC that:

- we developed our capex forecast using a bottom-up build for each category of capex, and
- more than 70 per cent of our forecast capex is based on market prices determined by our competitive procurement process described in Section 5.5.

We explained that our forecast capex is prudent and efficient, noting that it reflects our best estimate of the market-tested costs that we will incur.

The TAC was generally supportive of our forecasting approach and our forecast capex.

### Managing cost uncertainty

We discussed with the TAC three key areas of cost uncertainty during the 2024-29 period:

- **The Capital Expenditure Sharing Scheme (CESS)** – We explained that we do not support the application of the CESS to the WSB project because the uncertain operating environment conditions and project characteristics, which are beyond our control, give rise to asymmetric risk. This means the probability of overspending the AER’s capex allowance is greater than the probability of underspending it. It would therefore not be in the long-term interest of consumers to apply penalties or rewards for differences between actual and forecast expenditure where these differences are driven by factors other than true efficiency savings or losses. We invited the TAC members to share their views on whether they support our proposal or consider that the CESS should apply.

  At our meeting on 3 May 2023, a TAC member representing the Energy Users Association of Australia (EUAA) requested that we provide a summary of the pros and cons of not applying the CESS. On 25 May 2023, we circulated a paper addressing this request and discussed it at our TAC meeting on the same day. On 7 July 2023, at the TAC's request, we will hold a deep dive to further discuss this matter and better understand the TAC's views and positions.

- **Costs arising from future rounds of contestable paired generation** – At our TAC meeting on 22 March 2023, we discussed three options to address this cost uncertainty including:
  - Option 1 – forecast the cost based on the expected number and location of future paired generators and include this in our forecast capex
  - Option 2 – include a nominated cost pass-through event with no materiality threshold
  - Option 3 – include a revenue adjustment mechanism for either the entire amount of the difference between the forecast (per option 1) and the actual cost

  During the meeting, some TAC members sought clarification on proposed contract arrangements and associated risks, and whether the project would form part of our existing Regulatory Asset Base (RAB). We invited TAC members to submit any further feedback on the three options via email. However, we did not receive any responses. Nor did we receive any feedback when we revisited these issues at our next TAC meeting on 3 May. On 4 May, we emailed the TAC member seeking their feedback on these options. We did not receive any feedback from the TAC on these options.

- **Adjustment mechanisms** – At our meeting on 25 May, we outlined our approach to our proposed Adjustment mechanisms, noting that we propose to include three automatic and three non-automatic adjustments. TAC members seemed reasonably supportive of our proposal.

Table 3-2 provides an overview of the topics discussed in each of the TAC meetings for WSB. Our engagement with the TAC has provided valuable feedback to inform the development of this Revenue Proposal. We are committed to continuing to engage with our TAC on this Revenue Proposal throughout the post-lodgement period.

Table 3-2: Summary of TAC meetings, WSB engagement topics and meeting dates

<table>
<tr><th>Meeting 2023</th><th>Engagement topics</th></tr>
<tr><td>1 March</td><td>• NSW Regulatory Framework, entities and roles under the NSW roadmap<br>• Overview of WSB project - contestable and non-contestable components<br>• Status of the contestable components - SIPS (battery) and paired generation services<br>• Procurement process and timeline for network augmentation<br>• Key elements of the non-contestable revenue proposal and differences to the NER<br>• Timeframes for the non-contestable revenue proposal and determination</td></tr>
<tr><td>22 March</td><td rowspan="2">• Recap of the WSB project - contestable and non-contestable components<br>• Recap WSB project – project scope and cost categories and forecasting method<br>• Procurement process and timeline for network augmentation<br>• Application of the CESS – seeking TAC views and positions<br>• cost uncertainty arising from future rounds of contestable paired generation – seeking TAC feedback on the options presented</td></tr>
<tr><td>3 May</td></tr>
<tr><td>25 May</td><td>• Regulatory timeline - draft Revenue Proposal is due to EnergyCo on 26 May 2023<br>• Indicative capex and opex forecasts<br>• Options for addressing the asymmetric risk arising from the CESS<br>• Proposed automatic and non- automatic adjustment mechanisms</td></tr>
</table>

### 3.3.2. Pre-lodgement engagement with the AER

We have met regularly with the AER in preparing this Revenue Proposal. We have kept the AER abreast of our competitive procurement process and sought the AER's feedback and views on our draft regulatory models and key positions, including on matters that are specific to the NSW framework:

- **Audit requirements** – These are reflected in the Information Notice.
- **Financeability of the project** – On 26 April 2023, we met with AER staff to understand the AER's draft depreciation guideline principles.
- **Pre-period costs** – We discussed options for how these costs should be recorded and reflected in the PTRM and whether and, if so, the WACC that should be applied to these costs.
- **The CESS** – We reiterated our concerns with the CESS and that we consider it should not apply to this project given that this Revenue Proposal relates only to a single project, which means that we cannot re-prioritise capex across a portfolio of projects.

The AER's feedback on these matters has informed the content and structure of this Revenue Proposal and supporting models.

We also discussed with the AER the nature and scope of our engagement activity with the TAC noting the following challenges:

- this is the first non-contestable Revenue Proposal under the NSW regulatory framework
- the EII Regulations were amended in December 2022
- the AER's Guideline was only finalised in April 2023
- the tender process for the contestable works (paired generations) has not yet been finalised and it has direct implications for the non-contestable forecast capex for SIPS controls, and
- the tender process for Augex (substations and transmission line works) was only completed in May 2023.

AER staff acknowledged these challenges and accepted that, given these timeframes, it was not possible to publish a draft Revenue Proposal ahead of submitting our Revenue Proposal to EnergyCo on 26 May 2023. AER staff attended our TAC meetings to observe first-hand our engagement and hear the views and preferences of TAC members.

### 3.3.3. Pre-lodgement engagement with EnergyCo

We have met regularly with EnergyCo in preparing our Revenue Proposal, noting the:

- interrelationship with the contestable elements of the project, and
- need to meet the delivery timeframes set out in the Ministerial Order

On 26 May 2023, in accordance with the NOD, we provided EnergyCo a draft version of our Revenue Proposal. We received EnergyCo's approval of this Revenue Proposal on 20 June 2023, and have incorporated its comments relating to minor wording changes.

# 4

# Forecast opex

# 4. Forecast opex

This chapter sets out the total 2024-29 forecast opex for the Project. We have applied our approved cost allocation methodology to allocate costs between EII Act services and other services, including Transmission Services, which are subject to regulation under the NER.

## 4.1. Overview

Our total forecast opex for the Project for the 2024-29 regulatory period is $24.9 million, including debt raising costs. We have used a bottom-up-build approach to determine our forecast opex, which comprises the following categories of opex:

- **Maintenance costs** – These costs are estimated based on the routine inspection and maintenance regimes as per the current maintenance plans for substations and transmission lines or proposed maintenance plans where the equipment is new and no existing maintenance plans exist (i.e., SIPS control).
- **Operating costs** – These costs reflect the labour costs associated with meeting our obligations under the NOD, SIPS service agreement and Paired Generation service agreement.
- **Insurance expenses** – This covers the estimated premiums for [redacted] for the WSB assets, once they are commissioned.

We have also:

- applied the labour escalation rates as set out in the AER's 2023-28 Revenue Determination to account for changes to real labour costs. This required us to extend the AER's escalation rates for an additional year being 2028-29, and
- added benchmark debt raising costs, which are discussed in Chapter 7.

Table 4-1 set out our forecast opex for WSB, by category.

Table 4-1: Forecast opex for WSB ($M, Real 2023-24)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 202829 | Total |
|---|---|---|---|---|---|---|
| Maintenance costs (excluding labour escalation) | - | 0.3 | 0.8 | 0.6 | 0.3 | **2.1** |
| Operating costs (excluding labour escalation) | 3.4 | 4.1 | 4.0 | 4.6 | 4.2 | **20.2** |
| Insurance | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | **1.7** |
| Real input cost escalation | 0.0 | 0.1 | 0.1 | 0.1 | 0.2 | **0.6** |
| **Total (excluding debt raising costs)** | **3.7** | **4.8** | **5.2** | **5.7** | **5.0** | **24.4** |
| Debt raising costs | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | **0.5** |
| **Total (including debt raising costs)** | **3.8** | **4.9** | **5.3** | **5.8** | **5.1** | **24.9** |

## 4.2. Key opex assumptions

Table 4-2 details the key assumptions underpinning our opex forecasts. Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6A.1.2(6) of the EII Chapter 6A, as discussed in Chapter 12.2 of this Revenue Proposal.

Table 4-2 Opex key assumptions

| Key assumption | |
|---|---|
| Legislative and regulatory obligations | Our opex forecasts are based on our current legislative and regulatory obligations, our licence requirements, the Minister's direction on WSB, and contractual arrangement relating to WSB, in particular the NOD.[47] |
| Bottom-up-build | Our opex forecasts reflect a bottom-up build because no base year is available from a preceding regulatory period. This is discussed in Section 4.3. |
| Alignment with capex forecast | Our opex forecasts are aligned with our forecast capex to ensure that the same considerations underpinning our capex forecast are captured – albeit indirectly – in our opex forecast. This is discussed in Section 4.4.1 |
| Cost allocation and capitalisation | Our opex forecasts reflect our expenditure capitalisation policy and our CAM, which provides an appropriate basis for attributing and allocating costs to, and between, our prescribed transmission and other services. |
| Cost escalations | The cost escalations that we have applied in developing our opex forecasts are representative of the increased costs that we will incur in the next period.[48] |
| Inflation | The inflation that we have applied in developing our opex forecasts is representative of the inflation-related costs that we will incur in the next period and is consistent with the AER-preferred inflation forecasting method.[49] |
| Cost pass throughs and revenue adjustments | The AER will approve our nominated pass-through events and revenue adjustments. |

## 4.3. Pre-period opex

We commenced work on the Project in 2022-23 to ensure we could meet the commissioning dates described in Section 2.1, being:

- Interim Service Period by 1 November 2024,[50] and
- complete SIPS by 1 August 2025.

We refer to the costs that we incurred on the Project in 2022-23 and 2023-24, as pre-period costs. Table 4-3 details the pre-period opex of $3.1 million that we have and/or expect to incur. This relates to contractual arrangements with EnergyCo, the Infrastructure Planner. In particular, under the NOD we are required to make the Network Operator appointment fee payment of $3.1[51] million to the Infrastructure Planner by June 2023.

[47] In accordance with Section 4.2.1(a) of AER's WSB non-contestable information notice.
[48] Real labor cost escalators adopt the labour escalators in the AER's 2023-28 Revenue Determination. This is the simple average of forecasts provided by KPMG and BIS Oxford Economics.
[49] AER, Regulatory Treatment of Inflation, Australian Energy Regulator, December 2020.
[50] Otherwise known as the Interim SIPS
[51] The $3.0M (nominal) payment made on 16 June 2022-23 translates to $3.1 million when adjusted for inflation.

Table 4-3: Summary of opex forecast prior to the 2024–29 regulatory period (Millions, Real 2024)

| Component | 2022-23 | 2023-24 | Total |
|---|---|---|---|
| Operating and maintenance | 0.0 | 0.0 | 0.0 |
| Operations costs | 0.0 | 0.0 | 0.0 |
| Network operator payment | 3.1 | 0.0 | 3.1 |
| Insurance costs | 0.0 | 0.0 | 0.0 |
| **Opex excluding DRC** | **3.1** | **0.0** | **3.1** |
| Debt raising costs | 0.0 | 0.0 | 0.0 |
| **Opex including DRC** | **3.1** | **0.0** | **3.1** |

We have included these costs as a revenue adjustment for the 2024-25 year within the EII PTRM, consistent with the AER's guidance note on the EII PTRM.[52]

## 4.4. Opex forecasting approach

As noted above, we have applied a bottom-up-build to determine our forecast opex for the 2024-29 period.[53] We have adopted a bottom-up-build approach because:

- no base year is available from a preceding regulatory period, because this is our initial Revenue Proposal for the WSB project. This means that we are not able to apply the base-step-trend approach to forecast opex
- it is consistent with the approach used to derive our internal budget for WSB over the 2024-29 regulatory period, and
- it is consistent with the opex forecasting approach for an ISP project which would be subject to a Contingent Project Application under the National Electricity Rules (NER). The AER has accepted a bottom-up-build approach to determine forecast opex for these projects.

In determining our forecast opex we have identified and quantified:[54]

(a) the number and cost of permanent and casual staff engaged to operate and/or maintain EII regulated network assets either exclusively or on a pro rata basis as appropriate

(b) the cost of external contractors, consultants and other service providers providing operating and/or maintenance services in relation to the regulated network assets, and

(c) insurance and other ongoing expenses exclusively associated with the regulated network assets.

Table 4-4 sets out our total forecast opex by component, together with a summary of the basis of the forecast.

Table 4-4: Basis for determining forecast opex, by category ($M, Real 2023-24)

| Opex category | Value | Basis for Opex forecast |
|---|---|---|
| Maintenance costs (excluding labour escalation) | 2.1 | Current and proposed maintenance activity unit rates multiplied by projected volumes of activities |

52 See: AER, *Final Guidance note – Amendments to NER PTRM for determinations under the Electricity Infrastructure Investment Act and Regulations*, June 2023, p.9. The revenue adjustment was presented in end of year terms.

53 Our opex forecast reflects the operating expenditure objectives, criteria and factors as set out in EII Chapter 6A clauses 6A.6.6(a), 6A.6.6(c) and 6A.6.6(e), respectively.

54 In accordance with Section 5.4.1 of the AER's Non-Contestable Guideline

| Opex category | Value | Basis for Opex forecast |
|---|---|---|
| Operating costs (excluding labour escalation) | 20.2 | Projected labour requirements multiplied by labour rates for each resource type and expected annual external audit expenses |
| Insurance | 1.7 | Based on independent report from our insurance broker |
| Real input cost escalation | 0.6 | Labour escalators as set out in the AER's 2023-28 Revenue Determination |
| Debt raising costs | 0.5 | These costs are calculated in the EII PTRM by multiplying the opening RAB value for each year by a debt raising cost benchmark |
| **Total forecast opex** | **24.9** | |

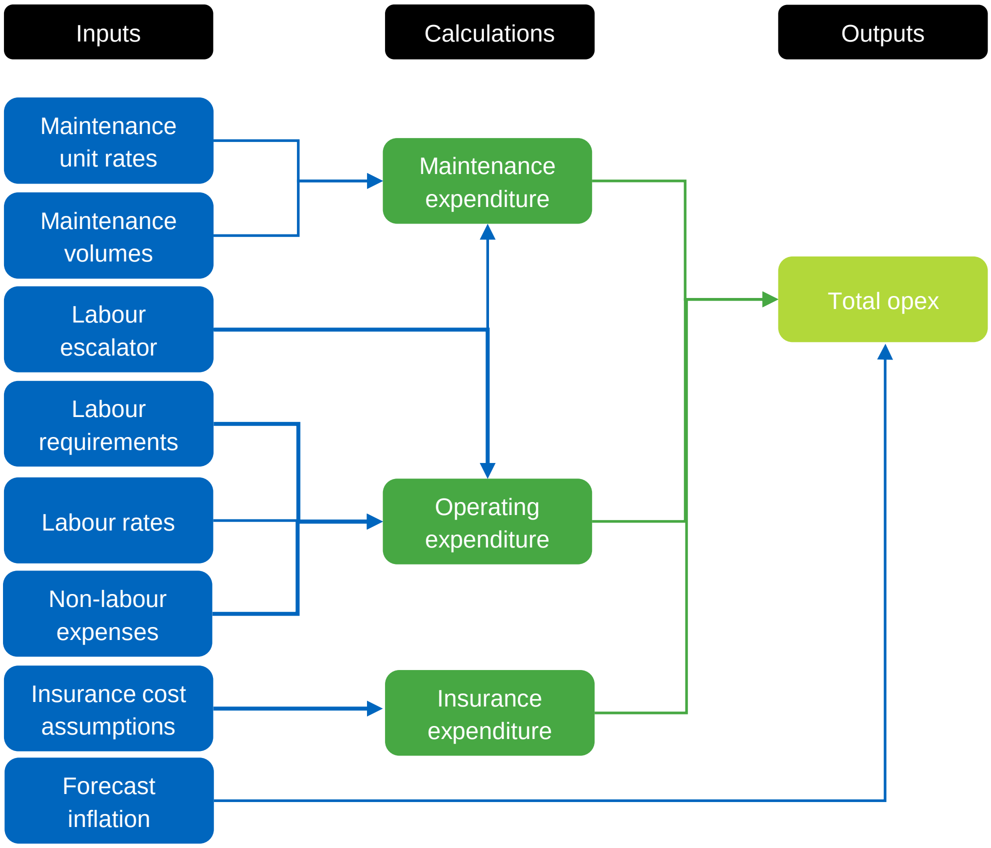
Figure 4-1 shows diagrammatically how we have determined our forecast opex for the Project, applying the following two-step process:

- **Step one** involves determining the base expenditure by:
  - multiplying unit rates by forecast volumes for maintenance activities
  - forecasting expected labour requirements multiplied by labour rates for each resource type and forecasting non-labour expenses for operating activities, and
  - basing the operational insurance premium costs on the independent expert report from Aon.
- **Step two** involves applying labour escalators to the base labour expenditure (in step one), as relevant, and adding an allowance for debt raising costs.

This bottom-up build approach reflects the following:

- existing and proposed maintenance plans and unit rates
- expected labour requirements
- expected annual audit requirements
- external input as appropriate (e.g., third-party estimates for insurance premiums), and
- real cost escalators and debt raising costs.

Figure 4-1: Process to determine forecast opex for the WSB Project




Note: debt raising costs, although a component of forecast opex, are not shown. Debt raising costs are calculated within the PTRM, as explained in our Revenue Proposal.

Our forecast opex is prudent, efficient and reasonable. This is demonstrated by the:

- rigorous, well-defined and transparent opex forecasting methodology set out in this document
- use of a bottom-up-build to forecast opex
- alignment of forecast opex with forecast capex for the Project, and
- robust approach used in determining forecast opex.

### 4.4.1. Alignment with our capex forecast for WSB

Our forecast opex aligns with our forecast capex because:

- operating and maintenance activities are assumed to begin once capital assets are installed (namely, once Interim Service Period assets are commissioned in November 2024)
- operational insurance coverage will commence[55] once the assets are commissioned, and
- debt raising costs are assumed to be incurred when new debt is required to fund capital investment.

This alignment ensures that the same considerations underpinning our capex forecast are captured – albeit indirectly – in the opex forecast.

55 [redacted].

The entire asset life cycle forms part of our ISO55000 Certified Asset Management System. This represents a shift in lifecycle phase from build to operate and maintain. The drivers, objectives and values underpinning the entire asset lifecycle are aligned across our business.

### 4.4.2. Real labour price escalation

Two components of the opex forecast, including maintenance plus operating costs, are primarily driven by labour costs. As expenditure forecasts were collected during 2022-23, in Real 2023 dollars, labour escalation needs to be applied from 2023-24 onwards.

