



People. Power. Possibilities.

System Security Roadmap Operational Technology Upgrades

Contingent Project Application

May 2026



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Executive Summary

Background

The National Electricity Market (NEM) is undergoing a deep evolution as it decarbonises. In 2015, 85% of generation in NSW was coal fired, with approximately 4% or less than 1 GW provided by utility-scale wind and solar generation. By 2035, the generation mix will be entirely different. Coal is forecast to account for only 5% of generation, while large-scale renewable generation and storage will account for over 70%, and 20% from household solar and storage.

A renewable grid, with its intermittent, weather-dependent generation, is a more dynamic and complex system. To meet consumer expectations for reliable electricity, we need stronger analytical and operational capabilities to plan, manage and operate an electricity system that is becoming more distributed, dynamic and unpredictable. We also need to optimise the operation of new types of transmission assets, most notably synchronous condensers, to ensure that there is sufficient system strength to enable consumers' energy needs to be met at the lowest cost.

Transgrid has already observed that the NSW electricity system is operating closer to the edge of its secure operating envelope. This means that the system is more likely to tip into insecure operating conditions if a credible contingency occurs. This requires increased scrutiny from operators who must intervene more frequently to maintain system security.

In the absence of substantial upgrades to our operational capabilities, consumers will be impacted in two ways:

- We would need to operate the system in a more conservative way using static operating limits, to have confidence that the system will remain within its required technical envelope. This might require constraints to be imposed more frequently, which would potentially limit the output of some low-cost renewable generation and create upward pressure on electricity bills.
- There is an increased likelihood of emergency outages or disruptions when our operators are overburdened, which would directly impact consumers. This risk is heightened when operators are processing multiple sources of information following extreme weather and other contingency events, which are increasing in frequency.

To avoid these impacts on consumers, and maintain reliable and secure energy supply, it is essential that we upgrade our operational capability. Upgrading our operational capability will enable us to improve asset utilisation, facilitate lower cost outcomes for consumers and reduce the risk of service degradation.

System Security Roadmap Operational Technology Project

To address the challenges described above, in December 2022 we proposed a System Security Roadmap (SSR) Operational Technology Project (the Project) as part of our capital expenditure (capex) forecasts for the 2023-28 regulatory control period (regulatory period). At that time, the Australian Energy Regulator (AER) recognised the need for the Project, but requested that we undertake further work before seeking regulatory approval. In particular, the AER commented that:

- 'Early Works' were required to clarify the required operational technology upgrades and tools for use in Transgrid's control rooms and corporate offices.

- The proposed project scope should be capable of objective verification through AEMO’s written support and by applying a RIT-T or equivalent economic evaluation.¹

Given these observations, the AER decided that the Project should be classified as a Contingent Project, and the following triggers must be satisfied in order for Transgrid to submit a Contingent Project Application (Application):²

- Completion of the RIT-T process, which demonstrates that the proposed technological upgrades and tools maximise net economic benefits.
- AEMO’s written support for the proposed technological upgrades and tools identified in the RIT-T, following completion of Early Works.
- Transgrid Board commitment to proceed with the Project, subject to the AER amending the Revenue Determination pursuant to the National Electricity Rules (NER).

Each of these triggers has now been satisfied. Transgrid is therefore submitting this Application in relation to the Project. We briefly summarise the RIT-T assessment, stakeholder engagement and AEMO’s written support for the Project before setting out our capex and operating expenditure (opex) forecasts. We also note that Transgrid’s Board has committed to proceed with the Project, subject to the AER adjusting our maximum allowed revenue for the 2023-28 and 2028-2033 periods in accordance with this Application.

The delivery of the Project scope described in this Application will commence in July 2026 and is expected to be completed by end July 2031. From 2023-24 onwards, Transgrid undertook extensive development work, including the RIT-T assessment, to determine the optimal scope for this Project, as explained in further detail below.

Early Works and RIT-T assessment

Our Early Works activities culminated in the successful completion of the RIT-T and the development of this Application. In particular, Transgrid investigated and considered alternative options for improving our control systems and corporate office capabilities. This process involved extensive investigation and planning by our internal teams, and the commissioning of expert input from independent international and Australian experts, the Electric Power Research Institute (EPRI) and GHD Advisory (GHD). It has also been informed and refined through comprehensive market testing, centred on a request for information (RFI) process.

In the final stage of the RIT-T, known as the Project Assessment Conclusions Report (PACR), we narrowed our assessment to the following credible options from a technical, commercial, and project delivery perspective³:

- **Option 1: Reactive capability** – provides enhancements to Transgrid’s existing core operational technology and tools to improve the reactive capabilities of Transgrid’s control room and corporate offices.
- **Option 2: Proactive capability** – in addition to the enhancements to Transgrid’s existing core operational technology and tools in Option 1, Option 2 provides further, moderate enhancements to Transgrid’s existing operational technology and tools, in addition to several new capabilities, so that

¹ AER, *Final Decision, Transgrid Revenue Determination 2023-28* [Transgrid Revenue Determination 2023-28, Attachment 5 Capital Expenditure](#), April 2023, pp 47.

² The precise wording of these triggers is provided in Appendix A.

³ The Draft Project Assessment Report also considered Option 3 (Predictive Capability), which was subsequently ruled out as it had a high degree of cost and functional uncertainty.

Transgrid can proactively plan for, and respond to, operational issues across its control room and corporate offices.

Option 2 includes the technology initiatives and capabilities in Option 1, typically at a higher level of technical uplift with commensurate increases in scope and capabilities. We assumed a staged approach for the implementation of the technology initiatives under each option to prioritise initiatives to maximise the value delivered and optimise the project schedule.

We developed the two options as packages to reflect the minimum incremental technology solution required to enable a defined level of capability (i.e., reactive or proactive). As a result, partial implementation of either option would not achieve the intended capability uplift, and so would not provide the benefits identified in the RIT-T. These benefits include avoided unserved energy, reduced fuel costs and lower greenhouse gas emissions. The scope and timing of the two options were tested and refined to reflect the responses to the RFI and our engagement with the participants.

In accordance with the RIT-T requirements, we conducted a net market benefit assessment against three scenarios consistent with AEMO's Integrated System Plan (ISP). The analysis showed that both options are expected to deliver net benefits across all three ISP scenarios, with Option 2 providing a NPV of \$118.9 million compared with \$52.0 million for Option 1 on a weighted average basis. Accordingly, Option 2 was identified as the preferred option. The RIT-T process was followed by further minor refinements to our capex forecasts in preparing this Application.

In addition to completing the RIT-T, we also completed the Alarm Management Project as an enabling initiative. As noted by EPRI, this work was required to reduce alarm volumes and to prepare for future intelligent alarm processing solutions.⁴ As an enabling initiative, the Alarm Management Project is treated as Early Works and the actual costs of competing this initiative is included in this Application.

Stakeholder engagement

Transgrid recognises that it must explain to consumers why it is undertaking significant investments, and the benefits those investments will provide to consumers. In relation to this Project, the Transgrid Advisory Council (TAC) was engaged early and consulted throughout the planning and development of the RIT-T.

During our engagement, the TAC heard directly from EPRI about the need for enhanced operability capabilities nationally and internationally, and we explained our specific capability needs and the urgency to address them. TAC members were given a guided tour of our control room, hearing first-hand from Transgrid's control room staff about some of the challenges the increasing complexity is posing as a result of the energy transition.

Our engagement with the TAC has been positive and has provided Transgrid with feedback that has been incorporated in articulating the need, developing the cost estimates, quantifying the benefits, and assessing the options. The TAC is supportive of the investment need, and Transgrid will continue to brief the TAC as the Project progresses through the AER's review process.

⁴ Available at: https://www.transgrid.com.au/media/f5po3uzu/epri-transgrid-padr-recomendations_final.pdf

AEMO's Letter of Support

In accordance with the trigger events specified in the AER's 2023-28 Revenue Determination for Transgrid (Revenue Determination), AEMO has provided a letter of support for the Project which was defined as Option 2 in the RIT-T. In that letter, AEMO made the following observations:

“Option 2 (Proactive capability) addresses the technology and the monitoring decision making and controllability capability uplift required and is consistent with AEMO's and other interconnected TNSP's and DNSP's functional obligations to manage the transmission network.

Transgrid's proposal also aligns with AEMO's own Operations Technology Program Roadmap and Engineering Roadmap. These identify the engineering challenges that emerge from the transition to a renewable energy system, and the uplift in operational capabilities that AEMO needs to enable this transformative change while maintaining electricity system reliability, security, and resilience.

Importantly, there are interdependencies between the roles of AEMO and Network Service Providers (NSPs) and systems and capabilities must effectively interface, support and complement each other. Investments by AEMO alone will not be sufficient; a capability uplift will also be needed by NSPs for system security to be maintained across the National Electricity Market (NEM). These investments are urgently needed to manage the security of the power system and to complement investments AEMO is making under its own Operations Technology Roadmap and associated program.

AEMO and Transgrid have validated the technology roadmap alignment required to realize the benefits. Each have engaged collaboratively to date to define emerging power system needs, and the future operational technology and tools required to address them. We look forward to continuing to work together to refine and implement solutions to maintain a reliable and secure power system, in the best interests of consumers.”

Transgrid welcomes AEMO's confirmation that the proposed investments are urgently needed to manage the security of the power system and to complement investments AEMO is making under its own Operations Technology Roadmap and associated program. AEMO's assessment is consistent with the findings in the RIT-T that the proposed Project is in the best interests of consumers.

Capex

During the RIT-T process, Transgrid undertook substantial work to establish market-based cost estimates for delivering the Project. In particular, Transgrid worked closely with DGA Consulting and two System Integrators (SIs) through an RFI process to establish market-based cost estimates for each component of the Project. Following the publication of the PACR in October 2025, these capex forecasts have been updated to reflect:

- the application of Transgrid's latest FY2027 labour rates to capitalised labour FTEs
- an increase in the assumed hours per FTE for capitalised labour
- the inclusion of debt and equity raising costs
- the reduced estimated cost of preparing this Application
- other minor changes.

The net impact of these changes is an increase in the total capex costs of approximately 3% compared to the cost estimates in the PACR.

Table E1 shows the total capex for each component of the Project and the amount that will be incurred during the 2023-28 regulatory period. Appendix B provides this cost information by asset class, required for preparing the AER's Post Tax Revenue Model (PTRM).

Table E1: Capex forecast (\$m, 2022-23)

Technology initiative	Total capex	Capex in 2023-28 regulatory period
Outage management	1.4	1.3
Alarm management, visualisation and situation awareness enhancement	33.7	8.9
Fault level and system parameter monitoring and power system analysis capability	6.8	-
SCADA/AEMS system ⁵	33.2	18.1
Facilities	5.1	4.6
Data management and network modelling system	27.1	16.8
Training technologies, operational document management system and operational planning systems	13.1	9.3
Operational forecasts and look-ahead contingency assessment	4.1	-
Wide area monitoring	6.4	-
Smart Transmission Device Management	3.8	-
CPA submission ⁶	5.8	5.8
Program implementation	22.1	9.7
Contingency/risk	-	-
Total (excluding labour escalation and equity raising costs)	162.5	74.5
Labour escalation ⁷	0.2	0.0
Equity raising costs	0.8	0.8
Total Capital Expenditure⁸	163.5	75.3⁹

We are confident that the forecast capex is prudent and efficient in accordance with the capex criteria and capex factors in the NER. Our confidence in the capex forecasts is based on the staged RFI process that we have undertaken with multiple vendors during the course of the RIT-T assessment and Early Works activities, and the independent review of our cost estimates (including our contingency allowance) undertaken by DGA Consulting.

⁵ This includes the Dual Homing Initiative.

⁶ CPA submission includes the CPA submission costs, but also Early Works which include Project planning, including preparation of RIT-T and submission of the CPA, independent expert reviews; engagement with service providers; and preparation of this Application. These activities are described in Section 2.2.

⁷ Labour escalation costs are calculated by multiplying the projected labour components of forecast capex by the real labour cost escalators approved in the AER's Revenue Determination.

⁸ Equity raising costs and labour escalation costs were not included in the PACR. Equity raising costs are calculated using the AER's PTRM and are explained in further detail in Appendix G.

⁹ Totals may not sum due to rounding. The contingency allowance discussed in section 3.2.3 is included within the technology initiatives and total above.

DGA Consulting has concluded that the capex estimates presented in this Application represent an efficient level of costs to deliver the scope of the proposed upgrades in our operational technology capability. A copy of DGA Consulting’s report is provided as an attachment to this Application.

Opex

Our incremental opex forecasts in this Application have been prepared on a bottom-up basis, consistent with the approach typically adopted for new technology projects. These costs relate to:

- internal support and monitoring for new assets being commissioned as part of the Project, which require additional FTEs
- license fees
- switching portal hosting of cloud infrastructure.

Our forecast incremental opex for the 2023-28 regulatory period is shown in Table E2 below.¹⁰

Table E2: Incremental opex forecast for the 2023-28 regulatory period (\$m, 2022-23)

Sub-category	2023-24	2024-25	2025-26	2026-27	2027-28	Total
License fees for operational planning system	-	-	-	-	0.2	0.2
Additional FTEs – support and maintenance for operational planning	-	-	-	-	0.4	0.4
Switching portal hosting					0.1	0.1
Total excluding debt raising costs	-	-	-	-	0.7	0.7
Debt raising costs	-	0.0	0.0	0.0	0.1	0.1
Total including debt raising costs	-	0.0	0.0	0.0	0.8	0.8

Please note that numbers do not add due to rounding.

Our incremental opex is expected to increase during the 2028-33 regulatory period as additional technology initiatives are commissioned and become operational. Specifically, by the end of that regulatory period, our annual incremental opex is forecast to increase to \$7.8 million, compared to \$0.8 million in the 2027-28.

The success of the Project depends on the AER approving both an appropriate capex and opex allowance to enable the required technology initiatives to be implemented and operated to achieve the Project objectives. We understand that the NER requires the AER to determine the Project’s opex allowance for the 2028-33 period in its 5-yearly Revenue Determination, rather than in its decision on this Application. Nevertheless, Transgrid would welcome the AER’s provisional assessment of the Project’s opex allowance during the 2028-33 period so that the Board is able to fully commit to the Project.

We are confident that our forecast incremental opex is prudent and efficient in accordance with the opex criteria and the opex factors in the NER. We note that DGA Consulting reviewed our forecast incremental opex costs and concluded that they are prudent and efficient.¹¹

¹⁰ Please note that this table only outlines the opex for this regulatory control period. Total incremental opex for the Project is at Appendix I

¹¹ DGA Consulting, *Independent Review of System Security Roadmap Operational Technology Upgrade Costs – Contingent Project Application*, 26 March 2026, version 1.0 Final.

Incremental Revenue and customer bill impacts

Incremental revenue requirement

Table E3 summarises the incremental forecast revenue requirement of \$3.0 million (\$Nominal) for the Project over the 2023-28 regulatory period, applying the capex and opex forecasts described above, expressed in nominal terms. The table shows the revenue requirement by building block component and briefly explains how we have calculated each component. The calculation of incremental revenue is consistent with the assumptions and PTRM underpinning the Revenue Determination.

Table E3: Incremental revenue breakdown (\$m, nominal)

Building block	Incremental revenue	Approach
Return on capital	3.3	Calculated by multiplying the forecast opening capital base for a given year by the allowed rate of return adopted by the AER for that year
Return of capital	(1.1)	Calculated as forecast straight line depreciation for each asset class less indexation of the capital base
Opex	0.9	Bottom-up build
Revenue adjustments	-	None
Corporate income tax	(0.1)	Calculated as forecast pre-tax income multiplied by the corporate tax rate, less the assumed value of imputation credits
Annual revenue requirement (i.e. unsmoothed)	2.9	Sum of each building block above
Impact of smoothing	0.1	Calculated by resolving the year 4 and 5 X-factors, so the NPV of the Maximum Allowed Revenue (MAR) for the 2023-28 regulatory period matches that of the forecast annual revenue requirement for the same period
MAR (i.e. smoothed)	3.0	Annual revenue requirement adjusted for impact of smoothing
NPV (as at 30 June 2023)	2.3	

Table E4 sets out the incremental revenue requirement for each of the remaining years in the 2023-28 regulatory period.

Table E4: Incremental revenue requirement by year (\$m, nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Return on capital	-	0.3	0.5	0.6	1.9	3.3
Return of capital (depreciation)	-	(0.1)	(0.2)	(0.3)	(0.5)	(1.1)
Opex	-	0.0	0.0	0.0	0.9	0.9
Revenue adjustments	-	-	-	-	-	-
Corporate income tax	-	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)
Annual revenue requirement (i.e. unsmoothed)		0.1	0.3	0.3	2.2	2.9
Impact of smoothing		(0.1)	(0.3)	(0.3)	0.8	0.1
MAR (i.e. smoothed)		-	-	-	3.0	3.0
NPV (as at 30 June 2023)						2.3

Customer bill impacts

We have estimated the impact of the incremental revenue required to deliver the Project on customer bills. Our assessment indicates that, as a result of the direct costs of the Project, the indicative increases will be \$0.30 per annum for residential customers and \$0.80 per annum for small business customers in 2027-28, which is the final year of the 2023-28 regulatory period.

