



Draft Plan

2028-33 Regulatory
Determination

September 2026



Acknowledgement of Country



Namoi River, Kamilaroi Country,
northern New South Wales

In the spirit of reconciliation, Transgrid acknowledges the Traditional Custodians of the lands, skies and waterways across New South Wales and the ACT where we live, work and travel.

We pay our respects to Elders past, present and emerging, and we extend that respect to Aboriginal and Torres Strait Islander peoples and communities across the lands on which we operate.

We recognise that every place we work holds deep cultural meaning, living connection and enduring responsibility. This connection inspires and informs the care with which we undertake our work.

Country is not a backdrop to our activities. It shapes how we must listen, engage and act. That understanding informs our commitment to work with deepening respect, protect what matters and strengthen relationships with the communities on whose Country we operate.

Contents

1 Our role and changing environment	17
1.1 Who we are	18
1.2 Our operating environment	19
1.2.1 Understand and balance the interests of NSW & ACT electricity consumers	19
1.2.2 Maintain a safe, secure and reliable electricity network	20
1.2.3 Enable a system powered by more renewables	21
1.2.4 Meet new and changing demand	23
1.2.5 Deliver the best value for money	24
1.3 Using future scenarios to inform investment decisions	24
1.3.1 A responsible and transparent approach to data centre growth	25
1.3.2 Distribution connected data centres	26
1.3.3 Transmission connected data centres	26
2 What we are hearing and how we are responding	27
2.1 How we are engaging	28
2.1.1 A tiered and deliberative engagement framework	28
2.1.2 Consumer Advisory Group and Consumer Working Group	29
2.1.3 Transgrid Consumer Panel	31
2.1.4 Broader customer and stakeholder engagement	33
2.1.5 Ongoing business-as-usual engagement	33
2.2 What we are hearing and how we are responding	33
2.2.1 Putting downward pressure on costs in a cost-of-living crisis	34
2.2.2 Equitable cost recovery	35
2.2.3 Transparency of our proposal and its impact on consumers	37
2.2.4 Reliability and services outcomes	39
2.2.5 Protecting communities from severe weather events	41
2.2.6 Delivering the capital program	42
2.2.7 Robust business cases and assumptions	43
2.2.8 Managing greater complexity and innovating	45
3 Draft Plan	46
3.1 The 'Draft Plan' proposal	47
3.1.1 Our approach	47
3.1.2 Cost escalation and estimation	48
3.1.3 Deliverability	50
3.1.4 Prioritisation	51
3.1.5 Alignment with AER expectations	51
3.1.6 Incorporating CWG and Consumer Panel feedback	52
3.2 Capital expenditure overview	55
3.2.1 Prescribed service capex (excluding ISP projects)	57
3.2.2 Augmentation	60
3.2.3 System security and operability	71
3.2.4 Replacement	75

3.2.5	ICT	81
3.2.6	Cyber security	85
3.2.7	Property	86
3.2.8	Fleet	88
3.2.9	Overheads	89
3.3	Operating expenditure.....	89
3.3.1	Base year.....	91
3.3.2	Trend	93
3.3.3	Step.....	94
3.3.4	Category specific forecasts.....	98
3.4	Revenue, RAB and consumer bills	103
3.5	Other elements	107
3.5.1	Incentive schemes.....	107
3.5.2	Cost pass through events	109
3.5.3	Pricing methodology	109



A few words from our Board and Executive team

We are pleased to share our Draft Plan for 2028–33. Our Board and Executive team have been closely involved in its development and are committed to ensuring our final proposal reflects the long-term interests of consumers.

In simple terms, this Draft Plan explains the work we think is needed on the shared transmission network from 2028 to 2033, what it may cost, how it may affect bills, and where we still want your feedback before we submit our final Revenue Proposal to the Australian Energy Regulator (AER).

Reflecting our commitment to placing downward pressure on energy bills, we have sought to balance the need to deliver a safe, reliable and secure network that provides energy certainty for consumers and businesses, while keeping that investment as prudent and efficient as possible. Our Draft Plan would reduce the transmission component of a typical residential electricity bill by \$2 a year, or \$6 a year for small business, over the 2028–33 period relative to the final year of the current period. We will do this while seeking to maintain reliability in the face of growing risks and accommodating a six-fold increase in demand growth.

At the beginning of this process, we recognised that the level of trust that regulators and consumer advocates have in Transgrid is not where we want it to be. We committed to using this process as an opportunity to improve how we engage with our consumers and their representatives to build trust, transparency and accountability.

To do this, we have engaged broadly with consumer advocates through our Consumer Advisory Group (CAG) and Consumer Working Group (CWG), with industry participants and, for the first time for us as part of a Revenue Proposal, end use consumers via our Consumer Panel. At the same time, our Draft Plan has been developed in a highly challenging operating environment, including:

- **Costs outpacing inflation** due to labour and global supply chain shortages we have seen the cost of key materials outpace inflation by 2–3 times over the last five years.
- **Substantial new loads from data centres.** Compared to 0.5 GW of growth over the current 2023–28 period, we are forecasting peak demand to grow by 3 GW over 2028–33, with 2.5 GW driven by data centres.
- **An ageing network.** About 11% of our assets are operating beyond their technical life, asset defects and risks typically increase as the network ages. This proportion will rise to 33% by the end of the 2028–33 period, if no investment is made.
- **Growing complexity and risks** as renewable generation grows from 46% to 90% creating new operational challenges. Together with increasing cyber threats (cyber phishing attacks for instance surged 1,200% from 2022 to 2025) and resilience risks particularly from extreme winds in rural parts of NSW.

We heard that consumers expect us to meet these challenges to deliver a safe, secure and reliable supply of electricity at the lowest cost. Our Draft Plan sets out how we intend to implement the feedback we have received. It reflects what we have done to constrain expenditure, improve resilience, maintain reliability – all with an eye to future price and risk outcomes. To summarise, our Board and Executive are focussed on delivering a 2028–33 Revenue Proposal that will:

- **Understand and balance the interests of NSW & ACT electricity consumers:** We have uplifted our consumer engagement, highlighted by the establishment of our CWG and Consumer Panel and will continue to provide consumers the opportunity to actively shape our proposals and plans.
- **Maintain a safe, secure and reliable electricity network:** Our services are essential to powering the lives of consumers. While we must innovate, utilise our data and systems and maximise the use of our existing assets to reduce costs we must also continue to deliver a safe, secure and reliable service.
- **Enabling a system powered by more renewables:** As coal-fired generation retires (~7 GW exiting by 2035), the grid needs new sources of system strength and stability from large synchronous condensers and grid-forming batteries to support a system increasingly dominated by renewable generation (21 GW of new utility solar and wind capacity by 2035). At the same time, we only wish to invest where necessary and to use the lowest cost technologies. To maintain flexibility, we have identified projects that may be necessary to keep the system stable during 2028–33 and beyond.

- **Meeting new and changing demand:** Population growth of ~1.4% per annum, electrification (~5.5 TWh combined increase by FY35) and large new loads like data centres (~26 TWh) are driving the need for network augmentation. We continue to test demand forecasts carefully, consider alternative solutions and use existing capacity wherever possible to reduce costs.
- **Deliver value for money:** There is a clear expectation that we carefully consider the need, timing and scope of all potential options to demonstrate restraint when forecasting expenditure requirements. We are conducting thorough and detailed testing of our planned investments to assess alternatives, staging and timing and accurately cost and sequence their delivery. This work builds on our learnings to date in managing the scale and pace of the transition combined with global conflicts and supply chain shocks.

Even after applying this restraint, the work required to maintain reliability, respond to demand growth and manage emerging risks means our proposed capital expenditure increases to \$3.7 billion over 2028-33. This reflects a period of significant change for the energy system and for Transgrid. It is not business-as-usual. Importantly, we have tested this increase against consumer feedback and are at the lower end of expenditure increases seen by comparable Australian and international transmission businesses.

While expenditure needs are increasing, demand is also forecast to grow, largely due to data centres, with energy consumption forecast to increase by 26%. This means the cost of the network will be spread across more electricity use, helping to put downward pressure on electricity bills.

Given the extent of network upgrades data centres will trigger, we have sought to maximise the opportunity for consumers - greater utilisation, lower bills and a strengthened network - while protecting them from the risks. We are also supporting government pricing reforms for data centre connections, including the use of 'take or pay' arrangements where these customers pay for contracted capacity. Depending on what data centre connections eventuate, these reforms have the potential to reduce the transmission component of consumer bills by \$8 for the typical household.

Further, and partly in response to our work with the CWG, the NSW and Federal governments are considering 'causer pays' reforms for data centre connections. While still being developed, we expect that these reforms will substantially reduce the proportion of network upgrade costs recovered from the broader customer base.

To finalise our Revenue Proposal for 2028-33, we invite all interested parties to engage with this Draft Plan. The feedback we have received to date has been beneficial to our Board and Executive team in guiding the development of our plans and embedding consumer-centric decision making at Transgrid.

Lastly, we would like to thank the AER, members of the CWG and CAG, community members and large customers for their ongoing participation in our engagement program. Their time, expertise and constructive challenge have helped inform and shape the thinking presented in this Draft Plan.

On behalf of Transgrid's Board and Executive team,



Brett Redman.
Chief Executive Officer Transgrid Group

Overview of the Draft Plan

Purpose of the Draft Plan

This Draft Plan is designed to show consumers and stakeholders how their feedback is shaping our 2028-33 Revenue Proposal. It explains what we have heard, how we have responded, what this may mean for bills and reliability, and where we still want input before our final proposal is submitted.

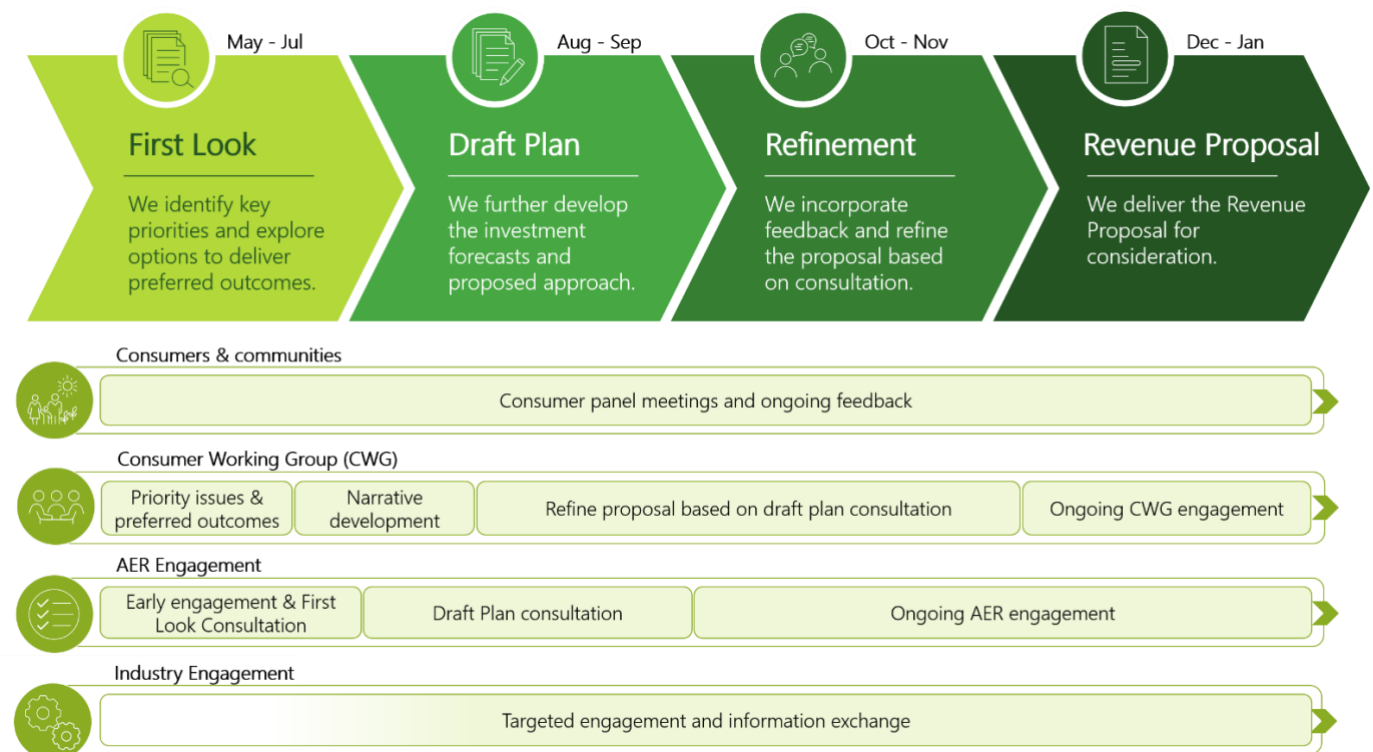
We are publishing the Draft Plan now, so people can see our thinking early, not after decisions have already been made. Consumers and advocates have asked for clearer information, earlier engagement, and a better explanation of the trade-offs between affordability, reliability, resilience and future demand. This document is intended to support that conversation.

This is a key part of our enhanced engagement program for our 5-yearly regulatory resets and is an important step in our shift toward more transparent and open engagement. It marks a transition to engaging earlier and more deeply with consumers, the Consumer Working Group (CWG), and the Australian Energy Regulator (AER) on key proposal inputs, desired outcomes, trade-off decisions and a detailed review of our plans and priorities.

The forecasts and positions in this Draft Plan are not final. They are a point-in-time view, that will continue to be tested and refined through further engagement, evidence and challenge. In particular, we want feedback on whether the plan properly reflects what consumers have told us they need: reliable service, efficient costs, careful investment, transparent bill impacts and a practical pathway through the energy transition.

Enquiries and feedback on this Draft Plan can be made to your.voice@transgrid.com.au by 30 October 2026. We will then finalise our Revenue Proposal to the AER which is due for submission 29 January 2027. The AER will then commence a formal engagement process to make a final decision by April 2028. This will include an opportunity for consumers and interested parties to make a submission directly to the AER and for Transgrid to submit a Revised Proposal in late 2027 in response to the AER's draft decision, latest conditions and consumer feedback.

Figure 0 -1 Engagement and proposal development timeline



How we are responding to consumer feedback

Having provided initial forecasts to the CWG early in March 2026, we have been engaging deeply on our engagement focus areas, draft forecasts and positions. In addition, we have completed four of five sessions with our Consumer Panel, testing specific topics and trade-offs as well as interviewing our large industrial and commercial customers and other industry participants. Across these engagement activities, consistent themes have emerged which we set out in the table below along with our response. We provide further detail in Chapter 2.

Table 0-1 How we are responding to customer feedback

What we have heard	How we have responded in this Draft Plan
Transgrid must carefully consider the scope, timing and need for investment in the context of the cost-of-living crisis. Transgrid must demonstrate all options have been considered to constrain costs.	Applied five levers of constraint, as suggested by CWG, in our project and program level assessments. Removed \$372m of replacement expenditures (repex) and \$291m of augmentation expenditures (augex), not applied material cost escalation (\$615m if similar 2023-28 price increases occur in 2028-33) and removed \$50m of opex step changes to further constrain customer bill increases.
In servicing rapid growth, Transgrid must ensure costs are recovered equitably and that consumers benefit from the increased utilisation of the network.	Identified and supported policy changes to protect customers from costs caused by distribution-connected data centres. Depending on the chosen implementation, this could save consumers up to \$400-\$500m. Proposed changes to our pricing methodology to charge certain large loads, like data centres, based on contracted demand ('take or pay') to ensure these customers pay their fair share of the costs and have this embedded in government policy. This has the potential to further lower residential customer bills by \$8 per year on average over the 2028-33 period compared to the last year of the current period (FY28).
Transgrid should provide a clearer explanation of changes occurring in the electricity industry, its role within these changes and how the perspective of consumers is guiding our future plans. When consulting with consumers, Transgrid should also provide clear and complete information, particularly with respect to electricity bills.	Developed a narrative, tested by the CWG and consumer panel, to guide our proposal, our Transmission Annual Planning Report (TAPR) and for ongoing internal use. Provided a complete view of bill impacts across scenarios. This includes the impact of expenditure included in this Revenue Proposal as well as a broader view of bill outcomes from projects we expect to undertake related to AEMO's Integrated System Plan and the NSW Government's Electricity Infrastructure Roadmap.
Transgrid should maintain a safe, secure and reliable network at existing service levels.	Our replacement program is designed to maintain the current level of risk borne by customers and the wider community. This requires an increase in investment to offset the increase driven by a larger number of assets operating beyond their design life. Our program ensures risk does not grow (which would be inconsistent with customer feedback and would be challenging to reverse in future periods) nor does it allow for reducing risk from current levels (to avoid putting additional pressure on customer bills).