We have adopted the labour escalators in the AER's 2023-28 Revenue Determination. This is the simple average of forecasts provided by KPMG and BIS Oxford Economics. Given that the AER's determination only includes forecasts out to 2027-28, we have extrapolated the forecast by setting the 2028-29 real labour escalator equal to the average of that adopted by the AER for 2023–24 to 2027-28.

Table 4-5: Real labour escalation forecast for the 2024–29 regulatory period

| Component | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 |
|---|---|---|---|---|---|---|
| Real labour escalation (%) | 0.39% | 1.31% | 1.15% | 0.43% | 0.30% | 0.72% |
| Real labour escalation ($M, Real 2023-24) | | 0.0 | 0.1 | 0.1 | 0.1 | 0.2 |

### 4.4.3. Maintenance costs

Maintenance costs are forecast by assessing the number and timing of expected maintenance tasks for the Project and the associated unit costs.

Maintenance activity – which underpins those costs – cover both:

- condition based or defect maintenance, and
- routine maintenance and inspection work.

We expect to incur some relatively minor routine inspection, condition based and corrective maintenance costs from 2025-26, the year following when the assets are first commissioned given the newness of the assets. Key elements of the forecast routine maintenance opex are:

- warranty inspections on circuit breakers, instrument transformers and disconnectors installed at the various northern and southern substations
- end of defects liability period transmission line inspections for new and modification structures on lines 39, 3L/4 and 5, and
- annual testing of the SIPS control, including for:
  - control units at each monitored location
  - cyber security, and
  - communications system integrity.

Forecast opex has been calculated by multiplying current standard unit rates for seven different maintenance activities by the expected quantities of these activities. Two new rates have been developed for new maintenance tasks required for the SIPS control.

Table 4-6 sets out the maintenance activities, which are assigned to four broad maintenance plan requirements.

Table 4-6: Maintenance activities

| Maintenance plan requirement | Maintenance activity |
|---|---|
| New maintenance activities | [redacted] |
| | [redacted] |
| SIPS control | [redacted] |
| Substations assets maintenance[56] | [redacted] |
| | [redacted] |
| | [redacted] |
| | [redacted] |
| Transmission line assets maintenance[57] | [redacted] |
| | [redacted] |

Table 4-7 sets out the key inputs and assumptions used to calculate the maintenance expenditure forecast.

Table 4-7: Forecast maintenance opex for WSB

| Item | Description |
|---|---|
| Unit rates | Unit rates for each maintenance activity combine both standard labour and material unit rates and:<br>• are based on standard jobs sourced from data in our accounting system (in 2022-23 dollars) and have been converted to 2023-24 dollars<br>• reflect the average actual rates of all employees assigned to labour resource categories (based on the nature of the work performed) which exclude labour on-costs and overhead costs. Actual labour rates reflect our Enterprise Agreement (EA) and individual employment contracts where the EA does not apply, and<br>• for maintenance of assets that are not currently in our fleet, are based on expected estimates to undertake the maintenance task. |
| Quantities | Quantities, or maintenance frequencies, are based on the standard frequencies outlined in our maintenance plan for each asset class under our ISO55001 certified Asset Management System (AMS) and Electricity Network Safety Management System to manage network safety risks to SFAIRP and ALARP. These include substations plant and equipment, transmission lines and SIPS control. |

56 [redacted]

| Item | Description |
|---|---|
| | The activities are assumed to start in the 2025-26 year, i.e., the year after the first assets are commissioned. |
| Real input cost escalation | Real input escalation is applied only to the labour component of the unit rates and is based on the labour escalation rates approved by the AER in its 2023-28 Revenue Determination.[58] This is described in Section 4.4.2. Consistent with the AER's determination, we have not adopted any real material escalation.<br><br>As the unit rates are current – and so assumed to be in 2022-23 dollars – real labour escalation is applied cumulatively for 2022-23 to the year in which the costs are expected to be incurred. This means, for instance, that three years of labour escalation are applied when estimating labour costs in 2025-26. |
| Assumptions | Key assumptions:<br>• no allowance has been made for non-standard assets or design, other than the SIPS control, which do not have a current standard design<br>• based on past experience defect costs have been estimated as a percentage of expected routine maintenance costs:<br>- 80 per cent for transmission lines<br>- 200 per cent for substations<br>- 300 per cent for SIPS control |

Table 4-8 sets out the forecast maintenance costs for the Project over the 2024-29 period by category.

Table 4-8: Maintenance costs forecast for WSB for the 2024-29 regulatory period ($M, Real 2023-24, excludes labour escalation)

| Maintenance costs | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Transmission lines | - | - | 0.2 | 0.3 | - | 0.5 |
| Substations | - | - | 0.2 | 0.0 | - | 0.3 |
| SIPS control | - | 0.3 | 0.3 | 0.3 | 0.3 | 1.3 |
| **Total maintenance costs** | **-** | **0.3** | **0.8** | **0.6** | **0.3** | **2.1** |

### 4.4.4. Operations costs

Operating costs are based on our expected activities to manage and meet the requirements set out in agreements for WSB, including relating to:

- the NOD
- the SIPS service agreement
- paired generation service agreements, and
- regulatory submissions.

58 Specifically, the labour escalation rates adopted by the AER in the opex model used for that 2023-28 Revenue Determination were adopted. Given that decision did not extend to 2028-29, we estimated the labour escalator for that year as the value forecast for 2027-28.

We expect to incur labour costs from 2024-25 once the first WSB assets are commissioned. Key elements of our operating costs include:

- contract management costs associated with the ongoing management and reporting of the NOD and service agreements
- network planning and network operations costs associated with monitoring and updating the SIPS control, and
- regulatory submissions for the annual adjustments associated with the SIPS and Paired Generator contestable revenue determinations, annual adjustments associated with the non-contestable revenue determination and for the preparation of our 2029-34 non-contestable revenue proposal.

Table 4-9 sets out the key inputs and assumptions used to calculate the operating costs for WSB.

Table 4-9: Operating related opex for WSB

| Item | Description |
|---|---|
| Labour resource requirements | We have forecast the expected FTE labour resource requirement for each task required to operate the SIPS, including:<br>• contract management costs averaging 4.5 FTEs in 2024-25 and 5.3 FTEs each year from 2025-26 to 2028-29 in order to address the following activities required by the NOD, SIPSA and PGSA:<br>- attending regular liaison committee meetings and to undertake regular required reporting<br>- reviewing and approving documentation, such as operating protocols<br>- calculating payments and charges<br>- annual performance tests, including use of independent engineers<br>- audit costs, and<br>- providing technical, contract/commercial support and legal SMEs and associated administrative support.<br>• an annual expense for external audit required under the SIPSA and PGSAs<br>• network planning and network operations costs associated with monitoring and updating the SIPS control averaging 0.3 FTEs in 2024-25 and 0.6 FTEs each year from 2025-26 to 2028-29<br>• preparation of<br>- within-period regulatory submissions, including for the annual adjustments associated with the SIPS and Paired Generator contestable revenue determinations and the non-contestable revenue determination averaging 0.8 FTEs from 2024-25 to 2028-29, and<br>- our 2029-34 non-contestable revenue proposal averaging 1.2 FTE in 2027-28 and 0.5 FTE in 2028-29. |
| Labour rates | Labour costing rates are the average rates calculated based on the actual rates of all employees assigned into labour resource categories including labour on-costs and overhead (or support) costs.<br>Actual labour rates are sourced from human resources (HR) remuneration and benefits team in accordance with the Enterprise Agreement (EA) and individual employment contracts where the EA does not apply.<br>Resource categories are based on the nature of the work performed. |

| Item | Description |
|---|---|
| Real input cost escalation | Real input escalation is applied only to the labour component of the unit rates and is based on the labour escalation rates approved by the AER in its 2023-28 Revenue Determination.[59] This is described in Section 4.4.2. Consistent with the AER's determination, we have not adopted any real material escalation.<br>As the unit rates are current – and so assumed to be in 2022-23 dollars – real labour escalation is applied cumulatively for 2022-23 to the year in which the costs are expected to be incurred. This means, for instance, that three years of labour escalation are applied when estimating labour costs in 2025-26. |
| Assumptions | Labour resource requirements are assumed based on estimated effort required to fulfill the requirements of the NOD, SIPSA and PGSAs. |

Table 4-10 summarises the resulting forecast for operating costs over the 2024–29 regulatory period.

Table 4-10: Operating cost forecast for WSB for the 2024–29 regulatory period ($M, Real 2023-24, excludes labour escalation)

| Operating costs | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---:|---:|---:|---:|---:|---:|
| Contract management | 2.8 | 3.4 | 3.3 | 3.3 | 3.3 | **16.0** |
| Network planning | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | **0.4** |
| Network operations | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | **0.8** |
| Regulatory submissions | 0.4 | 0.4 | 0.4 | 1.0 | 0.7 | **3.0** |
| **Total Operating costs** | **3.4** | **4.1** | **4.0** | **4.6** | **4.2** | **20.2** |

### 4.4.5. Insurance costs

We engaged our insurance broker to review the Project's materials and detail high level insurability, risk allocation and insurance financing solutions. Table 4-11 sets out the annual insurance premium forecast by our insurance broker in its report dated 13 March 2023.

Table 4-11: Insurance cost forecast for the 2024–29 regulatory period (Millions, Real 2024)

| Component | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---:|---:|---:|---:|---:|---:|
| Insurance costs | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 1.7 |

We expect to incur opex associated with insurance premiums for assets required for the Project once they are commissioned. We require three types of insurance for our infrastructure assets including those for WSB:

- [redacted]
- [redacted]

[59] Specifically, the labour escalation rates adopted by the AER in the opex model used for that 2023-28 Revenue Determination were adopted. Given that decision did not extend to 2028-29, we estimated the labour escalator for that year as the value forecast for 2027-28.

[redacted]

[redacted] Insurance cover will be required once the WSB assets are commissioned, with the first stage by November 2024 and the second stage by August 2025.

Our insurance partner has estimated the costs of insuring WSB during construction and once the assets are operational.[60] The construction phase insurance costs are included in the capex forecast (indirect costs), as explained in Chapter 5. The operational phase insurance costs are included in the opex forecast for WSB. [redacted]

Table 4-12 sets out the key inputs and assumptions used to calculate the insurance-related opex for WSB, [redacted] Full details are set out in an independent report from our insurance broker, which is provided as an attachment to this Application.

Table 4-12: Insurance-related opex for WSB

| Insurance type | Description |
|---|---|
| [redacted] | [redacted] |
| [redacted] | [redacted] |

### 4.4.6. Debt raising costs

Debt raising costs are the transaction costs incurred each time debt is raised or refinanced as well as the costs for maintaining the debt facility. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs. These costs are discussed in Section 7.8 of this Revenue Proposal.

60 [redacted] Non-contestable Project Insurance Report, 13 March 2023

# 5

# Forecast capex

# 5. Forecast capex

This chapter sets out the total 2024-29 forecast capex for the Project, which has been developed in accordance with our Expenditure Capitalisation Standard. We have also applied our approved cost allocation methodology to allocate costs between EII Act services and other services, including Transmission Services, which are subject to regulation under the NER.

## 5.1. Overview

The WSB Project has unique characteristics. It involves designing, installing, commissioning and operating:

- uprating existing transmission lines and substations. This involves:
  - uprating transmission lines 3L, 4 and 5 to operate at 85°C and line 39 to operate at 120°C. This requires augmentation of the existing transmission lines, which includes the installation of new and strengthening of existing structures and modifying insulator arrangements, and
  - uprating 22 substations from Dumaresq, near the Queensland border, down to Upper Tumut in the Snowy Mountains, near the Victorian border, to allow associated transmission lines to operate at higher ratings. This requires the replacement of HV terminal equipment and modification of secondary systems.[61]
- the SIPS control, which will monitor the transmission lines for overload conditions and when an overload is detected act accordingly to engage the SIPS (battery) and paired generation services.[62] The SIPS control will be the most complex scheme of its type installed in the NEM and will be critical to the reliability and security of the NSW power system into the future.

Our total capex forecast for the 2024-29 period is $255.4 million (Real 2023-24)[63,64] and comprises:

- $69.8 million for the transmission line network augmentation works, which comprises the uprating of transmission line 39 Bannaby to Sydney West and lines 3L/4 and 5 Yass to Marulan
- $108.4 million for the substation augmentation works, which comprises the uprating of equipment across 22 substations, of which 11 are located in Northern NSW and 11 in Southern NSW
- $19.3 million for the SIPS control works, which involves:
  - design, install and commissioning works, which will be undertaken using internal and contracted labour resources,
  - establishing a new underground fibre optic cable link between our Armidale substation and a paired generator site
  - procuring the SIPS control panels and equipment, and
  - costs associated with future rounds of paired generation being integrated into the scheme[65]
- $57.2 million for our labour and indirect costs (including real input costs), which comprises:
  - project management capex associated with setting up and managing WSB
  - construction management for augmentation works

[61] This will remove constraints on 20 transmission lines increasing the ability to transmit energy over the network.
[62] EnergyCo, Waratah Super Battery, March 2023
[63] This is development and construction capex
[64] This includes pre-period capex incurred prior to 1 July 2024
[65] We will deliver the SIPS control using internal resources due to the highly complex and highly specialised nature of the SIPS control design, installation and commissions works. These costs are included in the SIPS control cost category

- project support roles such as design, legal, commercial and environmental approvals, and
- other labour and indirect costs, such as stakeholder and community engagement and insurance costs.

- $0.7 million for equity raising costs.

The delivery of the project is required to meet the strict delivery milestones set out in the Ministerial Order:

- interim SIPS by 1 November 2024, which involves:
  - transmission line augmentation of line 39 Bannaby to Sydney West
  - substation augmentation at the 11 Northern NSW sites, and
  - designing, installing and commissioning SIPS control.
- complete SIPS by 1 August 2025, which involves:
  - transmission line augmentation of lines 3L/4 and 5 Yass to Marulan, and
  - substation augmentation at the 11 Southern NSW sites.

Table 5-1 sets out the total forecast development and construction capex for WSB by capex category and year. This includes pre-period costs that were incurred in 2022-23 and 2023-24 to ensure we can meet the commissioning dates described in Section 2.1. Section 5.3 explains our pre-period capex.

Table 5-1: Total forecast capex for WSB, including pre-period capex ($M, Real 2023-24)

| | Pre-period costs | | Total pre-period | Forecast | | | | | Total 2022-29 | Total 2024-29 |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2022-23 | 2023-24 | | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | | |
| Transmission line Augex | - | 21.7 | **21.7** | 48.1 | - | - | - | - | **69.8** | **48.1** |
| Substation Augex | - | 34.4 | **34.4** | 62.5 | 11.5 | - | - | - | **108.4** | **74.0** |
| SIPS control | 1.9 | 11.2 | **13.1** | 6.2 | - | - | - | - | **19.3** | **6.2** |
| Labour and indirect costs | 9.5 | 27.6 | **37.2** | 18.0 | 1.7 | - | - | - | **56.9** | **19.8** |
| Real input costs | - | 0.1 | **0.1** | 0.2 | 0.0 | - | - | - | **0.3** | **0.2** |
| Sub-total | **11.4** | **95.0** | **106.5** | **134.9** | **13.3** | **-** | **-** | **-** | **254.7** | **148.2** |
| Equity raising costs | - | - | - | 0.7 | - | - | - | - | 0.7 | 0.7 |
| Total capex | **11.4** | **95.0** | **106.5** | **135.6** | **13.3** | **-** | **-** | **-** | **255.4** | **148.9** |

We do not have any forecast capital expenditure for activities other than development and construction.[66] At this stage, we do not expect to undertake any development and construction capex in the subsequent regulatory control period.[67]

[66] To address clause 6A.6.7(b)(3)(iii)(B) of EII Chapter 6A
[67] To address Section 4.2 (g) (iii) of the RIN

Sections 5.6 to 5.9 explain and justify our forecast capex by category. Our capex forecast is prudent, efficient and reasonable, as demonstrated by:

- the application of our governance framework and process, discussed in an attachment to this Revenue Proposal
- a rigorous, well-defined and transparent capex forecasting methodology, discussed in Section 5.4
- the reliance on detailed scopes of work and market testing to the greatest extent possible, discussed in Section 5.4, and
- external validation of our capex forecast, discussed in Section 5.12.

## 5.2. Key capex assumptions

Table 5-2 details the key assumptions underpinning our capex forecasts. Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6A.1.1(5) of the EII Chapter 6A, as discussed in Chapter 13 of this Revenue Proposal.

Table 5-2 Capex key assumptions

| Key assumption | |
|---|---|
| Legislative and regulatory obligations | Current legislative and regulatory obligations, our licence requirements, the Minister's direction on WSB, and contractual arrangement relating to WSB, in particular the NOD. |
| Unit rates and project costs | The unit rates and project costs that we have applied in developing our capex forecasts are representative of the costs that will be incurred in the regulatory period. |
| Cost allocation and capitalisation | Our capex forecasts reflect our capitalisation policy and our CAM, which provides an appropriate basis for attributing and allocating costs to, and between, our prescribed transmission and other services. |
| Cost escalations | The cost escalations that we have applied in developing our capex forecasts are representative of the increased costs that we will incur in the next period. |
| Inflation | The inflation that we have has applied in developing our capex forecasts is representative of the inflation-related costs that we will incur in the next period and is consistent with the AER-preferred inflation forecasting method. |
| Cost pass throughs and Revenue Adjustments | The AER will approve our nominated pass-through events and Revenue Adjustments. |

## 5.3. Pre-period capex

As discussed in Section 4.3, we commenced work on the Project in 2022-23 to ensure we could meet the project commissioning dates described in Section 2.1. We refer to the costs that we incurred on the Project in 2022-23 and 2023-24, as pre-period costs. These costs relate to the following activities:

- project management of WSB, including the PDD, NOD, SIPSA and PGSAs

- assessing the feasibility of the augmentation works
- defining the scope of works for SIPS control and augmentation works
- undertaking the procurement process for the augmentation works
- procurement of equipment
- detailed design works for SIPS control, including testing, and augmentation works
- environmental approvals, community, and stakeholder engagement, and
- commencing construction works.

Table 4-3 details the pre-period capex of $106.5 million that we have and or expect to incur for the development and construction of the project.

Table 5-3: Summary of pre-period capex (Millions, Real 2024)

| Capex category | 2022-23 | 2023-24 | Total |
|---|---:|---:|---:|
| Augex | - | 56.1 | **56.1** |
| *Transmission lines* | - | *21.7* | *21.7* |
| *Substations* | - | *34.4* | *34.4* |
| SIPS control | 1.9 | 11.2 | **13.1** |
| Labour and indirect costs | 9.5 | 27.7 | **37.2** |
| **Total capex** | **11.4** | **95.0** | **106.5** |

We have included these costs within the opening asset base to be recovered over subsequent regulatory periods. Where pre-period capex is directly attributable to an asset class, such as transmission lines, we have attributed the relevant pre-period capex directly to an 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.