We have also estimated the project's contribution to a typical residential and small business bill for the 2028-2033 regulatory period. On average, the project is expected to contribute approximately \$2.80 per annum to bills for a residential customer and \$8.60 per annum for a small business customer.

As already noted, the Project will help ensure lower cost renewables provide a greater share of generation than would otherwise be the case, which will put downward pressure on bills. Although we have not factored these savings into the bill impact analysis, the RIT-T demonstrates that the expected benefits from the Project substantially outweigh the costs. Further information is provided Section 5.2 of this document.

1. Introduction

1.1. Purpose

This Application seeks the AER's approval to amend the Revenue Determination to incorporate the prudent and efficient capex, opex and associated revenue required to deliver the Project.

The Project comprises a program of technology initiatives and investments to upgrade the operational technology and tools for use in our control room and corporate offices. The case for these investments has been extensively explored through the RIT-T process and reviewed by independent experts, including GHD Advisory and DGA Consulting. The Project is supported by AEMO and EPRI, and their letters of support are provided as attachments to this Application.

The case for the Project was considered by the AER during its review of Transgrid's Revenue Proposal for the 2023-28 regulatory period. At that time, the AER concluded that the Project should be classified as a contingent project to allow for further work to refine the scope of work and cost estimates. In particular, the AER determined that three triggers would need to be satisfied for Transgrid to submit the Project for AER approval:¹²

- **Completion of the RIT-T.** Transgrid must demonstrate that the proposed technological upgrades and tools maximise net economic benefits in accordance with the RIT-T.
- **AEMO's written support.** Transgrid must obtain AEMO's written support for the proposed technological upgrades and tools, which is identified as the preferred option in the RIT-T, following completion of Early Works.
- **Board commitment to proceed.** Transgrid's Board must commit to proceed with the Project, subject to the AER amending the Revenue Determination pursuant to the NER.

Each of these triggers has been satisfied and, therefore, Transgrid is submitting this Application in accordance with the NER requirements.

1.2. Consumer benefits

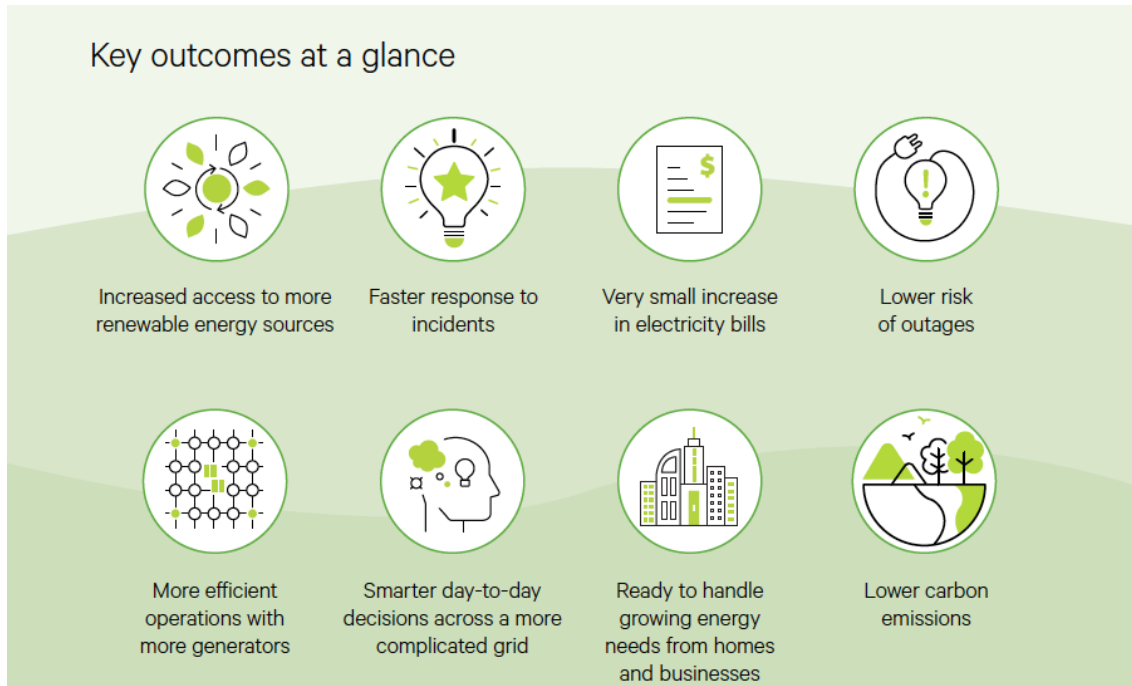
From a consumer perspective, the Project is expected to deliver significant benefits which are approximately twice the project costs. Specifically, the RIT-T analysis completed in October 2025 showed that the net economic benefits (after allowing for project costs) are expected to be \$118.9 million in present value terms. Specifically, the RIT-T analysis identified the following sources of benefit from the Project:

- **Fewer outages** – the proposed investments are expected to materially reduce expected unserved energy compared to the base case.
- **Lower generation costs** – the proposed investments enable us to operate the network less conservatively, effectively increasing network utilisation. As a result, we will be able to reduce the quantity and duration of constraints affecting lower-cost renewable generators, thereby reducing wholesale prices and greenhouse gas emissions.

¹² The precise wording of these triggers is provided in Appendix A.

In addition to the consumer benefits described above, Figure 1 provides a broader description of the Project outcomes, which include changes in that way that we work to deliver the service outcomes consumers expect. Figure 1 was developed in collaboration with the TAC to assist stakeholders and consumers in better understanding the rationale for the Project and the changes it will bring.

Figure 1 Outcomes and benefits from the proposed upgrades in Operational Technology



The RIT-T analysis also examined an alternative option (defined as Option 1) that involved a more limited scope of work than proposed in the Project. The RIT-T analysis showed that this lower level of investment would reduce the net economic benefit by more than 50% from \$118.9 million to \$52.0 million. The RIT-T therefore confirms that the Project provides an optimal level of investment that maximises net economic benefit.

1.3. Compliance with the NER

This Application and the supporting documents address the matters in clause 6A.8.2(f) of the NER, which require that:¹³

- the forecast total capex for the Project meets the threshold as referred to in clause 6A.8.1(b)(2)(iii), i.e. the larger of \$30m or 5 per cent of the MAR in the first year of the regulatory period
- the amounts of forecast capex and incremental opex reasonably reflect the capex criteria and the opex criteria in the NER, taking into account the capex factors and the opex factors respectively, in the context of the contingent project
- the estimates of incremental revenue for the 2023-28 regulatory period are reasonable
- the proposed commencement and completion dates are reasonable.

¹³ See NER cl 6A.8.2(e)(1) and 6A.8.2(f).

1.4. Structure of this document

This Principal Application document is structured as follows:

- Section 2 discusses the background to the Project, the proposed scope and delivery timeframes.
- Section 3 sets out our forecast total and annual capex for the Project, and explains our forecasting methodology.
- Section 4 sets out our forecast total and annual incremental opex for the Project, and explains our forecasting methodology.
- Section 5 presents a build-up of the forecast incremental revenue requirement associated with the Project, and also presents a customer bill impact assessment.
- Appendix A describes the regulatory requirements that pertain to this Application and sets out compliance checklists against the requirements in clause 6A.8.2(b) of the NER and the Guidelines.
- Appendix B presents the capex forecast from section 3 by asset class, consistent with the AER's PTRM.
- Appendix C presents the capex forecast from section 3 in \$2024-25 terms, to enable a comparison with the capex forecasts presented in the PACR;
- Appendices D-H provide further detail regarding the building blocks of the forecast incremental revenue requirement and MAR impact.
- Appendix I provides further detail regarding our forecast incremental opex, including opex beyond the 2023-28 regulatory period.
- Appendix J provides is our Risk Cost Basis of Estimation, which adds detail as to the basis for our estimates of risk costs.

All values in this Application are provided in \$2022-23, consistent with the Revenue Determination, unless otherwise stated.

The attachments and models for this Application are summarised in Table 1-1.

Table 1-1: Documents and models comprising this Application

Document /model number	Name	Content/purpose
A.1	Principal Application document (i.e. this SSR Operability CPA)	Requests that the AER amend the forecast capex allowance, forecast opex allowance and MAR in its Revenue Determination, based on the incremental capital and operating cost forecasts for the Project set out in this document.
A.2	DGA Consulting Independent Cost Review	Provides independent verification and assessment of reasonableness of the forecast capital and operating costs and overall program timing.
A.3	Letters of support from AEMO and EPRI	AEMO and EPRI each explain their support for the Project.

Document /model number	Name	Content/purpose
A.4	CEO letter confirming Board intention to proceed	Our Board has committed to proceed with the Project subject to the AER adjusting allowed revenue commensurate with the capex and opex estimates presented in this Application.
Capex and opex models		
A.5	Capex forecast model	Combines the direct non-labour forecast with the labour and overhead forecast before applying labour escalation and allocating the forecast to RAB asset classes.
A.6	Direct non-labour model	Includes the non-labour capex forecasts for each asset under development, prior to mapping the corresponding technology initiatives to the RAB asset classes.
A.7	Labour and overhead costs spreadsheet	Includes the incremental FTE forecast for the Project and calculates the associated labour and labour related costs.
A.8	Opex forecast model	Combines the incremental labour and non-labour opex forecast based on a bottom-up forecasting approach and applies labour escalation.
PTRM and other regulatory models		
A.9	Post tax revenue model - Revised	Sets out the calculation of the revised total revenue for the 2023-28 regulatory period using AER's model.
Compliance documents		
A.10	Confidentiality Claims	Explains the elements of this Application that are redacted and why.
Cost documents		
A.11	Internal Labour Estimation (Option B)	Explains the basis for Transgrid's bottom-up cost buildup.

2. Project background, scope and timeframes

This section provides background information on the Project, the proposed scope and timeframes. It explains that the Project scope, delivery model and timeframes have been developed through the completion of the RIT-T process, with input from independent experts including EPRI, GHD Advisory, DGA Consulting and AEMO. We have received letters of support for the Project from EPRI and AEMO, which are provided as attachments to this Application.

The remainder of this section is structured as follows:

- Section 2.1 explains the ‘project need’, which is driven by the challenges associated with the energy transition.
- Section 2.2 summarises our Early Works activities, including the completion of the RIT-T process.
- Section 2.3 describes the project scope and benefits of the preferred option identified through the RIT-T process
- Section 2.4 explains our delivery model and proposed timelines for delivering the Project
- Section 2.5 summarises the views expressed by EPRI and AEMO in support of the project scope in the RIT-T.

2.1. Project need, driven by the energy transition

The energy transition in NSW/ACT is occurring at a rapid pace and is driving increased complexity in power system operations and operational planning. The next decade will be a period of profound transformation as the reliability and security of the transmission system relies on a large number of small, distributed Variable Renewable Energy (VRE) connections and storage resources.

The renewable grid is inherently more complex and exposes consumers to the risk of a less reliable and secure energy supply. In particular, as coal plants retire, the grid loses system security services provided by synchronous generation, such as inertia, system strength, and frequency control. TNSPs must integrate new technologies like synchronous condensers, grid-forming inverters, and batteries to maintain system security. VRE sources like solar and wind are weather-dependent, leading to fluctuations in energy generation. This intermittency makes it challenging to predict and balance supply and demand in real-time.

The transmission control room is the nerve centre of the network, where operators work 24 hours per day each day of the year to monitor and manage the flow of power through the network through interaction with the assets on the network, in coordination with AEMO. Control centre operations are impacted through the following factors, which are driven by the energy transition:

- Frequent and unpredictable change in generation requiring voltage stability correction
- Maintaining stable operation of the network as inverter-based resources replace conventional generation
- Facilitating increasing volumes of outage requests for connections and co-ordination of many more parties
- More challenging management and coordination of lack of reserve planning and response with AEMO
- Increasing volumes and duration of contingency violations and radial load feeds, which exposes consumers to increased reliability risks

- Reduced network stability as a result of low minimum demand and reverse power flows.

These complexities are evidenced by the control room metrics in Figure 2 below, which shows significant growth between 2015 and 2023.

Figure 2: Measures of growing control room complexities, 2015-2023

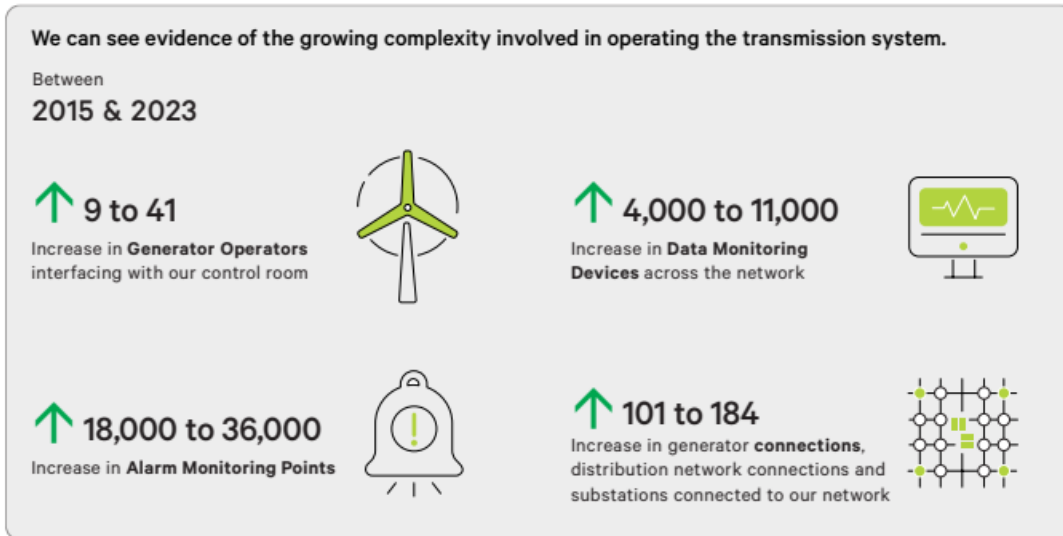
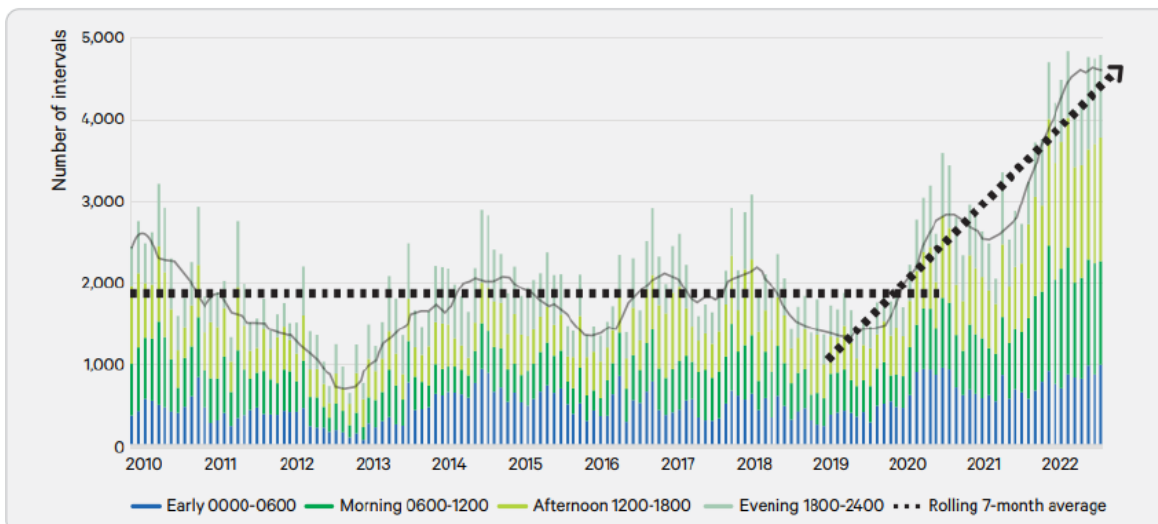


Figure 3 shows the significant increase in scenarios where the network is operating closer to the edge of its technical operational envelope. As the grid approaches the edge of its operating envelope there is an increasing risk that a disturbance will cause voltage instability and widespread outages. In this environment, we cannot rely on legacy operational capabilities that are ill-equipped to manage the increasing complexities and risks associated with the energy transition.

Figure 3: Increasing risk of violating of the NSW power system's technical envelope¹⁴



¹⁴ Operating intervals (5-minute granularity) per month when at least one credible contingency on the NSW transmission system would have resulted in a violation of the power system technical envelope.