What we have heard	How we have responded in this Draft Plan
	To deliver on this customer feedback, we have developed our plans on a forward-looking basis, considering the condition of our assets and the probability and consequence of asset failure. Given the increasing proportion of our assets operating beyond their design life, underlying risk will increase without higher levels of investment. While we plan on a forward-looking risk basis, we also consider outturn performance. However, this data varies from year to year depending on which assets happen to fail and is not, on its own, a reliable indicator of the risk customers will face in future.
Transgrid should apply the AER's Network Resilience Guideline and consider resilience spend that is targeted, well-evidenced and supported by engagement to protect vulnerable communities from severe weather events	We have identified a single resilience project to strengthen the single line which services the Broken Hill region. This project will reduce the frequency of storm-related impacts (we have experienced two in the last 20 years) and avoid the need for costly restoration and local power generation.
Transgrid must robustly test and demonstrate its proposed investments are not just necessary and least cost but also deliverable in a period of supply chain disruption and increased industry demand	We have uplifted our deliverability analysis to identify key constraints such as workforce capacity, market availability, long-lead items and outages. While this work is ongoing, the preliminary analysis indicates that our program is deliverable but additional work is required to improve the phasing and sequencing of the overall portfolio.
Where an increase in expenditure is required, it must be supported by a high standard of evidence and accord with AER guidelines, expectations and industry best practice	We increased the depth and quality of our analysis in preparing this Revenue Proposal particularly in key areas including: our demand forecast (which drives a large part of our augmentation program) and our replacement program to ensure we get the balance right between costs and risk at both the project and portfolio level. We aligned key inputs and expenditure forecasting methodologies, such as the Value of Customer Reliability, with AER prescribed values and guidelines, including those related to consumer engagement.
Transgrid must adapt to the growing complexity of the electricity system and improve its ability to innovate and adopt non-network solutions	Consideration of non-network solutions has been embedded into our options analysis along with additional layers of challenge to ensure we consider innovative approaches as well as traditional solutions. We have proposed targeted opex step changes to uplift our operability and planning capabilities which will drive efficiencies in an increasingly complex operating environment. We have optimised outages through our deliverability planning and have included measures to improve workforce capability, capacity and training.

Key outcomes and bill impacts

Our Draft Plan is to maintain the current level of service while constraining cost increases wherever feasible. Consistent with customer and stakeholder feedback, we are not seeking to improve the quality of our service where this results in a higher cost nor are we proposing to increase the level of risk the community and our customers bear. However, due to cost increases, operational complexity, asset condition, new sources of demand, as well as increased cyber and resilience threats, maintaining the current level of service will require an increase in expenditure.

While we face increasing risk and cost pressures, there are also opportunities. In particular, the substantial new loads from data centres provide an opportunity to increase the utilisation of our network to both lower costs to household consumers while strengthening our network through grid support services like flexible demand.

We present a summary of the bill impacts associated with this Draft Plan. Figure 0 2 shows the indicative residential bill impacts over the current regulatory period and the next 2028-2033 regulatory period.

These estimates reflect the expected bill impact from movements in our Transmission Use of System (TUOS) charges, which recover the costs of providing our core shared transmission network service. Our TUOS charges are set under our approved Pricing Methodology, comprising fixed connection charges and demand-based charges. These charges are paid by NSW/ACT distribution networks and directly connected transmission customers. Distribution networks, in turn, recover our charges through the network tariffs they charge electricity retailers. Retailers set the final prices paid by consumers.

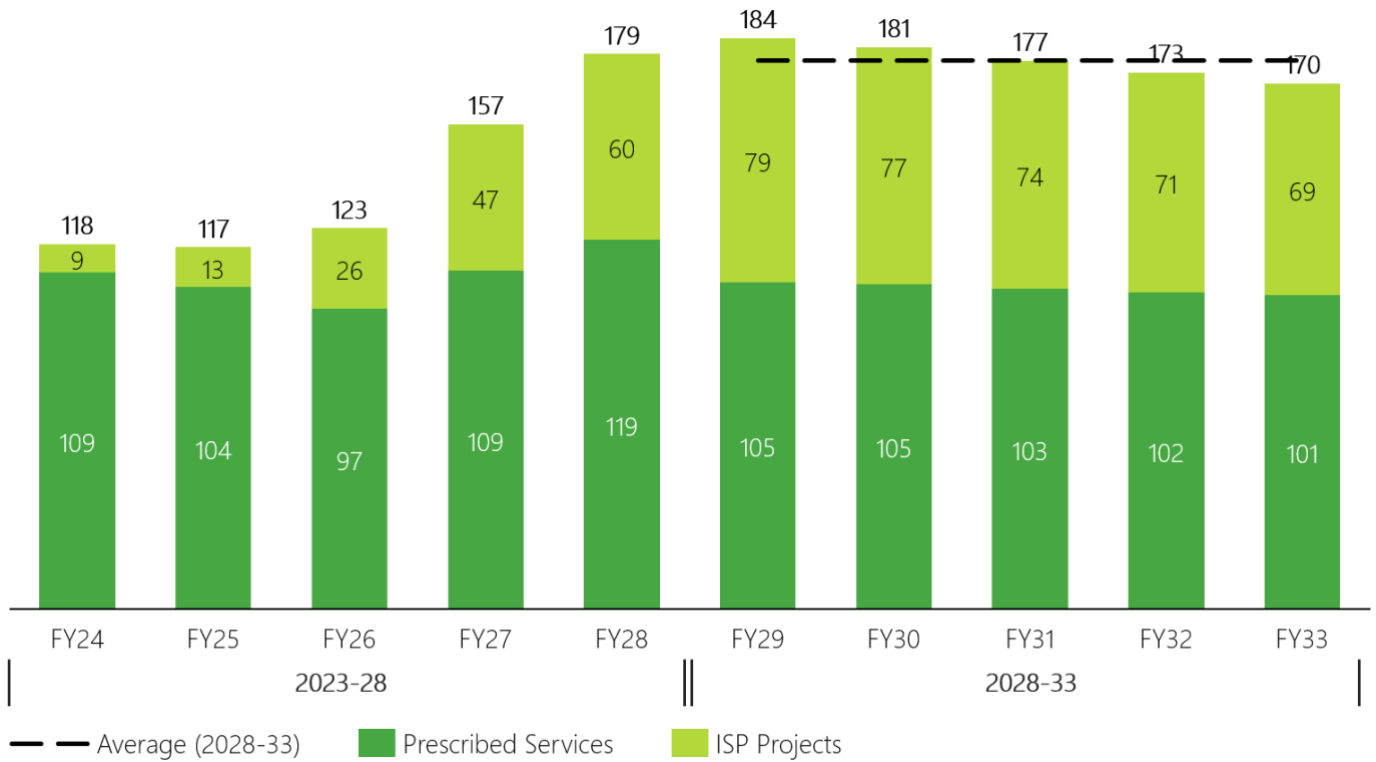
The amount of transmission costs in your electricity bill depends on your distribution network and retailer, and how they recover our costs through their own prices. Distribution networks predominantly recover our costs through usage-based charges, so your contribution to transmission costs can vary with how much electricity you use. We have estimated bill impacts based on the AER's Default Market Offer (DMO), taking a weighted average of the average residential and small business customer across the NSW distribution networks. They are therefore indicative and the actual prices will vary based on your consumption, distribution networks and retail allocations of our costs, and additional projects we may undertake during the 2028-33 period through other regulatory pathways. Nevertheless, we provide these impacts as an indication as to whether this proposal is placing upward or downward pressure on overall bill movements.

It should also be noted that the increase in our component of electricity bills over the 2023-28 period was primarily driven by the delivery of large AEMO ISP projects – Project EnergyConnect, HumeLink and the Victoria New South Wales Interconnector West (VNI West) – to implement the Integrated System Plan. These projects increase our Regulated Asset Base (RAB) and in turn our revenue requirements and customer bills. These projects are to facilitate the energy transition to decarbonise the economy and drive longer-term bill reductions which flow through to other elements of consumer's bills. This increase in bills is in line with the expectations of policymakers that the infrastructure required to support the energy transition will put upward pressure on electricity bills in the short term before renewable generation sources place a downward pressure on bills over the longer term.

Nevertheless, we are mindful of the impacts of further cost pressures on consumers that fund these increases now without a guarantee on how overall electricity prices will change in the future. In building trust and delivering value it is critical to strike the right balance between managing costs and enabling a timely energy transition to unlock its expected benefits.

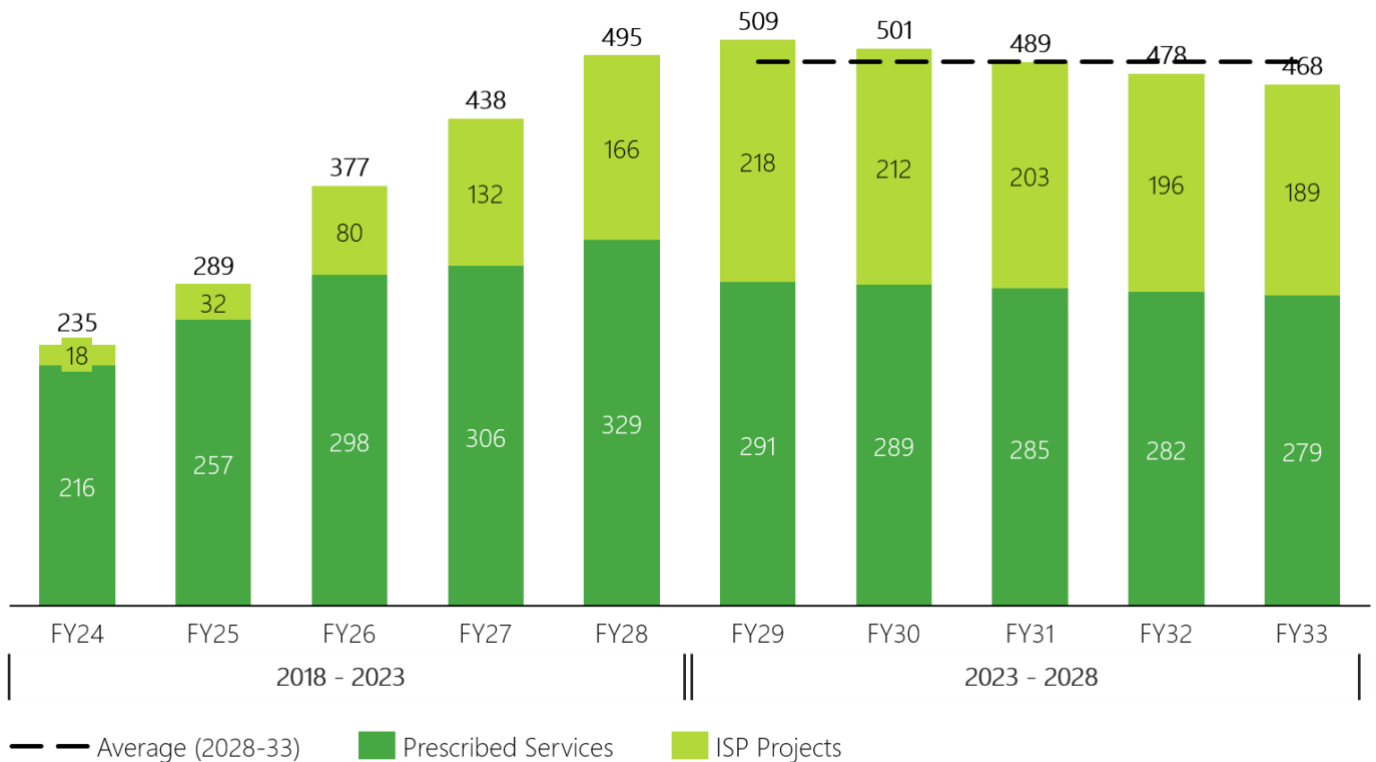
Over the 2028-33 period, we are forecasting that the transmission component of residential consumer bills will be, on average \$2 lower, compared to the last year of the current regulatory period (2027-28). This reduction is due to the forecast increase in energy consumption over 2028-33 as well as our efforts to find opportunities to constrain cost increases and drive efficiencies.

Figure 0-2 Indicative bill impacts – Transgrid component of residential bill (\$m, Real 2027-28)



Similarly, we expect small business bills to be, on average, \$6 a year lower than in 2027-28, as shown in Figure 0-3 below.

Figure 0-3 Indicative bill impacts – Transgrid component of small business bill (\$m, Real 2027-28)



These bill outcomes will not occur in isolation to the remainder of the bill and could vary for a variety of reasons, including:

- This proposal includes a number of assumptions such as demand, the AER's Rate of Return Instrument (RORI), inflation which, if varied, could result in materially different pricing outcomes.
- How an individual residential or small business consumer uses the network (i.e., when and how much they consume).
- How distributors and retailers allocate our costs and structure their prices.
- The pace and scale at which data centres actually connect to and utilise the network and associated pricing reforms like "take or pay" and NSW Government causer pays and contribution reforms.
- Additional projects we have or may undertake to support the delivery of AEMOs Integrated System Plan or the NSW Government's Electricity Infrastructure Roadmap. While these projects will only proceed if they deliver net consumer benefits, they will also impact the bill outcomes shown above.

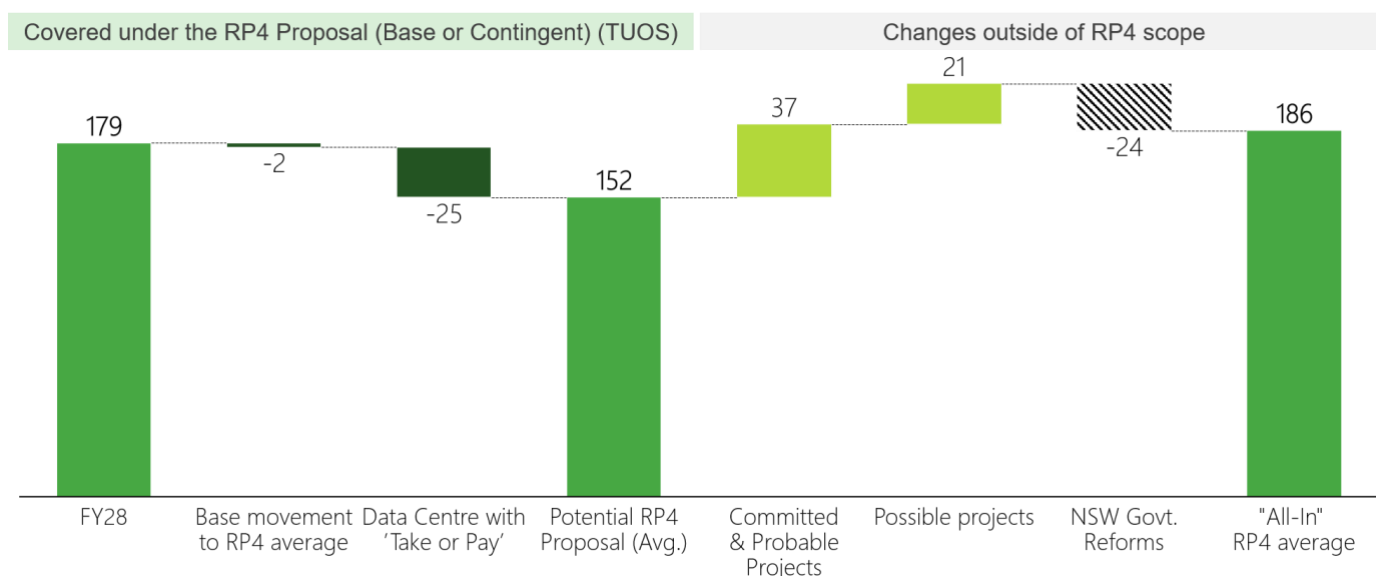
Throughout our engagement activities, consumers have told us they value transparency on future bill movements. While these changes remain uncertain, they provide useful content and insight in reviewing our 2028-33 proposal. To address this, we provide an estimate below of significant sources of uncertainty that could impact the bill outcomes presented in this proposal, being data centres and future major projects.

For data centres, we have sought to provide an indication of the impact of significantly faster and higher data centre growth which results in higher spend but also higher energy consumption. We have also included the impacts of our associated "take or pay" pricing reforms which are designed to provide protections to consumers and a fair and reasonable approach to data centre proponents looking to connect to the grid and secure supply. Specifically, we intend to charge these customers on the basis of their contracted demand rather than actual usage. This is to protect consumers against the risks of capacity reservation and any funding of potentially underutilised assets. For the wider consumer base, these changes effectively bring forward the bill-reducing benefits of increased network utilisation.

For future major projects, we have relied on the latest and best information available on the status of each project and its expected cost, and have forecast which projects are proposed to be committed to and commence during the 2028-33 period. These projects are subject to a higher degree of uncertainty with only preliminary timing and costings available. We have not developed proposals for these projects, nor have they been fully assessed or approved.

As part of this analysis, we have also provided an estimate of the impacts of reforms being considered by the NSW Government around equitable cost recovery arrangements and how some of the costs for these major projects or NSW Roadmap costs more broadly could be, in part, recovered from data centres.

Figure 0-4 Indicative bill impacts – Transgrid component of residential bill (with Data Centres and Possible New Projects) (\$m, Real 2027-28)



This analysis includes an estimate for projects committed under the EII Act: accelerated synchronous condensers, Waratah Super Battery and CWO Enabling Works; probable projects: South-West REZ RNIP, Far West Solution, Sydney Ring South (early works) and the Hunter Transmission Project; as well as possible projects that may proceed during 2028-33: New England REZ, VNI West Stage 2 (Interconnector Line) and two additional synchronous condensers.

We note this analysis only reflects our preliminary views on projects yet to be assessed or approved and that the NSW Government reforms remain under review. This analysis also only captures the cost to consumers and does not consider the consumer benefits these projects will deliver, for instance by increased energy security or downward pressure on wholesale electricity costs. For how other changes, such as demand or the AER's final decision on the changes to the rate of return instrument, could impact revenue and bill outcomes, refer to section 3.4.

How we align with AER expectations

In developing the Draft Plan, we have had careful regard to AER guidance, including the expectations for a high-quality proposal set out in its Better Resets Handbook (the Handbook). Since the Handbook was introduced, we have sought to apply its principles consistently through our reset processes, and we recognise its continued importance in supporting transparent, well-evidenced and consumer-focused regulatory proposals. The Handbook remains valuable guidance on best practice engagement, expenditure forecasting methodologies and the AER's positions on key topics. At the same time, the operating environment for transmission networks has changed materially since the Handbook was developed. As outlined in section 1.2, we are no longer operating in a steady-state environment where expenditure needs can be assumed to remain constant or decline over time. Table 0-2 sets out how the Draft Plan aligns with the Handbook's expectations, while also explaining the areas where current system conditions require additional context.