## 5.4. Capex forecasting methodology

We are committed to delivering the Project at the lowest sustainable cost to maximise benefits to customers. We are using our best endeavours to provide accurate forecasts of the prudent, efficient and reasonable capex of the Project. To ensure that customers are paying no more than they should be for the services that they will receive, our forecast capex reflects:

- detailed scopes of work, which have been independently assessed by GHD as discussed in Section 5.12, and
- to the greatest extent possible, market-tested costs from our competitive procurement process which has been undertaken in accordance with our compliance and governance requirements.

We expect that at least 70.8 per cent of the capex for WSB will be based on market prices obtained through competitive tender processes described in Section 5.5, which provides a high degree of confidence that our forecast capex is prudent and efficient.

Table 5-4 sets out our total capex by category and outlines the approach we have used to forecasting capex.[68]

Table 5-4: Total forecast capex for WSB by category ($M, Real 2023-24)

| Capex category | Forecasting method | Market price | Capex $M | % of total capex |
|---|---|---|---|---|
| Transmission lines | Design & Construct contract | Yes | 68.3 | 26.7% |
| | Rates from our procurement panels for key equipment | Yes | 1.4 | 0.6% |
| | Other Construction Costs | No | 0.1 | 0.0% |
| Substations | Design & Construct contract | Yes | 97.7 | 38.3% |
| | Rates from our procurement panels for key equipment | Yes | 9.6 | 3.8% |
| | Other Construction Costs | No | 1.1 | 0.4% |
| SIPS control | Forecast capex internal bottom-up build | No | 8.0 | 3.2% |
| | Quotation from our communications service provider for new fibre optic link | Yes | 1.3 | 0.5% |
| | Rates from our procurement panels for key equipment | Yes | 2.5 | 1.0% |
| | Future Paired Generation | No | 6.2 | 2.4% |
| | Other Construction Costs | No | 1.3 | 0.5% |
| Labour and indirect costs | Actual capex reflects records in Ellipse | No | 3.5 | 1.4% |
| | Forecast capex internal bottom-up build | No | 53.4 | 20.9% |
| Real input costs | Internal bottom-up build using AER's forecast real labour cost escalators | No | 0.3 | 0.1% |
| Equity raising costs | Benchmark calculation using the AER's assumptions | No | 0.7 | 0.3% |
| **Total capex** | | | **255.4** | **100.0%** |

Our capex forecast is explained and justified in the following supporting documents:

- Labour and indirect cost forecast for WSB – Attachments A.3
- Independent engineering capex verification and assessment – Attachment A.7.

[68] 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.

## 5.5. Our procurement approach

The WSB procurement process focuses on the following components that are required for the Project:

- design and construction for uprating the transmission lines and substations
- SIPS and HV plant and equipment
- design, installation and commissioning of the SIPS control, and
- construction of a new communications link for SIPS control between a paired generator site and our existing network.

We are using three broad models to procure the above components:

- **Design and construct contracts** – These will be implemented for transmission lines and substations augmentation works.
- **Directly procured assets** – We will procure SIPS control and HV plant and equipment utilising our existing panel arrangements. Some items will be provided as free issue items to the D&C contractor for the augmentation works.
- **Construction only contracts** – These have been used to establish the new communications link required for SIPS control.

Each procurement model is explained below.

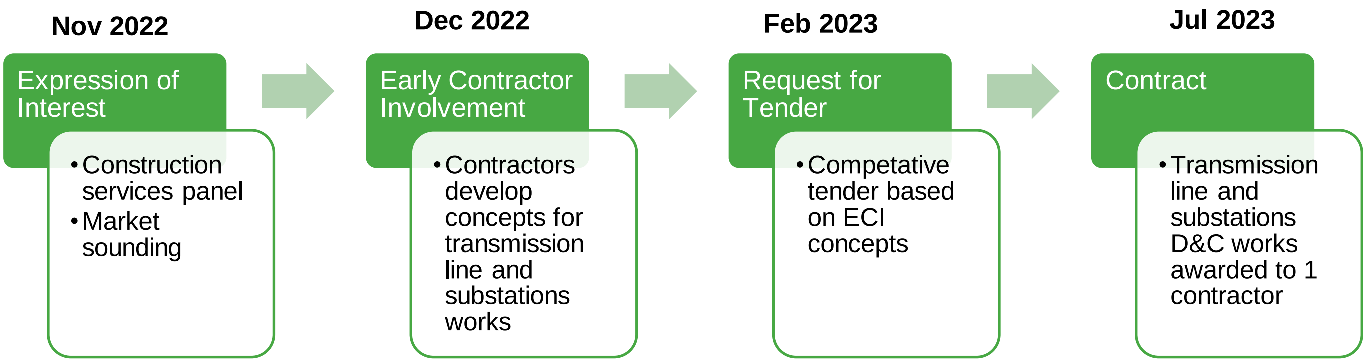
### 5.5.1. Design and construction for transmission lines and substations

To ensure we deliver the Project at the lowest sustainable, whole of lifecycle cost to maximise benefits to customers, we undertook a competitive procurement process for the design and construction of substations and transmission line augmentation works.

Overall, our procurement process is characterised by three key phases which progressively reduce risk and increase confidence in the design and construction works.

Figure 5-1 summarises at a high-level the three key stages of the procurement process, ahead of awarding contracts.

Figure 5-1: Transmission line and substations works (including SIPS installation and pre-commissioning works) procurement process



The procurement process involved three phases:

- **Expression of Interest (EOI)** – In November 2022, we invited four members of our existing construction services panel, which had previously been established using a competitive process, to participate in the EOI. We approached panel members that are well-established suppliers of transmission line and substation works. This approach is consistent with our business-as-usual (BAU) procurement policies. Due to constraints in the labour market, only one panel member, [redacted] expressed an interested in proceeding to the next phases of the tender process for both the transmission line and substation works. To maintain competitive tension, we approached other suppliers identified through our BAU market sounding activities:
  - For transmission lines, [redacted] was also invited to participate in the next stages of the process given its capability and capacity to undertake the transmission line works. Both [redacted] proceeded to the ECI stage, and
  - For substations, [redacted] was invited to participate in the next stages of the process given its capability and capacity to undertake the substations works. Both [redacted] proceeded to the ECI stage.
- **Early Contractor Involvement (ECI)** – In December 2022, we initiated the competitive ECI process with [redacted] (transmission lines and substations), [redacted] (transmission lines only) and [redacted] (substations only). We provided the three tenderers with the relevant technical requirements and information. They were each asked to undertake their own concept designs to achieve technical compliance and to specify how they would most efficiently deliver the works. The ECI allowed the tenderers to develop the necessary detail and technical solutions to respond to the RFT with their optimised scope.

  [redacted] submitted an ECI response that contained a developed scope of work. [redacted] submitted an ECI response based on a limited desktop study and [redacted] withdrew from the ECI process citing insufficient resourcing to respond but maintained its interest in being involved in the RFT.

- **Request for Tender (RFT)** – In February 2023, we issued the three tenderers ([redacted] with the competitive RFT documents and schedules:
  - [redacted] were issued with transmission lines documents and schedules, and
  - [redacted] were issued with substation documents and schedules. Due to resource constraints [redacted] subsequently withdrew from the RFT.

  To assist each of the tenderers in preparing their responses, we held several internal risk workshops to ensure all risks were allocated to the party best placed to manage the risk. Design optimisation workshops were held following the ECI stage to refine the scope to meet the need of the project. As part of the RFT process, we held meetings with both tenderers to discuss their submissions and clarifications. The project team also undertook a value engineering workshop with internal stakeholders to optimise the engineering solution for transmission line foundation and tower strengthening works. This resulted in a reduced (more efficient) scope for the required strengthening works. This enabled a lower cost solution to be adopted and reduced the program risks.

On 27 March 2023, we received submissions from two tenderers for the transmission lines and one tenderer for the substations. We assessed these offers based on our standard evaluation criteria as well as compliance with the social procurement requirements to determine the preferred contractor(s). Following the evaluation process, [redacted] offer was preferred overall taking into account all technical and commercial aspects of the offers.

Further details of the evaluation criteria are set out in our WBS RFT Evaluation Plan, provided as an attachment to this Revenue Proposal. A preferred tenderer has been identified through this process.

The outcome of the tender process is that we will engage a single supplier, [redacted] to undertake the design and construction work for both transmission lines and substation. To meet the project delivery timeframes, in June 2023 we will enter into an Early Works Agreement with [redacted] It is expected that the contract will be awarded to [redacted] in July 2023.

### 5.5.2. SIPS control and HV plant and equipment

We have existing period agreements with suppliers for HV plant and equipment and secondary systems equipment. There are generally multiple potential providers of this equipment, and we routinely enter into period agreements with suppliers using a competitive process. That is, our existing period agreements for suppliers of HV plant and equipment and secondary systems were established using competitive processes in accordance with our BAU procurement processes and policies. We will provide the HV plant and equipment that we are procuring as free issue items to [redacted] for the substations and transmission line works.

We require HV equipment for the transmission line and substation works:

- **For transmission lines** – We require insulators, which are HV equipment, to support and electrically separate the transmission line conductors from the towers. We are directly procuring the insulators required to uprate Lines 39, 3L/4 and 5 from our existing panel suppliers. We have multiple suppliers of transmission line insulators on our panel and have identified the lowest cost suppliers. All other transmission line equipment will be procured by the contractor.

- **For substations** – We require HV plant including:
  - 330 kV circuit breakers
  - 330kV current transformers
  - 330kV voltage transformers
  - 330kV disconnectors and associated earth switches
  - 330kV line traps
  - conductor for busbars, droppers and switchbay connections, and
  - insulators for installation of the equipment listed above.

  For the major components for the substation works, we have identified, through our existing period agreements and compliance requirements, the most competitive supplier having regard for lead times and delivery costs. We expect to acquire the various required HV plant and equipment components from multiple panel members.

We also require SIPS equipment to implement the SIPS control. In particular, we require control logic units and substation secondary system panels. SIPS control is developed on the basis of our Special Protection Scheme (SPS) standard designs and requires hardware from suppliers that have previously provided this equipment to Transgrid.

### 5.5.3. SIPS control Design and implementation

The complex and specialised nature of the SIPS control means that we are best placed to design and implement it, because:

- designing and programming the SIPS control require highly specialised skills and testing to ensure the integration and operation of the scheme works as intended
- we have extensive internal expertise in developing Remedial Action Schemes (RAS) using our proven standard design philosophy, which will be leveraged to achieve efficiency and reduce risks in SIPS development
- engaging an external provider to design the SIPS control would involve us providing extensive oversight and review, resulting in duplication and overlap in resources, which in turn would increase costs
- installing the SIPS control across 19 sites will involve testing and commissioning with our SCADA system. If we rely on an external provider, a high level of our Transgrid staff involvement would still be required to ensure the scheme is implemented safely and does not impact our network reliability. This is therefore a less efficient approach because it would increase the overall costs
- we are best placed to consult with AEMO on the design development, testing and commissioning of the SIPS control scheme, including interfacing of the BESS and PG
- this delivery strategy has proven to be the most efficient based on multiple Special Protection Scheme (SPS) implemented across our network, and
- the highly specialised skillset required for the implementation, testing and commissioning of this complex scheme is not readily available in the market.

We have developed a bottom-up build of the resources required to design, install, test and commission the SIPS control.

## 5.6. Transmission lines capex

The transmission line scope of work set out in the NOD requires us to uprate (i.e., increase the capacity) of three existing transmission lines to facilitate the SIPS. Table 5-5 sets out the required uprating at each transmission line based on our planning works.

Table 5-5 Transmission line augmentation work requirements

| Transmission line | Uprating requirement | Delivery date |
|---|---|---|
| Line 39 Bannaby to Sydney West | Increase capacity from 85°C to 120°C | 1 November 2024 |
| Line 3L/4 Yass to Marulan | Increase capacity from 68°C to 85°C | 1 August 2025 |
| Line 5 Yass to Marulan | | |

Increasing the operating temperature of these transmission lines means that the conductor will sag more at these higher operating temperatures, reducing conductor clearances in some sections of the transmission lines below the safe clearances in AS/NZS 7000.

These uprating requirements were provided to the ECI tenderers to develop a concept design and scope of works, which was then included in the D&C request for tender as part of the technical specification discussed in Section 5.5.

The ECI developed concept design is summarised in Table 5-6.

Table 5-6 Scope of transmission line capex works

| Transmission line | Scope quantity | | | |
|---|---|---|---|---|
| | New structure install | D string and V string install | Tower strengthening | New footings |
| Line 39 Bannaby to Sydney West | 2 suspension | 64 | 16 | 4 |
| Line 3L/4 Yass to Marulan | 8 suspension and 2 tension | 199 | 84 | 20 |
| Line 5 Yass to Marulan | 2 suspension and 3 tension | 182 | 79 | 13 |

The works will require the three transmission lines to be taken out of service to allow for safe access by construction crews. Due to network constraints, concurrent outages cannot be taken on any of Lines 39, 3L/4 and 5. Further, outages on lines 3L/4 and 5 can typically only occur in April and Spring due to the constraints that would result on the NSW to Victoria power transfer. These constraints impact the timing and scheduling of the construction works. Accordingly, the works are scheduled as follows:

- Line 39: February 2024 to November 2024
- Line 3L/4: February 2024 to October 2024
- Line 5: October 2024 to April 2025

The works for uprating lines 39, 3L/4 and 5 involve:

- contracted design and construction works, including:
  - the design works comprising detailed electrical, civil and structural engineering
  - procurement of transmission line structures and steelwork
  - erecting, installing and pre-commissioning the structures and insulator arrangements, and
  - civils works including access tracks, tower foundation works and landscaping.
- HV equipment procurement of transmission line insulators.

Through the internal risk workshops described in Section 5.5, we have identified other costs associated with construction (other construction costs or OCC) that we expect to incur in delivering the WSB Project. These activities are not in the tenderer's contract price but relate to the tendered works. The procurement process revealed that these activities either have risks that the tenderers are not able to accept or are more cost effective for Transgrid to undertake. Our OCC cost forecasting methodology, provided as an attachment to this Revenue Proposal, sets out how we have calculated the expected cost for transmission line augmentation works, which is summarised in Table 5-7.

Table 5-7: Other construction costs - transmission lines

| Other construction costs | $Million | Basis of OCC capex forecast |
|---|---|---|
| Design | 0.1 | Localised corrosion on 15 transmission line towers is expected to require remediation as part of the augmentation works. This cost is based on expected rates to remediate the 15 towers. |
| **Total** | **0.1** | |

Table 5-8 sets out our forecast capex for transmission lines which reflects the procurement process described in Section 5.5 for design and construction and HV equipment.

Table 5-8:: Summary of transmission line capex (excluding pre-period costs)[1]

| Transmission line | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Design & Construction | 47.7 | - | - | - | - | **47.7** |
| HV Equipment | 0.3 | - | - | - | - | **0.3** |
| Other construction costs | 0.1 | - | - | - | - | **0.1** |
| **Total** | **48.1** | **-** | **-** | **-** | **-** | **48.1** |

Notes: 1. Pre-period transmission line costs are $21.7 million

## 5.7. Substation capex

The substation scope of work set out in the NOD requires us to uprate (i.e., increase the capacity) of substation equipment that is currently constraining the rating of the associated transmission lines to facilitate the SIPS. Table 5-9 sets out the required uprating at each substation based on our planning works.

Table 5-9 Nature of substation capex works

| Substation | Transmission line terminal equipment for uprating at each substation | Delivery date |
|---|---|---|
| Northern substations and line 39 substations | | |
| Liddell | 81, 82, 84, 84 | 1 November 2024 |
| Newcastle | 81 | |
| Tomago | 82 | |
| Muswellbrook | 83, 88 | |
| Tamworth | 84, 85, 86, 88 | |
| Armidale | 8U, 86, 8C, 8E | |
| Uralla | 85, 8U | |
| Dumaresq | 8C, 8J | |
| Sapphire | 8E, 8J | |
| Bannaby | 39 | |
| Sydney West | 39 | |
| Southern substations | | |
| Yass | 3, 3L, 5 | 1 August 2025 |
| Canberra | 7 | |
| Stockdill | 1 (pending detailed design) | |
| Collector | 3L, 4 | |
| Marulan | 4, 5 | |

| Substation | Transmission line terminal equipment for uprating at each substation | Delivery date |
|---|---|---|
| Macarthur | 17 | |
| Avon | 17 | |
| Sydney South | 11 | |
| Dapto | 11 | |
| Upper Tumut | 1 | |
| Lower Tumut | 3, 7 | |

Table 5-9 sets out the rating of the transmission lines that are currently constrained by the thermal rating and control/protection system settings of associated substation equipment. The scope of works required to achieve the uprating involves:

- replacing existing substation equipment with equipment that has a higher thermal rating of 3,150 A or 4,000 A, and
- amending the control and protection system settings to facilitate the higher rating.

Table 5-10 sets out the scope of works required at each substation.

Table 5-10 Scope of substation capex works

| Substation | Scope of HV equipment replacement works | Scope of secondary systems modifications works |
|---|---|---|
| Northern substations and line 39 substations | | |
| Liddell | 6 Circuit Breakers, 6 Current Transformers, 2 Line Traps, 13 Disconnectors, 14 Earth Switches, Droppers and bay conductors replacement on 3 line bays | • Control, automation and protection system updates<br>• Increase current transformer ratio |
| Newcastle | 2 Circuit Breakers, 2 Current Transformers, 1 Line Trap, 1 Disconnector, 1 Earth Switch, Droppers and bay conductors replacement on 2 line bays | |
| Tomago | 1 Line Trap, 5 Disconnectors , 6 Earth Switches, Droppers and bay conductors replacement on 1 line bay | |
| Muswellbrook | Nil | |
| Tamworth | 2 Line Traps, 3 Disconnectors, 2 Earth Switches, Overhead bus, droppers and bay conductors on 2 bays | |
| Sapphire | Nil | |
| Armidale | 1 Line Trap, 1 Earth Switch, Overhead bus and bay conductors on 1 bay and droppers on 4 bays | |
| Dumaresq | Droppers on 2 bays | |
| Uralla | Droppers on 2 bays | |

| Substation | Scope of HV equipment replacement works | Scope of secondary systems modifications works |
|---|---|---|
| Bannaby | Droppers and bay conductor replacements on 1 bay | |
| Sydney West | 2 Disconnectors, droppers, bay conductors on 1 bay | |
| Southern substations | | |
| Yass | Overhead bus, dropper and 2 bay conductor replacements | • Control, automation and protection system updates |
| Canberra | 2 Circuit Breakers, 2 Current Transformers and 1 bay conductor | |
| Collector | Droppers replacement on 2 bays | |
| Macarthur | 2 Current Transformers, 1 Line Trap, 4 Disconnectors, 5 Earth Switches, Overhead bus, droppers and bay conductors | |
| Sydney South | 1 Line Trap, droppers and bay conductors on 1 bay | |
| Dapto | 1 Circuit Breaker, 2 Disconnectors, 1 Earth Switch, Overhead bus, droppers and bay conductors on 1 bay | |
| Marulan | 6 Current Transformers, 2 Line Traps, 12 Disconnectors , 14 Earth Switches, Overhead bus, droppers and bay conductors on 2 bays | |
| Upper Tumut | Overhead bus, droppers and bay conductors on 1 bay | • Control, automation and protection system updates<br>• Increase current transformer ratio |
| Lower Tumut | Overhead bus, droppers and bay conductors on 2 bays | |
| Avon | 1 Current Transformer, 1 Voltage Transformer, 1 Line Trap, 2 Disconnectors, 1 Earth Switch, Overhead bus, droppers and bay conductors on 2 bays | |

The works will require various substation equipment and transmissions lines to be taken out of service to allow for safe access by construction crews. The works are scheduled for:

- Northern substations: October 2023 to August 2024
- Southern substations: February 2024 to March 2025

The substations works involve:

- contracted design and construction works:
  - the design works comprising detailed high voltage electrical, secondary systems, civil and structural engineering and design
  - installing and pre-commissioning the new substation equipment, including civil foundation works, and
  - modification of the secondary systems at the substations.