At the time of our 2023-28 revised Revenue Proposal in December 2022, the need for the project had been established, but further work was required to prepare a detailed project scope and cost estimates. To progress these detailed requirements, we obtained independent advice from EPRI and GHD Advisory and worked closely with AEMO to determine the requirements and desired outcomes, rather than specific solutions.

By October 2024, Transgrid had undertaken sufficient work to progress the RIT-T, which is discussed in the next section. Throughout the RIT-T process, we continued to work closely with independent experts, and AEMO to assess the scope, likely costs and benefit realisation of alternative options. In relation to the project need, this further work confirmed that upgrades to Transgrid's operational capability are urgently needed, as explained by EPRI in its recommendation report:¹⁵

“Transgrid’s operability capability needs to be aligned with the network as it is today and robust enough to meet the demands of the power system in the future. Aligning the operability upgrade requirements with the VRE growth projections for demand and renewables in the ISP allows Transgrid to consider the need for investment under various ISP scenarios.”

Transgrid should develop operational capability for the most likely future energy scenarios – the Step Change and Progressive Change scenarios by 2030. The time element and pace of growth in the network are important considerations. The Step Change scenario projects VRE in the NSW to grow by 19 GW by 2030.

This rate of growth is likely to continue and may accelerate beyond 2030. Even if the Step Change scenario growth rates are not reached by 2030, they will be reached in the early 2030s. Time is also a factor in the need for imminent investment, as the nature of IT projects for control centres and high-reliability organisations requires many years from planning to commissioning. Also the vendor marketplace is small and stretched, as most other system operators around the world are embarking on similar capability uplift projects.

To summarise, it would not be operationally prudent to wait until the early 2030s, with accelerating growth in VRE and the transmission network, to begin the process of uplifting Transgrid’s operational capability – a process which will take until the mid-late 2030s to deliver adequate solutions.”

2.2. Early Works and RIT-T

As explained in section 1.1, this CPA is subject to three trigger events including the following requirement:

- Transgrid must obtain AEMO’s written support for the proposed technological upgrades and tools, which is identified as the preferred option in the RIT-T, following completion of Early Works.

Transgrid notes that the term ‘Early Works’ is not defined in the CPA trigger. Nevertheless, Transgrid considers that it has completed Early Works by undertaking extensive analysis through the RIT-T process, including the completion of independent technical assessments and proportionate market testing to validate scope, costs, and delivery approach. In this case, those activities were undertaken through targeted technical assurance and a structured RFI process, which is discussed in further detail in section 3.2.

¹⁵ Evolving Transgrid’s Operational Technology (OT) Capability Independent report by EPRI to evaluate Transgrid’s Operational Technology (OT) Capability, April 2025, pp 21.

Sections 2.2.1 to 2.2.3 below summarise each stage of the RIT-T process, noting that the full documentation is available on Transgrid’s website.¹⁶ Section 2.2.4 provides a description of the Alarm Management Project, which we recently completed in order to prepare for the future intelligent alarm processing solutions.¹⁷ As an enabling initiative, the Alarm Management Project is also regarded as an Early Works activity as the completion of this initiative facilitates the timely delivery of the Project. The costs of Early Works have been included in this Application in accordance with the Revenue Determination.¹⁸

2.2.1. Project Specification Consultation Report

Transgrid commenced the RIT-T process with the publication of the Project Specification Consultation Report (PSCR) on 14 October 2024.¹⁹ The PSCR identified three potentially feasible options which would provide progressively increasing levels of operational capability:

- **Option 1: Reactive capability**, which would provide enhancements to Transgrid’s existing core operating technology (OT) capabilities to improve the reactive capabilities of Transgrid’s control room and corporate offices.
- **Option 2: Proactive capability**, which would extend Option 1 by adding further enhancements across a portfolio of Transgrid’s existing OT capabilities, as well as additional new capabilities, so that Transgrid can proactively plan for, and respond to, operational issues across its control room and corporate offices.
- **Option 3: Predictive capability**, which would provide a suite of advanced enhancements to existing capabilities, as well as adding advanced new capabilities, to enable Transgrid to employ a predictive approach to operations in our control room and corporate offices.

Each option also identified the required increase in staffing levels to leverage the capability from the technology upgrades. The PSCR also discussed the two options that were not considered to be technically feasible and, therefore, were not progressed. These options were:

- A significant uplift in human resources, without investing in operational technologies and tools. This option would not address the risks arising from legacy systems and processes in a changing operational environment.
- A fully automated technology solution that could be implemented without additional staffing. The risks and costs associated with this option were assessed as being unacceptable.

2.2.2. Project Assessment Draft Report

The PSCR was followed by the publication of the Project Assessment Draft Report (PADR) on 12 May 2025, followed by a 6-week consultation period²⁰ The PADR refined the set of credible options based on further analysis and independent advice. It also presented an NPV analysis of the costs and benefits of the credible options in accordance with the RIT-T requirements.

¹⁶ Available at: <https://www.transgrid.com.au/projects-innovation/system-security-operability/>

¹⁷ Available at: https://www.transgrid.com.au/media/f5po3uzu/epri-transgrid-padr-recomendations_final.pdf

¹⁸ AER, *Attachment 5 – Capital expenditure | Final decision – Transgrid transmission determination 2023–28*, April 2023, pp 30.

¹⁹ Available at: <https://www.transgrid.com.au/media/klpbpcrg/transgrid-system-operability-pscr.pdf>.

²⁰ Available at: https://www.transgrid.com.au/media/ghufc1va/transgrid-padr_operational-tools-final-version.pdf.

The benefits assessment in the PADR adopted a ‘case study’ approach, which is a transparent and tractable method of quantifying the market benefits that would be obtained from proposed upgrades to Transgrid’s operational tools.

In particular, the case studies link technology upgrades in operational capabilities to specific, distinct outcomes and identifies the consequential market benefits. This approach enables us to identify how further upgrades to our operational capability would improve market outcomes and deliver additional benefits.

In addition to providing a transparent method for assessing upgrades to our operational capability, the case study assessment of market benefits was conservative in two respects:

- the approach quantified a subset of the total market benefits that can be readily identified using a set of transparent assumptions
- we adopted conservative modelling assumptions to ensure that benefits were not overestimated.

Table 2-1 below summarises the benefits that were identified from each of the case studies.

Table 2-1: Summary of market benefit case studies (\$m)

ID	Case study	Benefit driver
Case study 1	Reduction in the likelihood of unserved energy	<p>Early detection and intervention for faults reduces the probability of an event escalating to an outage event with unserved energy, as well as the need to operate the network more conservatively and take assets offline. This outcome arises from better visibility of asset conditions and network fault levels, prioritisation of information and supported decision making, which together reduces the cognitive load on control room operators in a complex operating environment.</p> <p>The RIT-T only quantifies the benefits related to the reduction in the likelihood of unserved energy and does not quantify any additional benefits from reduced risk of asset failure or less conservative network operation.</p>
Case study 2	Increase in network utilisation	Alleviating pre-emptive and conservative static limits on inverter-based generation, through real-time and near-term network analysis replacing static scenario measurements. This facilitates less conservative network asset utilisation by enabling dynamically changing inverter limits and providing the ability to operate closer to the power system’s technical envelope.
Case study 3	Reduction in the duration of outages	Reduction in planned outage duration associated with switching operations through automation of planned generator inverter changes.

In addition to assessing the benefits, the PADR also included a detailed consideration of the scope and costs for each option, which was centred on the RFI process as discussed in further detail in section 3.2.1. The cost benefit analysis in the PADR identified Option 2 as the option that maximises net market benefits, and therefore as the preferred option in accordance with the RIT-T.

2.2.3. Project Assessment Conclusions Report

Following the publication of the PADR, we undertook additional work and obtained an independent assessment of the cost estimates for Options 1 and 2 from DGA Consulting. This further work resulted in minor changes to the scope of works for both options, and improvements to the project scheduling and the timing of costs. These changes led to minor changes in the cost-benefit assessment.

We also continued to work with the two vendors from the RFI process to obtain updated cost estimates for those technology initiatives where the scope of works had been refined. DGA Consulting reviewed these updated cost estimates, and we continued to work with each vendor to improve the cost estimates for each option and the associated initiatives.

The PACR confirmed the findings from the PADR. In particular, the cost benefit analysis concluded that both Options 1 and 2 are expected to deliver net benefits, with Option 2 providing a NPV of \$118.9 million compared with \$52.0 million for Option 1 on a weighted average basis. Accordingly, Option 2 was confirmed as the preferred option. The Project presented in this Application is fully aligned with Option 2 in the RIT-T.

2.2.4. Alarm Management Project

During the scoping exercise for the Project, it became evident that urgent work was required to address the rapid increase in the number of alarms and alarm monitoring points, which increased from approximately 18,000 in 2015 to 36,000 in 2023 and 55,000 in February 2025. To address this urgent need, we completed the Alarm Management Project at a cost of \$2.96 million to reduce alarm volumes. That project was delivered on time and on budget.

In addition to addressing the unacceptable risks associated with the increase in the number of alarms, the Alarm Management Project was also required in order to prepare for future intelligent alarm processing solutions, as noted by EPRI in its independent report.²¹ As an enabling initiative, the Alarm Management Project's actual expenditure incurred has been included in this Application.

2.3. Project Scope and Benefits

The Project comprises 10 integrated initiatives that together address the risks and challenges arising from the energy transition, and maximises the net economic benefits in accordance with the RIT-T. Table 2-2 below briefly describes the scope of work for each of the 10 integrated initiatives, the benefits that will be provided and the program dependencies.

An important input to the Project scoping exercise was Transgrid decisions to upgrade its existing GE Vernova (GEV) Advanced Energy Management System (AEMS) rather than introducing a new AEMS system. This decision was made because the GEV AEMS is a fit-for-purpose, and industry leading solution used by other NSPs and AEMO. Retaining this core technology enables Transgrid to focus on obtaining complementary operational technologies without 'starting from scratch' on our full suite of operational technologies, which we would expect to be a more costly exercise. As a result, all technologies are compatible with the GEV AEMS.

²¹ Available at: https://www.transgrid.com.au/media/f5po3uzu/epri-transgrid-padr-recomendations_final.pdf

Table 2-2: Project scope, benefits and interdependencies

	Initiative	Scope	Benefits	Integrated program dependencies
1.	Outage management	<ul style="list-style-type: none"> Configure SCADA to send control signals to reduce or increase the number of inverters. Provide portal access for generators to view the status and receive notification of inverter switching activities undertaken during the outage. 	<ul style="list-style-type: none"> Reduce outage and switching execution time, directly lowering renewable curtailment duration. Improve coordination and compliance through automated workflows and controlled information access supporting increasingly complex outage switching requirements. 	The execution of switching steps requires the SCADA/AEMS system.
2.	Alarm management, visualisation & situational awareness enhancements	<ul style="list-style-type: none"> Update master alarm/SCADA point source, naming configuration, priorities and grouping rules. Deploy rules management solution to manage versions of alarm/SCADA point configurations, import and export alarm configurations. Configure AEMS/SCADA to import configurations, to report on alarm performance, group to a single parent alarm and include alarms relative to technical envelope boundaries. Implement alarm flood suppression and off normal alarm detection and identification. Ungrouping of legacy alarms that are concentrated to a single alarm. Correlate alarms with external sources (i.e. weather, fire, defects, etc). Workflow alarms to create defects and guide operator response actions. 	<ul style="list-style-type: none"> Reduce nuisance alarms and alarm floods so operators can identify and act on credible system risks faster. Faster identification of root causes during alarm flood and high-stress system conditions. More timely and accurate decision making to reduce risk of blackouts, reduce risk of asset failure and reduce risk to personal safety. 	<ul style="list-style-type: none"> Requires access to operational data (i.e. OARaNTEC). Requires advanced alarm functionality within the SCADA/AEMS. Integrates with document management solution. Requires SCADA/AEMS initiative to securely integrate external data sources with SCADA/AEMS. Requires operator console screen reconfiguration to optimise visualisation for situational awareness.

	Initiative	Scope	Benefits	Integrated program dependencies
3.	Fault level & system parameter monitoring & power system analysis capability	<ul style="list-style-type: none"> Configure AEMS Fault Level Calculation (FLC) application to enable real-time FLC execution, with updated modelling parameters. Increase AEMS data sets to include harmonics and EMT technical envelope data. Implementation of the AEMS time domain capabilities (i.e. voltage control and transient stability analysis). Tuning to improve accuracy of AEMS calculations for impedances, mutual coupling data, ratings, and fault definition cases. 	<ul style="list-style-type: none"> Reduce unnecessary binding constraints and renewable curtailment caused by conservative or stale fault level assumptions. Enable faster, defensible operational decisions by automating fault level, impedance, and parameter calculations using maintained technical envelope data. AEMS time-domain capabilities allow operators and planners to simulate how the power system responds over time to disturbances, controls, and restoration actions, enabling secure operation closer to technical limits in a highly dynamic grid. 	<ul style="list-style-type: none"> Requires access to operational data and network models for analysis. Requires functionality within the AEMS to automate calculations. Provides input for operational planning and data management initiative to maintain an accurate technical envelope data.
4.	SCADA/Advanced Energy Management System (AEMS)	<ul style="list-style-type: none"> Upgrade GE SCADA software suite to version 3.5. Upgrade GE AEMS applications to version 3.5 (State Estimator, Contingency Analysis, Study & DTS). Upgrade data network to securely share data between systems. Replacement of SCADA/AEMS platform infrastructure, being server, storage, network, and desktop computers. 	<ul style="list-style-type: none"> Provide a stable platform that reliably supports integration of operational technologies without manual workarounds. Secure transfer of data in and out of the SCADA/AEMS. Enable operators to access supported, secure SCADA/AEMS capabilities with reduced system risk and downtime during real-time operations. 	<ul style="list-style-type: none"> Facilities upgrade necessary to increase data centre capacity to host additional on-premises hardware. This SCADA/AEMS initiative enables the secure integration of data management and network models into the SCADA/AEMS. This SCADA/AEMS initiative delivers software functionality required by other initiatives (e.g. alarm management, fault level, forecasting, etc).

	Initiative	Scope	Benefits	Integrated program dependencies
5.	Facilities	<ul style="list-style-type: none"> Replace operator consoles and associated minor building modifications to accommodate wallboard. Additional workstations to accommodate additional support staff. Increase floor space and services for one SCADA/EMS datacentre. Increase capacity of backup power supplies at another datacentre. Establish fit for purpose training rooms. 	<ul style="list-style-type: none"> Enable safe and effective adoption of new tools by aligning control room layout, displays, and workstations with upgraded visualisation and situational awareness capabilities. Ensure sufficient on-premise datacentre capacity to operate upgraded SCADA/AEMS and dependent applications. Accommodate additional staff that support the new technologies 	<ul style="list-style-type: none"> Visualisation and situational awareness technology enhancements must be aligned with control room layout to support effective, human-centred operations. SCADA/AEMS system requires more on-premises datacentre capacity to securely accommodate the hardware required for the new technologies.
6.	Data management and network modelling system	<ul style="list-style-type: none"> Establish an operational data management platform using a common information model (CIM) to share planning and operational data. Establish an Operational Asset Ratings and Network Technical Envelope Data (OARaNTEC) solution to be the Single Version of The Truth (SVoTT) for operational ratings. 	<ul style="list-style-type: none"> Provide operators and planners a single, trusted source for real-time ratings and network limits used in operational decisions. Reduce conservative operating margins caused by inconsistent or outdated technical envelope data. 	<ul style="list-style-type: none"> Operational data is an input for operational planning, forecasting, alarm management, fault level and AEMS.
7.	Training technologies and operational document management systems & operational planning systems	<ul style="list-style-type: none"> Establish an advanced simulator-based SCADA/AEMS training environment. Establish an enhanced management system for operating manuals. Establish six new operational planning roles to carry out operational studies. Procure additional operational planning software (PSSE and PSCAD) and hardware required for the new roles. 	<ul style="list-style-type: none"> Improve operator performance during incidents through faster access to procedures and realistic simulator training. Reduce onboarding time and variability in operator response to complex system events. Strengthen operational decision quality by ensuring credible, up-to-date technical limits are defined and maintained. 	<ul style="list-style-type: none"> All initiatives require simulated operator training of new technologies and workflow integration of operating instructions. The facility initiative will establish fit for purpose training rooms. The fault level & system parameter monitoring & power system analysis initiative will require establishing an ongoing management of technical limits and operating parameters.