Table 0-2 Transgrid's alignment to Better Resets Handbook

Component	AER Expectation	Draft Plan
Consumer engagement	Commitment of AER resourcing for fast-tracked Regulatory Proposals (or key elements)	While our proposal is not eligible for the Early Signal Pathway, we remain committed to engaging deeply and extensively with customers, consumers and key stakeholders on our preliminary forecasts and positions. This included preparing a 'First Look' of our proposal which we provided to the AER and CWG. This has led to several issues being identified and resolved already. We are working through the remainder.
	Consumers partner with network businesses in forming proposals, rather than providing feedback on pre-determined positions.	CWG and Consumer Panel established to engage and collaborate on key forecasts, positions and trade-offs.
	Deep involvement of key staff and Executive as well as Board support and participation.	Our engagement plan and topics have been co-designed using industry best practice principles and led by Transgrid's Board and Executive.
Capital expenditure	Top-down testing of the total capital expenditure forecast and at the category level, with expenditure not materially above prior period spend.	We have undertaken top-down and category level testing of our expenditure forecast. However, we are currently forecasting an increase in expenditure. This reflects that Transgrid is not operating in a steady-state environment. That said, we note that expenditure is expected to reduce between periods when ISP projects are considered.
	Evidence of prudent and efficient decision-making on key projects and programs	We continue to prepare supporting strategies and business cases to demonstrate the efficiency and prudence of our proposed investments. Only compliance based and positive cost-benefit investments have been included in our forecasts.
	Evidence of alignment with asset and risk management standards	We have refined our forecasts through engagement, cost-benefit analysis and asset management practices which align with AER guidance and industry best practice. This includes the adoption of the AER's VCR.
	Genuine consumer engagement on capital expenditure proposals	We have engaged extensively on our capital forecasts providing iterative forecasts, sample business cases and engaging with the CWG and Consumer Panel on key trade-offs and investment categories.
Operating expenditure	Utilise AER base-step-trend methodology for deriving forecast.	Transgrid is positioned within the efficient frontier and will apply the base-step-trend methodology to derive an operating expenditure forecast.
	Apply benchmarking and productivity adjustments	We have applied the trend and productivity factors which the most recent published Annual Benchmarking report.

Component	AER Expectation	Draft Plan
Regulatory modelling and depreciation	consistent with AER values and approach outlined in most recent Annual Benchmarking Report.	
	Step changes limited to legislative changes and capex/opex trade-offs	Step changes have been identified consistent with the AER criteria, reduced following consultation and will be subject to AER review. However, we have are also proposing category specific forecasts for material uncontrollable costs elements of our operating expenditure stack.
	Utilises the AER's post-tax revenue model, roll-forward model and depreciation tracking.	We are applying the AER's post-tax revenue model, roll-forward model and depreciation tracking module. We are also intending to adopt the AER's capex model for transmission which is currently being developed.
	Customer engagement on any proposal for depreciation acceleration, changes to asset classes or lives.	We are not proposing any material changes to asset classes, lives or depreciation.

Key: ■ Aligned or enough information to suggest 'on track' ■ To be determined / unknown ■ Not aligned or not 'on track'

Finalising our Revenue Proposal

We provide more detail on our approach and the draft positions in the remainder of this document. Over the coming months we will continue to refine our forecasts and our supporting evidence in response to ongoing engagement activities. The sections and guidance we would appreciate your feedback on to finalise our 2028-33 Revenue Proposal are set out in the table below by 30 October to your.voice@transgrid.com.au.

Table 0-3 Overview of the Draft Plan

Section	What is the purpose of this section?	What we would like your views on
Overview	To provide a summary of this Draft Plan, key topics, engagement findings and forecasts for the 2028-33 period.	Does this Draft Plan deliver the right outcomes for consumers? What principles should guide cost recovery for large energy users, like data centres, where their demand materially drives additional network investment or brings forward investment that would otherwise occur later?
Our role and changing environment	This is for people interested in understanding more about what our role is, what is happening in the energy industry and how we see the future unfolding.	Have we clearly articulated our purpose and narrative? What are the outcomes that matter most to you or the people you represent?
What we are hearing and how we are responding	This section is to outline the feedback and insights we have received to date from our engagement activities.	Have we accurately reflected the themes and perspectives from engagement to date? Are we responding to this feedback reasonably?
Draft Plan	This section is for people interested in a detailed overview of our preliminary inputs, forecasts and positions and methodology for deriving them.	Do our preliminary positions align with your expectations? Are there any further changes you would recommend we consider?

Section 1

Our role and changing environment



1.1 Who we are

We operate the high voltage transmission network in NSW and the ACT providing a safe, secure and reliable supply to more than 3 million homes and businesses, supporting the energy needs of more than 9 million consumers across the region. Our network transports electricity from a diverse range of generation sources – wind, solar, hydro, gas and coal – to large industrial customers and the distribution networks that deliver power to homes and businesses. Each year, we transport approximately 66,000 GWh of electricity across NSW and the ACT, reflecting the scale and criticality of our role in the energy system.

Our network forms part of the backbone of the National Electricity Market (NEM) including:

- 98 substations and switching stations
- 14,314 kilometres of high-voltage transmission lines
- 106 kilometres of underground cables
- 4000+ kilometres of optical fibre
- 6 key interconnectors linking NSW to QLD, VIC and SA.

The network includes both regulated transmission assets delivered under the National Electricity Rules (NER) framework and major developments supporting the NSW Electricity Infrastructure Roadmap, which may be subject to different funding and cost recovery arrangements.

Our core role is to operate, maintain and develop the transmission network so that electricity can be transported safely, reliably and efficiently across NSW and the ACT. This includes ensuring the system remains secure as the mix of generation changes, supporting the connection of new generation and large loads, and enabling electricity to flow from where it is generated to where it is needed.

A strong transmission system is critical to delivering reliable and affordable electricity for consumers. It supports access to lower-cost generation, enables economic growth, and helps maintain energy security and reliability across NSW and the ACT.

We are currently delivering a portfolio of transmission investments to support these outcomes. This includes a number of large, strategic infrastructure projects — such as EnergyConnect, HumeLink, the Victoria NSW Interconnector (VNI) and the Hunter Transmission Project — some of which are being progressed under separate regulatory and policy frameworks. These projects are critical to enabling the broader energy transition and are a key part of the overall development of the transmission system.

Alongside these major projects, we continue to invest in the ongoing operation, maintenance and development of the network to ensure it remains secure, safe, reliable and capable of meeting changing demand. It is these ongoing services and investments that will be the focus of our 2028–33 Revenue Proposal. Our proposal will set out the efficient costs required to deliver day-to-day network services, manage asset risks, support connections and maintain reliability for consumers, and, subject to the AER assessment, ultimately determines the transmission component of electricity bills.

1.2 Our operating environment

For decades, electricity in NSW has been delivered to consumers through a system that was relatively stable and predictable. Large power stations operated continuously, demand grew gradually, and infrastructure could be planned and replaced over long timeframes. In that environment, electricity felt dependable, and difficult investment choices were rarely visible to households. Capital expenditure over the 15 years from 2006-2020 averaged \$489m per annum as we upgraded and refreshed the network in a stable and gradual way.

The deep energy transition has changed these conditions. We are now in a transformative period, our capital spend averaged \$1,365m per annum over the most recent 5 years (2020-2025) as we deliver major projects such as EnergyConnect, HumeLink and VNI West.

Today, the electricity system is being asked to deliver more under greater uncertainty, tighter timeframes and increasing pressure on costs. Affordability and reliability remain core expectations, but the forces acting on them have intensified. In many cases, they now pull in different directions.

We are developing our plans for the 2028-33 period in this environment of challenge and change. To meet the long-term interests of consumers we must respond to these challenges efficiently and prudently. In this section we outline what we consider to be the key themes and external changes that are shaping our current performance and future plans:

- Understand and balance the interests of NSW & ACT electricity consumers
- Maintain a safe, secure and reliable electricity network
- Enable a system powered by more renewables
- Meet new and changing demand
- Deliver the best value for money.

1.2.1 Understand and balance the interests of NSW & ACT electricity consumers

We are very mindful that the energy transition is ramping up at the same time as many are experiencing a cost-of-living crisis. NSW households and businesses are under financial strain and rely heavily on maintaining access to an affordable supply of electricity. Since our final decision was made for the 2023-28 determination in April 2023 there has been a 26% cumulative increase in NSW household electricity bills, as measured by the AER's Default Market Offer. Beyond electricity, interest rates and inflation have materially increased. This is resulting in falling savings, increased reliance on credit and an increasing financial pressure on many Australian households, including higher levels of mortgage and rental stress.

We also recognise that consumers are experiencing the energy transition in very different ways and this extends to where consumers live – whether that be in the city or in regional areas where the energy transition is more visible. Many households and businesses are also making substantial private investments in technologies such as rooftop solar, batteries and electric vehicles to better manage their electricity costs and improve their resilience to rising prices.

However, not all consumers have the financial capacity, housing circumstances or access to capital needed to make these investments. This is creating an increasing difference between those who can actively manage and reduce their electricity costs and those who remain more exposed to electricity price increases. Unlike many other household expenses, electricity consumption is often difficult to significantly reduce without impacting comfort, wellbeing or economic participation, making affordability particularly important for consumers who have limited ability to invest in alternative energy solutions.

We are aware of the value our service provides and its importance to everyday lives of people. Our investment decisions must be carefully considered in this environment as our stakeholders and consumers expect us to take all available steps to constrain our costs.

At the same time, we are mindful of the criticality of the role of the transmission network to reducing future electricity prices and in enabling the economic security and prosperity of NSW and Australia. A delayed transition risks widespread outages or expensive measures to keep critically ageing coal-fired generators operating. Policymakers expect that a timely and cost-effective energy transition will unlock lower cost renewable generation that will ultimately provide for lower electricity prices. Our challenge is striking the right balance between investment, deferral and utilising non-network solutions to deliver our services at the lowest possible cost.

We also know that while building major infrastructure can create jobs, it can also be disruptive to local communities that live by and around new generation and transmission infrastructure. While the energy transition can benefit NSW and Australia as a whole, the impacts of the investments are limited to specific communities. We embed landowner feedback into route selection, easement design and construction planning aiming to reduce disruption, build trust and enable timely access for delivery.

This engagement is critical to maintaining the social licence of the energy transition. At this important time, Transgrid and the industry more broadly need to be transparent with consumers including the combined effect of all investments across the system and the impact on total bills. We need to make clear that these changes will impact their future and enable them to have an opportunity to provide their input to shape our plans and thinking. To do this, we have engaged with industry, Government, large energy users and end-use consumers to improve our transparency and accountability.

1.2.2 Maintain a safe, secure and reliable electricity network

Our core responsibility remains unchanged: to safely and reliably transport electricity from where it is generated to where it is needed across NSW and the ACT. As the energy system becomes more complex, this requires us to connect and integrate increasing volumes of generation and customer demand, maintain a secure and reliable supply of electricity, protect the grid from a growing range of risks, and plan, expand and upgrade the network over time. While doing this, we must carefully balance costs and manage risks to deliver long-term outcomes for consumers.

Like the coal-fired generators they connect to, much of the existing network was built decades ago, and the risk of asset failure is increasing as equipment ages. We closely monitor the risk of asset failure and its potential impact on reliability, safety, bushfire risk and the environment. As many of our assets were installed in the 1960s and 1970s this risk is increasing as condition deteriorates and the opportunities for maintenance, deferral, retirement or refurbishment to avoid replacement diminish.

Our assets are also operating in more challenging conditions as the impacts of climate change emerge. Our network is exposed to increasingly extreme weather events as storms, high winds and bushfires increase the risk of low probability, high consequence events occurring. We must carefully model, assess and manage the risk of long duration outages and major incidents through either more efficient responses to these events and/or investment in strengthening the network and associated protection systems.

The risk to the network is not just physical, our operational and information technology systems must also be safe against the threat of cyber-attacks. We are subject to the requirements of the Security of Critical Infrastructure (SOCRI) Act and must take steps to ensure our assets are secure against both physical and virtual access from third parties.

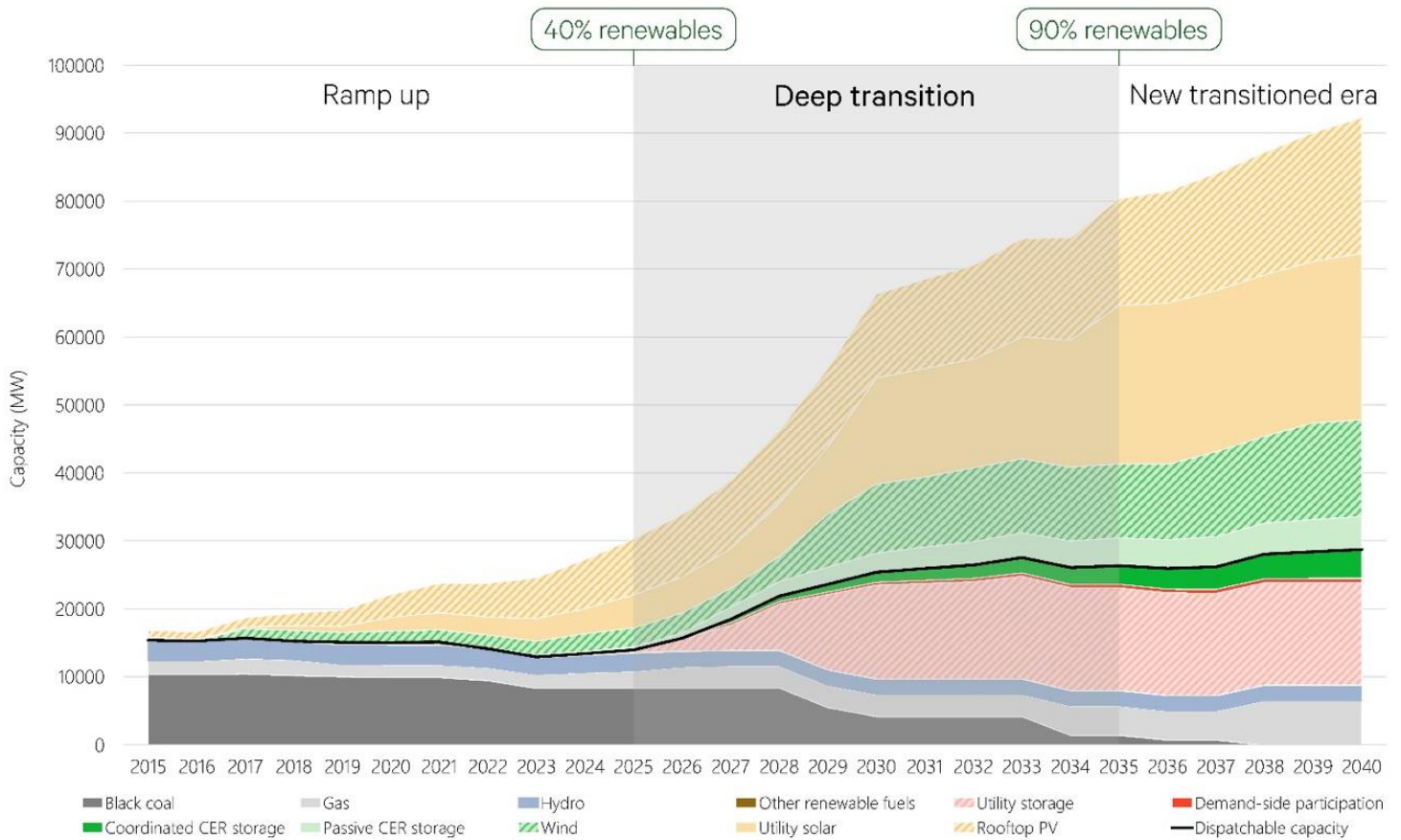
Further details on our plans to maintain reliability and security of our ageing network are provided in section 3.2.4.

1.2.3 Enable a system powered by more renewables

Ten years ago, renewable sources contributed 10% of the generation capacity and in 2026, this has increased to around 40% in NSW. This shift will further accelerate over the next decade and by 2035, AEMO's 2026 ISP expects that more than 90% of generation capacity in NSW will come from renewables.