- HV equipment including:
  - 330 kV circuit breakers
  - 330kV current transformers
  - 330kV voltage transformer
  - 330kV disconnectors and associated earth switches
  - 330kV line traps
  - conductor for busbars, droppers and switchbay connections, and
  - insulators for installation of the equipment listed above.

As noted above, through the internal risk workshops described in Section 5.5, we have identified OCCs that we expect to incur in delivering the WSB Project. These activities are not in the tenderer's contract price but relate to the tendered works. The procurement process revealed that these activities either have risks that the tenderers are not able to accept or are more cost effective for Transgrid to undertake. Our OCC cost forecasting methodology, provided as an attachment to this Revenue Proposal, sets out how we have calculated the expected cost for substation augmentation works, which is summarised in Table 5-11.

Table 5-11: Other construction costs - substations

| Other construction costs | $Million | Basis of OCC capex forecast |
|---|---|---|
| Design | 0.1 | Additional design review and coordination resources are expected to be required to manage and resolve issues arising from the large number of detailed design interfaces across the 22 substations and interface with SIPS control design on this Project. This is calculated based on the expected FTE resource requirements. |
| Procurement | [redacted] | Expected additional costs for equipment price increases, delays in equipment delivery resulting in testing and delay costs, and additional payments to meet steel delivery timeframes. This has been calculated based on FTE resource requirements, contractor disruption rates and expected equipment price changes. |
| Construction | [redacted] | The augmentation requires outages on our main 330kV network transferring power between NSW, Victoria and Queensland. We expect to incur disruption payments to the contractor resulting from short notice outage rescheduling arising due to network constraints. This has been calculated from the contractor disruption rate. |
| Contract management | [redacted] | [redacted] |
| **Total** | **1.1** | |

Table 5-12 sets out our forecast capex for substations, which reflects the procurement process described in Section 5.5 for design and construction and HV equipment for the required substation works.

Table 5-12: Summary of substations capex (excluding pre-period costs)[1]

| Substations | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Design & Construction | 60.0 | 10.9 | - | - | - | **71.0** |
| HV Equipment | 1.9 | - | - | - | - | **1.9** |

| Substations | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Other construction costs | 0.5 | 0.6 | - | - | - | **1.1** |
| **Total** | **62.5** | **11.5** | **-** | **-** | **-** | **74.0** |

Notes: 1. Pre-period costs are $34.4 million

## 5.8. SIPS control capex

The NOD requires that we deliver a SIPS control scheme, including delivery, testing and implementation of the scheme by 1 November 2024. The SIPS control scheme will:

- increase power transfer capability from regional NSW to the Sydney/Newcastle/Wollongong region under system normal conditions by relaxing dispatch constraints, allowing existing transmission lines to be more highly utilised
- monitor existing transmission lines and substations for overloads, and
- manage any overloads by controlled dispatch of the Waratah Super Battery and runback of Paired Generators.

The SIPS control scheme will interface with our system operators via our SCADA system and also interface with AEMO's dispatch engine (NEMDE).

The SIPS control scheme will comprise:

- one core logic unit which will control the scheme
- one terminal site at the WSB BESS to monitor and control the BESS
- three terminal sites, one at each of the paired generators to monitor and control the paired generators, and
- 14 network monitoring sites at existing substations in northern and southern NSW, which will monitor 37 transmission lines for overload.

The scope of works to implement the SIPS will involve constructing a new underground fibre optic communications link from one of the paired generator sites to our existing network and installing:

- the central data concentrator for the core logic unit
- a logical controller and panel in a modular building at the WSB BESS site
- a logical controller and panel in existing substation buildings at the three paired generation sites, that have already been negotiated, and establishing duplicated communications links to each site, and
- a logical controller and panel at each of the 18 network monitoring sites within existing substation buildings and establishing duplicated communications links over existing infrastructure to each site.

The SIPS control capex scope also involves designing the logic and testing and commissioning the scheme.

All components of the SIPS will be duplicated across independent No.1 and No.2 systems for redundancy.

The SIPS control will be the largest and most complex of its type in the NEM. Accordingly, to identify potential risks and their mitigants associated with developing and implementing the SIPS control we held a number of risk workshops. We determined the expected capex arising from the identified risks using the detailed probabilistic risk assessment set out in our OCC forecasting methodology provided as an attachment to this Revenue Proposal. The expected cost for SIPS control works is summarised in Table 5-16.

Table 5-13: Other construction costs – SIPS control

| Other construction costs | $Million | Basis of OCC capex forecast |
|---|---|---|
| **Design** | 0.5 | Additional design costs which are expected to be incurred due to additional requirements being discovered during detailed design, arising for [redacted]. This is calculated based on the expected costs which may arise. |
| **Construction** | 0.7 | Expected minor adjustments to equipment delivery timeframes due to supply chain issues (resulting in potentially air freighting some equipment to maintain delivery schedule), resource requirements, environmental approvals and encountering rock. This has been calculated based on the expected costs which may arise. |
| **Total** | 1.3 | |

Table 5-14 sets out our forecast capex for SIPS control which reflects the procurement process described in Section 5.5.

Table 5-14: Summary of SIPS control capex (excluding pre-period costs)[1]

| SIPS control | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Design, Installation and Commissioning | 1.1 | - | - | - | - | 1.1 |
| Equipment | 0.1 | - | - | - | - | 0.1 |
| Communications link | - | - | - | - | - | - |
| Future paired generation | 3.7 | - | - | - | - | 3.7 |
| Other construction costs | 1.3 | - | - | - | - | 1.3 |
| **Total** | **6.2** | **-** | **-** | **-** | **-** | **6.2** |

Notes: 1. Pre period costs are $13.1 million

## 5.9. Indirect and labour costs

We will incur labour and indirect capex in the delivery of WSB. These costs relate to activities that would not be incurred if we did not proceed with WSB. Our indirect capex is grouped as follows:

- **Historical indirect capex** – This is capex that we incurred on the Project from 27 October 2022 to 31 March 2023. This represents the actual costs incurred on WSB to 31 March 2023 less the $3 million provided by EnergyCo to develop the project
- **Forecast indirect capex** – We have grouped this capex into seven sub-categories:
  - **Project Management** to directly manage the Project, including various Deeds and Agreements
  - **Other support and corporate roles** to provide support for the Project including engineering and design, health and safety, legal, risk & audit and network operations

- **Transaction procurement support** to support the tender process and ongoing support of contract administrative management
- **Regulatory approvals** to provide support in preparing the revenue proposal
- **Community and stakeholder engagement** for activities associated with engaging with the community and stakeholders affected by the Project, and
- **Environment** to undertake assessments, prepare and submit environmental approvals, including stakeholder consultation.

SIPS control implementation labour and indirect costs to manage, design, construct, test and commission the SIPS control have been captured in our SIPS control capex (refer to the Design, Installation and Commissioning item in Table 5 14).

Table 5-14 sets out our forecast capex for labour and indirect capex, which reflect a bottom-up build of costs based on FTEs and external reports. We have submitted a separate document to the AER, entitled 'Labour and Indirect Costs', that provides further detail about the nature of these indirect capex categories.

Table 5-15: Summary of labour and indirect capex (excluding pre-period costs)[1]

| Capex category | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total capex |
|---|---|---|---|---|---|---|
| Labour (internal & outsourced, direct) | 11.9 | 1.2 | - | - | - | 13.0 |
| Indirect capex | 6.4 | 0.6 | - | - | - | 7.0 |
| **Total** | **18.2** | **1.8** | **-** | **-** | **-** | **20.0** |

Notes: 1. Pre period costs are $37.3 million

## 5.10. Future paired generator capex

At the time of submitting this Revenue Proposal, EnergyCo has undertaken one tender round of paired generation for WSB. [redacted]

The number of location of paired generators that will be procured in these future rounds is unknown. This means that the following costs relating to future paired generator tender rounds during the 2024-29 period are uncertain:

- managing the negotiation of the paired generation service agreement for each tender round, involving:
  - preparation of the technical specification
  - commercial negotiations, and
  - project management.
- designing, supplying, implementing, testing and commissioning the changes to the SIPS control, involving:
  - design and development works for each paired generator site
  - supply of equipment and/or services required for each paired generator site

- delivery of the site works for each paired generator site, and
- testing and commissioning of the modified SIPS control scheme to integrate the new paired generators.

[redacted]

- [redacted]
    - [redacted]
    - [redacted]
    - [redacted]
- [redacted]
    - [redacted]
    - [redacted]
    - [redacted]

[redacted]

[redacted]

| [redacted] | | | | |
|---|---|---|---|---|
| [redacted] | | | [redacted] | |
| [redacted] | [redacted] | | [redacted] | |
| [redacted] | | | | |
| [redacted] | [redacted] | | [redacted] | |
| [redacted] | | | | |
| [redacted] | [redacted] | | [redacted] | |
| [redacted] | | | | |
| [redacted] | [redacted] | | [redacted] | |
| [redacted] | | | | [redacted] |

We have forecast a total of $3.7 million for the future rounds of paired generation as shown in Table 5-17. We have also included an adjustment event to correct for differences between our forecast and actual capex for paired generation. This adjustment mechanism is discussed in Chapter 12.

Table 5-17: Forecast capex for future paired generation ($M, Real 2023-24) (excluding pre-period costs)[1]

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Future paired generation | 3.7 | - | - | - | - | **3.7** |

Notes: Pre-period costs are $2.5 million

## 5.11. Deliverability plan

We recognise that the delivery of the WSB project will be undertaken at the same time that we are delivering AEMO's ISP Projects, including Project EnergyConnect, HumeLink and VNI West, as well as our BAU work program approved by the AER in its 2023-28 Revenue Determination.

Our Deliverability Plan, provided as an attachment to this Revenue Proposal, explains how we propose to deliver the WSB Project as well as ISP Projects and our BAU capital program in a safe, reliable and efficient manner.

The nature of the substation and transmission line works align closely with our BAU work program. The speed at which this project is required is the key difference and, as such, an appropriate procurement strategy was developed to ensure the project's success.

The SIPS works are highly technical and require specialist resources to design, safely implement, test and commission whilst also maintaining network security. A suitably skilled internal team has been assembled for this.

Given our many years of experience and well-established processes backed by appropriate levels of planning and preparation, we believe we are well positioned to mitigate and optimise the delivery of the WSB Project. We are ready to deliver the future grid, with our Major Projects Business Unit, while continuing to maintain the safety, security and reliability of the existing network, with our Delivery Business Unit.

We are confident that our internal workforce and external contractors together provide the efficient level of competent and skilled resources that will enable us to deliver the forecast work program. Our Deliverability Plan explains our approach and ability to source the physical labour required to undertake the planned level of activity over the 2024-29 period.

## 5.12. Independent external validation

We engaged GHD to undertake an independent engineering verification and assessment of our capex forecast. GHD's assessment:

- verified that the scope of the Project is appropriate to meet the requirements in the Ministerial Order
- considered the reasonableness of the Basis of Preparation (BOP) detailed in the capital forecasting methodology
- assessed the accuracy and supportability of the resulting capital forecast using a range of assurance techniques. These included validation against tender results, benchmarking against comparative projects, selection testing recalculation and alignment with industry practice
- considers our capex forecast is reasonable if it is within ± 20 per cent the level of accuracy expected at this project stage taking into account the BOP and considering level of support held / developed for each capital forecast component.

Overall, GHD concluded that our forecast capex for the Project is likely to sit within ± 20 per cent which is considered to be reasonable at this stage of the project development and that our development and construction capex is prudent, efficient and reasonable. GHD's independent review therefore supports the consistency of our forecast capex with that which would be incurred by a prudent, efficient and reasonable business.

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

# 6

# RAB, depreciation, and financeability

# 6. RAB, depreciation, and financeability

This chapter sets out forecast changes in the Project's asset base and the forecast return of capital (depreciation). These are calculated within the PTRM, which is provided as an attachment to this proposal.

## 6.1. Overview

Our RAB reflects the value of assets used to deliver the Project. The opening RAB is the capitalised value of both opex and capex pre-period costs, which we incurred prior to the start of the 2024-29 regulatory period, adjusted for financing costs.

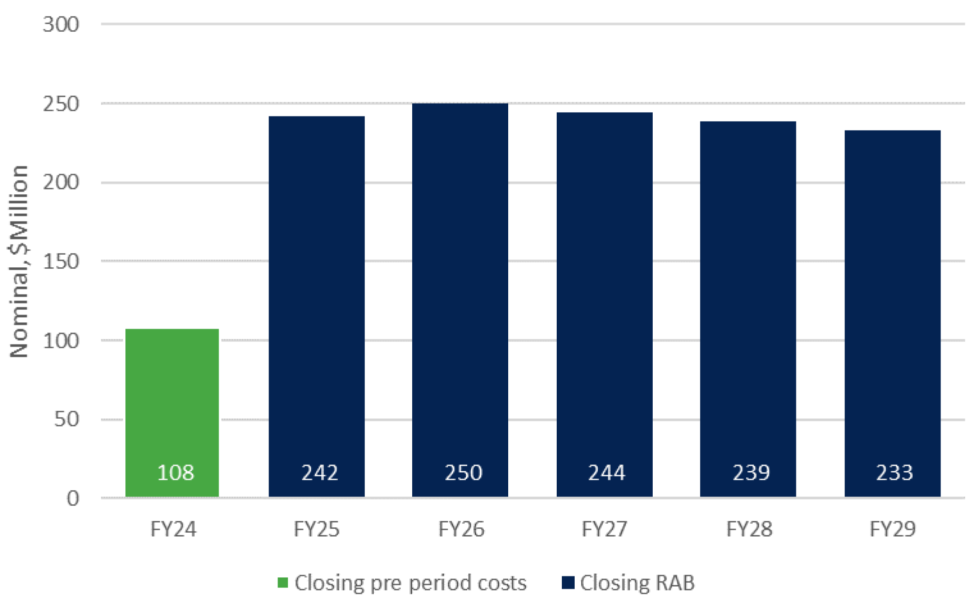
The RAB is projected over the 2024-29 period using forecast inflation, capex, and depreciation. Forecast capex and pre-period costs are allocated to asset classes that reflect the nature of the assets created. That expenditure is depreciated based on the standard economic lives that range from short-life assets, such as communications assets (with a 10-year life), to long-life assets, such as transmission lines (with a 50-year life). We have used the standard asset lives in the AER's 2023-28 Revenue Determination, with two exceptions. We have added two new asset classes, one for SIPS control and one for financeability.

The RAB value is used to calculate the revenue required to recover our efficient costs associated with the return on capital and depreciation. We propose that the value of the RAB is calculated (or rolled-forward) over the 2024-29 period consistent with the EII regulatory framework and PTRM. The RAB value is adjusted each year to reflect:

- increases due to inflation (indexation)
- increases due to new capex net of any contributions from customers or proceeds from any asset sales, and
- removal of straight- line depreciation.

Our opening RAB value in July 2024 is $108.1 million, as shown in Figure 6-1.

Figure 6-1: How the RAB changes over time (Millions, Nominal)



## 6.2. Establishing the opening RAB as at 1 July 2024

Table 6-1 sets out the opening RAB as at 1 July 2024, which is driven by:

- pre-period capex incurred in 2022-23 and 2023-24, and
- inflation and the allowed rate of return.

The opening value as at 1 July 2024 is estimated to be $108.1 million (nominal). This includes a financeability adjustment that moves $20.3 million (nominal) from the Transmission Lines, Substations and SIPS control asset classes into a dedicated 'Financeability Asset' asset class. That adjustment is discussed further in Section 6.5.

Table 6-1: Opening RAB by asset class as at 1 July 2024 (Millions, Real 2023-24)

| Asset class | Pre-period capex | Financing costs | Financeability adjustment | Opening RAB |
|---|---|---|---|---|
| Transmission Lines | 36.1 | 0.5 | (6.9) | 29.8 |
| Underground Cables | - | - | - | - |
| Substations | 57.2 | 0.9 | (10.9) | 47.2 |
| Secondary Systems | - | - | - | - |
| Communications (short life) | - | - | - | - |
| SIPS control | 13.1 | 0.2 | (2.5) | 10.8 |
| Business IT | - | - | - | - |
| Minor Plant, Motor Vehicles & Mobile Plant | - | - | - | - |
| Transmission Line Life Extension | - | - | - | - |
| Land and Easements | - | - | - | - |
| Synchronous Condensers | - | - | - | - |
| Leasehold Land and Property | - | - | - | - |
| Financeability Asset | - | - | 20.3 | 20.3 |
| Buildings - capital works | - | - | - | - |
| In-house software | - | - | - | - |
| Equity raising costs | - | - | - | - |
| **Total RAB** | **106.5** | **1.6** | **-** | **108.1** |

### 6.2.1. Pre-period capex

In order to meet the Project's commissioning dates set out in the NOD, we have undertaken activities and incurred capex prior to the commencement of the 2024-29 regulatory period. To ensure that we can recover these costs, we have incorporated them into our proposed revenue for the 2024-29 regulatory period. We have achieved this by incorporating this pre-period capex into the opening RAB for the 2024-29 regulatory period. We have also included the financing costs, which cover the time value of money over the period from when we incur the pre-period costs to 30 June 2024. As shown in Table 6-1, the estimated pre-period capex is $106.5 million.

Due to timing of the submission date for this Revenue Proposal, we have estimated the pre-period capex in 2022-23 and 2023-24. We will replace the 2022-23 estimated pre-period costs with actual expenditure in our Revised Revenue Proposal, which is due to be submitted to the AER by 9 November 2023. Pre-period opex is discussed in Section 4.3.

### 6.2.2. Financing costs

Pre-period capex was capitalised to the opening RAB, along with financing costs. As shown in Table 6-1, these financing costs are estimated to be $1.6 million. These costs have been calculated using the allowed rates of return proposed in Section 7.6, assuming that expenditure is incurred in the middle of the year. For instance, capex incurred in the 2022-23 year is adjusted by half a year of the 2022-23 rate of return and one year of the 2023-24 rate of return to determine the closing value as at 30 June 2024.

### 6.2.3. Depreciation

No depreciation is applied to the pre-period costs when establishing the opening RAB. Once added to the RAB, these costs are then depreciated on an as incurred basis.