	Initiative	Scope	Benefits	Integrated program dependencies
8.	Operational forecasts and look ahead contingency analysis	<ul style="list-style-type: none"> Uplift to AEMS to provide persistent access to AEMO forecast data. Configure and tune the AEMS contingency analysis tool for day-ahead decision support and forecasting. 	<ul style="list-style-type: none"> Enable operators to identify and mitigate emerging security risks hours to days ahead of real-time. Improve preparedness for outages and forecast conditions, enabling operators to pre-emptively setup the network for expected conditions, reducing reactive interventions. 	<ul style="list-style-type: none"> Requires access to operational data and network models. Requires functionality within the AEMS to automate forecasts and contingency analysis. Provides input to operational planning to undertake studies to prepare plans for forecast conditions.
9.	Wide area monitoring	<ul style="list-style-type: none"> Securely pass Phasor Measurement Unit (PMU) data to the AEMS. Configure AEMS wide area monitoring module to display phase angle difference and update the state estimator. 	<ul style="list-style-type: none"> Improve real-time system visibility and state estimation accuracy to support secure switching and disturbance response. Enable early intervention due to early disturbance detection. Reduce risk of cascading faults. 	<ul style="list-style-type: none"> Input into AEMS to improve accuracy of system calculations.
10.	Smart transmission device management	<ul style="list-style-type: none"> Uplift in the capability of the AEMS to receive new SCADA point types from smart devices and schemes. 	<ul style="list-style-type: none"> Improve operator awareness and confidence in maintaining system security closer to technical limits. Reduce avoidable unserved energy events by making protection scheme behaviour transparent in operations. 	<ul style="list-style-type: none"> Schemes are executed using SCADA/AEMS. Additional smart transmission schemes are required to enable operation closer to technical limits, supported by enhanced data management of the technical envelope. Increased schemes that are identified from the operational planning area.

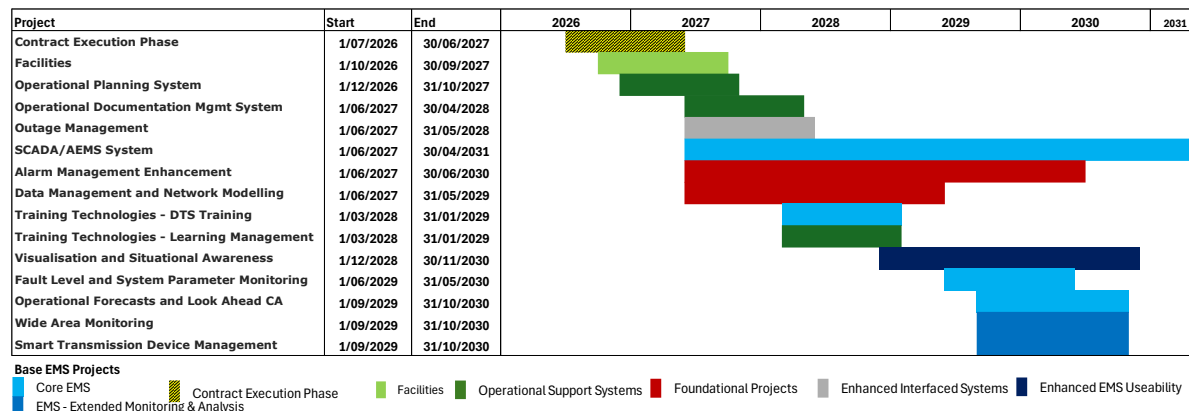
2.4. Delivery model and timeframes

In accordance with the market engagement process, we have adopted an SI delivery model. Using an SI to deliver the suite of projects overcomes the challenges of managing sub projects with multiple interdependencies. The SIs identified through the market engagement process are large global organisations which reduce delivery risk by sourcing a team of SMEs and project experts that are able to provide a coordinated approach across a complex program of work. The SI delivery model also ensures that a single contracting entity can be held responsible for delivery.

The proposed timescales and sequencing have been developed to further reduce delivery risk and ensure that benefits can be obtained from the Project as soon as practicable. DGA Consulting has reviewed each of the timing of each initiative and the sequencing to ensure that the Project can be delivered prudently and efficiently.

The proposed project schedule is presented in Figure 4.

Figure 4 Proposed project schedule



2.5. Letters of support from EPRI and AEMO

Transgrid has actively collaborated with AEMO throughout the RIT-T process to ensure that the preferred option is consistent with both party's operational needs. This collaboration is especially important as Transgrid's and AEMO's operational capabilities and systems have significant interdependencies, and therefore both parties need to work together to:

- avoid unnecessary duplication of investment (and effort across our organisations)
- ensure our investment complements AEMO's operational capabilities and responsibilities.

As already noted, we engaged EPRI to assess our operational technology capabilities and gaps. AEMO provided input into the independent assessment conducted by EPRI to validate and prioritise the operational capabilities and tools we require to meet the evolving operational needs of our control room. The collaborative engagement between Transgrid, EPRI and AEMO has ensured that the operational technologies and tools that the Project will deliver are appropriately scoped.

As part of that process, Transgrid engaged with AEMO's technical specialists through several deep dive workshops to discuss in detail the capabilities of Transgrid's proposed investments and how the enhanced capabilities would interact with AEMO's systems. These workshops confirmed the expected benefits from the improved capabilities, including the ability to operate the network in a less conservative manner. Furthermore, the proposed upgrades will enable AEMO to be notified of changes in system constraints, which will facilitate broader operational benefits.

In June 2025, EPRI provided the following commentary in support of Transgrid's decision to adopt Option 2 and noted the importance of proceeding with that investment urgently:²²

"Given the long lead time for approvals, funding and procurement, it is essential that all transmission owner/operators invest and develop continuously in their OT system capability, with a forward time horizon of 5-7 years. To have systems capable of managing the 2030 network in place by 2030, it is essential to start the approvals, procurement, and design process as early as possible. To address 2030 network risks, technology needs to be updated some years in advance.

²² Available at: https://www.transgrid.com.au/media/f5po3uzu/epri-transgrid-padr-recomendations_final.pdf

In the April 2025 report that assesses the Transgrid operational capabilities, EPRI recommended:

- A generalized uplift in operational technology capability to address operability gaps, categorised in 10 different technology solutions
- The need for continuous investment in operational technology capability given the long lead times and uncertainty associated with long term electricity system operation.

[...]

EPRI can endorse Transgrid's recommended approach, to proceed with Option 2 for operational technology capability uplift as it is judicious and aligns well with the recommendations from the original Evolving Transgrid's Operational Technology (OT) Capability report."

AEMO also endorsed Option 2 in its letter of support, which included the following commentary:²³

"The EPRI ETOTC report offered 3 recommendations for technology solution initiatives, with Option 2 (Proactive Capability) achieving desired outcomes. Option 1 (Basic Capability Uplift) will be too limited in scope and has built in constraints which will not go far enough in mitigating potential reliability risks given current growth patterns. Option 3 was ruled out after a market analysis, due to inherent uncertainty in needs.

Option 2 (Proactive capability) addresses the technology and the monitoring decision making and controllability capability uplift required and is consistent with AEMO's and other interconnected TNSP's and DNSP's functional obligations to manage the transmission network.

Transgrid's proposal also aligns with AEMO's own Operations Technology Program Roadmap and Engineering Roadmap. These identify the engineering challenges that emerge from the transition to a renewable energy system, and the uplift in operations capabilities that AEMO needs to enable this transformative change while maintaining electricity system reliability, security, and resilience.

Importantly, there are interdependencies between the roles of AEMO and Network Service Providers (NSPs) and systems and capabilities must effectively interface, support and complement each other. Investments by AEMO alone will not be sufficient; a capability uplift will also be needed by NSPs for system security to be maintained across the National Electricity Market (NEM). These investments are urgently needed to manage the security of the power system and to complement investments AEMO is making under its own Operations Technology Roadmap and associated program.

AEMO and Transgrid have validated the technology roadmap alignment required to realize the benefits. Each have engaged collaboratively to date to define emerging power system needs, and the future operational technology and tools required to address them. We look forward to continuing to work together to refine and implement solutions to maintain a reliable and secure power system, in the best interests of consumers."

Transgrid welcomes the letters of support from EPRI and AEMO, which confirm that the Project scope is prudent and efficient. We also note that the outcome of the RIT-T process demonstrates that the Project maximises net market benefits.

²³ Available at Attachment A.3: <https://www.transgrid.com.au/media/jnrhr0eq/20250915-update-support-transgrid.pdf>

3. Capex Forecast

This section sets out the forecast capex that Transgrid considers to be required to undertake the Project, together with the supporting evidence that this expenditure is prudent and efficient. The forecast capex in this Application is consistent with the estimates adopted in the PACR, subject to the following modifications:

- we have made minor revisions to some capex elements (described in section 3.1.1), and added in labour escalation and equity raising costs (consistent with Transgrid’s approved capex model, opex model and PTRM)
- we present the capex in this Application in real \$2022-23 terms.²⁴

3.1. Capex Forecast

Table 3-1, Table 3-2, and Table 3-3 below provide a breakdown of the capex forecast for the Project by technology initiative and for each year of the current and next regulatory periods. Appendix B breaks down these same estimates by asset class as required for the AER’s PTRM.

Table 3-1: Overview of forecast capex (\$m)

Capex initiative	Total capex	Capex in 2023-28 regulatory period
Outage management	1.4	1.3
Alarm management, visualisation and situation awareness enhancement	33.7	8.9
Fault level and system parameter monitoring and power system analysis capability	6.8	-
SCADA/AEMS system ²⁵	33.2	18.1
Facilities	5.1	4.6
Data management and network modelling system	27.1	16.8
Training technologies, operational document management system and operational planning systems	13.1	9.3
Operational forecasts and look-ahead contingency assessment	4.1	-
Wide area monitoring	6.4	-
Smart Transmission Device Management	3.8	-
CPA submission ²⁶	5.8	5.8
Program implementation	22.1	9.7
Contingency/risk	-	-
Total (excluding labour escalation and equity raising costs)	162.5	74.5

²⁴ This is consistent with the PTRM for our 2023-28 regulatory determination. The PACR presented capex forecasts in \$2024-25 terms. Appendix C presents the CPA capex forecast in \$2024-25 terms, to aid the AER and other stakeholders in comparing these updated forecasts with the PACR forecasts.

²⁵ This includes the Dual Homing Initiative.

²⁶ CPA submission includes the CPA submission costs, but also Early Works which include Project planning, including preparation of RIT-T and submission of the CPA, independent expert reviews; engagement with service providers; and preparation of this Application. These activities are described in Section 2.2.

Capex initiative	Total capex	Capex in 2023-28 regulatory period
Labour escalation ²⁷	0.2	0.0
Equity raising costs	0.8	0.8
Total Capital Expenditure²⁸	163.5	75.3²⁹

Table 3-2 below presents the Project costs for each year of the 2023-28 regulatory period. It shows costs from 2023-24 onwards, which reflect the extensive work undertaken to scope the Project and undertake the analysis described in section 2 of this Application, which constitute Early Works. The AER has stated that the costs of Early Works are ‘recoverable through the contingent project process if the costs are determined to be prudent and efficient’.³⁰

Table 3-2: Forecast capex by year – 2023-28 regulatory period (\$m)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Total capex forecast	4.5	3.9	1.1	19.2	46.6	75.3

Note: Total may not sum due to rounding.

Table 3-3 presents the forecast annual capex for each year of the next regulatory period, with Project completion expected in July 2031.

Table 3-3: Forecast capex by year – next regulatory period (\$m)

	2028-29	2029-30	2030-31	2031-32	2032-33	Total
Total capex forecast	34.7	36.9	16.5	0.2	-	88.2

Note: Total may not sum due to rounding.

3.2. Capex Forecasting Approach

This section explains the basis for our capex forecasts, which reflects our SI delivery model and proposed project timelines which were set out in section 2.4. The SI delivery model means that each technology initiative that comprises the Project will be delivered through a combination of SI and Transgrid resources. As explained below, we have ensured that the capex forecasts reflect an appropriate allocation of tasks between the two parties, which has been reviewed by DGA Consulting to ensure that the scope of work is fully covered, with no missing activities or duplication.

²⁷ Labour escalation costs are calculated by multiplying the projected labour components of forecast capex by the real labour cost escalators approved in the AER’s Revenue Determination.

²⁸ Equity raising costs and labour escalation costs were not included in the PACR. Equity raising costs are calculated using the AER’s PTRM and are explained in further detail in Appendix G.

²⁹ The contingency allowance discussed in section 3.2.3 is included within the technology initiatives and total above. Totals may not sum due to rounding.

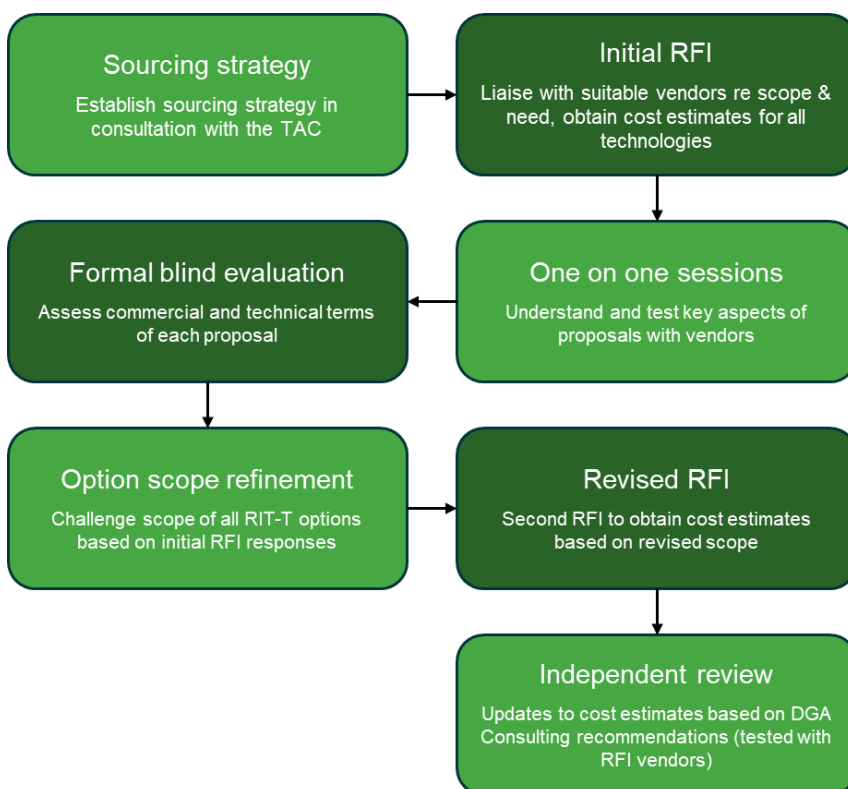
³⁰ AER, *Attachment 5 – Capital expenditure | Final decision – Transgrid transmission determination 2023–28*, April 2023, pp 30.

3.2.1. System Integrator costs

As explained in Section 2, Transgrid undertook a market-based process to estimate the project scope and costs. Figure 5 provides an overview of our approach, which commenced in late 2024 with a sourcing strategy followed by an initial RFI that was designed to obtain market information regarding:

- the availability of, and capacity to deliver, the required technologies
- right-sizing solution designs and associate software products
- alternative delivery approaches and schedules
- cost estimates for each of the technologies.

Figure 5 Market based process for estimating SI costs



We received four responses to the initial RFI, which were from [REDACTED]. The three other invited parties [REDACTED] did not respond. The responses revealed that:

- the proposed capability improvements could be achieved with fewer technology initiatives, but
- the capex and opex cost for each initiative were substantially higher than expected.

As shown in Figure 5, Transgrid subsequently undertook one-on-one sessions with all four respondents, followed by a formal blind price evaluation of the responses. As a result of that process, we concluded that two respondents [REDACTED] had not demonstrated adequate technical ability to meet the identified need, leaving two respondents [REDACTED] to proceed to the Option Scope Refinement and Revised RFI stages.