Figure 1-1 Installed generation capacity in NSW – historical and forecast (GW, 2015 – 2040F)

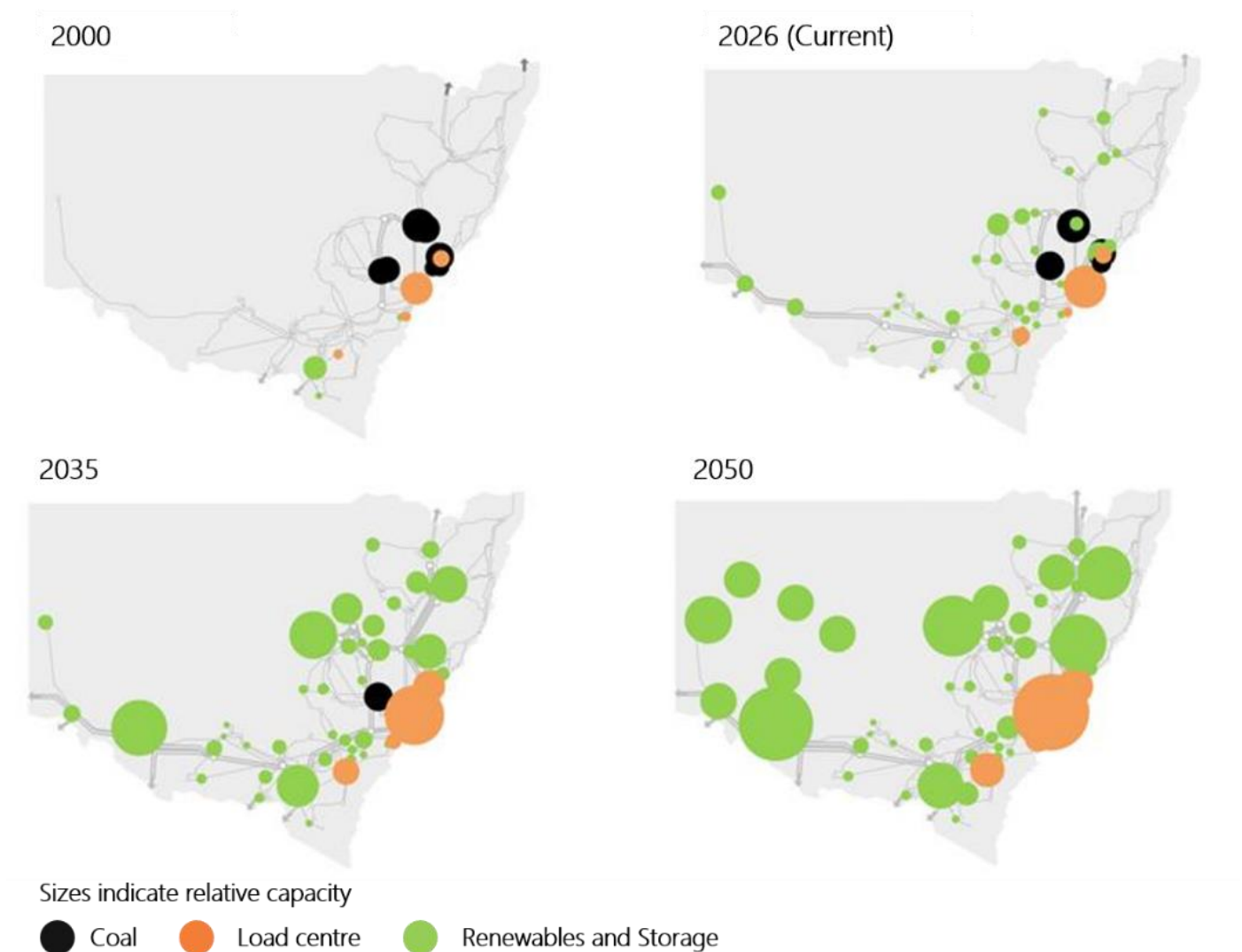
Historical and forecast electricity capacity in NSW*



*AEMO 2026 ISP, AER State of the Electricity Market (various historical), AEMO Generation Information, Transgrid analysis

This means we will need to move electricity from a few large, centralised sources of coal generation to larger numbers of renewable generation connected across NSW, the state's Renewable Energy Zones (REZs) and at both distribution and transmission levels. This change requires a larger and stronger transmission backbone.

Figure 1-2 Forecast changes in generation across NSW (Illustrative)



Delivering this transition also requires significant collaboration and coordination across a range of stakeholders to enable timely and efficient investment across the transmission system. A key driver of the transition has been the NSW Electricity Roadmap. The Roadmap targets 12 GW of new renewable energy generation and 2 GW and 16 GWh of long-duration storage by 2030, consistent with delivering the lowest-cost pathway to net zero as identified through AEMO's Integrated System Plan (ISP) and NSW policy frameworks. As a result, a significant portion of the investment required to support the energy transition – including both large infrastructure projects and supporting system investments – is funded through the NSW Roadmap arrangements or contingent project mechanisms, rather than through the five-year regulatory determination.

While these investments are progressed through separate processes, they have a material impact on the overall cost of electricity and shape the operating and investment environment within which our 2028–33 Proposal is being developed. We are mindful of these cost impacts and continue to work closely with governments, industry and community stakeholders to coordinate delivery and manage costs for consumers.

While the costs of connecting new generation are largely addressed through these separate frameworks, our 2028–33 Proposal is increasingly focused on the challenges of operating and maintaining a secure system as the generation mix changes. A renewable grid relies on intermittent, weather-dependent generation, creating a more dynamic and complex power system. This drives the need for additional investment in system security services (such as system strength and inertia) and operability to ensure the network remains stable and within a secure operating envelope.

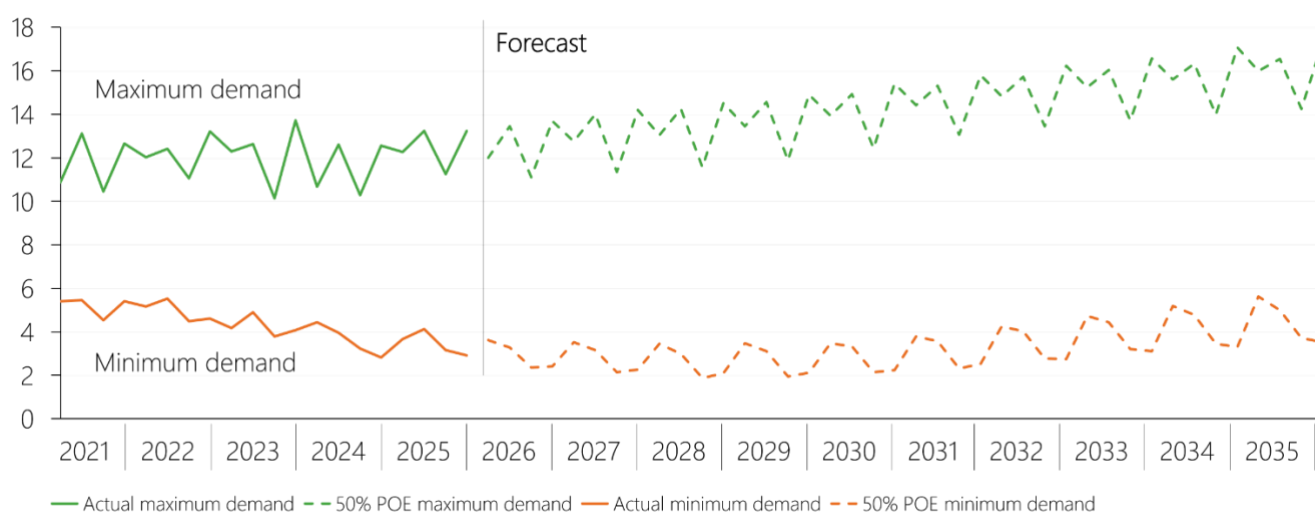
Replacing system security services historically provided by coal generation is expected to involve the delivery of synchronous condensers, services from around 5 GW of new build grid-forming batteries and the redispatch of hydro and gas. In parallel, our control room operators will require new tools, systems and capability to manage a fundamentally different grid. Further detail on these investments is provided in section 3.2.3 and 3.3.3.

1.2.4 Meet new and changing demand

Population growth, electrification and large new loads such as data centres are driving the need for targeted network augmentation. We are currently supporting more than 10 GW of new renewable energy and storage projects with around 37 GW more by 2035. The energy transition has also continued to accelerate at a household and distribution network level. NSW has now installed over one million rooftop solar units (around 9 GW) with around 6 GW more forecasted by 2035.

These solar systems will increasingly be paired with small-scale battery systems with Distribution REZs beginning to emerge as a complement (or alternative) to large-scale investment, including areas already identified and progressing through planning and development. This shift is seeing more dynamic swings in electricity demand. Since 2021, minimum grid demand in NSW has fallen by around 32% on a 50% Probability of Exceedance (POE50) forecast basis, largely as a result of increasing rooftop solar being relied upon in afternoons. This trend is forecasted to reverse over time as large new loads, such as, connect and progressively increase demand on the network. Low levels of minimum demand can create operational, reliability and system security challenges for the grid as rapid changes in supply and demand can occur with changes in the weather.

Figure 1-3 Historic NSW maximum and minimum demand (2010-2035) (GW)



As minimum demand emerges as a challenge, we must also plan for growth in peak demand. This is especially driven by the electrification of households, businesses, industry and transport.

By 2035, we expect there to be as many as two million EVs on NSW and ACT roads. Electrification of buildings and major industry (such as manufacturing and steel production) is in its early stages, alongside the continued population growth across NSW. This includes strong growth in Western Sydney as industry develops around the Western Sydney Airport, as well as in other parts of NSW where population growth, industrial development and electrification are collectively driving higher energy demand.

Industrial demand growth specifically is being driven by the international boom in data centres as AI, cloud computing and digital infrastructure become a central feature of the economy and modern way of life. We are observing a rapid increase in interest from large data centres with forecast demand measuring in hundreds of MWs or in excess of 1 GW per site. Transgrid alone received over 27 GW of connection enquiries from data centres to date with over 8 GW at or past the connection application phase. From our joint planning activities, we know that some of the NSW and ACT distributors also have high levels of interest.

These data centres present major opportunities for the NSW economy, creating highly skilled jobs, supporting innovation and attracting high-tech investment. However, the land, water and power demands of these new large-load entrants must be carefully managed to ensure these benefits are not offset by additional costs on consumers or impacts on the reliability of our services. We are working closely with industry, Government and other key stakeholders in balancing the need to service this growth and ensuring consumers benefit from these connections.

These changes in demand and consumption are at various stages of development but are expected to create the need for targeted network augmentation across multiple regions and add several gigawatts to peak demand over the coming years and decade. Already capacity into Sydney region is limited by the existing 330 kV network.

We provide further details of the impact on Data Centres later in section 1.3 along with detail on the augmentation required to accommodate these new loads in section 3.2.2.

1.2.5 Deliver the best value for money

To deliver the best value for money we will exercise cost discipline and manage delivery complexity. Where investment is necessary, we must deliver on budget, on time and at lowest cost to ensure consumers can realise the benefits of it. The scale and pace of the transition combined with global conflicts and supply chain shocks can make this particularly challenging, but we must robustly test our plans and processes to manage these risks.

We know that the energy transition is not going to be a smooth process. These large and complex projects may experience delays despite best efforts given the tremendous ambition of the shift planned in NSW. We must ensure there remains a sufficient supply buffer within the energy system to handle any delays or changes to the intended transition path.

This risk is exacerbated by the fact that we now rarely operate in “ordinary conditions”. Instead, we are facing a series of major hurdles on a regular basis such as the Covid-19 pandemic, international conflicts and supply chain shocks. The energy transition requires an enormous amount of skilled labour, materials and equipment sourced from Australia and around the world. We have observed a marked increase in costs across networks in Australia as these challenges are felt. Industry productivity has been declining in recent years as a result of the inflationary environment. These challenges have been felt beyond the energy industry with Infrastructure Australia noting delivery is being constrained by skill shortages, hampered by projects delays and impacted by rising construction costs across transport, building, utilities and social infrastructure projects.

Recent conflicts in the Middle East have highlighted the vulnerability of many countries to supply chain shortages for critical inputs like fuel. Our forecasting, contracting, delivery and procurement processes must adjust for these growing risks and not simply forecast on a steady-state basis. Instead, we are accounting for risks and uncertainties in our planning process and robustly test the deliverability of our program of works under a range of conditions. This increases the complexity and effort required to develop a Revenue Proposal which can cover a period up to seven years into the future.

1.3 Using future scenarios to inform investment decisions

To help manage forecasting and regulatory uncertainty risk and to guide our proposal development process, we identified future scenarios which may plausibly occur as we progress our forecasts through various stages of refinement. The purpose of these futures was to help understand the interrelationship between macro-environmental factors, consumer outcomes, and our plans.

Since the development of our preliminary forecasts, we have prepared and published our 2026 Transmission Annual Planning Report which represents our updated forecasts and is the basis of this proposal

Another scenario presented is our **“Data Centre”** future which is our 2026 TAPR but with additional demand (and corresponding generation) to supply data centre growth.

This scenario is particularly useful for understanding the impacts of additional spend that may be required to facilitate the connection of data centres. We have proposed several contingent projects for the 2028-33 period that relate to data centre growth. While triggering these projects over the course of the 2028-33 period would materially increase our capital spend requirements, they would also significantly increase the energy delivered and utilisation of our network, and likely result in a decrease in consumer bills.

The Data Centre scenario therefore provides insights on how much additional investment may be required along with the revenue and pricing impacts on consumers. It will also help us identify which investments would be better suited for inclusion as a base capex vs contingent project or even pass-through event such as where the cost, timing or need of a particular project is uncertain.

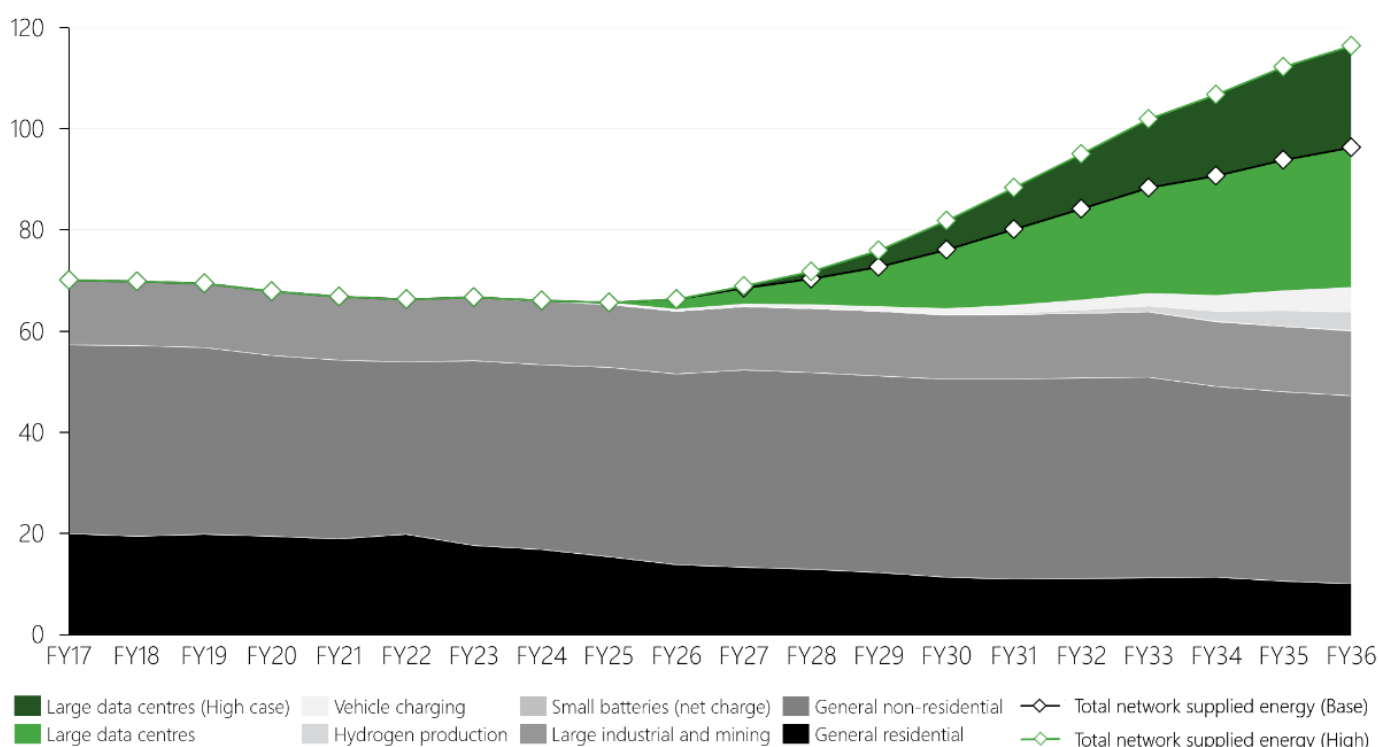
1.3.1 A responsible and transparent approach to data centre growth

The international boom in data centre investment – as AI, cloud computing and digital infrastructure become a central feature of the economy and our modern way of life – creates risks and opportunities for energy consumers and, more broadly, the NSW and Australian economy.

Data centres present a major opportunity to create highly skilled jobs, support innovation and attract high-tech investment. There are also significant opportunities for electricity consumers. Greater energy usage will improve network utilisation and support a stable and secure grid. As our costs are largely fixed and revenue recovery capped, the increased utilisation of the network could help lower electricity prices.

The scale of the additional data centre loads is reflected in our current forecast of energy consumption, shown in Figure 1-4 below. We note that the ultimate size of these loads is uncertain; and could be substantially higher than what we are forecasting.

Figure 1-4 Composition of NSW region annual network energy consumption (2016/17 - 2036/37) (TWh)



While the opportunity is significant, so too are the risks. These additional loads are driving additional and earlier investment. There is also a risk that we overinvest to accommodate loads which do not eventuate. While in this case these assets will not be entirely 'stranded', as they will strengthen and improve the quality of our network service regardless of what loads eventuate, it could result in higher than necessary costs. There is also risk that if loads grow faster than the capacity of our network there are risks to reliability and security of supply.

Our focus has been, and will remain on, facilitating the opportunities for consumers while considering how we can manage the risks.

To achieve this goal, we have worked closely with our CAG and CWG to explore this issue. The CWG in particular, stressed that consumers should not bear the cost of network augmentation that is primarily driven by specific users or sectors. We provide further details on the feedback we have heard in section 2.2. We agree, and in developing this Draft Plan we have taken several additional steps beyond our usual processes – to robustly challenge and understand the drivers of our investment program.

1.3.2 Distribution connected data centres

The primary challenge relates to distribution connected data centres driving loads on the shared transmission network. This is an issue for two reasons.