## 6.3. Forecast RAB over the 2024–29 regulatory period

Table 6-2 sets out our forecast RAB value for each year of the 2024–29 period. We have derived the RAB values in line with the NER and using an AER's existing PTRM with minimal adjustments. Only actual and estimated capex attributable to the provision of the WSB Project in accordance with our cost allocation methodology has been included in the RAB.

We have rolled forward the opening RAB value of $108.1 million (nominal) at 1 July 2024 by:

- adding forecast indexation, which we have calculated based on the AER's December 2020 final decision on the treatment of expected inflation, which is also reflected in the AER's PTRM.
- adding forecast net-capex
- deducting straight-line depreciation, and
- deducting accelerated depreciation of the 'Financeability Asset' asset class, which returns the value of that asset over the 2024-29 period and is further discussed in Section 6.5.

Table 6-2: RAB roll forward over the 2024–29 period (Millions, Nominal)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 |
|---|---|---|---|---|---|
| Opening RAB | 108.1 | 242.2 | 250.0 | 244.3 | 238.5 |
| Forecast indexation | 3.0 | 6.7 | 6.9 | 6.7 | 6.6 |
| Net capex | 142.1 | 14.3 | - | - | - |

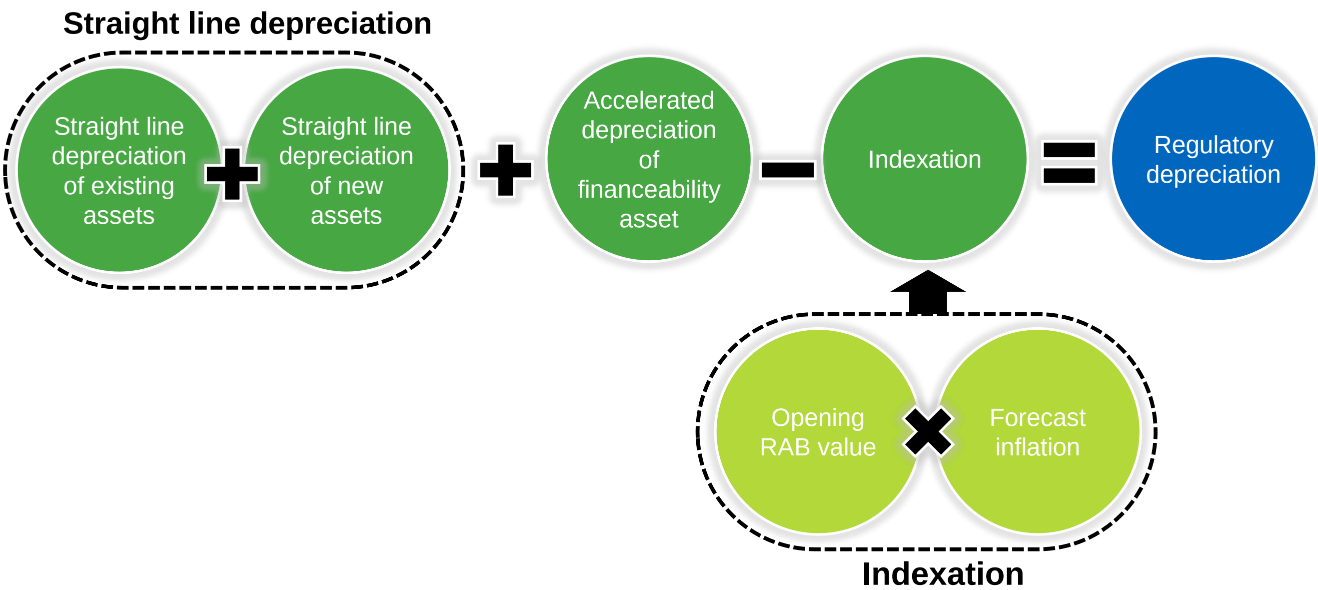
| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 |
|---|---|---|---|---|---|
| Forecast straight-line depreciation | (11.0) | (13.0) | (12.7) | (12.5) | (12.3) |
| Accelerated depreciation | - | - | - | - | - |
| **Closing RAB** | **242.2** | **250.0** | **244.3** | **238.5** | **232.8** |

## 6.4. Depreciation methodology

Depreciation is the mechanism through which we recover our expenditure on our network investments over the economic life of the assets.

We have projected depreciation using the straight-lined depreciation method. Figure 6-2 shows the AER's approach to regulatory depreciation, which is to subtract forecast indexation (which increases the RAB) from straight-line depreciation (which reduces the RAB).

Figure 6-2: How regulatory depreciation is calculated




### 6.4.1. Straight-line depreciation

We have calculated straight-line depreciation for our existing assets (as at 30 June 2024) and forecast assets for the 2024-29 period within the AER's PTRM using the straight-line depreciation method for all asset classes except for 'Financeability Asset'. As discussed in Section 6.5, we have adopted an alternative depreciation profile for that asset class. We have also applied the straight-line depreciation method to all other asset classes using as incurred capex rather than as commissioned capex.

Table 6-3 sets out our proposed standard asset lives. We propose to use the same asset classes and standard asset lives approved by the AER in its 2023-28 Revenue Determination, with two exceptions:

- A new asset class has been added for SIPS control with a standard asset life of 5.5 years.[69] We have proposed a standard life of 5.5 years because EnergyCo, as the Infrastructure Planner for the WSB

[69] The expected economic life of the asset is the period over which the asset is expected to generate economic returns.

Project, has determined that the SIPS service (battery) will only be required for the period from 1 November 2024 to 30 April 2030. In accordance with the Ministerial Direction, we will design and construct the SIPS control specifically for this purpose. At the end of SIPS Service period (30 April 2030) the SIPS control assets will not have an ongoing life. The SIPS Service Agreement does not provide for any SIPS Service Period extension for an additional term.[70] This is in contrast to the network augmentations are expected to have an economic life in line with typical regulatory and accounting depreciation policy.

- A new asset class has been added to ensure the Project is financeable (i.e., that we can efficiently obtain finance to carry out the project).[71] However, because we are proposing to accelerate the depreciation of this asset over the 2024-29 period so as to ensure that the project is financeable in each year of the period, remaining and standard lives are not required. This is discussed further in Section 6.5.

Table 6-3: Proposed asset lives (Years)

| Asset class | Remaining asset lives in years (at 1 July 2024) | Standard asset lives |
|---|---:|---:|
| Transmission Lines | 50.0 | 50.0 |
| Underground Cables | - | 45.0 |
| Substations | 40.0 | 40.0 |
| Secondary Systems | - | 15.0 |
| Communications (short life) | - | 10.0 |
| SIPS control | 5.5 | 5.5 |
| Business IT | - | 4.0 |
| Minor Plant, Motor Vehicles & Mobile Plant | - | 8.0 |
| Transmission Line Life Extension | - | 35.0 |
| Land and Easements | - | n/a |
| Synchronous Condensers | - | 40.0 |
| Leasehold Land and Property | - | 5.0 |
| Financeability Asset | n/a | n/a |
| Buildings - capital works | - | 40.0 |
| In-house software | - | 5.0 |
| Equity raising costs | - | 42.3 |

### 6.4.2. Indexation

Indexation for a given year is calculated by multiplying the opening RAB value by forecast inflation. In December 2020, the AER published its updated approach to estimating expected inflation, which is also

[70] Clause 6.3A of the Network Operator Deed sets out the limited reasons for which the SIPS Service Period End Date can be extended.

[71] In accordance with clause 6A.6.3(d) of the EII Chapter 6A. This requires the AER to modify the depreciation schedules to ensure the Revenue Determination is consistent with the objects specified in Section 3(1)(a) to (c) of the EII Act and to ensure that the Network Operator is capable of efficiently obtaining finance to carry out the network infrastructure project.

reflected in its PTRM. We have applied the AER's updated approach to estimating expected inflation in this Revenue Proposal. Our forecast inflation is addressed in the next chapter.

### 6.4.3. Regulatory depreciation

The calculation of the forecast straight-line depreciation, indexation, and regulatory depreciation is presented in Table 6-4.

Table 6-4: Forecast regulatory depreciation (Millions, Nominal)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Forecast straight-line depreciation | 3.8 | 8.3 | 8.9 | 9.2 | 9.4 | 39.7 |
| Accelerated depreciation | 7.1 | 4.7 | 3.7 | 3.3 | 2.8 | 21.7 |
| Less forecast indexation | (3.0) | (6.7) | (6.9) | (6.7) | (6.6) | (29.8) |
| Regulatory Depreciation | 8.0 | 6.4 | 5.8 | 5.8 | 5.7 | 31.6 |

## 6.5. Financeability cashflow adjustment

Projects are financeable if equity investors have confidence that they will be able to earn a reasonable return for the risk associated with the project, and that the allowed regulated cashflows associated with the project will be sufficient to support the benchmark credit rating (BBB+) at the benchmark level of gearing (60 per cent).

If these conditions are not met, then investors will not agree to commit capital to the project, even if it would be a net benefit to consumers. In the case of PTIPs such as WSB, the projects have been deemed by the State Government to be high-priority projects for the state, given the benefits those projects would deliver to consumers in NSW. It is therefore imperative that these projects remain financeable under the regulatory framework so that they proceed and deliver the expected benefits to consumers.

Consistent with the 2022 RoRI, the proposed return on capital allowance for WSB assets assumes that a benchmark efficient network operator undertaking the project would raise 60 per cent of its finance via debt at a BBB+ credit rating and maintain these benchmark financing parameters in each year of the regulatory period. Our view is that the regulated cashflows associated with the WSB project should be sufficient to support the AER's BBB+ benchmark credit rating at the benchmark gearing level of 60 per cent in each year of the regulatory period. If this does not occur, then equity investors would need to sacrifice some of their allowed return in order to ensure that the project is financeable.

We therefore propose the implementation of an objective, replicable and predictable financeability test that would determine:

- whether a financeability problem exists in any year of the regulatory period, and if so
- how much additional regulated cashflow would be required in that year to address that financeability problem.

It is essential that this test is objective, replicable and predictable financeability so that investors can be certain when committing to a PTIP project (which may be years before any financeability problem becomes apparent) that the regulatory framework will deal effectively with any financeability problem that may arise. Without this certainty, our investors cannot commit to financing and delivering PTIP projects.

To this end, we propose to address potential financeability problems associated with WSB in two ways:

- First, we propose that the depreciation allowance for this project be determined on the basis of 'as-incurred' capex rather than 'as commissioned' capex. Typically, for prescribed transmission services under the NER, a depreciation allowance would be provided only once capital assets have been commissioned. Consequently, this results in reduced cashflows being available to the provider of the prescribed transmission services during the construction of new assets, which may contribute to a financeability problem for the firm. We propose that, for WSB, the depreciation allowance would be provided on capex as it is incurred. This would deliver higher cashflows to the project in its early years and reduce the severity of any financeability problem.
- Second, we propose the implementation of an objective, replicable and predictable financeability test that would address any financeability problem that remains unaddressed even after the application of as incurred depreciation.

In relation to the second of these proposals, we engaged Frontier Economics to develop a financeability test that would provide investors with the requisite certainty to commit to PTIP projects.[72] The test developed by Frontier Economics involves applying a formula that determines the minimum extent to which the regulatory depreciation allowance would need to be increased in any given year in order to ensure that the project can support the AER's BBB+ benchmark credit rating at the benchmark gearing level of 60 per cent in each year of the regulatory period.

The formula developed by Frontier Economics is based on the criteria used by Moody's when rating regulated electricity networks in Australia and is therefore tailored to reflect the quantitative and qualitative factors that rating agencies take into consideration. The advantage of the formula is that it produces outcomes that are entirely predictable, and therefore meets the certainty requirements of investors.

The formula would not result in Transgrid earning a return on capital that is greater than the AER's allowed rate of return. To the contrary, the formula ensures that the project will be financeable in each year, and that debt and equity investors can expect to earn the allowed return set by the AER. If a financeability problem is identified, then regulated cashflows would be reprofiled to the minimum extent necessary, in an NPV-neutral manner (thus preserving the AER's NPV=0 principle). This would allow the project to be financeable, and thus unlock the expected benefits to consumers associated with the project.

To give effect to this in the EII PTRM, we have used the following steps:

1. Added a new 'Financeability Asset' asset class.
2. Populated the 'Year-by-Year Depreciation on Opening RAB' input section at the bottom of the 'PTRM input' sheet with straight-line depreciation of all asset classes except for 'Financeability Asset'.
3. Determined the minimum depreciation needed for each year over the 2024-29 period so that the regulated cashflows are just enough to meet the formula advised by Frontier Economics and input this against the 'Financeability Asset' asset class in the year-by-year depreciation inputs.

The minimum depreciation needed – which we have referred to as accelerated depreciation in the tables above – is determined on the 'Supporting information' sheet of the EII PTRM by systematically updating the depreciation inputs at row 152 so that the weighted score at row 155 is 1.

[72] Frontier Economics, A proposed financeability test for Priority Transmission Infrastructure Projects in NSW, 24 May 2023.

Table 6-5 below presents the financeability cashflow adjustment (i.e., the additional depreciation allowance required to address a financeability problem for WSB assets), after the application of as-incurred depreciation.

Table 6-5: Financeability cashflow adjustment (Millions, Nominal)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Minimum additional depreciation allowance required to maintain AER benchmark financing parameters | 7.1 | 4.7 | 3.7 | 3.3 | 2.8 | 21.7 |

Note: the accelerated depreciation input at row 152 of the 'Supporting information' sheet in the EII PTRM are in Real 2023-24 dollars. The values shown in this table and those above are in nominal dollars. As such, the $21.7 million (nominal) total depreciation shown here is equivalent to the $20.3 million noted in Table 6-1.

## 6.6. Roll forward of the 2024-2029 regulatory period

We propose to use forecast depreciation to roll-forward the RAB to the start of the regulatory period starting 1 July 2029 consistent with the approach adopted for prescribed transmission services under the NER.

# 7

# Rate of return, inflation and debt and equity raising costs



Transgrid

Transgrid

# 7. Rate of return, inflation and debt and equity raising costs

This chapter sets out our proposed rate of return, inflation, and debt and equity raising costs for the 2024-29 regulatory period. These values are reflected in the PTRM and rate of return models included as attachments to this Revenue Proposal.

## 7.1. Overview

We estimate a rate of return of 6.80 per cent for the 2024-29 regulatory period, using the AER's binding 2022 Rate of Return Instrument (RORI) and recent observable market data. The final rate of return will be calculated using updated market data.

We estimate forecast inflation of 2.75 per cent using the method included in the AER's PTRM. This inflation forecast is used to index the RAB over the 2024-29 regulatory period. The AER will update the inflation forecast in its subsequent decisions to reflect the latest available forecasts published by the Reserve Bank of Australia (RBA).

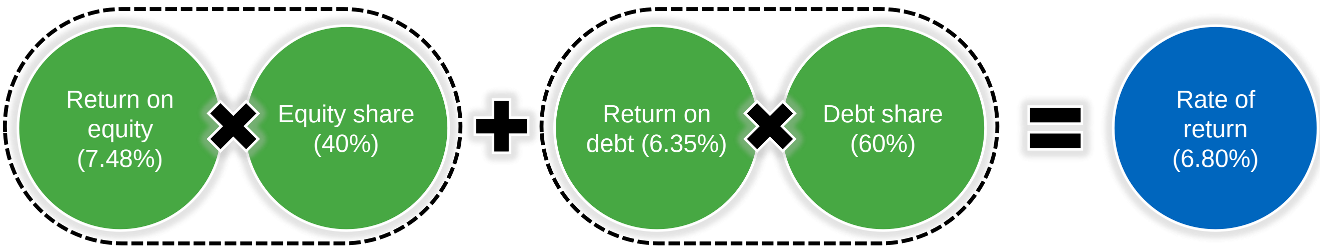
The PTRM also allows for debt and equity raising cost to compensate for efficient capital raising costs. We estimate equity raising costs of $0.7 million and debt raising costs of $0.5 million for the 2024-29 regulatory period.

## 7.2. Rate of return

The rate of return, otherwise known as the weighted average cost of capital (WACC), represents the average cost of debt and equity an efficient firm would incur to raise funds from a range of investors and capital markets to finance investments in our network. It is the return required by debt and equity investors on invested capital (the RAB) and is compensation for the risks and opportunity costs those investors bear when committing capital to the business.

The rate of return is estimated as a weighted average of the return on equity and the return on debt as shown in Figure 7-1.

Figure 7-1: Our proposed rate of return




We have used placeholder averaging periods to estimate market observable parameters, as follows:

- risk-free rate parameter: 17 February to 16 March 2023, and
- prevailing return on debt: 5 to 16 December 2022.

These are same averaging periods used by the AER to determine the rate of return adopted in its 2023–28 Revenue Determination.

As discussed in Section 7.5, the final rate of return and annual updates to it for the 2024-29 regulatory period will be determined to reflect the averaging periods as agreed with the AER.

Our return on capital allowance is calculated by multiplying the rate of return and the value of our opening RAB in each year of the regulatory period. Forecast return on capital is shown in Table 7-1.

Table 7-1: Forecast return on capital (Millions, Real 2023-24)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Opening RAB | 108.1 | 235.7 | 236.8 | 225.2 | 214.0 | |
| Rate of return (%) | 6.80% | 6.80% | 6.80% | 6.80% | 6.80% | |
| **Return on capital** | 7.2 | 15.6 | 15.7 | 14.9 | 14.2 | **67.5** |

## 7.3. Return on equity

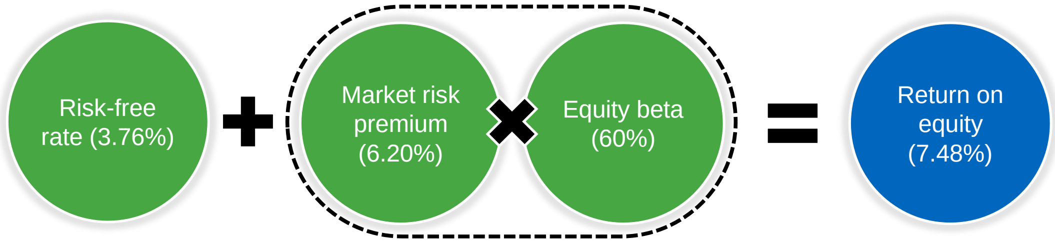
The return on equity is the return required by equity investors to provide equity capital.

We propose a return on equity of 7.48 per cent calculated in accordance with the 2022 RORI. In particular, we have used the Sharpe-Lintner Capital Asset Pricing Model, which, as shown in Figure 7-2, combines a risk-free rate parameter with the product of the market risk premium and equity beta.

We have adopted the value in the 2022 RORI for market risk premium (6.20 per cent) and equity beta (0.6). We have estimated the risk-free rate parameter using yields on Commonwealth Government Securities observed over the 20 trading days to 16 March 2023 to be 3.76 per cent.

This is a placeholder estimate of the risk-free rate for the purpose of this Revenue Proposal. The AER will calculate our actual risk-free rate using the method outlined in Clauses 7 and 8 of the 2022 RORI as well as our nominated averaging period, which is provided as an attachment to this Revenue Proposal.

Figure 7-2: Our proposed rate of equity




## 7.4. Return on debt

The return on debt is the return required by debt investors for lending funds to invest in new assets and continue financing existing assets.