As there were cost and scope variations across technology initiatives between the two SIs, we applied a final stage of independent review to determine the prudent and efficient cost. In particular, we engaged DGA Consulting to conduct a cost and scope review, which involved direct engagement and challenge with each

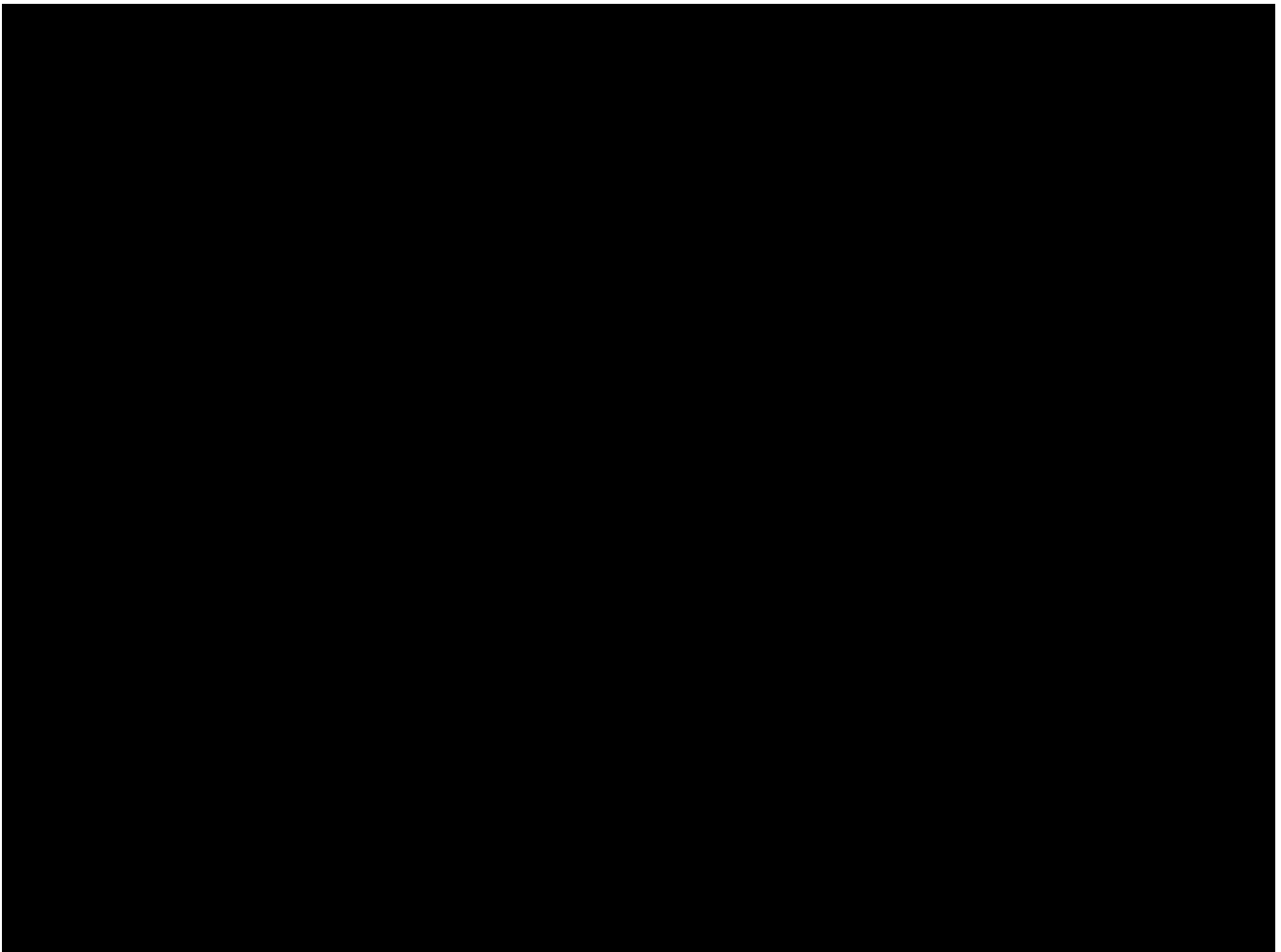
SI to ensure that each estimate reasonably reflected efficient costs of delivering the proposed scope of work. During this process, DGA Consulting tested the cost estimates for each technology initiative to ensure that reasonable and consistent assumptions were adopted in each case, while noting that each SI was able to adopt their preferred solutions in response to the RFI.

To develop our forecast for each technology initiative, we adopted the average of the revised estimates provided by the two SIs following DGA Consulting's review.

A further efficiency saving (adjustment) has been applied to the average cost for specific initiatives where DGA Consulting considered that further savings could be obtained through a competitive tender process. We consider that this approach ensures that the forecast expenditure is prudent and efficient, having obtained market-based estimates and then applied an efficiency adjustment based on independent expert advice.

Table 3-3-1 below shows the estimates provided by each SI following DGA Consulting's review; the average cost estimate for each technology initiative; and the efficiency adjustment advised by DGA Consulting. The resulting forecast total project cost for the SI component of the Project is \$98.0 million compared to the estimates of [REDACTED] provided by the two SIs.

Table 3-3-1: Cost estimates by System Integrator (\$M, 2024-25)

The table content is completely redacted with a large black rectangular block.

³¹ Hardware costs for all initiatives are centralised under the SCADA/AEMS system initiative in [REDACTED] response.



Our view is that the cost estimation process, which involved extensive engagement with global service providers combined with an independent review, has produced a scope of work and cost estimate that is prudent and efficient. DGA Consulting's report includes the following commentary, which confirms our view:³²

“DGA believe that Transgrid's market engagement approach with SIs has been extensive and provides a strong basis for the cost estimates. Transgrid's market engagement process is common and appropriate for estimating a 5 year Operational Technology program as a full Request for Proposal (RFP) would be impractical at this stage in a project lifecycle to improve the cost estimates.

The current level of interaction with the SIs has been appropriate for the market based assessment with the level of analysis and clarification similar to an RFP process. The interaction with SI over eight months included multiple reviews, a series of questions, several workshops and resulted in multiple revisions of the SIs' estimated costs. This ensured both SIs had a consistent set of GEV costs, phased software deliveries within their schedules, consistent opex/capex allocations and clarity on the split between Transgrid and SI activities. This process led to a material amount of cost refinement. In DGA's view any further interaction may impact on the competitive nature of the RFP process.”

3.2.2. Transgrid's internal costs

Transgrid's internal cost estimates for the Project were developed using a structured, bottom-up methodology. Our internal cost forecast has been prepared to address the resource requirements to support the scope of work that will be provided by the SIs. Our resource requirements include labour, equipment, materials and expenses to ensure that each technology initiative can be delivered in accordance with the project schedule.

Our internal labour costs were developed through a series of facilitated workshops involving SMEs on project delivery, control room operations, SCADA/EMS engineering, data, testing, architecture, change management and facilities. These workshops drew directly on Transgrid's recent experience in delivering comparable operational technology and facilities projects to determine the resourcing requirements and profile in accordance with the Project schedule.

³² DGA Consulting, *Independent Review of System Security Roadmap Operational Technology Upgrade Costs – Contingent Project Application*, 26 March 2026, version 1.0 Final, pp 15.

The scope, assumptions and quantum of Transgrid's internal delivery labour distinguish Early Works expenditure already incurred from forward-looking internal support for delivery of the preferred option. These are set out in detail in A.11 Internal Labour Estimation (Option B) document, which underpins the internal cost forecasts included in this Application.

The scope of our labour costs includes the following project delivery activities:

- Project management, administration, and risk management
- Testing and validation, including SCADA and test management resources
- Technology architecture and IT support (infrastructure, security, and networks)
- Health, Safety, and Environment (HSE) oversight
- Change management and process transition activities
- Data governance and management roles
- Control centre and SCADA operations support
- Outage management software development
- Facilities oversight for works at Newcastle and Wallgrove
- Project close-out and handover activities.

We engaged DGA Consulting to ensure that the scope of work attributable to our internal labour is consistent with the scope and cost estimates provided by the SIs.

The Project requires upgrades to control room and data centre works to support the new operator visualisation initiatives and on-premise SSR-related equipment and servers. This work is essential to ensure that the facilities infrastructure is able to support the Project objectives.

The facilities-related costs for the Project were scoped based on the specific requirements of the Newcastle and Wallgrove control rooms and data centres. The scope included modifications to control rooms to support new operator visualisation initiatives, such as demolition, partitions, floor and wall finishes, painting, electrical and mechanical services, furniture, and fixtures. Additionally, the scope includes the refurbishment of existing structures to accommodate 18 additional staff, and includes provisions for power, air conditioning, communications, computers, and office furniture.

The Newcastle Data Centre requires a complete upgrade, including power, air conditioning, fire systems, racks, flooring, and security, while the Wallgrove Data Centre requires a power upgrade to house SSR-related equipment and servers. These upgrades were also scoped to ensure the facilities are capable of supporting the new technologies and operational requirements that will be delivered by the Project.

The facilities-related costs are included in our forecast equipment, materials and expenses for the Project, which also include:

- High-spec servers for operational planning systems
- New control room operator consoles for production and training rooms
- Accommodation for additional staff
- Office setup for the project team
- Travel and accommodation expenses for SMEs
- Training costs for courses such as GE GridOS
- Recruitment and visa fees for outsourced consultants
- Costs for setting up tailored contract terms and conditions

Our cost estimates were developed using the 'MTWO' cost estimating tool. The MTWO cost estimating tool uses actual costs built up over more than 10 years from labour quantities from recently completed projects. The MTWO estimating database is reviewed annually to reflect the latest outturn costs and confirm that estimates are within their stated accuracy range and represent the most likely expected cost of delivery (P50 costs). As part of this annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies to ensure that the cost estimates reflect the best available information. For further information on this, please see Attachment A.11 Internal labour estimation (Option B).

In summary, the cost estimates for our internal costs reflect a comprehensive build-up of the resource requirements, noting the importance of aligning this scope of work with the Project requirements and the works to be delivered by the SIs. Table 3-2-2 shows the Transgrid cost by initiative.

Table 3-3-2: Transgrid's internal cost estimate by initiative

Initiative	Cost (\$M, 2024-25)	Cost (\$M, 2022-23)
Outage management	1.5	1.4
Alarm management, visualisation and situation awareness enhancement	8.5	8.0
Fault level and system parameter monitoring and power system analysis capability	0.7	0.6
SCADA/AEMS system	7.3	6.9
Facilities	5.4	5.1
Data management and network modelling system	5.4	5.1
Training technologies, operational document management system and operational planning systems	3.6	3.4
Operational forecasts and look-ahead contingency assessment	1.4	1.3
Wide area monitoring	1.5	1.4
Smart Transmission Device Management	0.3	0.3
Program implementation	16.5	15.5
Total	51.9	49.0

DGA Consulting has provided an independent review of our cost estimates, which confirms that our internal resource requirements have been appropriately scoped:³³

“DGA is satisfied that there is clarity in responsibilities between the SIs/Transgrid and the bottom-up estimates demonstrate a sound approach to avoid double counting of costs between Transgrid’s and the SI’s estimates.”

DGA’s further comments on the total capex for the Project are discussed in section 3.3 below.

³³ DGA Consulting, *Independent Review of System Security Roadmap Operational Technology Upgrade Costs – Contingent Project Application*, 26 March 2026, version 1.0 Final, pp 16.

3.2.3. Risks and contingency allowance

The underlying bottom-up cost forecasts, including vendor and internal costs, do not contain an allowance for risk or contingency. We have undertaken a risk assessment for each initiative and as a program. The risks include:

- seven at the individual technology initiative level:
 - small vendor cost increases following contracting
 - small adjustments to scope required following contracting
 - additional outage management design effort with generators
 - more than expected testing leading to more resources and rework
 - more than expected data quality issues
 - additional time for contracting switching access with generators
 - potential for communication links from SCADA to the field requiring upgrade.
- two at the broader Project level, including:
 - system integrator contract termination
 - system module interoperability risk.

These identified risks are assessed for both likelihood and consequence, and are quantified to determine an expected risk allowance such that there is a 50 per cent probability that the total project cost will not be exceeded. The total project P50 risk allowance is calculated using @risk software (Monte Carlo simulation) and represents Transgrid's best estimate of the efficient cost of delivery, having regard to identified risks and mitigation measures. Refer to Appendix J which details each risk likelihood and consequence.

Transgrid has applied lessons learnt from our recent technology projects (i.e. last EMS replacement and Digital Core Finance, Works and Asset Management replacement project) to mitigate risks where possible, minimise the organisational change impact, and keep costs low. The lessons learnt include:

- utilising a SI to provide design and proactive delivery management
- establishing clear governance frameworks, validating requirements, starting design early and developing a dedicated project resourcing model, reducing operational conflicts
- implementing a robust, standardised, automated testing framework with strong integration.

The total contingency allowance (i.e., the sum of the allowance for each of the seven risks) is \$15.6m (or \$16.5m \$FY25). DGA Consulting made the following comments regarding this component of the capex forecast:³⁴

“DGA believes this percentage contingency allowance appropriately reflects project risk, noting that compounding contingencies have been avoided by excluding contingency in the build-up of internal and SI cost estimates. This contingency allowance is significantly below the 15% recommended by one of the SIs.”

³⁴ DGA Consulting, *Independent Review of System Security Roadmap Operational Technology Upgrade Costs – Contingent Project Application*, 26 March 2026, version 1.0 Final, pp 18.

3.3. Forecast capex is prudent and efficient

We are confident that our forecast capex is prudent and efficient, reflecting the amount that is reasonably required to deliver the Project, in accordance with the capex criteria and capex factors in the NER.

Our confidence in the efficiency of the capex forecasts is based on the staged market engagement process over 8 months that we have undertaken with multiple SIs during the course of the RIT-T assessment, and the independent review of our cost estimates (including our contingency allowance) by DGA Consulting, who have supported the efficiency of our capex estimates.

We note that we were unable to obtain industry benchmarking for the costs of the Project due to the lack of precedent for these investments in the context in which Transgrid is deploying them. We contacted multiple parties that provide benchmarking analysis for IT/OT projects, but they were unable to assist with providing benchmarking of the types of investments we are proposing. DGA Consulting were able to use their expertise to provide a thorough review of the reasonableness of our estimated costs, as discussed in section 3.2 above. We consider that this independent review, together with our market engagement process, is sufficient to establish the efficiency of our proposed costings, in the absence of benchmarking analysis.

Our confidence in the capex forecasts is based on the careful scoping, challenging, rescoping, and testing of alternative credible options that occurred during the market-based process. The Project scope has benefited from extensive investigation and planning in collaboration with AEMO, and the commissioning of expert input from independent international and Australian experts (EPRI and GHD Advisory). This extensive work has enabled us to assess our control room and operational capabilities against future operational needs and international best practice.

DGA Consulting reached the following conclusions regarding our total capex, which supports our view that the forecast is prudent and efficient:³⁵

“DGA has reviewed the proposed capital cost estimates for the program and considers them to represent an efficient and reasonable level of expenditure to deliver the proposed capability. The estimates appropriately reflect the scope, timetable constraints, and resource availability, including the necessary use of SI services to achieve the required outcomes. DGA supports the capital cost estimates as a sound basis for delivery of the proposed scope.”

Importantly, the letter of support from AEMO confirms that the Project is urgently required to address the identified need described in the RIT-T and section 2.1 of this Application:³⁶

“These investments are urgently needed to manage the security of the power system and to complement investments AEMO is making under its own Operations Technology Roadmap and associated program.”

3.4. Capex threshold

The NER requires that proposed capex for a contingent project must exceed either \$30 million, or 5 per cent of the MAR for the first year of the regulatory period, whichever is greater.³⁷ Table 3-4 shows that the forecast capex satisfies this threshold.

³⁵ DGA Consulting, *Independent Review of System Security Roadmap Operational Technology Upgrade Costs – Contingent Project Application*, 26 March 2026, version 1.0 Final, pp 4.

³⁶ Attachment A.3 to this Application.

³⁷ NER, clauses 6A.8.1(b)(2)(iii) and 6A.8.2(b)(4)(i).

Table 3-4: Contingent project thresholds (\$M, Nominal)³⁸

AER Decision - First year MAR	5% of MAR (Contingent Project Threshold)	Project Capex	Does the expenditure meet the threshold?
923.99	46.20	163.5	Yes, as the Project capex of \$163.5m is over \$46.2 million

³⁸ See AER – Transgrid 2023-28 – Final Decision – PTRM – Humelink S2 – 2025-26 RoD update – January 2025.xlsx, 'Revenue Summary' tab.

4. Incremental Opex Forecast

This section sets out our forecast incremental opex that Transgrid considers to be reasonably required to undertake this project, together with the supporting evidence that it is prudent and efficient.

The forecast incremental opex set out in this Application for the 2023-28 regulatory period is the same as the estimates used in the PACR, aside from some minor adjustments which are less than \$0.1 million in total.

4.1. Incremental Opex Forecast and Basis for Forecast

We have applied a bottom-up build approach to forecast the incremental opex for this project. This methodology is consistent with the NER requirements for Contingent Project Applications.

Our forecast of incremental opex required for the Project for the 2023-28 regulatory period is \$0.8 million, including debt raising costs, or \$0.7 million, excluding debt raising costs. As the first technology initiatives are not expected to be commissioned until September 2027, the incremental opex for 2023-28 reflects 10 months of the expected annual opex.

The incremental opex for the Project is not typical of other IT projects due to the critical nature of the infrastructure assets. In particular, solutions need to be hosted on-premises rather than being cloud-based and, therefore, require ongoing support and monitoring on-site for newly commissioned assets.

Our forecast incremental opex relates to licensing, support and maintenance for new assets, including:

- annual license fees for the new PLEXOS and PSCAD software required to continue to use the software
- two of six additional people to support and maintain the quality of power system models used in operations planning
- annual cloud subscription to host the outage management webpages.

DGA has reviewed our forecast incremental opex, including the proposed scope, and confirmed that the forecast costs are reasonable.³⁹ Our forecast incremental opex for the remainder of the 2023-28 regulatory period is set out in Table 4-1. We consider that the forecast incremental opex reasonably reflects the opex criteria (which are underpinned by prudence and efficiency), taking into account the opex factors, in the context of the Project.