First, while we have always worked closely to distribution networks, historically this has only required distributors to provide aggregate demand forecasts. We have not – and still do not (due to confidentiality agreements between distribution networks and connection applicants) – have visibility of granular customer specific information on specific loads. This constrains our ability to understand the drivers of load growth, sensitivities and develop plausible and consistent scenarios across all distribution networks.

To address these constraints, we have worked closely with distribution networks to challenge and test their forecasts and commissioned Baringa to produce a single coordinated forecast focused on data centre contribution (taking into account factors such as project maturity and duplication).

Second, there is a gap in the regulatory framework where we cannot charge capital contributions to parties who connect to the distribution network. Data centre connections at the distribution level are driving significant investment at the transmission level. In this Draft Plan we have identified significant investment which is only required or brought forward into the 2028-33 period driven, to a large extent, by data centre load. This amounts to about \$400-\$500 million of investment – around a third of our augmentation forecast – plus an additional around \$2 billion in contingent projects which could be required if additional data centre loads are realised. Further details on our demand forecast augmentation plans are set out in section 3.2.2.

We have engaged policy makers, including with the NSW Government, the AEMC and Commonwealth Government, on this issue. We welcome and are supporting the development of both the NSW data centre reforms as well as the Australian Government's recent Rule Change proposal to the AEMC.

We anticipate that these reforms will allow us to recover a proportion of the costs imposed from data centre proponents. However, the amount is uncertain and will depend on the framework put in place. In this Draft Plan, we have not included an estimate of the capital contribution we expect to recover. This means that the net expenditure (expenditure minus potential customer contributions) and in turn our revenue requirement and bill impacts are likely an overestimate at this stage.

1.3.3 Transmission connected data centres

Unlike distribution connected data centres, data centres which connect directly to us pay for all of the connection and augmentation works that are triggered by their connection. These costs and contributions do not form part of this revenue proposal as they are recovered as negotiated services rather than part of the shared service.

However, in addition to expenditure and revenue forecasts, revenue proposals will set out the pricing methodology we will apply to our shared service. As part of this, we intend to implement 'take or pay' arrangements where certain large loads, like data centres, pay for their contracted demand rather than their actual usage. This will increase the proportion of revenue recovered from data centres as they ramp up to their contracted load. We set out additional details on our pricing methodology in section 3.5.3.

Section 2

What we are hearing and how we are responding



2.1 How we are engaging

Building on the lessons from the revenue proposal process for the 2023-28 period and feedback from consumers, advocates and regulators, we have significantly uplifted the way we engage on this Revenue Proposal. Our engagement approach is designed to be earlier, broader and more deliberative, so that consumer and stakeholder perspectives meaningfully influence our decisions as the proposal is refined.

Our engagement program is guided by the principles set out in our [2028-33 Revenue Proposal Stakeholder Engagement Plan](#) (Engagement Plan), including clarity of purpose, inclusivity, transparency, timeliness and a strong commitment to closing the loop on feedback.

To support this objective, we have broadened both the diversity of stakeholders we engage with and expanded the forums and channels for participation. This has enabled more diverse views to be considered throughout the development of our plans and strengthened the role of stakeholder feedback in shaping our proposed investments. Key new features to our engagement approach for the 2028-33 proposal include:

- **Establishing the Consumer Working Group (CWG):** Consisting of members with expertise in energy matters, the CWG is a sub-working group of our refreshed Consumer Advisory Group (CAG) and acts as a consumer advisory body focused on the 2028-33 proposal. The CWG has engaged deeply to test assumptions, trade-offs and provide a consumer focussed assessment of our proposal to help ensure consumer perspectives are considered and addressed in our proposal
- **Establishing the Transgrid Consumer Panel:** The Consumer Panel comprises of a broad cross-section of end-use consumers to elicit input on the matters and outcomes that mattered to them the most which helped us to understand and test consumer preferences and trade-offs.
- **Direct industry engagement:** We invited key industry stakeholders like generators, developers and retailers to participate in one-on-one meetings to present our draft plans and discuss issues most pertinent to them.
- **Continuous refinement of expenditure forecasts:** We have made updates to our forecasts through an iterative (four stages) and consultative process to provide early visibility of forecasts to the CWG and AER to improve transparency and demonstrate how feedback was being considered throughout the process.
- **Early engagement on positions and plans:** Providing the AER and CWG with a First Look (draft) of this Draft Plan, regulatory models and sample business cases and publishing this Draft Plan to provide stakeholders with an early view of our proposed priorities, investments and expenditure forecasts for the 2028-33 regulatory period. By publishing the Draft Plan ahead of our revenue proposal, we are creating an additional opportunity for stakeholders to provide feedback and help shape our proposal before it is formally submitted to the AER in January 2027.

This represents a significant cultural change for Transgrid and it has provided valuable consumer focussed insights that have been critical to informing the review and development of our 2028-33 forecasts in parallel by Transgrid's leadership team and Board.

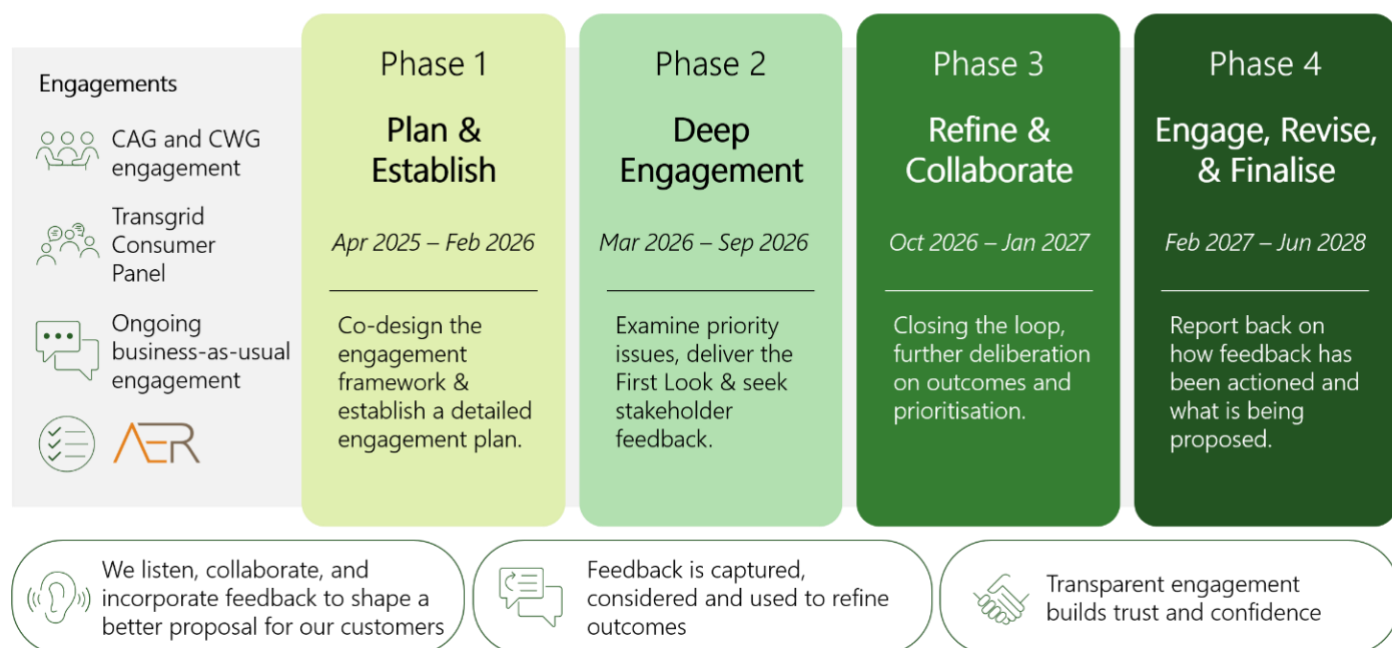
2.1.1 A tiered and deliberative engagement framework

Earlier this year, we published our [Engagement Plan](#) to support developing a Revenue Proposal for 2028-33 that genuinely sought and incorporated feedback from consumers. Consistent with good industry practice and the AER's expectations set out in the Better Resets Handbook, we are engaging through a mix of tailored forums that provide both depth and breadth of input across different stakeholder groups. This includes deep, ongoing engagement with consumer advocates, structured deliberation with residential consumers, and targeted engagement with customers and other stakeholders.

Figure 2-1 Integrated engagement approach across four phases of Revenue Proposal development

A tiered and deliberative engagement framework

Our engagement is integrated across four phases of developing our RP4 Proposal



2.1.2 Consumer Advisory Group and Consumer Working Group

Following feedback on the structure and effectiveness of the former Transgrid Advisory Council, we established a refreshed Consumer Advisory Group, supported by a smaller Consumer Working Group.

The CAG is made up of consumer representative bodies and independent consumer advocates and is Transgrid's primary advisory forum on strategic consumer and stakeholder issues. It meets regularly and has oversight of the revenue proposal process, including our overall approach to engagement and proposal development.

The CWG is a subset of the CAG and meets more frequently to support deeper, more technical engagement on specific topics. The CWG is the primary forum for working through complex issues, trade-offs and investment choices, and for testing our emerging positions as they are developed.

The CWG has an active role in shaping the engagement process, with members setting meeting agendas and nominating the key issues and focus areas for discussion. Topics were identified in advance, enabling Transgrid to prepare targeted materials for each meeting and ensure that relevant subject matter experts and decision-makers were available to participate in discussions. This supported more informed and in-depth engagement on complex technical issues and allowed feedback to be provided at a stage where it could meaningfully influence our analysis and emerging positions.

This helped ensure engagement was focused on themes and matters of greatest importance to consumers, including:

- Greater transparency of the full bill impact from our planned investment inclusive of ISP and EII projects.
- Testing the deliverability of the capital program concurrent with ISP and Roadmap projects, to provide confidence that our investment plans are realistic and capable of being delivered within the proposed timeframes.
- Understanding how demand forecasts underpin augmentation expenditure and the sensitivity of customer bills impacts to demand forecasts.
- The level of risk assumed in the replacement program and the extent that it is consistent with risk/cost tolerance inherent in the 2023-28 period.

- The extent to which proposed resilience investment aligns with the AER's expectations and guidance on resilience expenditure.
- How we have exercised our discretion in formulating our plans and forecasts to constrain costs, prioritise consumer outcomes and respond to the feedback we have received.

We note that engagement on some of these topics remains ongoing at the time of drafting this plan, nor does engagement mean an agreed position has been met. Rather, the value in engaging with the CWG has been its ability to provide a consumer focussed perspective on complex technical and regulatory issues. Through its diverse expertise and industry experience, the CWG has provided informed challenge on investment needs, cost drivers, risk assessments and expenditure trade-offs. This insight is improving the quality of our analysis, the level of transparency and accountability and helping to build confidence that emerging positions are being robustly tested. This insight has ranged from high level outcomes such as our proposal narrative down to business case level feedback to strengthen the robustness of our plans and help express them in a way that is meaningful to consumers and stakeholders.

The CWG has also been critical in supporting the development of our engagement materials and topics for the Consumer Panel. This has ensured a more balanced perspective has been provided to our Consumer Panel while also assisting us in interpreting and responding to the feedback we received.

Figure 2-2 Snapshots from CAG engagement



To date we had held 14 meetings with the CWG, ranging from three-hour sessions to extended workshops of up to five hours along with a series of ad hoc and issue specific discussions totalling over 100 hours of engagement in developing this Draft Plan. These meetings have been supported by written feedback and regular check ins, enabling us to obtain ongoing and timely CWG feedback on fast-moving components of the program.

2.1.3 Transgrid Consumer Panel

For the first time in our revenue determination process, we are engaging directly with residential consumers through a deliberative Consumer Panel. The Consumer Panel is made up of up to 45 consumers recruited from across NSW and reflects a range of locations and lived experiences.

The Consumer Panel met multiple times over several months in a mix of online and in-person sessions. This approach allowed participants to build their understanding of Transgrid, the regulatory framework and the energy transition while obtaining feedback on priorities, trade-offs and consumer outcomes.

Figure 2-3 Snapshots from our consumer panel #2 session held 30 May in Sydney



We also established the Consumer Panel to better understand how consumer priorities may differ across regions, communities and household circumstances, and how those perspectives should be reflected in the development of our proposal. At the time of finalisation of this document, four of the five planned Consumer Panel sessions had been held:

- Session 1 (21 April) focused on providing background information on the energy supply chain and the energy transition, Transgrid's role, and the regulatory framework and process.
- Session 2 (26 May – Regional NSW, online; 30 May – Greater Sydney, in person) commenced deeper engagement on several 2028-33 period focus areas, including emerging priorities and early trade-offs.
- Session 3 (30 June) focussed on the projected increase in data centre growth and the impact this could have on the network, local communities and customer energy bills.
- Session 4 (4 August – Regional NSW, online; 8 August – Greater Sydney, in person) invited feedback on the narrative and retested preferences around investment to improve resilience.

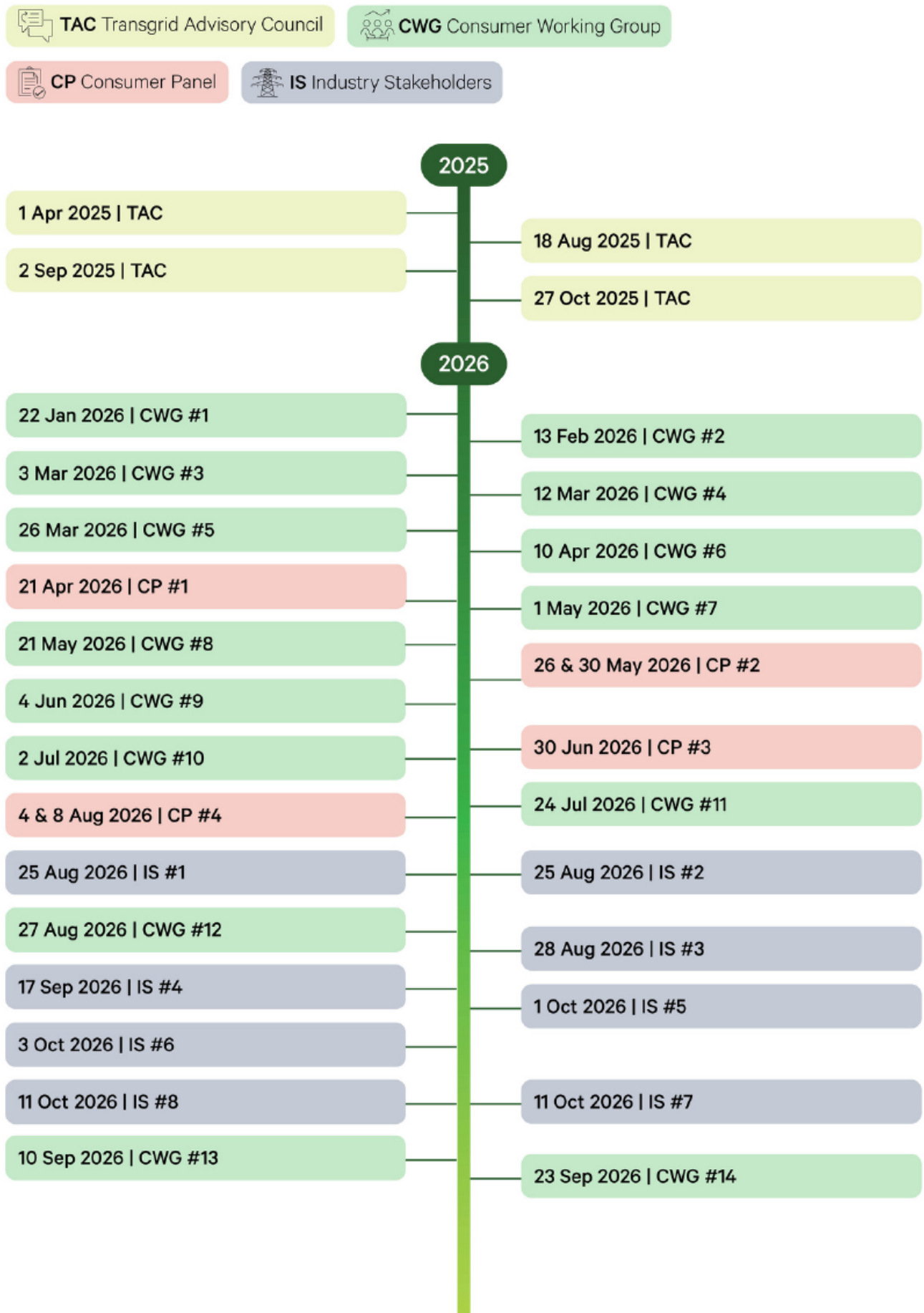
Participants have demonstrated a strong willingness to engage with complex issues and consider the trade-offs involved in maintaining reliability, supporting the energy transition and managing consumer costs. Insights from the panel have been shared with our leadership team and Board and are already helping to inform our understanding of consumer priorities and will continue to shape the development of our proposal.

The diversity of participants has revealed a range of preferences and priorities across the community. Where the forums highlighted differing perspectives, we carefully considered the feedback and comments to strike a balance, recognising that views vary on the trade-off between affordability and service outcomes. We will use the final meeting to circle back with the Consumer Panel and seek their views on whether the proposed balance is appropriate.