As required by the 2022 RORI, the return on debt is calculated as a trailing average of past return on debt observations. Given that the 2024-29 period will be the first for the regulatory services provided by the WSB assets, the 2022 RORI requires that we transition over a 10-year period from an on-the-day estimate of the return on debt to a 10-year trailing average. This means that we will commence the 10-year transition to the full trailing average in 2024-25.

Our estimate of the return on debt for the first year of the 2024-29 period is 6.35 per cent and has been calculated using the methodology in the AER 2013 Rate of Return Guideline. The 2024-25 observation is a placeholder until actual market data becomes available for the averaging period approved by the AER in its final decision for the 2024-29 period.

In line with the 2022 RORI, the 2024-25 observation is to be calculated using corporate bond data published by Bloomberg, the Reserve Bank of Australia, and Refinitiv (previously Thomson Reuters).

## 7.5. Averaging periods

As required by the 2022 RORI, we must propose averaging periods that the AER will use to update the market observable parameters used to estimate the return on equity and return on debt. The AER will calculate our actual risk-free rate using the method outlined in the 2022 RORI as well as our nominated averaging periods, provided as an attachment to this Revenue Proposal.

As discussed in Section 12.2, we propose updating the quarterly payment schedule each year to reflect updates to the return on debt using the approach set out in the 2022 RORI and the return on debt averaging periods approved by the AER. This is similar to the process that applies annually to prescribed transmission services.

## 7.6. Rate of return applied to pre-period costs

As discussed in Section 6.2.2, we propose including financing costs when capitalising opex and capex incurred prior to the 2024-29 regulatory period (i.e., 'pre-period expenditure') into the opening RAB. Since there was no mechanism by which these pre-period expenditures could have been recovered before the commencement of the regulatory period, a benchmark efficient business in Transgrid's circumstances would have needed to finance those costs and recovered them in future periods. The associated financing costs are prudent, efficient and reasonable and should therefore be recoverable by Transgrid over future regulatory periods.

Therefore, we propose to include a return on capital based on the nominal vanilla WACC for capex incurred in 2022-23 and 2023-24. This pre-period expenditure, and the return on it, would be capitalised into the opening RAB as at 1 July 2024, being subject to the 2024-29 determination at that point in time.

Section 37 of the EII Act requires the AER to take into account the principle that "a network operator is entitled to recover the prudent, efficient and reasonable costs incurred by the network operator for carrying out the infrastructure project." Reflecting this requirement, we consider that the following principles should be adopted when determining the rate of return applied to the pre-period expenditures in 2022-23 and 2023-24:

- the return that is capitalised in each year should reflect the cost of capital that would be incurred by a benchmark efficient service provider in that year – no more, and no less. Setting the allowed return in accordance with the benchmark efficient cost of capital is consistent with the NPV=0 principle and is in the long-term interests of consumers
- for this purpose, a benchmark efficient service provider is one that follows the financing approach that underpins the AER's 2022 RORI
- the return that is capitalised each year should be estimated as the nominal vanilla WACC using the same formula as underpins the AER's 2022 RORI

- WACC parameters should be estimated in a way that is consistent with the approach adopted in the AER's 2022 RORI, reflecting the relevant market data at the beginning of each year of capitalisation. This consistency is achieved as follows:
  - where the RORI adopts a fixed number for a particular parameter, that fixed number should be used, and
  - where the RORI adopts an approach for using prevailing market data, that approach should be applied to the market data as at the beginning of each relevant year.

The application of those principles to the pre-period expenditure is as follows:

- Gearing should be set to 60 per cent, the fixed figure that is adopted in the 2022 RORI.
- The allowed return on equity should be determined by setting:
  - the market risk premium to 6.2 per cent, the fixed figure adopted in the 2022 RORI
  - setting equity beta to 0.6, the fixed figure adopted in the 2022 RORI, and
  - setting the risk-free rate equal to the yield on 10-year Commonwealth government bonds, measured over the averaging period at the start of the relevant capitalisation year.
- The allowed return on debt should be determined in accordance with the benchmark efficient debt management approach that is adopted in the 2022 RORI. The RORI allowance is based on a prudent and efficient benchmark service provider issuing 10-year debt with a BBB+ credit rating, with the relevant yields taken from a pre-determined averaging period for each year. For the purpose of capitalising pre-period expenditure, the allowed return on debt should be calculated as follows:
  - for capex incurred in 2022-23, 60 per cent is taken to be financed with debt. The allowed return on that tranche of debt should be taken as the prevailing yield on 10-year BBB+ debt over the averaging period for 2022-23. That same allowed return on debt should be maintained for that tranche of debt over 2023-24, and
  - for capex incurred in 2023-24, 60 per cent is taken to be financed with debt. The allowed return on that tranche of debt should be taken as the prevailing yield on 10-year BBB+ debt over the averaging period for 2023-24.
- The allowed return on debt for this purpose cannot be set using an historical trailing average at the time this new debt is issued. This is because it is <u>new</u> debt for a major new project that requires its own determination. A 10-year historical trailing average allowance assumes that the regulated business already has in place a debt portfolio of 10-year staggered maturity debt. This would not be the case for a benchmark efficient service provider delivering the WSB, since this is a new project for which there was no pre-existing finance. Since it is impossible for the proponent to 'go back in time' and issue this debt at historical rates, any debt finance related to the pre-period expenditure must be issued at the market rates prevailing in the years in which that expenditure was incurred.
- Further, it is not the case that there is some source of 'general corporate debt' that can be used for this new project. All debt within our PTRM is already allocated to existing assets, so there is no surplus available for such major new projects.

The above methodology for capitalising returns for 2022-23 and 2023-24 best reflects an application of the 2022 RORI and the AER's assessment of the efficient financing practice of a benchmark efficient service provider that underpins the 2022 RORI. The resulting rates of return are shown in Table 7-2 below.

Table 7-2: Rates of return applying to pre-period costs (percent)

| Parameter | 2022-23 | 2023-24 |
|---|---|---|
| Return on equity | | |
| Averaging period | 10 February to 9 March 2022 | 17 February to 16 March 2023 |
| Risk-free rate | 2.20% | 3.76% |
| Market risk premium | 6.20% | 6.20% |
| Equity beta | 0.60 | 0.60 |
| Return on equity | 5.92% | 7.48% |
| Return on debt | | |
| Averaging period | 3 to 16 December 2021 | 5 to 16 December 2022 |
| Observation | 3.65% | 6.35% |
| Return on debt | 3.65% | 6.00% |
| Leverage | 60.00% | 60.00% |
| **Nominal vanilla WACC** | 4.56% | 6.59% |

Applying these rates of return to the pre-period costs produces a capitalised RAB as at 30 June 2024, at which point the rate of return adopted in the regulatory determination for the 2024-29 period takes effect.

## 7.7. Forecast inflation

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

We have calculated forecast inflation based on the AER's December 2020 final decision on the treatment of expected inflation, which is also reflected in the AER's PTRM. This is based on the geometric mean of:

- either one or two years of forecast inflation published by the RBA in its most recent Statement on Monetary Policy, depending on the availability of the RBA's forecasts, and
- three or four years transitioning to the midpoint of the RBA's inflation target, of 2.5 per cent.

As shown in Table 7-3, we have forecast inflation of 2.75 per cent per annum by applying this method and using the RBA's May 2023 Statement on Monetary Policy. Our rate of return and PTRM models provided as attachments to this Revenue Proposal sets out the detailed calculations of forecast inflation.

Table 7-3: Proposed inflation forecast (Percent)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 |
|---|---|---|---|---|---|
| | RBA Forecast | Linear transition to 2.5% | | | |
| Inflation forecast (%) | 3.00% | 2.88% | 2.75% | 2.63% | 2.50% |
| Geometric average (%) | 2.75% | | | | |

## 7.8. Debt and equity raising costs

Debt and equity raising costs reflect the costs we incur when raising debt and equity capital from external investors, and include agency, placement, arrange, legal, credit rating, and registration fees, and roadshow costs.

We have adopted the AER's preferred approaches and parameters to estimate these costs for a benchmark efficient business (rather than our actual costs), as described in Table 7-4. Our PTRM provided as an attachment to this Revenue Proposal sets out the detailed calculations of our debt and equity raising costs.

Table 7-4: Debt and equity raising cost estimation approaches and assumptions

| Component | Approach and assumptions |
|---|---|
| Debt raising costs | Debt raising costs are calculated for each year of the 2023-28 period by multiplying the opening RAB value for the year by a unit rate.<br>We propose adopting a unit rate of 8.28 basis points per annum as a placeholder, which is the value adopted by the AER in its 2023-28 determination for our prescribed transmission services. We anticipate that the AER will update this unit rate as part of its decision making to reflect the higher benchmark that would be expected to apply to projects like WSB with much smaller debt raising needs. |
| Equity raising costs | Equity raising costs are estimated in two steps:<br>• first, the PTRM calculates the share of earnings paid out and then reinvested and the uses these values – along with forecast cash flows – to determine how much additional equity is needed to maintain a 60 per cent leverage ratio<br>• second, the PTRM calculates the costs of the various funding sources, namely retained earnings, reinvested dividends, and equity offerings.<br>To apply this method, we propose adopting the parameters that the AER adopted for the 2023-28 period:<br>• imputation payout ratio (or earnings payout ratio) – of 87.87 per cent per dollar of income generated<br>• dividend reinvestment plan take up – of 30 per cent of each dollar paid out as dividends<br>• subsequent equity raising cost – of 3 per cent per dollar of equity raised in a subsequent equity raising, and<br>• dividend reinvestment plan cost – of 1 per cent per dollar of equity reinvested. |

Applying these approaches and assumptions gives the debt and equity raising cost forecasts set out in Table 7-5. Consistent with recent AER decisions, we treat debt raising costs as opex and equity raising costs as capex.

Table 7-5: Forecast debt and equity raising costs (Millions, Real 2024)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Debt raising costs | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.5 |
| Equity raising costs | 0.7 | - | - | - | - | 0.7 |

# 8

# Estimated cost of corporate income tax

# 8. Estimated cost of corporate income tax

This chapter sets out our forecast tax allowance for the 2024-29 period and how we have calculated this allowance.

## 8.1. Overview

We have calculated our income tax allowance using the AER's revised approach to the treatment of regulatory tax published in 2018 and subsequently reflected in its PTRM. We have used this to develop the EII PTRM for WSB, which is included as an attachment to this Revenue Proposal.

The approach applies the corporate tax rate of 30.0 per cent less the value of imputation credits (gamma) of 57.0 per cent of forecast tax payable set out in the 2022 RORI.

The approach also:

- recognises immediately expensing capex, and
- applies a diminishing value depreciation method when calculating tax depreciation to most asset classes rather than the straight-line method.

Our forecast tax allowance for the 2024-29 period is $1.6 million.

## 8.2. Forecast income tax allowance

This Revenue Proposal includes an allowance for tax costs consistent with the AER's revised method for the regulatory treatment of tax as reflected in the EII PTRM and the value of imputation credits (0.57) in the AER's 2022 RORI.

Under clause 6A.6.4 of the EII Chapter 6A, the forecast income tax allowance for a given year is calculated by multiplying estimated taxable income for that year by the expected statutory income tax rate and by 1 less the value of imputation credits. We have applied the statutory income tax rate of 30.0 per cent in the AER's PTRM.

Figure 8-1 shows the calculation of the corporate tax allowance which multiplies forecast taxable income by the statutory corporate tax rate and then deducts the assumed value of imputation credits. As shown, forecast taxable income is calculated as revenue less taxable expenses. Taxable expenses include the forecast operating costs less forecast tax depreciation less interest costs (based on the cost of debt).

Figure 8-1: How the tax allowance is calculated

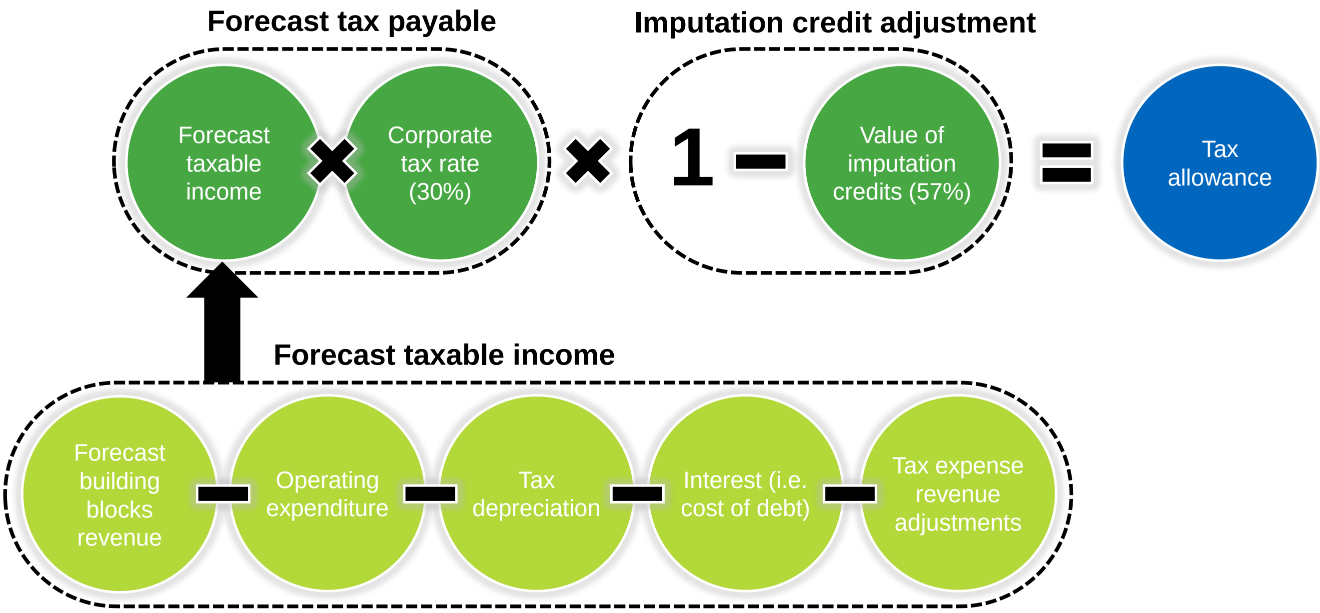



Table 8-1 sets out our forecast tax allowance for the 2024-29 period calculated using the AER's PTRM. Our forecast tax allowance comprises 1.27 per cent of our total building block costs (in real terms).

Table 8-1: Forecast income tax allowance (Millions, Real 2023-24)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Building block revenue | 23.1 | 26.7 | 26.4 | 26.1 | 24.5 | **126.8** |
| (-) Operating expenditure | (3.8) | (4.9) | (5.3) | (5.8) | (5.1) | **(24.9)** |
| (-) Tax depreciation | (4.3) | (12.2) | (11.5) | (10.5) | (9.6) | **(48.2)** |
| (-) Interest (i.e. cost of debt) | (4.0) | (8.7) | (8.8) | (8.3) | (7.9) | **(37.8)** |
| (-) Tax expense revenue adjustments | (3.4) | - | - | - | - | **(3.4)** |
| Taxable income | 7.6 | 0.8 | 0.8 | 1.5 | 1.8 | **12.5** |
| (x) Corporate tax rate (%) | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | **30.00%** |
| Tax payable | 2.3 | 0.2 | 0.2 | 0.4 | 0.5 | **3.7** |
| (-) Value of imputation credits (57%) | (1.3) | (0.1) | (0.1) | (0.2) | (0.3) | **(2.1)** |
| **Estimated cost of corporate income tax** | **1.0** | **0.1** | **0.1** | **0.2** | **0.2** | **1.6** |

## 8.3. Forecast tax depreciation

Forecast tax depreciation is an input to calculating forecast taxable income, which is calculated within the EII PTRM. The regulatory calculation of tax depreciation depends on:

- the value of the regulatory tax asset base (TAB) as at the commencement of the 2024-29 regulatory period (1 July 2024)
- immediately expensed capex, and
- standard and remaining tax lives.

Given that only as-commissioned capex is depreciated for tax purposes and the assets created by the WSB project are not expected to be commissioned until well into the 2024-29 regulatory period, the opening TAB is expected to be $104.1 million as at 1 July 2024.

Unlike the RAB, the regulatory TAB includes the value of capital contributions (which are expected to be small). These contributions attract a tax liability that we will pay, as well as tax expenses that we can claim over the life of the assets.

## 8.4. Tax asset lives

Table 8-2 sets out the proposed depreciation approach and standard asset lives for each asset class over the 2024-29 regulatory period. Given that there is no opening value for the TAB, there is no need to nominate remaining tax lives.

The depreciation approach and standard asset lives match those adopted by the AER in its 2023-28 revenue determination for Transgrid's prescribed transmission services.

Table 8-2: Proposed depreciation method tax asset lives (Years)

| Asset class | Depreciation method | Standard tax asset lives |
|---|---|---|
| Transmission Lines | Diminishing value | 50.0 |
| Underground Cables | Diminishing value | 45.0 |
| Substations | Diminishing value | 40.0 |
| Secondary Systems | Diminishing value | 15.0 |
| Communications (short life) | Diminishing value | 10.0 |
| SIPS control | Diminishing value | 5.5 |
| Business IT | Diminishing value | 4.0 |
| Minor Plant, Motor Vehicles & Mobile Plant | Diminishing value | 8.0 |
| Transmission Line Life Extension | Diminishing value | 35.0 |
| Land and Easements | Diminishing value | n/a |
| Synchronous Condensers | Diminishing value | 30.0 |
| Leasehold Land and Property | Diminishing value | 5.0 |
| Financeability Asset | n/a[73] | n/a |
| Buildings - capital works | Straight line | 40.0 |
| In-house software | Straight line | 5.0 |
| Equity raising costs | Straight line | 5.0 |

[73] Although the 'Financeability Asset' asset class is established in the opening RAB, we are not proposing to apply that adjustment to the TAB.

## 8.5. TAB roll forward over the 2024-29 period ($Millions, $Nominal)

Table 8-3 shows the forecast regulatory TAB for the 2024-29 period including the impact of immediately expensed capex. Tax depreciation starts in 2024-25. Given the newness of the assets, no disposals are forecast for the 2024–29 regulatory period.

Table 8-3: TAB roll forward over the 2024-29 period ($M, Nominal)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 |
|---|---|---|---|---|---|
| Opening TAB | 104.1 | 239.0 | 240.1 | 227.6 | 215.9 |
| Gross capex (as incurred) | 139.3 | 14.0 | - | - | - |
| Immediate expensing of capex | - | - | - | - | - |
| Asset disposals | - | - | - | - | - |
| Depreciation | (4.4) | (12.9) | (12.5) | (11.7) | (11.0) |
| **Closing TAB** | **239.0** | **240.1** | **227.6** | **215.9** | **204.9** |

# 9

# Incentive schemes



Transgrid

# 9. Incentive schemes

This chapter sets out our proposal in relation to the application of incentive schemes to the WSB project in the 2024–29 regulatory period.