Table 4-1: Incremental forecast opex for the Project – 2023-28 regulatory period (\$m)

Sub-category	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Annual license fees for new PLEXOS and PSCAD software	-	-	-	-	0.2	0.2
Additional FTEs – support and maintenance for operational planning	-	-	-	-	0.4	0.4

³⁹ DGA Consulting, *Independent Review of System Security Roadmap Operational Technology Upgrade Costs – Contingent Project Application*, 26 March 2026, version 1.0 Final, pp 19.

Sub-category	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Outage management external webpage cloud subscription	-	-	-	-	0.1	0.1
Total excluding debt raising costs	-	-	-	-	0.7	0.7
Debt raising costs	-	0.0	0.0	0.0	0.1	0.1
Total including debt raising costs	-	0.0	0.0	0.0	0.8	0.8

Note: Totals may not sum due to rounding.

We note that the incremental opex requirements for this Project will increase as additional technology initiatives are commissioned. Furthermore, as the major commissioning dates are scheduled for 2029 and 2031, the incremental opex for the 2023-28 regulatory period is relatively low compared to the opex requirements in the next regulatory period. Specifically, the incremental opex is forecast to be \$7.8 million in 2031-32 compared to \$0.8 million for the 2027-28 period.

Appendix I presents our opex forecast for the Project for the 2028-33 regulatory period. We understand that the NER does not allow the AER's decision on this Application to include an opex allowance for the 2023-28 regulatory period, even though an appropriate opex allowance is essential to the success of the Project. We intend to propose a step change to cover this additional opex as part of our regulatory proposal for the 2028-33 period, which will reflect the best information available at that time. The AER's formal decision on the Project's incremental opex will be made in its Revenue Determination for the 2028-2033 regulatory period.

Notwithstanding the NER requirements, we would welcome the AER's provisional assessment of our forecast opex for the 2028-33 regulatory period. It would not be prudent or efficient to proceed with significant capex without a reasonable degree of confidence that an appropriate opex allowance will be provided to operationalise the investment.

5. Incremental revenue and customer bill impact

This section sets out the incremental revenue forecast for the Project, our updated MAR and the indicative impact on the transmission component of customers' bills. This section focusses on the 2023-28 regulatory period.

Appendix A sets out how we have met the NER requirements when calculating incremental revenue.

The PTRM and roll forward model used to calculate incremental revenue have been provided as Attachments to this submission. The calculation of incremental revenue has been undertaken in a manner consistent with the assumptions and PTRM underpinning the Revenue Determination.

The capex and incremental opex used to calculate the incremental revenue set out below are consistent with the capex and incremental opex forecasts presented in the prior sections.

5.1. Incremental revenue

Table 5-1 summarises the incremental forecast revenue requirement of \$3.0 million (\$Nominal, smoothed) for this Project over the 2023-28 regulatory period. The table is broken down by building block components and briefly explains how we have calculated each component. The parameters used to calculate each of the building blocks are set out in Appendices D-H.

Table 5-1: 2023-28 incremental revenue forecast (\$M, Nominal)

Building block	Incremental revenue	Approach
Return on capital	3.3	Calculated by multiplying the forecast opening capital base for a given year by the allowed rate of return adopted by the AER.
Return of capital	(1.1)	Calculated as forecast straight line depreciation for each asset class less indexation of the capital base.
Opex	0.9	Bottom-up build, subject to independent review – see section 4.1
Revenue adjustments	-	None
Corporate income tax	(0.1)	Calculated as forecast pre-tax income multiplied by the corporate tax rate, less the assumed value of imputation credits.
Annual revenue requirement (i.e. unsmoothed)	2.9	Sum of each building block above.
Impact of smoothing	0.1	Calculated by resolving the year 4 and 5 X-factors, so the NPV of the MAR for the 2023-28 regulatory period matched that of the forecast annual revenue requirement for the same period.
MAR (i.e. smoothed)	3.0	Annual revenue requirement adjusted for impact of smoothing.

Table 5-2 sets out the incremental revenue requirement for each of the remaining years in the 2023-28 regulatory period. Although this CPA is submitted in FY2026-27, prices can only be updated in the financial year following a Determination being made, hence the revenue only being adjusted in 2027-28.

Table 5-2: Incremental revenue requirement by year (\$m, nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Return on capital	-	0.3	0.5	0.6	1.9	3.3
Return of capital (depreciation)	-	(0.1)	(0.2)	(0.3)	(0.5)	(1.1)
Opex	-	0.0	0.0	0.0	0.9	0.9
Revenue adjustments	-	-	-	-	-	-
Corporate income tax	-	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)
Annual revenue requirement (i.e. unsmoothed)		0.1	0.3	0.3	2.2	2.9
Impact of smoothing		(0.1)	(0.3)	(0.3)	0.8	0.1
MAR (i.e. smoothed)		-	-	-	3.0	3.0
NPV (as at 30 June 2023)						2.3

Note: Totals may not sum due to rounding.

5.2. Customer bill impact

We have assessed the impact of the change in incremental revenue associated with the Project on the average customer bill, excluding the benefits. We converted our MAR into indicative household and small business bills using forecast energy throughput and typical household and small business bill information, such as the typical bill size and the share of NSW residential and small business bills attributed to transmission charges.

Table 5-3 shows that the indicative customer bill impact is an average increase of \$0.30 per annum for residential customers and an average increase of \$0.80 per annum for small business customers in 2027-28 during the 2023-28 Regulatory Period.

Table 5-3: Impact of the Project on the transmission component of customers' bills (\$ per customer per year.)

Year	2023-24	2024-25	2025-26	2026-27	2027-28
Residential Bills					
Average bill based on Revenue Determination			2,117.7	2,129.9	2,135.9
Impact of Project	NA	NA	NA	NA	0.3
Updated typical customer bill			2,117.7	2,129.9	2136.2
Small Business Bills					
Average bill based on Revenue Determination			4,891.4	4,928.7	4,946.8
Impact of Project	NA	NA	NA	NA	0.8
Updated typical customer bill			4,891.4	4,928.7	4,947.6

To put these cost impacts into perspective, Table 5-4 shows the project capex alongside the bill impact, the market benefits and net market benefits. This analysis confirms that consumers can expect to benefit significantly if the Project proceeds as planned.

Table 5-4: Breakdown of Costs and Benefits of the Project for the 2023-28 period

Project Capex	Bill Impact	Market Benefits	Net Market Benefits
\$163.5m	\$0.30 for residential customers and \$0.80 per annum for small business customers in 2027-28.	\$296.8m	\$118.9m

We have also estimated the project's impact on a typical residential and small business bill for the 2028-2033 regulatory period. On average, the project is expected to add approximately \$2.80 per annum to bills for a residential customer and \$8.60 per annum for a small business customer. As the AER has not made a determination on Transgrid's revenue for the 2028-33 period, this assessment only provides a high-level indication of the expected impact of the project on customer bills for this period.

Appendix A Regulatory Requirements

A.1 Regulatory Requirements

This section sets out the relevant regulatory requirements for this Application and how they have been addressed.

Regulatory requirements

Clause 6A.8.2 of the NER sets out the requirements for making an application to amend a revenue determination to include a contingent project in relation to the relevant revenue determination.

This Application is made in accordance with the requirements of clause 6A.8.2(a), (a1) and (b) of the NER, i.e., it is being submitted:

- During the 2023 to 2028 regulatory period⁴⁰
- To amend the Revenue Determination that applies to Transgrid in respect of a contingent project accepted by the AER in its Revenue Determination⁴¹
- As soon as practicable after the occurrence of the trigger event(s), as set out in this Appendix⁴²
- Containing the information specified in clause 6A.8.2(b) of the NER, as set out in the compliance checklist at the end of this Primary Application.

Requirements for a CPA determination

Before it can make a determination on this CPA, the AER must be satisfied of the following:⁴³

- The trigger event has occurred
- The forecast capex meets the materiality threshold (demonstrated in section 3.4)
- Transgrid has complied with its obligations under clauses 5.16.4(z5D) and 5.16.4(z5E) relating to a material change of circumstances (MCC) assessment.

These requirements, and how Transgrid meets them, are outlined in this Appendix.

MCC Assessment not required

Clause 5.17.4(z5D) states that at the same time as a RIT-T proponent submits a CPA, the proponent must also provide the AER with a statement containing confirmation:

- on whether or not there has been an MCC, including any supporting analysis
- whether the proponent has met its obligations to reapply the RIT-T
- of the actions (if any) the RIT-T proponent was required to take pursuant to a determination by the AER and timeframe within which any such actions were to be completed
- of the actions (if any) the RIT-T proponent took as a result of the material change in circumstances and the date on which any such actions were completed.

⁴⁰ NER clause 6A.8.2(a).

⁴¹ NER clause 6A.8.2(a).

⁴² NER clause 6A.8.2(a1).

⁴³ NER clause 6A.8.2(e).

Clause 5.16.4(z5E) requires that the statement required by clause 5.16.4(z5D) be published by the RIT-T proponent at the same time, or as soon as reasonably practicable after, the RIT-T proponent's submission of a CPA.

Under Clause 5.16.4(z3A), Transgrid is only required to consider whether an MCC has occurred if more than six months has elapsed since the analysis required to apply the RIT-T was completed. The RIT-T PACR was published on 7 October 2025, and so it has been less than 6 months since that date.

Notwithstanding this provision, the developments since the PACR have only had a minor impact on the project costs and the expected timing of the Project, and are not expected to change the outcome of the RIT-T.

AER determination

If the AER is satisfied that the trigger event has occurred, the forecast total capex meets the materiality threshold and that Transgrid has complied with relevant obligations under the NER, then the AER must determine:⁴⁴

- For the 2023-28 regulatory period, the amount of capex and incremental opex for each remaining regulatory year that the AER considers is reasonably required for the purpose of undertaking the Project
- For the Project as a whole, the total capex that the AER considers is reasonably required for the purpose of undertaking the Project
- The likely commencement and completion dates for the Project
- The incremental revenue likely to be required by Transgrid for each remaining year in the 2023-28 regulatory period, based on the amount of capex and incremental opex that the AER considers to be reasonably required for the purpose of undertaking the Project.

The AER must then amend the Revenue Determination by varying the Revenue Determination only to the extent necessary to:⁴⁵

- Accommodate the capex and incremental opex that it determines to be reasonably required for the purpose of undertaking the Project
- Reflect the effect on the MAR and X-factors for each year in the remainder of the regulatory period.

The AER is required to accept the relevant amounts in this Application if it is satisfied that:⁴⁶

- the amounts of forecast capex and incremental opex reasonably reflect the capex criteria and opex criteria, taking into account the capex factors and opex factors, in the context of the contingent project.

NER requirements for Contingent Project incremental revenue calculations:

- in accordance with the requirements of the PTRM referred to in clause 6A.5.2
- in accordance with the requirements of the roll forward model (RFM) referred to in clause 6A.6.1(b)
- using the allowed rate of return for the relevant TNSP for the regulatory control period as determined in accordance with clause 6A.6.2

⁴⁴ NER clause 6A.8.2(e)(1).

⁴⁵ NER clauses 6A.8.2(e)(3) and 6A.8.2(h).

⁴⁶ NER clause 6A.8.2(f).

- in accordance with the requirements for depreciation referred to in clause 6A.6.3
- on the basis of the capex and incremental opex for the Project as set out above.⁴⁷

How this CPA complies with the regulatory requirements

Section 3 sets out:

- forecast total capex for the Project
- forecast capex for each remaining year of the 2023-28 regulatory period.

Section 3 also explains why the forecast capex is prudent and efficient, and how the reasonableness of the cost build-up has been supported by an independent review by DGA Consulting. Furthermore, section 3 demonstrates that the forecast capex for the Project reasonably reflects the capex criteria, as it is necessary for Transgrid to maintain quality, reliability and security of supply of its transmission services.⁴⁸ This is further confirmed by AEMO's formal letter of support (discussed in section 2.3).

Section 4 sets out the forecast of incremental opex for the remainder of the 2023-28 regulatory period related to the Project, and explains why that incremental opex is prudent and efficient, and therefore reflects the opex criteria in the NER.

Section 5 calculates the incremental revenue required for the remainder of the 2023-28 regulatory period, based on the forecasts of capex and incremental opex presented in sections 3 and 4. This calculation is based on the AER's PTRM as applied to Transgrid for the 2023-28 regulatory period, with all other inputs (e.g., asset lives, rate of return) maintained in line with the AER's determination.⁴⁹

The remainder of this Appendix addresses the other regulatory requirements set out above, i.e.:

- Explaining that the trigger events have occurred
- Setting out the project timing, including expected commencement and completion dates, and why those dates are reasonable
- Explaining the stakeholder engagement we have undertaken to date, demonstrating that the assumptions behind the expenditure forecasts have been subject to scrutiny from stakeholders.

For completeness, Appendix A.2 provides a checklist of all elements required to be included in the CPA, based on clause 6A.8.2(b), showing where they have been addressed in this Application.

In preparing this Application, we have had regard to the AER's Process Guideline for Contingent Project Applications.⁵⁰

⁴⁷ NER clause 6A.8.2(e)(2) and clause 6A.8.2(b)(7).

⁴⁸ The capex criteria are set out in clause 6A.6.7(c) of the NER.

⁴⁹ The cost of debt adopted in calculating the incremental revenue required has been based on the AER's updated cost of debt for Transgrid reflected in its latest published PTRM for Transgrid. See AER, *Transgrid 2023-28 - Final Decision - PTRM - Humelink S2 - 2025-26 Return on debt update - January 2025*.

⁵⁰ AER, *Process Guideline for Contingent Project Applications under the National Electricity Rules*, September 2007 available at: <https://www.aer.gov.au/system/files/ac06907-Final%20guideline.pdf>.

Trigger events

Under clause 6A.8.2(a)(1) of the NER, Transgrid can submit a CPA to the AER once we satisfy the specific trigger events for that contingent project as set out in a Revenue Determination,⁵¹ in accordance with the NER.

The table below sets out each of the trigger events for the project specified in the AER's 2023-28 determination, and how they have been met.

Table A 1 The trigger events for the Project have all been met

Trigger event	Status
<p>The Australian Energy Market Operator (AEMO)'s written support for the implementation of specific operational technology upgrades and tools for use in Transgrid's control rooms and corporate offices, following the successful completion of Early Works.</p>	<p>Complete.</p> <p>Transgrid undertaken early works to inform the specification and assessment of the proposed investment (see section 2.2).</p> <p>AEMO provided formal written support for the preferred option in the PACR (i.e., the Project the subject of this CPA) on 15 September 2025 (see section 2.5 and Attachment A.3).</p>
<p>Successful completion of a RIT-T, if a RIT-T is required or equivalent economic evaluation, which demonstrates that the preferred option (or part of the preferred option) that maximises net economic benefits is the investment in technological upgrades and tools that has written support from AEMO.</p>	<p>Complete (see section 2.2).</p> <p>The AER advised Transgrid that a RIT-T was required to be applied to this proposed investment.</p> <p>Transgrid commenced the RIT-T with the publication of the PSCR on 14 October 2024.</p> <p>On 7 October 2025, we published a PACR, which identified the preferred option to be proactive investment in operational tools (Option 2).</p> <p>No disputes were received on the PACR, and the RIT-T process is now complete.</p>
<p>Transgrid Board commitment to proceed with the development of the operational technology upgrades and tools (that has written support from AEMO), subject to the AER amending the Revenue Determination pursuant to the Rules.</p>	<p>Complete.</p> <p>See Attachment A.4.</p>

Project timing

The Project has a defined start and end date, and it is a distinct project supported by AEMO and EPRI. The Project will commence in July 2026 and is expected to be completed by end July 2031, pending the timely approval of this CPA. Due to the urgency of the identified need and criticality of operations,⁵² we may need to commence work ahead of a decision from the AER.

⁵¹ See NER clause 6A.14.1(4) (i) and (iii).

⁵² For further information on the urgency of the works, please see the EPRI Report and Letter of Support on Transgrid's project page [here](#) and Attachment A.3.

The proposed timing in this Application reflects a realistic assessment of the required dates for the activities to meet the target delivery dates of major releases in May 2029 and April 2031. The proposed project schedule has been subject to independent review by DGA Consulting. DGA Consulting considered the CPA schedule to be 'logical and appropriate and the timetable achievable'.⁵³

Stakeholder Engagement

Transgrid initially engaged with the TAC regarding operational tools investments as part of the System Security Roadmap proposed in our 2023-28 revised regulatory proposal. In its final decision, the AER considered that the TAC had not yet reached a firm position in support of the proposed investments, noting that stakeholders desired clearer illustration of risks, benefits and assumptions.⁵⁴

In light of this concern, Transgrid undertook extensive consultation with the TAC as part of the RIT-T assessment, focusing on the scope and range of investment options under consideration and the methodology used to quantify the benefits associated with the proposed investments. Importantly, a key outcome from our engagement is that the TAC is supportive of the identified need.