Figure 2-4 Snapshot from our consumer panel #4 session held 8 August in Sydney



Figure 2-5 Engagement timeline for Transgrid's Draft Plan



2.1.4 Broader customer and stakeholder engagement

Alongside our consumer-focused forums, we are engaging with a wide range of customers and stakeholders who have knowledge, experience or a direct interest in our plans. This includes:

- Transgrid-connected customers and large electricity users such as data centres
- Distribution network-connected small, medium and large business customers
- Industry peak bodies and associations
- Government agencies, regulators and system institutions
- Community, landholder and First Nations stakeholders

This engagement is tailored to the needs and interests of each group and includes topic-specific deep-dive workshops, small group meetings, one-on-one engagement and participation through peak bodies. At the time of preparing this Draft Plan these interviews remain ongoing. However, feedback to date has focussed on the importance of maintaining a reliable supply, reducing outages, improving the timeliness and cost of the connections process, adapting to the complex and changing energy system and considering non-network options and innovative solutions.

2.1.5 Ongoing business-as-usual engagement

We continue to draw on insights from our broader business-as-usual engagement, including ongoing relationships with communities, landholders, First Nations groups, industry participants, governments and regulators. Inputs from these channels complement our Revenue Proposal specific engagement and help ensure our proposal reflects a complete and current understanding of stakeholder views.

Publishing this Draft Plan provides a transparent basis for engagement and creates opportunities for feedback from all interested parties and individuals that can directly inform and influence further refinements to the proposal.

2.2 What we are hearing and how we are responding

A core focus of our engagement is transparency and accountability. We commit to clearly explaining what we have heard, how feedback has been taken into account, and why certain decisions or trade-offs have been made.

Our engagement to date has covered a wide range of topics, levels of detail and perspectives, reflecting the diversity of interests, expertise and lived experience brought to the engagement process. The section below is not a comprehensive listing of all feedback received and issues raised. Instead, it seeks to summarise the more material and consistent themes of our engagement. These themes are intended to illustrate the key areas where stakeholder feedback is influencing how we are refining our approach and shaping our emerging positions for the Draft Plan.

We recognise that reasonable stakeholders may place different weight on different issues or identify additional areas of importance. We therefore invite consumers and their advocates to provide feedback on whether any significant themes or perspectives have been omitted or under-represented in this section. This feedback will be considered as we continue to refine our approach and develop our January 2027 Revenue Proposal to the AER.

Figure 2-6 Snapshot from our consumer panel #4 session held 8 August in Sydney



2.2.1 Putting downward pressure on costs in a cost-of-living crisis

What we are hearing

Our engagement to date has reinforced that consumers and their advocates understand the scale of change underway in the electricity system. However, they are clear that this reform must occur in a way that is cost-constrained, transparent and equitable, particularly given current cost-of-living pressures.

Consumers and their advocates have consistently emphasised that the current cost-of-living environment materially changes expectations about investment. They expect Transgrid to exercise discipline by actively constraining costs and demonstrating restraint wherever possible – including applying a clear “capital constraint” to our forecasts.

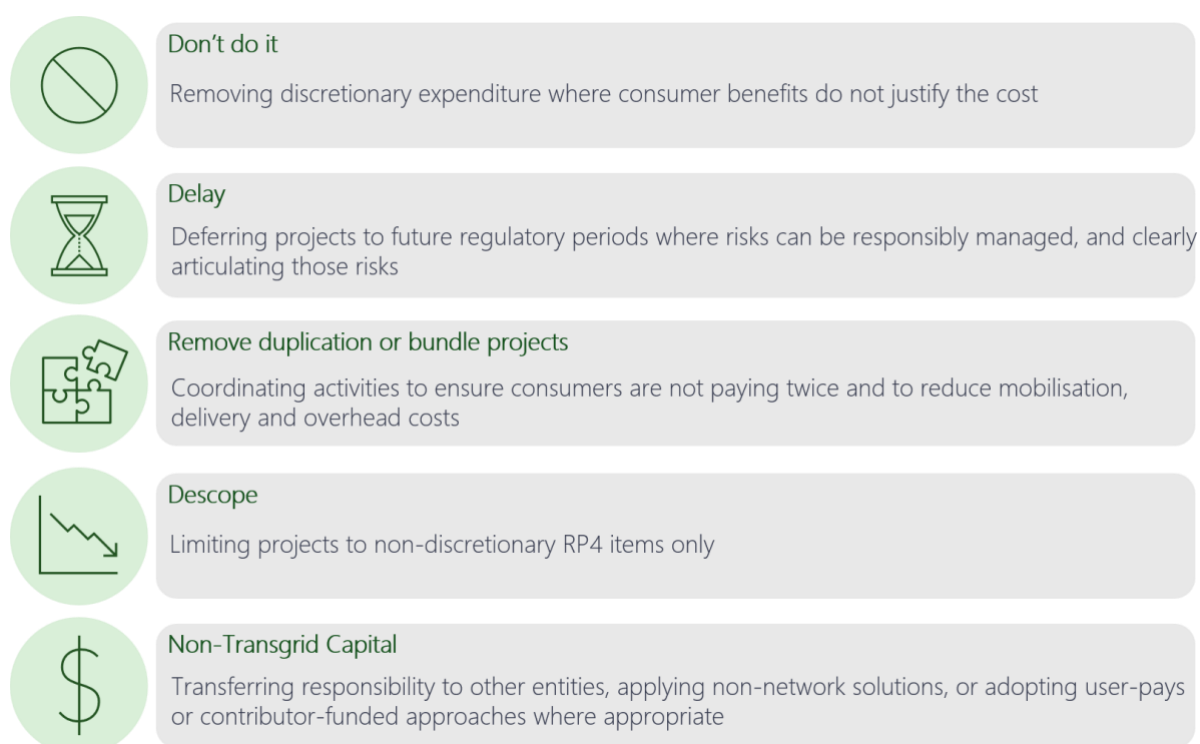
There is strong feedback that consumers want clear evidence that:

- All reasonable steps are being taken to minimise costs in the 2028-33 period to constrain our impact on electricity bills.
- Decisions are being made with cost impacts on consumers explicitly in mind, not just technical need.
- In developing projects and programs to meet our obligations we have exercised our discretion in how we achieve compliance that demonstrates cost discipline rather than treat those need as inevitable and invariable.
- Expenditure driven by discretionary needs or objectives has been actively challenged and delivers outcomes directly supported by consumers and stakeholders.
- Advocates have also stressed that cost constraint must be addressed early in the planning process and enacted across both bottom-up processes and subsequent top-down constraint analysis.

How we are responding

In response, we have revised our forecasts and positions to deliver an improved pricing outcome in 2028-33 while balancing future investment needs. A significant part of this has involved re-testing our investment options to explore and apply a range of cost levers, developed with input from the CWG. These levers form a core part of how we are developing and refining our investment program and include:

Figure 2-7 Transgrid’s cost levers



These levers are being tested and refined through ongoing engagement with the CWG, including through case studies and scenario-based discussions, to ensure that cost reduction measures are both credible and transparent. While this has been the focus of developing our capital plans, we have made additional adjustments to our proposal prioritising those which provide the most significant benefit for electricity prices. These include:

- Proposing pricing methodology changes for Data Centres to protect consumers from the risks of funding underutilised assets and to unlock the benefits of increased network utilisation.
- Reviewing our step changes to include costs which are demonstrably incremental, prudent and efficient. This has resulted in a \$50m reduction in our operating expenditure step change forecast.
- Removed \$291m of discretionary augmentation projects through targeted scope reductions and deferrals.
- Refining the replacement program to identify opportunities to defer or reduce scope, including NPV-positive projects. This has reduced forecast replacement expenditure by around \$370 million, while maintaining risk at current levels consistent with our obligations and consumer expectations.
- Utilising the contingent project mechanism for system security and augmentation projects where project scope, timing, and costs remain uncertain to maintain flexibility and reduce the risk of consumers paying for projects earlier than required. This reallocation has reduced our augmentation forecasts by approximately \$1 billion.
- Initiated a detailed review of non-network property condition assessments to identify opportunities to defer, reprioritise or remove lower-value renewal works. Although the review remains ongoing, it has identified savings that are driving a \$63m reduction in the condition-based property renewal program.
- Not applying cost escalation of material price growth and instead relying on prevailing costs in 2026. For reference, key material PPIs have consistently outpaced inflation by 2-3 times over the last several years, including a 41% increase in electrical equipment and 73% in electrical cabling cost industry benchmarks between 2021 and 2026. We are absorbing significant price risk in 2028-33 to manage future increases. If similar increase were experienced over 2028-33 this would increase forecast capex by \$615m.

Collectively, these changes and others result in average 2028-33 prices for the average residential consumer being \$2 lower than the last year of the current period. This reduction improves by a further \$8 with our take or pay pricing reforms with the potential for further reductions based on ongoing causer pays reforms being considered by the NSW and Federal Government for data centre connections.

While we are acutely aware of the desire for expenditure reductions, we are mindful of applying top-down constraints to our capital and operating plans that would only serve to increase risk or future costs. We have therefore made targeted expenditure reductions and focussed on data centre pricing reforms to put downward pressure on consumer electricity bills while balancing service quality and long-term investment needs.

We will continue to review and refine our forecasts for the latest information and consumer views in preparing our January 2027 Revenue Proposal to the AER which could result in further reductions (or increases) depending on scope and price changes and ongoing management review.

2.2.2 Equitable cost recovery

What we are hearing

This proposal is occurring in the context of the ongoing transition to renewable generation sources and cost-of-living concerns. At the same time, we are observing the rapid emergence of data centre connections as a new and significant source of load growth. Data centres present a unique opportunity to drive economic growth in NSW/ACT while improving the utilisation of electricity networks. At the same time, there is a risk to existing consumers of slow or lower than forecast take-up of network expansion that is made to facilitate this opportunity.

Given the importance of this topic, we were keen to test the views of consumers on the appropriate approach to take. We engaged directly with a Consumer Panel and CWG on the various pricing, connection and cost recovery approaches available to manage the substantial pipeline of connections on both the transmission and distribution networks across NSW/ACT.

A strong and recurring theme from consumers and their advocates is the importance of establishing cost recovery mechanism that reduces the risk of consumers funding a material uplift in augmentation capex to facilitate large users such as data centres. Our discussions have focussed on issues such as:

- Whether existing cost recovery arrangements appropriately reflect cost causation
- How risks associated with speculative or uncertain load growth are managed
- Whether augmentation costs will be shifted onto general consumers without commensurate benefits.

In considering this issue, the CWG were keen for Transgrid to lead policy reforms that aim to reduce stranding risk and promote the efficient utilisation of the network so that consumers can benefit from data centre connections.

Our Consumer Panel were appreciative of the risks of missing the opportunity of data centre connections and the risk of connection charges being passed through the costs for data centre supported services. Many felt it would be unfair for households to bear a disproportionate share of the costs through higher bills if data centres required new infrastructure or significantly increased network demand.

The panel were presented with three pricing options for how data centre growth should be managed. Broadly, they were supportive of moving away from the status quo approach to connections and cost recovery to 'take or pay' pricing or 'causer pays' arrangements (Option 3 from the options presented) so that consumers do not bear the cost of network augmentation that are primarily driven by data centres.

"This experience shows me that Transgrid actually has the opportunity to put responsibility on data centres and set a precedent for the rest of the world... Option 3 does that. It would be a waste not to pick that."

- Consumer Panel Participant

How we are responding

We are placing a stronger focus on ensuring costs are allocated equitably and reflect what is driving the need for investment, as we refine our augmentation program and pricing methodology. This includes:

- Collaborating with the NSW and ACT distribution networks to robustly test and refine their demand forecasts through our joint planning activities and seeking independent expert advice on emergent large loads to reduce the risk of investing early or excessively in network upgrades.
- Clearly identifying which components of augmentation are driven by new large loads, such as data centres.
- Managing potential augmentations for uncertain / uncommitted data centre loads via proposed contingent projects in order to reduce the risk of early or unnecessary investment.
- Leading advocacy with State and Federal policymakers for reforms that support user-pays, capital contributions, and to implement pricing methodology changes.
- We engaged directly on this topic with our Consumer Panel presenting options for how the current approach to connecting large energy users, like data centres, could be amended to promote more equitable outcomes.
- We are also engaging with the CAG and CWG on these policy reforms and our proposed positions informed by analysis of how different futures and cost recovery changes for large-load growth could affect costs and bills.

2.2.3 Transparency of our proposal and its impact on consumers

What we are hearing

The energy transition is driving significant investment across the electricity supply chain. Transgrid plays a critical role in supporting this transition by strengthening the grid to connect new renewable generation sources while maintaining a reliable and secure electricity supply.

Historically, consumer engagement with Transgrid has been more limited compared with retailers and distribution networks who provide more direct energy services to consumers and who contribute a greater proportion of their energy bills. However, as the energy transition reshapes the electricity system, consumers have told us they want a greater role in shaping the decisions that affect them. This reflects the principle of procedural fairness, recognising that customers ultimately fund investments and should have meaningful opportunities to influence decision-making.

We received clear feedback from the AER that our engagement in support of the 2023-28 Revenue Proposal was insufficient and that an uplift was required to align with the AER's expectations under the Better Resets Handbook and good industry practice. We have also reflected on feedback from consumer advocates and stakeholders that we must be more accountable, transparent and consumer focussed as an organisation, particularly at this critical stage of the energy transition.

The CWG have also been clear that our proposed material uplift in expenditure must be accompanied by a clear articulation of what is changing, why and how this will deliver outcomes consumers with value. Consistent with this, our Consumer Panel have shown significant interest in understanding who we are, our role within the electricity supply chain, the changes that are occurring due to the energy transition and how our plans will impact them.

Further, the CWG have stressed the importance of Transgrid providing consumers with the necessary context to provide informed feedback and make choices. Particularly with respect to presenting a complete picture of electricity price outcomes from the collective impact of all our planned investment so that consumers can provide feedback with the necessary context and understand what is occurring in the energy industry.

This contrasts to the usual approach of developing plans limited to our 'prescribed' shared transmission service – elements which the AER needs to review and decide whether to accept or reject. However, we are also making complementary significant investments which sit outside of the usual Revenue Proposal process, such as investments related to:

- AEMO's Integrated System Plan (ISP). While the costs of ISP projects, such as Project Energy Connect, Humelink, Victoria – New South Wales Interconnector West (VNI West), Sydney Ring South, are recovered through prescribed transmission charges, expenditure forecasting and regulatory approval sits outside of a Revenue Proposal process and instead occurs primarily mid-period through the contingent project mechanism. Given the link with the ISP and the scale of these projects, we identify and treat them separately in this Draft Plan.
- The NSW Electricity Infrastructure Roadmap. The costs of these projects are recovered under a separate framework and not included in our transmission charges, although costs are still recovered from end-consumers (just through a separate mechanism). These include projects like our Central West Orana REZ network upgrades, Synchronous Condenser Deployment Stage 1, and the Hunter Transmission Project.

Consumer advocates and the Consumer Panel have been clear that given this unique circumstance, our transparency must extend beyond the Revenue Proposal consumer bill impacts considered in isolation. Instead, stakeholders and consumers should be presented with the full impact of Transgrid's overall project portfolio on consumer bills, including how demand forecasts interact with bill impact analysis and how the costs of major projects — both within and outside our Revenue Proposal — flow through to consumer bills over time.

Figure 2-8 Snapshot from our consumer panel #4 session held 8 August in Sydney



How we are responding

We have developed an engagement plan to adopt industry best practices and embed consumer focussed decision making in our ways of working. This plan has been developed in consultation with the CWG and CAG and aligns with the AER's expectations in the Better Resets Handbook. This process has improved our ability to articulate our plans and thinking while also exposing our forecasts to thorough review and consumer focussed challenge. These benefits, while difficult to measure, are of great consequence and importance to Transgrid.

Our Consumer Panel sessions have had a consistent focus on explaining who we are, our role, the services we provide and broader industry context on the energy transition. We have developed a proposal narrative in consultation with the CWG to provide a clear and transparent explanation of the changes that are occurring, our intended focus areas and our commitments to consumers for the 2028-33 period and beyond.

A draft narrative was shared with the Consumer Panel for additional feedback and used internally to guide the development of our 2026 Transmission Annual Planning Report (TAPR) and to strengthen our consideration of the "why" in our business cases and supporting documentation. We intend to more deeply embed this work in our internal strategies and culture with ongoing visibility at the CAG.

In response to feedback, we are also strengthening how we assess, present and evidence consumer bill impacts to ensure they reflect the full cost implications of our investment decisions and are transparent, credible and decision-useful.

First, we are broadening the scope of our bill impact analysis beyond this Revenue Proposal in isolation. While expenditure and outcomes in this revenue proposal remain the focus of this process, we acknowledge that consumers ultimately experience the cumulative impact of multiple investment programs over time. Accordingly, we will provide greater transparency over the bill impacts associated with Transgrid's total project portfolio, including projects arising from the ISP and Energy Infrastructure Investment (EII) frameworks. This will enable consumers, stakeholders and the AER to understand how this proposal interacts with other major investment drivers that affect bills.

Second, we are strengthening how we explain interactions across the electricity bill stack. We recognise stakeholder feedback that changes in transmission charges cannot be viewed in isolation from other bill components. While some investments increase transmission use of system (TUOS) charges, they will, in parallel, reduce costs elsewhere – for example by alleviating congestion, reducing wholesale energy prices, improving system security or avoiding higher-cost alternatives.

Third, we are enhancing transparency around the role of demand forecasting in bill impact analysis. We recognise that bill impacts are driven by both total costs and the level and profile of demand over which those costs are recovered. In response, we will clearly explain how demand forecasts are used in calculating bill impacts and provide transparency on how changes in demand assumptions influence bill outcomes

This is intended to give stakeholders greater confidence in both the methodology and robustness of the bill impacts presented.

Finally, we intend to provide an indication of how proposed pricing methodology changes for data centres could impact our contribution to electricity bills for the 2028-33 period.