## 9.1. Overview

Incentive regulation key feature of both the NER and the EII regulatory frameworks. The AER's incentive schemes are intended to promote efficient cost and service performance over time. We support incentive regulation where it will be effective, given the particular circumstances of the project.

The AER's non-contestable Guideline explains that the AER intends to:

- apply the same expenditure incentive schemes, being the Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) that currently apply under the NER
- develop an EII specific Service Target Performance Incentive Scheme (STPIS), which would apply only from the second regulatory control period. This would not apply to the WSB Project in the 2024-29 regulatory period, and
- not apply either the NER small-scale incentive scheme or the demand management innovation allowance mechanism, consistent with the requirements of EII Regulation 47A(5).

We agree with the AER's position, with the exception of the proposed application of the EBSS and the CESS. We do not support the application of the EBSS and CESS to NSW Roadmap or AEMO's ISP projects.

The following sections explain our position on the CESS, EBSS and STPIS.

## 9.2. CESS

As previously discussed with the AER, we consider the application of the CESS to PTIPs including the WSB project (as well as AEMO's ISP projects) should be considered in the context of the overall risk associated with these projects.

In a stable and predictable operating environment with routine BAU investment across a portfolio of projects and programs, the CESS encourages transmission network service providers (TNSPs) to reduce their actual capex below the AER's total allowance. In these circumstances the CESS drives innovation, efficiency and the lowest possible prices for customers. This outcome requires that:

- a TNSP can reprioritise its capex across many projects and programs
- the capex is routine and stable BAU investment
- there are panel agreements in place which offer price certainty, and
- a TNSP has an equal probability of under (over) spending the AER's capex allowance.

In contrast, in an uncertain and inflationary operating environment the probability of overspending the AER's capex allowance is greater than the probability of underspending it. That is, for PTIP (and ISP) projects such as WSB, the CESS introduces asymmetric risk as a result of factors that are beyond our direct control because:

- we are being directed to undertake these projects in accordance the Ministerial Order and the NSW Electricity Infrastructure Roadmap (AEMOs ISP), which prescribe tight delivery timeframes. This is discussed in Chapter 2
- the projects are high value complex or specialised and cannot be re-prioritised across a portfolio of projects and programs
- the market is inflationary and uncertain due to increasing labour and materials costs, the inflation outlook remains uncertain and contractors are unwilling or unable to offer fixed price contracts.

**No ability to re-prioritise costs across a portfolio of projects and programs**

Under the EII regulatory framework, each project is subject to its own revenue determination. This is in contrast to the arrangements under the NER which relates to our entire capital portfolio for the regulatory period. As such, there is no opportunity to re-prioritise expenditure over a portfolio of projects in the same way as is possible under the NER. That is, there is no ability to offset any increase in costs for the WSB Projects, because the AER's Determination relates to the WSB project only.

**Increasing labour and material costs**

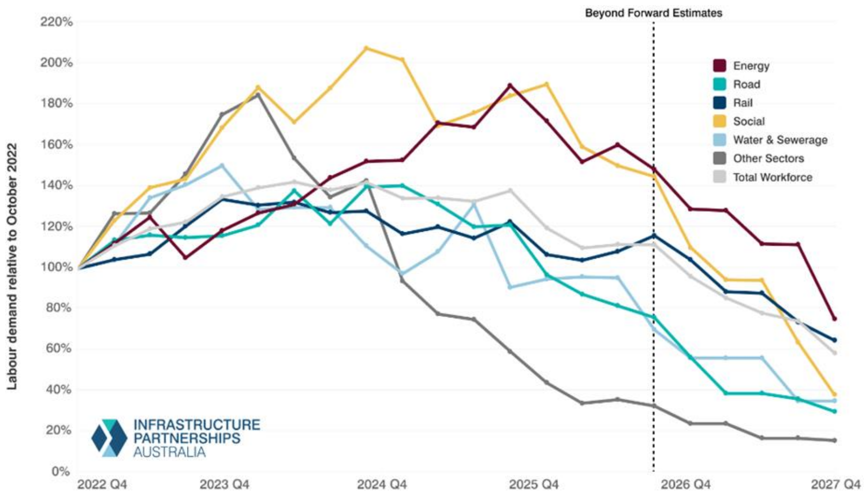
Labour costs are increasing due to the surge in infrastructure projects and the demand for construction workers, engineers and other skilled professionals required to deliver these projects, which include:

- the Commonwealth and State Government infrastructure investment programs including hospitals, road upgrades, bridge construction, and water infrastructure projects
- large transmission projects on AEMO's Optimal Development Path (OPD), the NSW Electricity Infrastructure Roadmap and other state governments agendas, including:
  - Project EnergyConnect, VNI West, Marinus Link, Sydney Ring
  - NSW Government's Renewable Energy Zones (REZs) such as Central-West Orana REZ, New England REZ or Hunter-Central Coast REZ, and
  - CopperString, which is supported by the Queensland Government and is being built by Powerlink in north Queensland

The IPA forecasts that the infrastructure labour force in NSW will be required to grow by 56 per cent by 2024 to deliver the pipeline of infrastructure projects across NSW and Australia.[74]

[74] Infrastructure Partnerships Australia (IPA), Infrastructure Election Monitor NSW – Red Book, Figure 3

Figure 3: Forecast Labour Demand of the Australian infrastructure pipeline over the next five years




Source: Infrastructure Partnerships Australia

The cost of materials required to build PTIP and AEMO's ISP projects is also soaring and volatile due to:

- the surge in surge in construction activity globally
- supply chain disruptions resulting in materials shortages
- the war in Ukraine driving up fuel costs, and
- fluctuations in global commodity market prices for raw materials, such as steel, concrete, copper and aluminium due to geopolitical factors, trade policies and supply disruptions.

**The inflation outlook remains uncertain**

As explained in our 2023-28 Revised Revenue Proposal (for prescribed transmission services) to the AER, there has been considerable and unexpected changes in actual inflation since May 2021.[75] Over the 12 months ending June 2022:

- headline CPI increased by 6.1 per cent over the 12 months ending June 2022, the highest year-ended CPI inflation since the early 1990s.[76] The Reserve Bank of Australia forecasts CPI inflation of 6.3 per cent for the year to June 2023, which is even higher[77]
- the inputs Producer Price Index (PPI) for the manufacturing sector increased by 17.7 per cent,[78] and
- the outputs PPI for heavy and civil engineering construction increased by 9.0 per cent.[79]

**Contractors are unwilling or unable to offer fixed price contracts**

Contractors are presently offering contracts with flexible pricing and risk-sharing arrangements to accommodate changes and unforeseen circumstances and safeguard against potential losses. This will assist to mitigate their own risk exposure, which has been heightened in recent times under fixed price

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[75] Transgrid, Revised Revenue Proposal, 2 December 2022
[76] Reserve Bank of Australia, Statement on Monetary Policy, August 2022, p. 43.
[77] Reserve Bank of Australia, Statement on Monetary Policy, May 2023, Table 5:1.
[78] ABS, 6427.0 Producer Price Indexes, Australia, Table 13. Input to the Manufacturing industries, division and selected industries, index numbers and percentage changes, June 2022.
[79] ABS, 6427.0 Producer Price Indexes, Australia, Table 17. Output of the Construction industries, subdivision and class index numbers, June 2022.

contracts, given the significant uncertainty associated with changes in input costs caused by labour shortages and increasing materials costs and supply chain disruption.

The D&C contract cost of $166.0 million included in this Revenue Proposal for transmission lines and substations reflects a variable contract cost.[80] If, however, the contractor was required to offer a fixed price contract then the D&C contract cost is expected to increase by around $30 million or 20 per cent. The variable contract cost in this Revenue Proposal therefore provides consumers with a higher probability of a lower price outcome.

As discussed in Chapter 12, we have also included an adjustment mechanism for unavoidable contract variations which recognises that the principal contractor will update its contract price subject to its final detailed design and changes in civil works costs. These cost variations are unavoidable because the principal contractor is unable to:

- offer a fixed price until final design is completed, due to the inflationary environment, and
- secure fixed prices from its sub-contractors who will carry out the civil works.

**Probability of overspending is higher than the probability of underspending**

These characteristics and market conditions are beyond the direct control of a TNSP. Taken together, they mean that despite our best efforts to accurately forecast the capex associated with PTIP (and ISP) projects, there will be unquantifiable costs that arise such that the probability of overspending is higher than the probability of underspending the AER's capex allowance. These projects are therefore expected to generate less than the return that investors would reasonably require to invest in these projects, because:

- the NER and EII Chapter 6A do not allow TNSPs to adjust the AER's capex allowance to address the difference between forecast and actual labour, materials and other price costs
- the AER's 2022 RoRI does not allow for a higher rate of return for ISP projects to compensate investors for the risk of unforeseen cost overruns that would result in a CESS penalty and the AER has not previously allowed general contingency or risk cost allowances, and
- we would need to fund the gap in financing the investment for the remainder of the period and would be penalised under the CESS for any overspend (net of that financing cost).

Investors will therefore not be willing to commit capital to these projects, which is not in the long-term interest of consumers, because these projects are critical to:

- the urgent energy transition which in turn will drive down energy prices
- support the Australian and NSW Government's commitment to a net-zero future, and
- ensure consumers continue to receive reliable and secure electricity.

We consider the CESS should not be applied to PTIP (and ISP) projects during the construction phase. Under this approach:

- investors can expect to earn a return that is in line with the efficient allowed rate of return set by the AER.
- the incentive framework is maintained because the TNSP would need to fund (i.e., bear the financing costs) of any capex above the AER's allowance during the regulatory period. Also, if the TNSP

[80] The $166.0 million comprises $68.3 million for transmission lines and $97.7 million for substations.

significantly overspends its total capex allowance, it could be penalised through the ex-post capex review process by having actual capex incurred excluded from the RAB.

This would ensure that we would have a reasonable opportunity to recover the efficient costs of delivering the project, consistent with the intent of the EII Act which provides that:[81]

> *a network operator is entitled to recover the prudent, efficient and reasonable costs incurred by the network operator for carrying out the infrastructure project.*

## 9.3. EBSS

We consider that the EBSS should also not apply to forecast opex in the 2024-28 period, for the same reasons set out in Section 9.3

## 9.4. STPIS

The STPIS provides Network Operators with incentives for maintaining and improving network performance. The STPIS provides an important counterbalance to the EBSS and CESS to ensure that service levels do not reduce as result of efforts to achieve efficiency gains.

Section 3.3 of the AER's Guideline explains that the AER will develop an EII specific STPIS and that this scheme would apply to non-contestable determinations from the second regulatory control period onwards. Therefore, no STPIS will apply to WSB in the 2024-29 period.

We look forward to engaging with the AER as the EII specific STPIS is developed.

[81] Section 37 of the EII Act

# 10

# Pass through events

# 10. Pass-through events

This Chapter sets out our nominated pass-through events and definitions for the 2024-29 regulatory period.

Our proposed process for making any adjustments to our revenue, and payment schedule, as a result of approved pass-through events is set out in Chapter 12.

## 10.1. Overview

Our operating environment is unpredictable and events beyond our control can substantially change our expenditure within a regulatory period. We exclude some high-cost, low-probability events from our expenditure forecasts to ensure that customers only pay for them if and when they actually occur.

Like the NER Chapter 6A, the EII Chapter 6A includes ‘cost pass through’ provisions so that we can recover (or pass through) costs of defined, unpredictable, high-cost events that are not included in the expenditure and revenue forecasts in the AER’s Final Decision. The AER determines the efficient costs of these events as they occur during the period.

The EII Chapter 6A.7.3 includes the following defined pass-through events, which are identical to those under the NER chapter 6A expect for the first event, being the regulatory requirement as defined in Section 46(3) of the EII Regulation, which is instead of the regulatory change event under the NER:

- regulatory requirement as defined in Section 46(3) of the EII Regulation
- service standard event
- tax change event
- insurance event
- inertia shortfall event, and
- fault level shortfall event.[82]

## 10.2. Nominated pass-through events

In addition to these defined events,[83] consistent with the AER’s 2023-28 Revenue Determination for our prescribed transmission services, we propose the following four nominated pass-through events for the 2024-29 regulatory period:[84]

- insurance coverage event
- insurer’s credit risk event
- natural disaster event, and
- terrorism event.

These four nominated pass-through events are defined as:

[82] The EII Chapter 6A includes the Fault Level Shortfall event. However, this is now removed from the NER Chapter 6A as a result of the System Strength Rules, which commence from 1 December 2025. The Fault Level shortfall event only applies under the NER until 1 December 2025 as a transitional arrangement.
[83] In accordance with EII Chapter 6A rule 6A.6.9(a)
[84] AER, Draft Decision, Transgrid Transmission Determination 2023 to 2028, September 2022

Table 10-1: Nominated pass-through events

| Event | Definition |
|---|---|
| Insurance Coverage Event | An insurance coverage event occurs if:<br>1. Transgrid:<br>(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<br>(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<br>2. Transgrid incurs costs:<br>(a) beyond a relevant policy limit for that policy or set of insurance policies, or<br>(b) that are unrecoverable under that policy or set of insurance policies due to changed circumstances, and<br>3. The costs referred to in paragraph 2 above materially increase the costs to Transgrid in providing NSW non-contestable services.<br>For the purpose of this insurance coverage event:<br>'changed circumstances' means movements in the relevant insurance market, including liability insurance, that are beyond the control of Transgrid, where those movements mean that it is no longer possible for Transgrid 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.<br>'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had:<br>(i) the limit not been exhausted, or<br>(ii) those costs not been unrecoverable due to changed circumstances.<br>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 regulatory control period in which Transgrid was regulated.<br>Note: For the avoidance of doubt, in assessing an insurance coverage event through application under clause 6A.7.3(j) of EII Chapter 6A, the AER will have regard to:<br>(i) the relevant insurance policy or set of insurance policies for the event<br>(ii) the level of insurance that an efficient and prudent Network Operator would obtain, or would have sought to obtain, in respect of the event<br>(iii) any information provided by Transgrid to the AER about Transgrid's actions and processes, and |

| Event | Definition |
|---|---|
| | (iv) any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event that occurs. |
| Insurer's Credit Risk Event | An insurer's credit risk event occurs if an insurer of Transgrid becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, Transgrid:<br>(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<br>(b) incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.<br>Note: In assessing an insurer credit risk event pass through application, the AER will have regard to, among other things:<br>(i) Transgrid'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<br>(ii) in the event that a claim would have been covered by the insolvent insurer's policy, whether Transgrid had reasonable opportunity to insure the risk with a different provider. |
| Natural Disaster Event | Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2024-29 regulatory control period that changes the costs to Transgrid in providing EII services, provided the cyclone, fire, flood, earthquake or other event was:<br>(a) a consequence of an act or omission that was necessary for the Network Operator to comply with a regulatory obligation or requirement or with an applicable regulatory instrument, or<br>(b) not a consequence of any other act or omission of the Network Operator.<br>Note: In assessing a natural disaster event pass through application, the AER will have regard to, among other things:<br>(i) whether Transgrid has insurance against the event, and<br>(ii) the level of insurance that an efficient and prudent Network Operator would obtain in respect of the event |
| 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:<br>(a) 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);<br>(b) and changes the costs to Transgrid in providing NSW non-contestable services. |

| Event | Definition |
| --- | --- |
| | Note: In assessing a terrorism event pass through application, the AER will have regard to, among other things:<br>(i) whether Transgrid has insurance against the event<br>(ii) the level of insurance that an efficient and prudent Network Operator would obtain in respect of the event, and<br>(iii) whether a declaration has been made by a relevant government authority that a terrorism event has occurred. |

# 11

# Maximum allowed revenue

# 11. Maximum allowed Revenue

This chapter sets out our total annual building block revenue requirement (ABBRR) for the 2024-29 period calculated using a building block approach.

## 11.1. Overview

Under the EII Chapter 6A, our total ABBRR is calculated in the same way as under the NER Chapter 6A. This involves using a building block approach which estimates our revenue as the sum of the efficient costs to provide our EII services. The building blocks include:

- **Return on capital** – This is discussed in Chapter 7.
- **Regulatory depreciation** (or return of capital) – This is discussed in Chapter 6.
- **Operating expenditure** – This is discussed in Chapter 4.
- **Revenue adjustments** – Given it is the first Revenue Proposal and regulatory period for this Project no revenue increments or decrements arising from incentive schemes are relevant.
- **Corporate income tax** (net of imputation credits) – This is discussed in Chapter 8.

Table 11-1 summarises the total revenue forecast of $137.7 million ($Nominal), broken down by building block component, and briefly explains how we have calculated each component.

This revenue is calculated within the EII PTRM included as an attachment to this Revenue Proposal as a simple sum of the four building blocks shown in the tables.

Table 11-1: Maximum allowed revenue over the 2024-29 regulatory period - Summary ($M, Nominal and Real 2023-24)

| Building block | $ Million, Nominal | $ Million, Real 2023-24 | Cross reference to other chapters |
|---|---|---|---|
| Return on capital | 73.7 | 67.5 | Refer Table 7-1 in Chapter 7 |
| Return of capital | 31.6 | 29.3 | Refer Table 6-4 in Chapter 6 |
| Opex[1] | 27.2 | 24.9 | Refer Table 4-1 in Chapter 4 |
| Revenue adjustments | 3.5 | 3.4 | Refer Table 4-3 in Chapter 4 |
| Corporate income tax | 1.7 | 1.6 | Refer Table 8-1 in Chapter 8 |
| Maximum allowed revenue | **137.7** | **126.8** | |

Notes: 1. Including debt raising costs

Table 11-2 shows the year-by-year breakdown of the forecast over the 2024-29 regulatory period in $Nominal.

Table 11-2: Maximum allowed revenue over the 2024-29 regulatory period - Detailed breakdown ($M, Nominal)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Return on capital | 7.4 | 16.5 | 17.0 | 16.6 | 16.2 | **73.7** |
| Return of capital | 8.0 | 6.4 | 5.8 | 5.8 | 5.7 | **31.6** |
| Operating expenditure | 3.9 | 5.2 | 5.8 | 6.5 | 5.9 | **27.2** |

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Revenue adjustments | 3.5 | - | - | - | - | **3.5** |
| Corporate income tax | 1.0 | 0.1 | 0.1 | 0.2 | 0.3 | **1.7** |
| **Maximum allowed revenue** | **23.7** | **28.2** | **28.7** | **29.1** | **28.1** | **137.7** |
| NPV (as at 30 June 2024) | | | | | | **113.0** |

Table 11-3 shows the year-by-year breakdown of the forecast over the 2024-29 regulatory period in $Real 2023-24.

Table 11-3: Maximum allowed revenue over the 2024-29 regulatory period | Detailed breakdown ($M, Real 2023-24)

| | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | Total |
|---|---|---|---|---|---|---|
| Return on capital | 7.2 | 15.6 | 15.7 | 14.9 | 14.2 | **67.5** |
| Return of capital | 7.8 | 6.0 | 5.3 | 5.2 | 5.0 | **29.3** |
| Operating expenditure | 3.8 | 4.9 | 5.3 | 5.8 | 5.1 | **24.9** |
| Revenue adjustments | 3.4 | - | - | - | - | **3.4** |
| Corporate income tax | 1.0 | 0.1 | 0.1 | 0.2 | 0.2 | **1.6** |
| **Maximum allowed revenue** | **23.1** | **26.7** | **26.4** | **26.1** | **24.5** | **126.8** |
| NPV (as at 30 June 2024) | | | | | | **113.0** |


# 12

# Payments and adjustments



Transgrid

# 12. Payments and adjustments

This chapter sets out the proposed schedule of quarterly payments that we will be paid over the 2024-29 period by the Scheme Financial Vehicle for carrying out the WSB Project and the methodology by which we have calculated these payments from the total revenue.