This engagement process has involved detailed technical discussions and clearer documentation of assumptions and methodologies. Through several collaborative sessions with the TAC, Transgrid has worked to ensure that the TAC members were able to provide meaningful input and feedback into the assessment process for the RIT-T. Transgrid considers that its enhanced engagement with the TAC on the technology initiatives during the RIT-T process addresses the earlier concerns raised by the AER.

Specifically, Transgrid engaged the TAC through six deep dive workshops between April 2024 and August 2025. The key topics that the TAC were consulted and informed on through these workshops were as follows:

- Deep dive 1 – April 2024: describe the need for investment including a presentation from international experts, EPRI
- Deep dive 2 – September 2024: discuss the scope, investment areas and proposed investment approach and programme
- Deep dive 3 – November 2024: discuss current operational challenges, the operability RIT-T and PSCR, RFI and approach to developing cost estimates and the benefits quantification approach
- Deep dive 4 – April 2025: control room tour and PADR briefing session
- Deep dive 5 – May 2025: consumer outcomes document co-creation session
- Deep dive 6 - August 2025: PACR briefing session.

The TAC engagement commenced early during the planning and development phase of the RIT-T. This early engagement allowed for extensive sessions on the project scope and consumer benefits, as noted above. The TAC members heard from independent experts, EPRI, about the need (including national and international commonalities) for the Project and the urgency for the project. The TAC collaborated in developing the process and methodologies employed to estimate the project cost and benefits and were given a tour of the control room. The table below summarises key messages from TAC engagement in relation to the Project and Transgrid's responses.

⁵³ DGA Consulting, *Independent Review of System Security Roadmap Operational Technology Upgrade Costs – Contingent Project Application*, 26 March 2026, version 1.0 Final, pp 13.

⁵⁴ AER, *Transgrid transmission determination – 1 July 2023 to 30 June 2028 – Attachment 5: Capital expenditure*, Final decision, pp 28.

Table A 2 Key outcomes of TAC engagement

What we heard	How we responded
The importance of employing a robust market testing process	We conducted a detailed market testing (RFI based) process as described in section 3.2.
The importance of clearly demonstrating consumer benefits	We worked with the TAC to develop a consumer benefits document explaining the benefits the Project is expected to deliver in an accessible manner (supplementary to the RIT-T documents), which can be found on our website. ⁵⁵
Support for case study approach to demonstrate benefits	Adopted a case study approach using conservative assumptions (e.g., excluding high impact low probability events), as described in section 2.2, and section 6 of the PACR.
Work with AEMO, other TNSPs and DNSPs to ensure alignment and avoid inefficient duplication	We engaged EPRI to work closely with AEMO to clearly define operational capability roles and responsibilities to prevent duplication and ensure complementary technologies. We also liaised with other TNSPs and DNSPs to inform the optimal scope and deliverability of the technology initiatives.
Consider how Transgrid can leverage from AEMO's work and engagement with the AER	We engaged with AEMO throughout RIT-T process, and obtained a letter of support from AEMO for the Project.

AER engagement

The AER's Process Guideline for Contingent Project Applications under the NER encourages TNSPs to engage with the AER prior to lodgement of a contingent project application.

We met with the AER in preparing this Application, and throughout the earlier RIT-T process. Prior to the RIT-T process, on 23 August 2024, the AER advised Transgrid that it considers a RIT-T both appropriate and desirable. More recently, the AER was comfortable to receive the CPA without further engagement ahead of submission and did not identify any materials beyond those required by the NER that Transgrid should provide.

⁵⁵ Available at: https://www.transgrid.com.au/media/eddcnhy/2025_consumer_outcomes_r11-1.pdf.

A.2 Compliance Checklists

The tables below shows how this Application complies with the NER and Guidelines.

Table A 3 Compliance with NER cl 6A.8.2(b)

NER, clause 6A.8.2(b) requirements	Reference in Application
an explanation that substantiates the occurrence of the trigger event	Section 2 and Attachment A.1.
a forecast of the total capex for the contingent project	Section 3.1
a forecast of the capital and incremental opex, for each remaining regulatory year which the Transmission Network Service Provider considers is reasonably required for the purpose of undertaking the contingent project	Sections 3.1 and 4.1
how the forecast of the total capex for the contingent project meets the threshold as referred to in clause 6A.8.1(b)(2)(iii)	Section 3.4
the intended date for commencing the contingent project (which must be during the regulatory control period)	Appendix A.1 'Project Timing'
the anticipated date for completing the contingent project (which may be after the end of the regulatory control period) and	Appendix A.1 'Project Timing'
<p>an estimate of the incremental revenue which the Transmission Network Service Provider considers is likely to be required to be earned in each remaining regulatory year of the regulatory control period as a result of the contingent project being undertaken as described in subparagraph (3), which must be calculated:</p> <ul style="list-style-type: none"> • in accordance with the requirements of the post-tax revenue model referred to in clause 6A.5.2 • in accordance with the requirements of the roll forward model referred to in clause 6A.6.1(b) • using the allowed rate of return for that Transmission Network Service Provider for the regulatory control period as determined in accordance with clause 6A.6.2 • in accordance with the requirements for depreciation referred to in clause 6A.6.3, and • on the basis of the capex and incremental opex referred to in subparagraph (b)(3). 	<p>Section 5.1</p> <p>Also see PTRM and financial model attachments.</p> <p>Also see Section 5 and Appendix E</p>

Table A 4: Compliance with AER Contingent Project Application Guidelines

Guidelines Section	AER guidance	Reference in Application
2.4	The AER considers that, to have a 'realistic expectation' of demand forecasts and cost inputs (per the capex and opex criteria in the NER), the TNSP must, as far as is practical, have completed and included in its application all option assessments, feasibility studies and any other investment appraisals.	See sections 2.2, 3 and 0.

Guidelines Section	AER guidance	Reference in Application
3	Pre-lodgement process	See Appendix A.1 'AER engagement'.
4.1	<p>The AER expects that the TNSP will include the best available supporting information in its application, which would generally include:</p> <ul style="list-style-type: none"> • final regulatory test assessments • tender submissions • contracts • other investment appraisals. 	Sections 2 and 3.

Appendix B Presentation of capex by asset class

This Appendix provides a breakdown of expenditure by asset class for both:

- the Project as a whole
- each year of the 2023-28 regulatory period.

It also presents direct capex, indirect capex, and total capex for each year in the next regulatory period. The totals are the same as presented in Section 3.1, with the presentation re-arranged in accordance with the PTRM asset class rather than by technology initiative.

The capex within each technology initiative was mapped to a more granular set of assets, and those assets have been mapped to the AER's PTRM asset classes as appropriate. Three PTRM asset classes are relevant to the Project, i.e.:

- Communications (short life) – this includes, for example: all operational technology solutions such as SCADA/AEMS software installation and configuration
- Business IT – this includes, for example: the servers, data network and storage that forms the infrastructure that the SCADA/AEMS software is installed on
- Minor plant, motor vehicles & mobile plant – this includes minor plant such as facilities modifications for example: data centre upgrade including cooling and power – motor vehicles and mobile plant are not relevant here.

We note that, as discussed in the PACR, some additional opex will be incurred in the next regulatory period to support a 10 year asset life for SCADA/AEMS (to align with the OT and IT asset life assumptions in the AER's PTRM) rather than the typical 7 year asset life.⁵⁶

Table B1 presents total capex by asset class.

Table B1: Capex by asset class (\$m)

Asset class	Standard life (years)	Total capex (\$m)	Capex in 2023-28 regulatory period (\$m)
Communications (short life)	10	92.6	22.9
Business IT	4	62.2	45.0
Minor plant, motor vehicles & mobile plant	8	7.9	6.6
Equity raising costs	44.3	0.8	0.8
Total		163.5	75.3

Note: Totals may not sum due to rounding.

⁵⁶ Transgrid, *System Security Roadmap Operational Technology Upgrades – RIT-T Project Assessment Conclusions Report*, October 2025, pp 53.

Table B2 below sets out the total capex for the entire project by direct capex, capitalised labour, and support costs for the entire project.

Table B2: Direct and indirect breakdown of total capex by asset class (\$m)

Asset class	Direct capex		Other capex	Total capex
	Non-labour	Labour	Support costs	
Communications (short life)	69.3	16.3	7.0	92.6
Business IT	46.0	11.3	4.9	62.2
Minor plant, motor vehicles & mobile plant	5.6	1.6	0.7	7.9
Equity raising costs			0.8	0.8
Total	121.8	29.3	13.4	163.5

Note: Totals may not sum due to rounding.

Table B 3 below sets out the proportion of capex by direct capex, capitalised labour, and support costs for the 2023-28 regulatory period.

Table B3: Direct and indirect breakdown of capex in 2023-28 regulatory period by asset class (\$m)

Asset class	Direct capex (2023-28 regulatory period)		Other capex (2023-28 regulatory period)	Total capex (2023-28 regulatory period)
	Non-labour	Labour	Support costs	
Communications (short life)	14.2	6.2	2.6	22.9
Business IT	32.8	8.5	3.7	45.0
Minor plant, motor vehicles & mobile plant	4.6	1.3	0.6	6.6
Equity raising costs			0.8	0.8
Total	51.6	16.0	7.7	75.3

Note: Totals may not sum due to rounding.

The tables below present the total capex forecast each year from section 3.1, broken down by PTRM asset class.

Table B 4: Total capex by asset class 2023-28 period (\$m)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Communications (short life)	2.1	2.2	0.6	3.8	14.2	22.9
Business IT	1.4	1.5	0.4	10.0	31.7	45.0
Minor plant, motor vehicles & mobile plant	0.2	0.2	0.0	5.5	0.7	6.6
Equity raising costs	0.8	-	-	-	-	0.8
Total capex (excluding equity raising costs)	3.7	3.9	1.1	19.2	46.6	74.5
Total capex forecast	4.5	3.9	1.1	19.2	46.6	75.3

Note: Totals may not sum due to rounding.

Table B 5: Total capex by asset class 2028-33 period (\$m)

	2028-29	2029-30	2030-31	2031-32	2032-33	Total
Communications (short life)	21.4	34.2	14.0	0.1	-	69.7
Business IT	13.1	2.5	1.5	0.1	-	17.2
Minor plant, motor vehicles & mobile plant	0.2	0.2	1.0	0.0	-	1.3
Equity raising costs	-	-	-	-	-	-
Total capex (excluding equity raising costs)	34.7	36.9	16.5	0.2	-	88.2
Total capex forecast	34.7	36.9	16.5	0.2	-	88.2

Note: Totals may not sum due to rounding.

Appendix C Presentation of capex and opex in \$2024-25

The PACR, released on 7 October 2025, presented capex and opex forecasts in \$2024-25. We explain in Section 3.2 that there have been minor updates to the capex forecasts since the PACR, and that the body of this CPA presents capex forecasts in \$2022-23 terms consistent with our Revenue Determination. Similarly, Section 4.1 outlines minor changes to the opex forecasts since the PACR, which have also been presented in \$2022-23 terms in the body of this document.

This Appendix presents the CPA total capex and incremental opex forecasts in \$2024-25 terms, so that stakeholders can more easily compare the CPA capex and opex forecasts to the information presented in the PACR.

Table C1: CPA total capex forecasts in \$2024-25 terms compared to the PACR

Technology initiative	PACR forecast (\$m, 2024-25)	CPA forecast (\$m, 2024-25)	CPA forecast (\$m, 2022-23)
Outage management	1.2	1.5	1.4
Alarm management, visualisation and situation awareness enhancement	32.0	35.7	33.7
Fault level and system parameter monitoring and power system analysis capability	6.5	7.3	6.8
SCADA/AEMS system	32.6	35.2	33.2
Facilities	5.3	5.4	5.1
Data management and network modelling system	26.5	28.7	27.1
Training technologies, operational document management system and operational planning systems	13.2	13.9	13.1
Operational forecasts and look-ahead contingency assessment	3.7	4.3	4.1
Wide area monitoring	6.5	6.8	6.4
Smart Transmission Device Management	3.7	4.1	3.8
CPA submission	6.2	6.1	5.8
Program implementation	13.2	23.4	22.1
Contingency/risk	16.5	-	-
Total (excluding labour escalation and equity raising costs)	167.1	172.2	162.5
Labour escalation		0.2	0.2
Equity raising costs		0.8	0.8
Total capex	167.1	173.3	163.5

Note: The contingency allowance discussed in Section 3.2.3 above is included within the technology initiatives and total above. Totals may not sum due to rounding.

The table below compares the opex forecasts for the 2023-28 regulatory period from the PACR with the opex forecasts presented in this CPA in \$2024-25 terms.

Table C2: CPA incremental opex forecast in \$2024-25 terms compared to the PACR

	PACR forecast (\$m, 2024-25)	CPA forecast (\$m, 2024-25)	CPA forecast (\$m, 2022-23)
License fees for operational planning system	0.3	0.3	0.2
Additional FTEs – support and maintenance for operational planning	0.5	0.4	0.4
Switching portal hosting	-	0.1	0.1
Total excluding debt raising costs	0.8	0.8	0.7
Debt raising costs	-	0.0	0.0
Total including debt raising costs	0.8	0.8	0.8

Note: Totals may not sum due to rounding.

Appendix D Rate of return

The NER requires Transgrid to model incremental revenue based on the rate of return determined by the AER. The table below sets out the WACC used by Transgrid to calculate incremental revenue.

The WACC used is consistent with the Revenue Determination, updated for the 2025-26 cost of debt, and so satisfies the requirements under clause 6.6A.2(b)

Table D1: Rate of return parameters used to model incremental revenue

WACC parameter	Value	Year
Risk free rate	3.76%	
Forecast inflation	2.92%	
Market risk premium	6.20%	
Gearing	60.00%	
Equity beta	0.6	
Nominal pre-tax return on debt	4.63%	for 2023-24
	4.57%	for 2024-25
	4.63%	for 2025-26
	4.82%	for 2026-27
	4.97%	for 2027-28
Nominal post-tax return on equity	7.48%	
Nominal vanilla WACC	5.77%	for 2023-24
	5.73%	for 2024-25
	5.77%	for 2025-26
	5.88%	for 2026-27
	5.97%	for 2027-28

Appendix E Depreciation

We have calculated incremental depreciation in a manner consistent with the Revenue Determination.

The table below sets out the asset lives adopted by Transgrid to calculate the depreciation component of incremental revenue. We have used standard asset lives approved by the AER in its Revenue Determination.

Table E1: Asset lives used to estimate incremental depreciation

Asset category	Standard life (years)	Notes
Communications (short life)	10.0	As per the Revenue Determination.
Business IT	4.0	
Minor plant, motor vehicles & mobile plant	8.0	
Equity raising costs	44.3	As per recent AER decisions, this is calculated as the weighted average standard life for forecast net commission capex.

The table below sets out the incremental depreciation and resulting revised depreciation proposed by Transgrid.

Table E2: Incremental depreciation (\$m, nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Approved regulatory depreciation	88.8	88.2	80.8	119.9	119.6	497.3
Incremental regulatory depreciation	-	(0.1)	(0.2)	(0.3)	(0.5)	(1.1)
Revised regulatory depreciation	88.8	88.1	80.6	119.6	119.0	496.1

Note: Totals may not sum due to rounding.

Appendix F Tax allowance

We have calculated the tax allowance in a manner consistent with the approach adopted by the AER in its Revenue Determination.

The table below sets out the incremental tax allowance and revised tax allowance proposed by Transgrid.

Table F1: Incremental tax allowance (\$m, nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Approved tax allowance	24.2	19.1	11.7	9.2	11.2	75.2
Incremental tax allowance	-	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)
Revised tax allowance	24.2	19.1	11.7	9.1	11.1	75.1

Note: Totals may not sum due to rounding.

Appendix G Debt and equity raising costs

Our forecast incremental revenue includes allowances for debt and equity-raising costs, consistent with the Revenue Determination. Both costs are calculated automatically within the PTRM. Debt-raising costs are included within the opex building block and are calculated as follows:

- Projected opening RAB at the start of each regulatory year is multiplied by assumed gearing (of 60 per cent) and the debt-raising cost benchmark (of 0.083 per cent).

Equity raising costs are included within the capex forecast and recovered via the return on and of capital building blocks. These costs are calculated as follows:

- retained cash flows are projected by subtracting opex, interest payments, revenue adjustments, tax payable, and dividends from projected smoothed (i.e., MAR) revenue
- equity raising is projected by subtracting retained cash flows from the equity funding component of projected capex (assuming 60 per cent gearing), and split between distribution reinvestment and external equity raising sources
- equity raising costs are calculated by multiplying the two sources by assumed benchmark equity raising cost rates.

Table G1: Debt and equity raising costs (\$m)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Debt raising costs						
Revenue Determination (updated)	4.5	5.3	6.6	7.4	7.4	31.2
Incremental debt raising costs	-	0.0	0.0	0.0	0.0	0.0
Updated debt raising costs	4.5	5.3	6.6	7.4	7.4	31.3
Equity raising costs						
Revenue Determination (updated)	37.4	-	-	-	-	37.4
Incremental equity raising costs	0.8	-	-	-	-	0.8
Updated equity raising costs	38.2	-	-	-	-	38.2

Note: Totals may not sum due to rounding.