Through these actions, we aim to provide a clearer, more complete and more credible picture of consumer bill impacts, and to support informed discussion about the trade-offs inherent in delivering a timely, reliable and least cost energy transition.

2.2.4 Reliability and services outcomes

What we are hearing

Through our engagement with the Consumer Panel, we heard clearly that the reliability of electricity supply is a fundamental expectation for consumers and remains a high priority. While this view was shared broadly, it was particularly strongly expressed by participants living in regional NSW.

For regional consumers, reliability is not only about comfort or convenience. Participants emphasised that reliable supply underpins access to essential services and day-to-day functioning of households, businesses and communities. This includes powering water pumping for homes, agriculture and town supplies, enabling access to communications and digital services, supporting banking and payments systems, and maintaining access to health and community services.

Consumer Panel members also highlighted that regional communities often have fewer alternatives or redundancies available during outages, meaning disruptions can have more immediate and longer-lasting consequences. As a result, reliability failures can disproportionately affect regional consumers compared to those in metropolitan areas.

While the CWG have suggested that we should carefully consider the consumer impacts of our proposed level of replacement spend in the current cost-of-living crisis and its deliverability in the broader energy transition context. There was an expectation that we clearly articulate the costs, benefits and risks associated with our proposal over the short and long term when engaging with consumers. Based on our engagement with the Consumer Panel the CWG did not consider there was any justification for us to depart from AER inputs and guidance.

In more technical discussions with the CWG, suggested improvements included a more nuanced consideration of the discretion we exercise in meeting our compliance obligations and more detailed assessment of options to defer, stage, scale and/or bundle works to improve efficiency and constrain costs.

In our discussions with other industry participants, particularly generators, we have heard that planned and unplanned outages can have material commercial consequences which in turn impact wholesale electricity costs. These industry participants were keen for Transgrid to facilitate the flow of renewable energy into the grid so that the expected benefits of the energy transition can be realised and maximised.

Overall, this feedback reinforced that consumers expect Transgrid to continue to prioritise reliability and safety and to constrain costs and manage investment pressures in delivering a safe, secure and reliable supply and not at the expense of it.

How we are responding

In response to this feedback, we are ensuring that reliability and service outcomes remain core considerations in our planning and investment decisions for 2028-33. We will continue to apply a risk-based approach that maintains asset risk profiles consistent with the allowance approved by the AER for the current regulatory period while also ensuring risk remains manageable in the next regulatory period and beyond. However, we note that even under this constraint the proportion of assets operating beyond their nominal service life continues to increase.

To determine efficient investment levels, we will apply the AER's VCR estimates, rather than a higher value, to assess reliability investments and ensure the benefits to customers are appropriately balanced against the cost of mitigation, cognisant that VCR estimates vary by customer segment and geographic location.

Applying our value framework and investment framework, which accords with the AER's guidance notes and prescribed values (like the VCR) produces a higher forecast than what we have proposed for 2028-33. This is because risk levels have increased over the 2023-28 period following reductions made to our allowance for the period and increasing costs to manage within (and above) it.

As a result, higher expenditure levels than what we are proposing remain NPV positive that would reverse this decline and return risk levels to those experienced by consumers in the 2018-23 period.

However, we note the expenditure objectives, AER expectations and feedback we have received from the CWG and Consumer Panel to constrain costs meeting our obligations and maintaining existing service levels. We have therefore reduced our replacement program from an unconstrained portfolio of \$3.8b which would improve performance (i.e., lower risk) and further reduced it by approximately \$370m that would have restored risk to 2018-23 levels. The latter represents a conservative estimate as costing for non-preferred options and investments remains ongoing.

The proposed investment instead represents a level that maintains existing risk levels balancing short-term costs with long-term investment needs. To constrain this spend we are improving how we:

- Assess and manage risks associated with ageing assets and changing operating conditions
- Prioritise investments that protect essential services and reduce the likelihood and consequence of outages, particularly in regional areas
- Explain reliability obligations and trade-offs in clearer consumer-focused terms, so stakeholders understand why certain investments are necessary and what risks they address

In addition, as cyber threats continue to evolve, we are investing in enhanced cyber security capabilities to protect its critical infrastructure and maintain compliance with the Security of Critical Infrastructure Act 2018 (SOCIA) and energy-sector regulatory requirements. This investment will improve our ability to detect, prevent, respond to and recover from cyber incidents across increasingly interconnected IT and OT environments. This in turn will reduce the risk of service interruptions and supporting reliable electricity supply outcomes for customers.

We are also embedding Consumer Panel insights into the development of the Draft Plan and our broader stakeholder engagement, ensuring that the lived experience of consumers – particularly those in regional and remote communities – informs discussions on reliability, resilience, and affordability trade-offs.

By doing so, we aim to strike an appropriate balance between containing costs and maintaining the level of reliability that consumers rely on to access essential services and participate fully in everyday economic and community life. Refer to section 3.2.4 for further information on our replacement program and our considerations in balancing constraint and risk.

2.2.5 Protecting communities from severe weather events

What we are hearing

We have identified the areas of our network that are most vulnerable to increasing frequency and network impact of severe weather, which can result in significant supply disruptions across large areas. The CWG indicated they expected us to apply the AER guideline on resilience expenditure to support our resilience program which requires, inter alia, clear customer support for investments proposed.

We took this issue to the Consumer Panel and discussed how Transgrid should approach network resilience planning to address climate risks. Participants generally supported increasing our focus on strengthening resilience, however views diverged between some respondents in metropolitan and regional areas.

Metropolitan customers felt that the cost of outages to households and communities would outweigh the cost of resilience investments, and some were willing to support additional investment if it provided greater energy security. While many were concerned about limiting increases to electricity bills, they also recognised that delaying investment could result in higher long-term costs if infrastructure is damaged or fails during extreme weather events.

“ I'm positive on paying for additional towards the Transgrid bill in order to potentially protect us from a much larger bill that may come across due to towers falling down.”

– Metro participant

“Maintain the current approach if conditions are stable. But conditions aren't stable. Weather is increasing in volatility. Temperatures are increasing, putting more pressure on supply.”

– Metro participant

There was a concern among some regional participants that large expenditures may prove unnecessary if extreme events do not occur as anticipated or if future technologies make planned investments obsolete. They generally viewed transmission outages as relatively infrequent and preferred a more targeted, efficient approach focused on the areas of greatest need before increasing overall spending.

“I don't think we need to spend any more to prevent natural disasters. They have always happened. It's more to do with poor planning than climate. This investment won't change bushfires.”

– Regional participant

Participants said they would need more information to make an informed decision on a resilience/cost trade-off, including:

- Evidence on risk and reliability, including outage frequency, duration, causes, impacts, and forecasts for future extreme weather events
- Transparency on investment options, including which projects are proposed, where they are located, and the benefits of spending more versus less
- Clear cost impacts, including how investments would affect bills and how costs would be shared across different customer groups

This information was provided prior to the following meeting and as part of re-testing preferences with additional bill impact information. However, we note our engagement did not involve a detailed discussion of various investment options as it was not intended to gain technical insights from end use consumers. Instead, it was designed to gain directional insights from consumers as to attitudes towards resilience risks, supporting specific communities and taking a more proactive approach (at an increased cost) to manage these risks. We recognise this supplements rather than replaces the need for us to conduct robust analysis and cost-benefit assessment of investment options.

In developing any proposed resilience spend, the CWG have recommended the preferred investment option be revisited to ensure that Transgrid identifies all options. This includes Transgrid intensive investments through to third party support options (such as Hydrostor) and how improved outage management services may improve the viability of “build back better” and fast response options. The CWG have also highlighted the longer-term replacement challenge that needs to be considered for the X2 line that has been the focus of resilience discussions.

How we are responding

To strike the right balance between affordability and the need to protect against severe weather events, we have reduced our proposed resilience expenditure to approximately \$180 million (from \$400m under the high-case scenario). Whilst a proactive approach to strengthening the network was supported by the Consumer Panel, we understood that expenditure should be targeted and the investment case based on clear evidence.

This reduction has been achieved by proposing a single resilience project that is focussed on strengthening the area of highest risk and greatest potential customer benefit, rather than developing a broad-based program covering assets across several regions sensitive to climate events. Details of our Line X2 Strengthening resilience project is provided in [section 3.2.4](#) of this Draft Plan.

Our resilience project will strengthen supply to far western NSW including Broken Hill and surrounding communities. These communities have experienced major supply disruptions from line and structure failures caused by strong convective winds in 2009 and 2024 which left them reliant on local generation and impacted several mining operations. In prioritising this project, we have placed greater emphasis on real-world experiences and demonstrated risk exposure, with a lower weighting applied to long-term climate modelling and more uncertain future projections, consistent with stakeholder feedback.

2.2.6 Delivering the capital program

What we are hearing

Stakeholders emphasised the importance of developing an investment program that is both prudent and realistically deliverable, with clear evidence that workforce capability, contractor capacity, material availability, and broader supply chain considerations have been factored into planning assumptions. Deliverability concerns and supply chain risks are heightened as networks and industry are competing to access skilled labour and materials to deliver the energy transition. These challenges could exacerbate as large-scale data centre builds command an increasing portion of available resources.

Stakeholders are seeking greater visibility of the frameworks, criteria, and trade-offs used to sequence and prioritise investments to ensure the program delivers the greatest value and risk reduction outcomes.

The CWG noted that deliverability is often a key constraint on investment programs. Noting historical concerns raised by the AER's engineering consultant EMCa of insufficient evidence of rigorous deliverability assessment. The CWG highlighted the importance of transparently demonstrating how projects are prioritised for delivery alongside ISP, Roadmap and any triggered contingent projects when resources are limited.

We also heard that it is important to clearly identify the deliverability challenges and constraints experienced by Transgrid and its network peers during the current regulatory period and demonstrate how these lessons have informed our plan. Stakeholders expressed a desire to understand how risks to delivery have been assessed, what assumptions underpin the proposed program, and how contingency planning is embedded within the delivery strategy to respond to potential changes in market conditions, resource availability, or project execution risks.

How we are responding

We are treating deliverability as a core planning constraint that directly shapes the 2028-33 expenditure profile, rather than a consideration applied after investment decisions are made. To support this, we have developed analytical tools that assess the portfolio against key delivery constraints, including workforce capacity, outage access, contractor availability, long lead material procurement, and regional delivery concentration.

These assessments have been used to determine project timing and sequencing across the portfolio. The analysis identified specific constraints related to outage coordination, workforce shortages at peak delivery periods, limited availability of specialist contractors, long lead equipment procurement risks, and high concentrations of work within particular regions and corridors.

Where constraints could not be mitigated through planning adjustments, project schedules were revised to maintain a realistic and achievable delivery program. To further strengthen deliverability, we are implementing a range of targeted controls, including early works activities, forward procurement strategies, early commitment to long lead equipment, enhanced outage management processes, and a workforce strategy aligned to forecast peak resource requirements. These measures are intended to support the efficient delivery of a significantly expanded investment program. Our method to optimally sequence our investment portfolio is outlined in [section 3.1.3](#) of this Draft Plan.

2.2.7 Robust business cases and assumptions

What we are hearing

Stakeholders told us that investment plans should be supported by a clearly demonstrated need and underpinned by robust analysis and reasonable assumptions. While there was broad recognition that we are entering a pivotal phase of the energy transition, and that additional investment will be required to maintain reliability, support changing demand and adapt the system, stakeholders were clear that this does not diminish the need for rigorous justification of proposed expenditure.

For demand-driven augmentation expenditure, participants highlighted the importance of working closely with the NSW and ACT distributors to ensure demand forecasting methodologies deliver reasonable estimates. This reflects the increased uncertainty surrounding future demand volumes and load profiles as more data centres connect to the network and their potential impact on energy prices. For replacement expenditure, the CWG highlighted the need to apply AER guidelines and key inputs, like the VCR, while also demonstrating the veracity of Transgrid inputs such as probability of failure curves, asset health and condition and the relative benefits of staged, partial and full replacement programs.

High-quality business cases can demonstrate investment decisions appropriately balance consumer outcomes, long-term system needs and affordability considerations and maintaining confidence that expenditure has been carefully scrutinised. With this in mind, we provided the CWG and AER with a sample of Option Evaluation Reports (OERs) for early review. The CWG considered these OERs could be improved by:

- more clearly demonstrating the need, scope and timing of investments through deeper option analysis;
- evidencing a deeper consideration of additional options, particularly non-network, staged, targeted and middle-ground options and capex-opex substitutes;
- transparently addressing timing, deferral and demand uncertainties; and
- more clearly articulating the problem statement and risk reduction or benefits in consumer centric terms that aligns with Transgrid's overall narrative and asset class strategies.

The AER noted that given the magnitude of the forecasts, it would expect detailed supporting evidence for the augmentation and replacement forecasts demonstrating how the proposed expenditure forecast represents the prudent and efficient level of expenditure required to meet the capital expenditure objectives.

How we are responding

Our capital expenditure for 2028-33 reflects the investment required to cater for high demand growth driven by the electrification shift and new large load loads; address growing asset failure risks; and to manage system strength risks arising as we transition to a more diverse energy mix.

As our operating environment changes, we need to adapt to how we deliver the services our customers expect from us. With service reliability and bill affordability the main priorities for customers, to strike the right balance our Draft Plan looks to maintain the current overall risk and service performance levels.

Our capital expenditure is underpinned by a suite of OERs that outline the case for investment for individual programs and projects. To ensure they represent value for money, we apply industry accepted assumptions and inputs like the VCR that align with AER methodology to determine the course of action that delivers the largest consumer benefit. We have also increased collaboration with the NSW and ACT distributors to ensure we have a common and confident understanding of underlying demand likely to arise during 2028-33 to minimise the risk we invest in more capacity than is required. The way we progressively challenge demand forecasts and integrate them into our augmentation program is described further in section 3.2.2.

We are working to uplift the quality of our OERs to a higher standard by incorporating feedback received by the AER and CWG, particularly with respect to genuinely and transparently considering a greater range of feasible options. Whilst our approach has been consistent with the AER's RIT-T guidelines, insofar only credible options to address the need are considered, we will broaden our focus to also consider not addressing the identified need (i.e. the base case) as well as test options typically not considered economically or technically feasible to demonstrate that a full assessment of options has occurred.

Our OERs will more clearly explain the underlying investment need, why the preferred option represents the best solution, and why the investment is required in 2028-33. Importantly, we have placed greater emphasis on articulating in plain language the value the investment delivers to consumers, including reliability, risk and affordability outcomes, rather than focusing predominantly on technical network requirements. To reflect this, we have developed standardised OER templates to ensure rigour is applied consistently across all our planning teams. We will continue to refine these OERs in response to the comments received to date and share updated versions for review with the CWG.

2.2.8 Managing greater complexity and innovating

What we are hearing

We have noted the importance of facilitating a timely and efficient transition to renewable generation sources. Policymakers have highlighted that this provides the lowest cost electricity supply over the longer term. This transition is well underway and its impacts are being observed in several areas, notably our increasing component of electricity prices. While less notable, this changing supply and demand mix is also having a profound impact on system planning and operability.

We have observed a marked increase in the level of modelling, analysis, engagement and investment required to support stable and secure operations. As part of our engagement with other industry participants such as large energy users, retailers, distribution networks and generators we received feedback on the need to improve the sophistication and capacity of our system planning and operations capabilities.

These participants considered we could better plan and optimise the network, reducing losses or unnecessary curtailment, through improving these capabilities. There was also feedback that we should have closer regard to non-network solutions and innovation opportunities to reduce the risk of over-investment in traditional and more expensive network solutions.

The latter aligns with feedback we have received from the CWG to more closely consider the role of storage in addressing emerging constraints and testing alternative solutions to ensure the lowest cost option is applied. The CWG were also keen to see Transgrid investigate opportunities to improve the Demand Management Innovation Allowance (DMIA) to support network innovation.

How we are responding

We are investing in smart and more advanced capabilities to support real-time monitoring and management of our rapidly changing network. To ensure we attain the requisite system strength enhancements and operability at an efficient cost, we are embedding consideration of both network and non-network solutions into our options analysis.

By applying a broader lens to our options analysis, innovative and emerging solutions are assessed on a level playing field alongside conventional network investments. This ensures the best value solution is selected where it can deliver the right service outcomes for generators, industry participants and consumers.

To support compliance with our system strength obligations, we have included an opex step change to uplift our network and operational planning capabilities and to procure non-network system strength services, including from synchronous machines and grid-forming batteries. We have also included a step change to complete the delivery of core operational technologies that commenced during 2023-28 via the System Security Roadmap Operational Technology Contingent Project.

Capital expenditure will also be required to maintain system security and ensure our system operability capabilities keep pace with increasing system complexity. Given there is currently some uncertainty regarding the scope, timing and location of these investments, we propose to include them as contingent projects. This is consistent with CWG feedback that this remains the most appropriate funding mechanism until these requirements become clearer.

We are also addressing stakeholder concerns regarding the impact that network outages and operational practices can have on the output of connected renewable generators. Through strengthened deliverability planning and enhanced outage management processes, we are improving our ability to coordinate network activities and minimise disruption to market participants. To support this, we are also improving our workforce capacity and training to ensure our workforce is right-sized and has the skills, capacity and expertise required to manage increasing operational complexity.