## 12.1. Payment schedule

In accordance with EII Chapter 6A, we have calculated a schedule of quarterly payments that we, as the Network Operator, propose to be paid by the Scheme Financial Vehicle for delivering the Project.

We have calculated these payments based on our forecast MAR for the 2024-29 regulatory period, which is discussed in Chapter 11. In particular, we have converted our MAR into a series of quarterly payments within the PTRM, provided as an attachment to this Revenue Proposal, such that the NPV of the payments matches the NPV of MAR.

Table 12-2 shows the forecast quarterly payments for the 2024-29 regulatory period. We propose that these are adjusted using the adjustment mechanism described in Section 12.4 for any adjustment amounts determined in accordance with sections 12.2 and 12.3.

Table 12-1: Forecast quarterly payments for the 2024-29 regulatory period ($M, Nominal)

| Year | Quarter 1 (September) | Quarter 2 (December) | Quarter 3 (March) | Quarter 4 (June) | Total |
|---|---|---|---|---|---|
| 2024-25 | 5.6 | 5.7 | 5.8 | 5.9 | 23.2 |
| 2025-26 | 6.7 | 6.8 | 6.9 | 7.0 | 27.5 |
| 2026-27 | 6.8 | 6.9 | 7.0 | 7.2 | 28.0 |
| 2027-28 | 6.9 | 7.0 | 7.1 | 7.3 | 28.4 |
| 2028-29 | 6.7 | 6.8 | 6.9 | 7.0 | 27.4 |
| Total | 32.8 | 33.3 | 33.9 | 34.4 | 134.3 |
| **NPV (as at 30 June 2024)** | | | | | 113.0 |

## 12.2. Adjustment Mechanisms

The EII regulatory framework provides that a revenue determination may include provision for the adjustment of any amount in the revenue determination, whether or not the amount relates to a capital cost.[85] The AER expects any adjustment mechanisms to be symmetrical in their application.[86]

These adjustment mechanisms are additional to the pass-through provisions (discussed in Chapter 10). The AER notes that, in assessing our proposed adjustment mechanisms, it is likely to have regard to the nominated pass-through events:[87]

85 Clause 51 of the EII Regulations and AER, AER non-contestable Guideline, April 2023, Section 5.5.
86 AER non-contestable Guideline, April 2023, Section 5.5.1.
87 AER non-contestable Guideline, April 2023, Section 5.5.1.

*We note that the EII contestable framework is largely consistent with the NER Chapter 6A framework and therefore already provides for a number of adjustment mechanisms including pass through events and nominated pass through events. In assessing any proposed adjustment mechanisms, the AER is likely to have regard to the nominated pass-through event considerations referenced in the EII Chapter 6A Rules.*

In relation to adjustment mechanisms:

- in some cases, these will be ‘automatic’, in the sense that the AER would not be required to review or remake its revenue determination.[88] In this Revenue Proposal, we propose annual updates to revenue for actual inflation, the return on debt update to the allowed rate of return, and additional contractual payments to EnergyCo, and
- in other cases, these would be ‘non-automatic’, such that the AER would be required to review or remake its revenue determination. For instance, the occurrence of a significant event (non-automatic adjustment mechanisms).

The rationale for distinguishing between automatic and non-automatic adjustments is that automatic adjustments can be determined with reference to published or audited data without the AER making any enquiries or conducting reviews. In contrast, non-automatic adjustments require the AER to make enquiries or conduct reviews to determine the prudent and efficient adjustment amount.

In accordance with Section 4.2.1(K) of the AER’s Information Notice and Section 5.5 of its non-contestable Guidance, the remainder of this section provides a formulaic description of our proposed adjustment mechanisms, including:

- a description of the components of revenue to be adjusted and the basis for the adjustment
- the timing of the adjustment for each component or relevant trigger event, and the timing of the application of the revised schedule of payments
- a detailed explanation of the proposed method of indexation, escalation or adjustment, and
- identification of the authoritative source (or sources) of indices or data to be used for any indexation, escalation or adjustment.

### 12.2.1. Formulaic description and proposed adjustments

The formula below sets out our proposed adjustment mechanism for the 2024-29 regulatory period, which provides for our quarterly payments outlined in Section 3.1 to be recalculated each year such that:

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

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,* expressed as a quarterly-compounding discount rate
- $AR_t$ (Adjusted) is the annual revenue requirement for year t, calculated using the PTRM, adjusted for *actual inflation, updated rate of return, and contractual payments to EnergyCo*

[88] See the Note in clause 51 of the EII Regulation where it states that an adjustment may be made for inflation without a review or remake of the revenue determination,

- *actual inflation* is the percentage change in the Australian Bureau of Statistics' (ABS) Consumer Price Index (CPI) All Groups, Weighted Average of Eight Capital Cities[89] from December in year *t-1* to December in year *t–2*[90]
- *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 (see discussion in Section 7.5)
- *contractual payments to EnergyCo* are any payments required to be paid by Transgrid in year t, which have not been included in the building block calculation in this Revenue Proposal
- $NAA_t$ is the AER's approved non-automatic adjustment amount for year t, which may be a positive or negative, calculated in accordance with the triggers described in Section 12.2.2, and
- $PTC_t$ is the AER's approved pass through cost for year t, which may be a positive or negative amount, determined in accordance with the pass-through provisions in EII Chapter 6A.

The process for adjusting our revenue in accordance with the above formula is set out in Section 12.3.

### 12.2.2. Non-automatic adjustment mechanisms

The adjustment mechanism in the previous section proposes non-automatic adjustments, which require the AER to review or amend its determination. As already explained, if applicable, the non-automatic adjustment is a dollar amount which may be positive or negative in the relevant year t. As the AER will specify the allowed dollar amount in its determination for each non-automatic adjustment, there is no requirement for an indexation to apply to non-automatic adjustments.

We propose three non-automatic adjustments:

- paired generation cost
- unavoidable contract variations, and
- contractor force majeure.

For each adjustment, we briefly describe the rationale for the adjustment and the proposed trigger event.

**Paired Generation Cost**

As explained in Section 5.10, we expect that EnergyCo will undertake at [redacted] tender rounds for paired generation associated with the WSB Project. The expected timing of these future paired generation tenders means that the full scope of the associated works may not be known [redacted]. While we have presented our best estimate of the pair generation capex in this Revenue Proposal, the actual cost remain highly uncertain. There is no purpose served in exposing us or our customers to the risk of forecasting error. For these reasons, a Paired Generation Cost adjustment is warranted.

In relation to the trigger event and the subsequent determination process, we propose that:

- A trigger event occurs when:
  - the next or subsequent tender rounds provides information which demonstrates that Transgrid's actual costs are likely to be higher (or lower) than the forecast amount accepted by the AER in relation to this Revenue Proposal; or

[89] If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

[90] For example, for the 2025–26 year, the CPI for t–2 is that measured at December 2023 and for t–1 is measured at December 2024.

- Transgrid's actual Paired Generation Cost are higher (or lower) than the forecast amount accepted by the AER in relation to this Revenue Proposal.

- As soon as practicable after the trigger event occurs, Transgrid must provide the AER with its updated forecast or actual Paired Generation Cost. Transgrid must also provide any additional information requested by the AER.
- The AER must determine the updated forecast or actual Paired Generation Cost, as the case may be, within 90 business days of receiving the request from Transgrid. For the avoidance of doubt, where a forecast amount is determined, it will be subsequently updated to ensure that only the actual costs are recovered by Transgrid.

**Unavoidable Contract Variations**

Transgrid and customers are exposed to unavoidable variations in contract prices that may result from:

- **Changes in the final design of the Project**. In particular, these costs may arise from changes to the Project scope in the contractor's final detailed design compared to the contractor's assumptions (based on the initial design) in the tender process. We expect that the contractor will finalise the detailed design for transmission lines and substations in the northern section by October 2023 and the Southern section by February 2024.
- **Changes in civil works costs**, which result in the contractor incurring higher or lower costs than those reflected in the construction contract. These costs would be incurred prior to the Project being built and operational. The cost variation to Transgrid is unavoidable because the principal contractor is unable to secure fixed prices from its sub-contractors who will carry out the civil works. This is because the scope of the civil works is currently unable to be finalised and therefore the principal contractor is unable to secure a fixed price, which price risk is passed through to Transgrid.

As noted in relation to Paired Generation Costs, no purpose is served in exposing us or our customers to the risk of forecasting error. For these reasons, an Unavoidable Contract Variations adjustment is warranted.

In relation to the trigger event and the subsequent determination process, we propose that:

- A trigger event occurs when:
  - a change in the final design occurs and the cost implications are known, or
  - a change in the civil works costs are higher (or lower) than the forecast amount accepted by the AER in relation to this Revenue Proposal.
- As soon as practicable after the trigger event occurs, Transgrid must provide the AER with the cost impact of the trigger event, including a detailed explanation of the proposed adjustment amount (which may be positive or negative). Transgrid must also provide any additional information requested by the AER.
- The AER must determine the Unavoidable Contract Variations cost, as the case may be, within 90 business days of receiving the request from Transgrid.

**Contractor Force Majeure**

Transgrid is exposed to the risk of costs arising from force majeure events, which disrupt the contractor during construction phase and result in additional construction costs (i.e., these costs would be incurred prior to the Project being built and operational). It is preferable to address this risk through an adjustment mechanism, rather than Transgrid seeking an allowance to cover the risk of a Contractor Force Majeure event.

In relation to the trigger event and the subsequent determination process, we propose that:

- A trigger event occurs when the contractor declares a force majeure and the actual or forecast cost implications of that declaration are known.
- As soon as practicable after the trigger event occurs, Transgrid must provide the AER with the forecast or actual cost impact of the trigger event, including a detailed explanation of the proposed adjustment amount Transgrid must also provide any additional information requested by the AER.
- The AER must determine the forecast or actual cost of the Contractor Force Majeure, as the case may be, within 90 business days of receiving the request from Transgrid. For the avoidance of doubt, where a forecast amount is determined, it will be subsequently updated to ensure that only the actual costs are recovered by Transgrid.

## 12.3. Proposed process to adjust revenue and quarterly payments

After any relevant amounts have been determined and approved by the AER (in accordance with the processes described in Section 12.2), our revenue, and payment schedule, then needs to be adjusted to take into account those revised amounts.

However, unlike the NER Chapter 6A, which contains the annual price setting process, the EII regulatory framework contains no explicit price control mechanism that can be used to make adjustments to the revenue and incorporate these amounts into updated quarterly payments from the Scheme Financial Vehicle.

Therefore, we have set out in Table 12-2 below our proposed process to facilitate adjustments to our revenue and the adjustment mechanisms described above. We have modelled this process on the annual price setting process that applies to our prescribed transmission services under the NER.

Table 12-2: Proposed Adjustment Mechanism

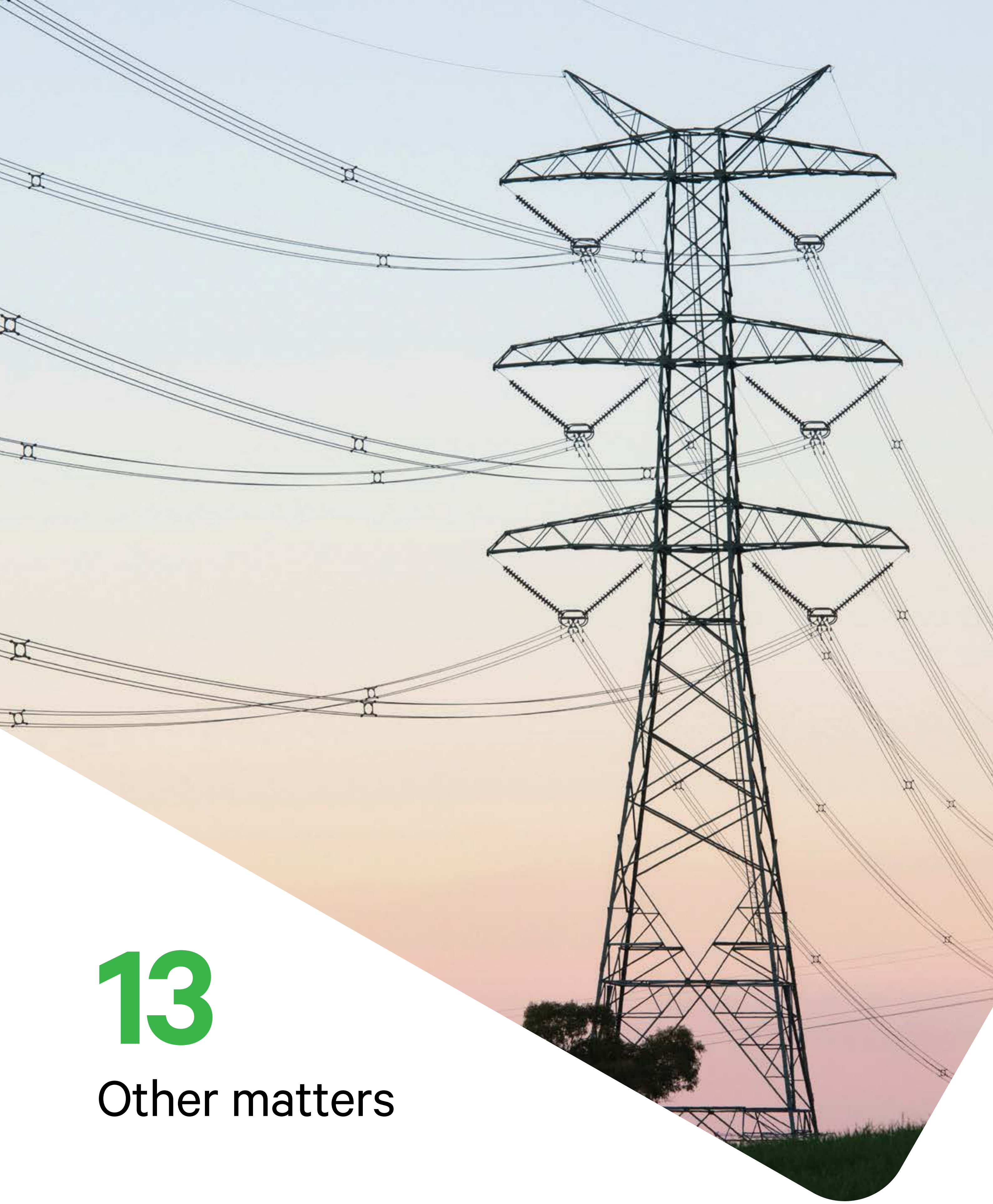
| Component | Description |
|---|---|
| Overall | The quarterly payment schedule is updated each year *t* to incorporate up to the adjustments in accordance with Section 12.2.<br>The adjustments are incorporated into the EII PTRM, which then outputs the updated quarterly payment schedule. The updated EII PTRM is subject to approval by the AER. |
| Adjustment of revenue process and timing | The payments are updated for each year using a three-step process:<br>1. Transgrid updates the latest version of the EII PTRM to incorporate the adjustments for the forthcoming year and submits this to the AER by 31 March.<br>2. The AER reviews the updates and advises Transgrid whether it accepts those updates or not by 31 May. If not, the AER provides Transgrid with an amended version of the EII PTRM that it approves.<br>3. Transgrid provides the updated quarterly payment schedule to the Scheme Financial Vehicle by 30 June along with the AER's approval. |
| Adjustments | The adjustments for year *t* will include:<br>1. **Automatic Adjustments** as defined in Section 12.2.1<br>2. **Non-Automatic Adjustments** as defined in Section 12.2.2, and<br>3. **Pass-through amounts** in accordance with the pass-through provisions of EII Chapter 6A. |

| Component | Description |
|---|---|
| Model updates | The adjustments are incorporated into the EII PTRM for year *t* as follows:<br>• actual inflation for year *t* is entered into the relevant cell at row [57] of the 'Revenue and Payments' sheet.<br>• the return on debt for year *t* is entered into the relevant cell at row 496 of the 'PTRM input' sheet<br>• any contractual payments to EnergyCo are input to the capex, opex, or revenue adjustment sections in the 'PTRM input' sheet as per the AER's approval of those amounts<br>• any approved Non-Automatic Adjustments are input to the capex, opex, or revenue adjustment sections in the 'PTRM input' sheet as per the AER's approval of those amounts.<br>• any approved pass-through amounts are input to the capex, opex, or revenue adjustment sections in the 'PTRM input' sheet as per the AER's approval of those amounts.<br>The updated quarterly payment schedule is then available at row [48] of the 'Revenue and payments' sheet. |

## 12.4. Form of control

The EII Regulation does not require an explicit form of control to be determined. This is because under the EII Regulations, Transgrid recovers its costs for delivering the Project on the basis that Transgrid is paid quarterly payments by the Scheme Financial Vehicle. Given this, there is no need to rebalance revenue across different tariffs or charging parameters.

Clause 51 of the EII Regulation does, however, allow for adjustments to those quarterly payments. We discuss our proposed adjustment mechanism above in Section 12.2 and Section 12.3.



# 13

# Other matters



Transgrid

# 13. Other matters

## 13.1. Confidential information

In accordance with clause 6A.10.1 (f)(2) of the EII Chapter 6A and the AER's Confidentiality Guideline[91], we have completed a confidentiality template as an attachment to this Revenue Proposal that details the matters for which we are claiming confidentiality.

## 13.2. Certifications

### 13.2.1. Certification statement

Schedules 6A.1.1(5) and 6A.1.2(5) 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 4.2, and
- capex are set out in Section 5.2.

Our certification statement is provided as an attachment to this Revenue Proposal.

### 13.2.2. Statutory declaration by Chief Executive

The AER's Information Notice requires an officer of Transgrid to make a statutory declaration attesting to the information provided in response to that notice.[92]

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 an attachment to this Revenue Proposal.

## 13.3. Compliance checklist

We have completed compliance checklists, which demonstrates how we have complied with the Minister's direction and our contractual arrangement relating to the Project, including the NOD. This is discussed in Chapter 2.

## 13.4. Supporting documentation

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

| Name |
|---|
| Confidentiality claims |
| Key capex and opex assumptions certification |

91 We have used the AER's Better Regulation Confidentiality Guideline, August 2017 noting that the AER's non-contestable Guideline, April 2023 p. 17 states that it will develop its EII Confidentiality Guideline in the second half of 2023.
92 AER, Information notice issued to Transgrid for the Waratah Super Battery project (non-contestable). The form of the statutory declaration is set out in Section 6.1.7 of the information notice.

| Name |
| --- |
| Regulatory Information Notice compliance checklist |
| Revenue Proposal Statutory Declaration |

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