Appendix H Amended MAR

The table below sets out the incremental change to MAR and revised MAR for each of the remaining years in the regulatory period.

Table H1: Amended annual MAR (\$m, nominal)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Approved MAR (unsmoothed)	865.6	967.8	1,124.8	1,330.6	1,383.3	5,671.9
Incremental MAR (Impact of the Project)	-	0.1	0.3	0.3	2.2	2.9
Revised MAR unsmoothed	865.6	967.9	1,125.0	1,330.9	1,385.5	5,674.9
Revised MAR (smoothed)	924.0	959.7	1,108.4	1,282.7	1,391.6	5,666.4
Revised X factor					(5.41%)	

Note: Totals may not sum due to rounding.

Appendix I Total incremental opex for the Project

The AER is required to determine only the incremental opex for each remaining year in the 2023-28 regulatory period in the CPA. This Appendix sets out forecast opex associated with the Project for the next regulatory period for transparency (noting that this is not required for the CPA). As explained in Section 4.1, the incremental opex is the additional costs that are expected to be incurred following the implementation of the technology initiatives that comprise this Project.

Due to the timeline for commissioning of these technology initiatives, particularly the major commissioning dates for new assets forecast for March 2029 and February 2031, incremental opex associated with the Project is forecast to increase from 2027-28 to 2031-32, and then remain steady thereafter.

The table below provides a breakdown of our opex forecast for the last year of the 2023-28 regulatory period and the following regulatory period.

Table I1: Incremental opex for the Project (\$m)

Sub-category	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	Total
SCADA/AEMS	-	0.2	1.0	1.0	1.0	1.0	4.1
Training technologies	-	0.0	0.0	0.0	0.0	0.0	0.0
Wide area monitoring	-	-	-	0.2	0.5	0.5	1.3
Alarm management technologies	-	0.2	0.8	0.8	0.8	0.8	3.3
Hardware maintenance uplift for SCADA/AEMS	-	0.2	1.0	1.0	1.0	1.0	4.1
Training attendance during the project	-	0.5	-	0.3	-	-	0.8
Data modelling and network management	-	0.2	0.6	0.6	0.6	0.6	2.6
License fees for operational planning system	0.2	0.3	0.3	0.3	0.3	0.3	1.7
Transgrid scope - Hardware maintenance and software licensing uplift (includes outage switching portal hosting)	0.1	0.2	0.2	0.2	0.2	0.2	1.1
FTEs							
System Operator (Control Room Operator)	-	-	-	0.2	0.5	0.5	1.1
Training System Engineer	-	0.0	0.2	0.2	0.2	0.2	0.8
SCADA Maintenance Engineer	-	0.2	1.0	1.0	1.0	1.0	4.1

Sub-category	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	Total
System Data Analyst (Network Model Management)	-	0.1	0.2	0.2	0.2	0.2	1.0
Support and maintenance for operational planning	0.4	0.6	0.9	1.1	1.4	1.4	5.7
Total excluding debt raising costs	0.7	2.7	6.1	7.0	7.6	7.6	31.8
Real inputs cost escalation	0.0	0.0	0.0	0.1	0.1	0.1	0.4
Debt raising costs	0.1	-	-	-	-	-	0.1
Total including debt raising costs	0.8	2.8	6.2	7.0	7.7	7.8	32.2

Note: Totals may not sum due to rounding.

In deriving these bottom-up opex estimates, we have been able to redeploy some staff to offset the incremental costs increase. We have refined our opex estimates following the independent review by DGA Consulting. DGA Consulting reviewed those revised estimates and consider that they are reasonable.⁵⁷

We intend to propose a step change to cover this additional opex as part of our regulatory proposal for the 2028-33 period, which will reflect the best information available at that time.

⁵⁷ DGA Consulting, *Independent Review of System Security Roadmap Operational Technology Upgrade Costs – Contingent Project Application*, 26 March 2026, version 1.0 Final, pp 19.

Appendix J Risk Cost Basis of Estimation

Transgrid has estimated capital costs on a P50 basis, consistent with its internal project governance framework. The underlying capital cost estimates are developed on a bottom-up basis and do not include any allowance for risk or contingency. A separate risk assessment was undertaken across a range of technology delivery subject matter experts to identify and quantify material project and program risks that could reasonably affect delivery costs.

Identified risks are assessed for both likelihood and consequence and shown in Table J1 below. This assessment has added \$16.5M to the base estimate.

Table J1: Risk cost basis of estimation

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
<u>Overall Program Risk</u>								
System Integrator contract termination	Robust contract design, rigorous vendor selection, performance monitoring and governance	30%	Increased project duration and associated costs	3,213,974	6,496,000	15,372,000	BC: 9 months ML: 18 months WC: 36 months of slippage due to SI contract termination, on-boarding of new SI Partner and re-work	N/A
System modules interoperability risk	Standard alignments and early design reviews, carry out Proof of Concept where possible, consult with Subject Matter Experts early in the design	30%	Increased project duration and associated costs.	1,797,494	4,209,205	10,533,529	BC: 3 months ML: 5 months WC: 10 months required to fix, test and deploy updates or new technologies to address interoperability issues	N/A

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Data management and network modelling system								
The vendor costs increase because of final tendering.	RFI has assessed requirements against high level designs.	50%	Higher costs and longer schedule	0	3,225,950	6,451,900	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates.
Contract scope variation required after contract execution	Contracts executed in stages with technical evaluation to include where practical a demonstration/prototype	30%	Higher costs and longer schedule	1,075,317	2,150,633	3,225,950	BC: 5% cost variation after contract is awarded ML: 10% cost variation WC: 15% cost variation	Assumption is contracts are made in stages to align with evolving data needs from the energy transition.
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	30%	Schedule slippage requires project team to be carried forward	150,000	300,000	450,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption 150k monthly burn rate	Transgrid internal resources to be extended to accommodate slippage in duration.

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Data quality and structure requires reworking on systems outside of the scope of this project	Internal estimates include several data management resources	40%	Higher costs to engage additional resources	565,000	655,000	1,310,000	BC: Additional 1x resources required for 60 days ML: 1x resources for 120 days WC: 2x resources for 120 days Assumption: 150k per month for Transgrid internal cost Vendor monthly cost is \$650k and 50% will be paid by vendor equates to \$325k	Higher data quality issues identified during the project that require addressing.
SCADA/Advanced Energy Management System (AEMS)								
The vendor costs increase as a result of final tendering.	RFI has assessed requirements against high level designs.	40%	Higher costs and potentially longer schedule	0	3,857,453	7,714,906	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates. Higher costs due to implementation of new capabilities and GridOS Architecture

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Vendor Scope Variation	Contract scope variation required after contract has been executed.	30%	Higher costs and potentially longer schedule	1,285,818	2,571,635	3,857,453	BC: 5% cost variation after contract is awarded. ML: 10% Cost variation WC: 15% cost variation	Additional requirements discovered as part of detailed design or product gaps [technical unknown requirements].
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	30%	Higher costs for schedule slippage	150,000	300,000	450,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption 150k monthly burn rate	This risk pertains to the successful implementation of the GridOS Architecture, given the introduction of new and unproven capabilities.
<u>Outage Management System</u>								
Technical solution proves inadequate, requiring rework (e.g. hardware, integrations)	Detailed design, incremental delivery, enterprise grade solutions, TOGAF framework	30%	Higher costs and longer schedule	124,898	187,347	312,245	BC: 10% cost variation after contract is awarded. ML: 15% Cost variation WC: 25% cost variation	Accommodate rework due to design changes or discovery during design phase.

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	30%	Higher costs for additional resources	150,000	300,000	450,000	BC: 1x no. of generators requires retesting ML: 2x no. of generators requires retesting WC: 3x no. of generators requires retesting	\$150k to cover the project resources cost for additional testing per generator.

<p>Transgrid may not be able to have contracts with generators</p>	<p>Transgrid requires third-party contracts to be established with generator owners. There is a risk that negotiations and agreement on these contracts may take longer than expected, potentially impacting the overall project schedule.</p>	<p>30%</p>	<p>Additional time for adoption of changes</p>	<p>0</p>	<p>1,100,000</p>	<p>2,200,000</p>	<p>BC: No delay due to contracts in place with 3rd party Generators</p> <p>ML: 10x 3rd party generator contracts need to be in-place</p> <p>WC: 20x 3rd party generators contracts need to be in place</p>	<p>If contracts are not in place the cost assumption per generator is:</p> <ol style="list-style-type: none"> 1. 20 days per generator to negotiate a contract: \$2k per day = \$40,000 (Legal, Commercial Specialist) 2. 20 days of Internal labour delay at \$2k per day = \$40,000 (SCADA SME, shared resources such as planner, project admin, Test Manager) 3. Update program and modify testing 20 days at @\$1500 per day= \$30,000 (1x AEMS Engineer)
<p>Operational forecasts and look ahead contingency analysis</p>								

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
The vendor costs increase as a result of final tendering.	RFI has provided requirements and assessed against high level designs.	40%	Higher costs and potentially longer schedule	0	358,302	716,605	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates.
Contract scope variation required after contract execution.	Contracts executed in stages with technical evaluation to include where practical a demonstration/prototype	30%	Higher costs and potentially longer schedule	119,434	238,868	358,302	BC: 5% cost variation after contract is awarded ML: 10% cost variation WC: 15% cost variation	
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	30%	Higher costs for additional resources	150,000	300,000	450,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption 150k monthly burn rate	This risk pertains to the successful implementation of the GridOS Architecture, given the introduction of new capabilities.

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Data quality and structure requires reworking on systems outside of the scope of this project	Internal estimates include several data management resources.	30%	Higher costs to engage additional resources	337,000	1,011,000	2,022,000	Best case: 1 month delay ML: 3 Month Delay WC: 6 Month Delay Assumption is \$150k burn rate per month and 50% of \$74k monthly vendor cost being \$37k	
Wide area monitoring								
The vendor costs increase as a result of final tendering.	RFI has provided requirements and assessed against high level designs.	40%	Higher costs and potentially longer schedule	0	749,734	1,499,468	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates.

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	30%	Higher costs for additional resources	150,000	450,000	900,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption 150k monthly burn rate	
Data quality and structure requires reworking on systems outside of the scope of this project	Internal estimates include several data management resources, scope could be refined around external data quality issues	30%	Higher costs to engage additional resources	362,000	452,000	904,000	BC: Additional 1x resources required for 60 days ML: 1x resources for 120 days WC: 2x resources for 120 days Assumption: 150k per month for Transgrid internal cost Vendor monthly cost is \$224k and 50% will be paid by vendor equates to \$122k	

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Smart transmission device management								
The vendor costs increase as a result of final tendering.	RFI has provided requirements and assessed against high level designs.	40%	Higher costs and potentially longer schedule	0	521,438	1,042,876	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates.
Contract scope variation required after contract execution.	Contracts executed in stages with technical evaluation to include where practical a demonstration/prototype	30%	Higher costs and potentially longer schedule	173,813	347,625	521,438	BC: 5% cost variation after contract is awarded ML: 10% cost variation WC: 15% cost variation	
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	40%	Higher costs for additional resources	150,000	450,000	900,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption 150k monthly burn rate	Need to carry resources due to schedule slippage.

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Fault level & system parameter monitoring & power system analysis capability								
The vendor costs increase as a result of final tendering.	RFI has provided requirements and assessed against high level designs.	40%	Higher costs and potentially longer schedule	0	883,421	1,766,841	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates
Contract scope variation required after contract execution.	Contracts executed in stages with technical evaluation to include where practical a demonstration/prototype	30%	Higher costs and potentially longer schedule	294,474	588,947	883,421	BC: 5% cost variation after contract is awarded ML: 10% cost variation WC: 15% cost variation	
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	40%	Higher costs for additional resources	150,000	450,000	900,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption 150k monthly burn rate	

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Data quality and structure requires reworking on systems outside of the scope of this project	Internal estimates include several data management resources, scope could be refined around external data quality issues	40%	Higher costs to engage additional resources	446,000	536,000	1,072,000	BC: Additional 1x resources required for 60 days ML: 1x resources for 120 days WC: 2x resources for 120 days Assumption: 150k per month for Transgrid internal cost Vendor monthly cost is \$413k and 50% will be paid by vendor equates to \$206k	
Alarm management technologies								
The vendor costs increase as a result of final tendering.	RFI has provided requirements and assessed against high level designs.	50%	Higher costs and potentially longer schedule	0	1,940,491	3,880,982	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Contract scope variation required after contract execution.	Contracts executed in stages with technical evaluation to include where practical a demonstration/prototype	30%	Higher costs and potentially longer schedule	646,830	1,293,661	1,940,491	BC: 5% cost variation after contract is awarded ML: 10% cost variation WC: 15% cost variation	
Testing requires more than expected resourcing and rework.	Test automation, strong test governance, well defined test cases as testing defined during the design phase	30%	Higher costs for additional resources	150,000	300,000	450,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption 150k monthly burn rate	
Data quality and structure requires reworking on systems outside of the scope of this project.	Internal estimates include several data management resources, scope could be refined around external data quality issues	30%	Higher costs to engage additional resources	390,000	480,000	960,000	BC: Additional 1x resources required for 60 days ML: 1x resources for 120 days WC: 2x resources for 120 days	

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Comms links, RTUs, HMI unable to cater to additional data coming into SCADA and require upgrading	Allowed for ungrouping at data concentrator, allowing for dual homing of RTU in base budget.	20%	Additional hardware and labour	-	1,000,000	2,000,000	BC: No sites required to be upgraded ML: 10x sites to be upgraded WC: 20x sites to be upgraded. Estimated at \$100k per site	Estimated cost per comms link upgrade \$100k per site
Visualisation and situational awareness enhancements								
The vendor costs increase as a result of final tendering.	RFI has provided requirements and assessed against high level designs.	50%	Higher costs and potentially longer schedule	0	1,623,631	3,247,263	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Contract scope variation required after contract execution.	Contracts executed in stages with technical evaluation to include where practical a demonstration/prototype	30%	Higher costs and potentially longer schedule	1,082,421	2,164,842	3,247,263	BC: 10% cost variation after contract is awarded ML: 20% cost variation WC: 30% cost variation	
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	30%	Higher costs for additional resources	150,000	450,000	900,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption 150k monthly burn rate	

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Data quality and structure requires reworking on systems outside of the scope of this project	Internal estimates include several data management resources, scope could be refined around external data quality issues	30%	Higher costs to engage additional resources	430,000	520,000	1,040,000	BC: Additional 1x resources required for 60 days ML: 1x resources for 120 days WC: 2x resources for 120 days Assumption: \$150k per month Transgrid internal cost Vendor monthly cost is \$374k and 50% will be paid by vendor equates to \$190k	
Training technologies								
The vendor costs increase as a result of final tendering.	RFI has provided requirements and assessed against high level designs.	40%	Higher costs and potentially longer schedule	0	901,809	1,803,618	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Contract scope variation required after contract execution.	Contracts executed in stages with technical evaluation to include where practical a demonstration/prototype	30%	Higher costs and potentially longer schedule	300,603	601,206	901,809	BC: 5% cost variation after contract is awarded ML: 10% cost variation WC: 15% cost variation	
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	30%	Higher costs for additional resources	150,000	300,000	450,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption \$150k monthly burn rate	Reflects the amount that is new technology and thus likely to require additional testing
Operational documentation management system								
The vendor costs increase as a result of final tendering.	RFI has provided requirements and assessed against high level designs.	40%	Higher costs and potentially longer schedule	0	249,196	498,393	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates

Risk Area	Treatment	Likelihood (%)	Consequence	Best Case (\$)	Most Likely (\$)	Worst Case (\$)	Quantitative Range Assumptions	Comment
Contract scope variation required after contract execution.	Contracts executed in stages with technical evaluation to include where practical a demonstration/prototype	30%	Higher costs and potentially longer schedule	83,065	166,131	249,196	BC: 5% cost variation after contract is awarded ML: 10% cost variation WC: 15% cost variation	
Operational planning system								
The vendor costs increase as a result of final tendering.	RFI has provided requirements and assessed against high level designs.	40%	Higher costs and potentially longer schedule	0	389,370	778,741	BC: No changes to Vendor's original cost submission ML: 15% cost variation WC: 30% cost variation	Best and worst case reflects RFI estimates
Testing requires more than expected resourcing and rework	Test automation, strong test governance, well defined test cases as testing defined during the design phase	30%	Higher costs for additional resources	150,000	300,000	450,000	BC: 1 month delay ML: 2 Month Delay WC: 3 Month Delay Assumption \$150k monthly burn rate	Additional testing required to test key functionalities and integration