Section 3

Draft Plan



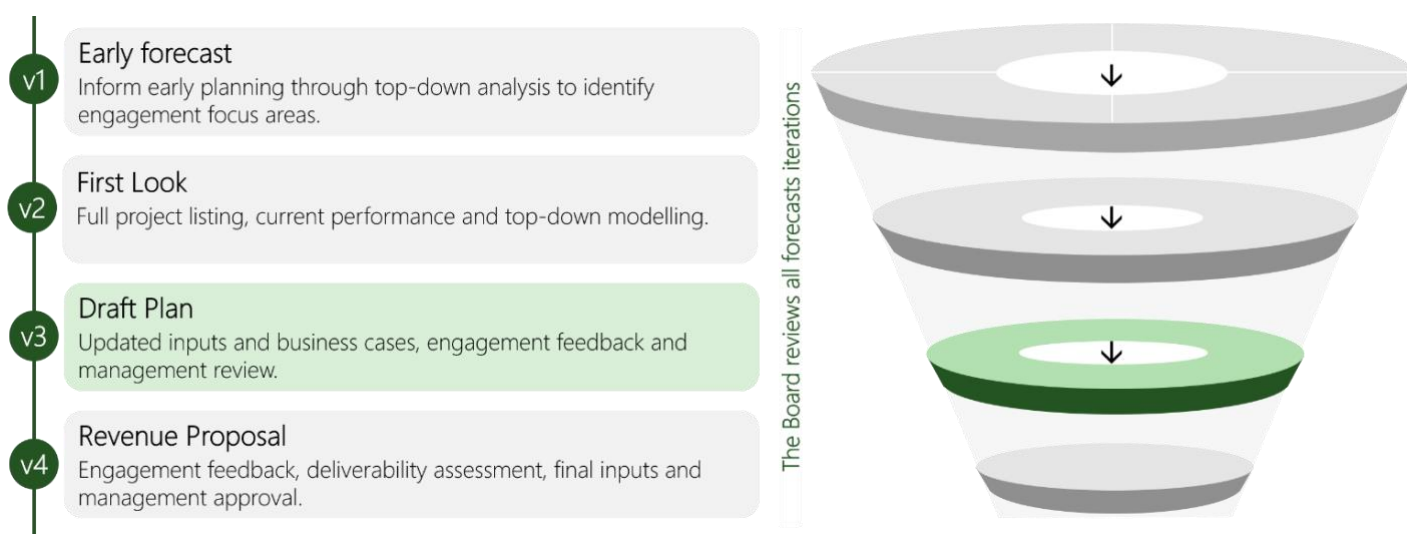
3.1 The 'Draft Plan' proposal

3.1.1 Our approach

Our approach to developing the 2028-33 expenditure forecasts is iterative and progressive, reflecting both the complexity of the investment program and the importance of incorporating stakeholder feedback throughout the process.

As shown in Figure 3-1, we are developing our forecasts over a series of versions. Each version deepens the supporting analysis, refines assumptions and improves the quality and robustness of the expenditure program, consistent with AER guidance and regulatory practice.

Figure 3-1 Iterative development and refinement of 2028-33 expenditure forecasts



We began with early forecasts presented to the CWG in March 2026. These initial forecasts were largely top-down and focused on identifying the key external drivers of investment and areas for further analysis. This stage was designed to establish a common understanding of the scale and nature of the investment task, and to support early engagement on the key issues.

Our version 2 forecasts, presented to the CWG in early June, and documented as part of a 'First Look' document – provided to the CWG and AER for feedback – represented the first integrated portfolio view. These forecasts incorporate both top-down analysis and bottom-up inputs from an initial set of Options Feasibility Studies (OFSs) which include cost estimates. We have refined and updated this portfolio view since then and our current forecast forms the basis of this Draft Plan.

Across these iterations, the program is being progressively strengthened. Early stages focus on identifying needs and establishing the overall scale of investment, while later stages place increasing emphasis on refining cost estimates, testing alternative options, optimising the portfolio and assessing deliverability constraints such as workforce, supply chain and outage availability.

Engagement with the CWG, Consumer Panel and the AER is embedded throughout this process. Feedback is used to test assumptions, challenge cost drivers and inform trade-offs between investment, risk and affordability. Updated versions of the forecasts are progressively shared to demonstrate how the program is evolving and how stakeholder input is being reflected. See section 3.1.6 below for more information on how we incorporated CWG and Consumer Panel feedback in our latest expenditure forecast.

Consistent with this approach, the forecasts presented in this Draft Plan represent a point-in-time view. They are not final positions and will continue to evolve as analysis is completed, cost estimates are refined and further stakeholder feedback is incorporated.

Figure 3-2 Snapshot from our consumer panel #4 session held 8 August in Sydney



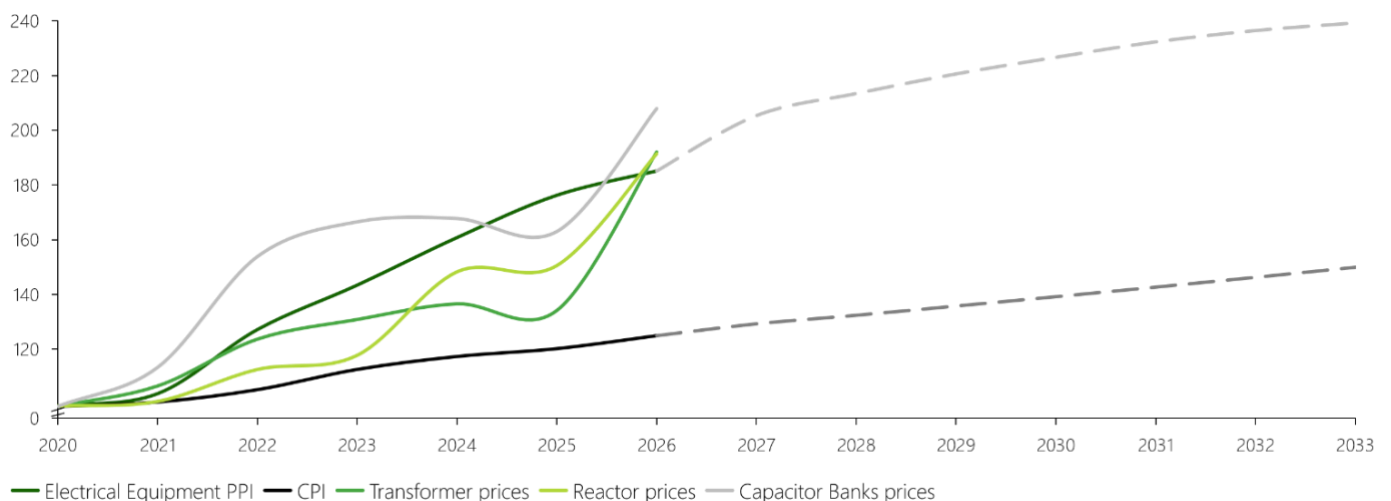
3.1.2 Cost escalation and estimation

Cost estimates are a critical input to the process outlined above in informing option selection, project timing and the assessment of economic efficiency.

Network productivity has declined in recent years as inflationary pressures have materially impacted the cost of building, operating and maintaining electricity networks. We note that AEMO identified that between 2023 and 2025 the cost estimates produced transmission cost data, used to estimate the cost of future ISP augmentations, had increased in real (after inflation) terms by 25% to 55% for overhead lines and 10% to 35% for substation projects.

This is consistent with our experience where, following the finalisation of our 2023-28 Revenue Determination, we have experienced substantially increasing costs for both labour and materials in response to global events and supply chain shocks. For example, we have seen a 41% increase in electrical equipment price index over the last 5 years, which has been felt directly within our asset program through price increases in transformers (55%), reactors (70%) and capacitor banks (35%). This trend has been seen reflected across most major asset classes.

Figure 3-3 Price indexes against asset category costs (index, normalised from 2020)



Like many other networks, we have been required to manage costs increasing at 2-3 times the rate of inflation over a sustained period of time within the AER's expenditure allowances. For us, this has involved overspending the allowance (i.e., incur financial penalties) in order to undertake necessary works to meet our obligations and deliver, as far as reasonably practicable, the outcomes committed to in our 2023-28 proposal.

For the 2028-33 period, it is likely that labour and material costs will continue to increase at levels materially above general inflation. To date, it has been the AER's practice to apply real escalation to labour while providing for no growth above general inflation for contract labour and materials. While inaccurate, this approach should prove neutral over the long-term under the incentive based framework where the forecast is unbiased,

However, in a demonstrated environment of prolonged real price growth across all key cost inputs this approach is downwardly biased and will produce an unrealistic forecast that is not corrected over time. We consider the current conditions are likely to be sustained due to ongoing international conflicts and the increasing demand for electricity related equipment and skilled labour to support the delivery of the energy transition in NSW, Australia and abroad.

In response to this enduring shift in conditions, we have updated our approach to more accurately track and produce a realistic estimate of project costs. A common approach for Revenue Proposals is to rely on AACE International Cost Estimate Classification System Class 5 (concept-level) estimates. This approach is adopted due to the significant resources required to produce more detailed cost estimates together with information constraints (e.g. scope definition).

However, given the scale and criticality of our investment program and our learnings over the 2023-28 period, we have sought to progressively uplift the quality of estimates where feasible and go beyond a Class 5 estimate. Where sufficient information is available, we are developing Class 4 (feasibility) and, in some cases, Class 3 (budget-level) estimates.

Improving the quality of our cost estimates allows better project screening, options selection and a reduction in uncertainty and allows key risks to be identified. However, this approach requires significantly more resources and increases the time each individual estimate takes to produce – e.g. to undertake risk workshops, loop in delivery teams to integrate current period lessons learned and seek additional information (e.g. from vendors).

We are also costing up alternative options in addition to the most likely option. In total we have developed around 1,300 individual cost estimates for about 540 identified needs. In some cases, we are preparing more than 10 options for a particular needs case. This approach multiplies the costing effort but provides confidence that we have appropriately considered all available options.

This expanded costing effort strengthens confidence that the proposed program will be assessed on a sound basis in determining an efficient set of investments.

While it provides confidence that our forecasts reflect prevailing market conditions it does not address the risk of input costs continuing to materially outstrip general inflation. To address this risk, we have applied labour escalation consistent with the AER's standard approach. That being, a blended forecast from two wage growth experts.

For material growth, a mix of PPIs and commodity based escalators have been adopted as a proxy noting the AER typically does not apply material escalation in estimating capex. In addition to these expert forecasts, we also have an extensive internal database of unit costs for key expenditure categories and equipment types that we can draw on to update and forecast input costs.

Applying similar growth rates for material growth as experienced over the 2023-28 period would increase our capex forecast by \$615m. However, consumers and their advocates have strongly encouraged us to exercise constraint in our cost forecasts to manage bill impacts during this cost-of-living crisis. Rather than remove necessary projects and programs to increase the risk consumers bear, we have elected to apply top down constraint to our overall forecast and to instead manage these likely cost increases as best as possible over the period through to be determined efficiency initiatives.

As part of this determination process, we wish to engage further with the AER on how material price growth is best forecast and applied to capex with the above figure being a top-down estimation. Regardless, we will need to consider whether absorbing this risk remains appropriate as part of our January and Revised Revenue Proposals as the external environment evolves and in response to any adjustments in the AER's Draft Decision.

3.1.3 Deliverability

The 2028-33 Deliverability Plan responds directly to feedback from the AER's 2023-28 determination. While the AER accepted the need for significant investment, it sought greater confidence that Transgrid's proposed capital program could be delivered in practice, taking account of workforce, supply chain, outage access and broader delivery constraints. The Plan addresses this feedback through a whole-of-Transgrid assessment of deliverability that evaluates the 2028-33 program alongside concurrent ISP projects, EII developments and other major project commitments competing for the same workforce, supplier, outage and delivery resources. By testing the proposed program against these constraints, the Plan indicates that the 2028-33 investment program is both prudent and achievable.

The 2028-33 capital program coincides with a period in which the electricity sector is competing for the same workforce, delivery partners, long lead equipment and windows of network access. While individual projects may be forecast prudently, consumers derive little benefit if the overall portfolio cannot be realistically delivered within the regulatory period.

We note that while we are forecasting an increase to our capital program (once Integrated System Plan projects are excluded), this is partially driven by the substantial input cost increases experienced. The percentage increase in spend does not, in isolation, reflect the step up in the volume of work we are proposing to undertake. Our transmission and substation replacement programs are broadly similar in scale across periods. We are forecasting to increase our digital infrastructure program and deliver a series of larger and more complex of augmentation projects in the 2028-33 period.

Nevertheless, given the increase, we have considered deliverability by identifying and assessing the key constraints we face. This has been informed by a suite of analytical tools we have developed to test the forecast. These include:

- **Portfolio sequencing** – we are sequencing every project against four things: crew availability, planning concurrency limits, outage windows, and risk profile priority.
- **Outage constraint assessment** – to identify which projects can and cannot be delivered concurrently. The results of this assessment feeds into the program sequencing and resourcing.
- **Role based workforce demand model** – we converted the sequenced program into annual demand across 60 key roles. This is allowing us to determine whether there is a workforce shortfall and put in plans to manage this risk.
- **Market availability assessment** – which applies discipline-level capacity to contractor supply — most materially for transmission line construction crews and protection and control engineering both of which are constrained nationally.
- **Long lead item register** – we developed a register of 170 items and mapped these items to sequenced construction dates to produce a risk assessment of whether the items will be available when required. The results of this analysis identify whether equipment will be ready in time for project start.
- **Regional and corridor concentration analysis** – to consider how crew location lines up with our work program.

Where a constraint could not be relieved, we are adjusting project timing or moving the project beyond the period. The controls we are progressing in response include early works, forward-pipeline procurement packaging, early commitment on long lead plant, a strengthened planned outage management process and a workforce strategy sized to the modelled peak.

3.1.4 Prioritisation

The scale of investment required, together with increasing affordability pressures, means we must make deliberate trade-offs about which projects are included in the expenditure forecast, and which are deferred. These trade-offs occur both across projects and programs, and over time.

To support this, we are integrating consumer and consumer representative perspectives, including CWG feedback, into our prioritisation approach, recognising that different decisions will affect customer outcomes in different ways.

Our approach involves two stages:

- First, we develop and assess category-level forecasts. This includes incorporating updated cost estimates, associated risks, deliverability considerations and stakeholder feedback. This step identifies which investments are essential (for example, safety or compliance-driven) and which have flexibility in timing or scope.
- Second, we undertake portfolio-level optimisation. This involves balancing investment priorities against the shorter term impact on prices, while also considering implications for safety, reliability, compliance, the environment as well as long term price and deliverability outcomes.

This analysis is refined iteratively as the forecast develops, with updated versions shared with the Board, CWG and the AER to demonstrate how the program is evolving and how feedback is being reflected.

As part of this process, we will also determine which projects are included in the base forecast and which are better addressed through contingent funding mechanisms. This includes considering the allocation of forecasting risk, avoiding unintended outcomes, and ensuring incentives remain aligned with consumer interests.

3.1.5 Alignment with AER expectations

Our approach to developing the 2028-33 expenditure forecasts is grounded in established regulatory practices and is consistent with AER guidance, including the Better Resets Handbook, relevant guidelines and insights from previous regulatory processes.

To support this, we have strengthened both our forecasting approach and supporting planning processes. This includes expanding the depth of analysis underpinning the program, improving cost estimation and embedding deliverability and prioritisation considerations. Table 3-1 summarises how we have addressed the AER's feedback from the 2023-28 revenue reset process in preparing the 2028-33 Revenue Proposal currently underway.

Table 3-1 How we have addressed feedback

Area	Key feedback themes for Transgrid	How we've addressed the feedback
Augmentation	New capex projects added late in the process lacked justification.	Provided the AER and CWG sample business cases that demonstrate the need, scope, credible solutions and optimal timing of key projects.
	Concerns that Transgrid could not realistically deliver all its proposed 2023-28 capex, deepened by Project Energy Connect inclusion.	Applied constraint-based sequencing of investment to provide a systematic, portfolio-level view of deliverability, rather than a project-by-project judgement.
	Customer affordability priorities were not clearly incorporated.	Forecasts evolve through iterative updates with cost levers applied at each stage and shared with the CWG.
Replacement	Risk methodology and application difficult to understand.	Revised Risk Assessment Methodology to prioritise customer outcomes and clarity.

Area	Key feedback themes for Transgrid	How we've addressed the feedback
	Risk and financial benefits overstated in some areas. Proposed expenditure was sensitive to global factors. Insufficient evidence of compliance obligation or cost/benefit. The proposed repex profile should be considered as part of the total package.	Wide stakeholder engagement on risk allocation options and models. Presenting the AER with whole-of-network risk profile. Employing scenario-based repex portfolios. Evidence for operational benefits and preferred options with rationale. Developing a clear repex narrative that explains forecast drivers.
Operating expenditure	Insufficient evidence provided to indicate Transgrid's proposed step changes were prudent and efficient, incl. cyber and system security.	Comprehensive consultation and evidence on proposed approach.
Stakeholder engagement	Engagement commenced too late and regressed compared to prior. Quality and robustness of information was deemed inadequate. Lack of demonstration on how consumer preferences influenced the proposal.	Earlier, wider and more comprehensive stakeholder engagement than in our previous proposals, including CAG, CWG, Consumer Panel and industry forums. Continuous attention to improve quality and depth of information provided. Including feedback loops to confirm the appropriateness of trade-offs.
Investment governance	General feedback relating to improvements to project governance, investment decision-making and sufficiency of evidence supplied.	Uplift in project governance framework (incl. Class A & B projects). Maturity uplift in project estimation and Class B and C & D separation.

A key feature of our approach is early and transparent engagement with the AER. This included the development of a First Look, as well as this Draft Plan document to support a 'no surprises' approach and to initiate more detailed engagement ahead of our Revenue Proposal. This provides an opportunity to seek early AER views on key areas of judgement, including prioritisation and areas of uncertainty. It is also intended to support a more efficient and robust development process by identifying and addressing critical issues early, rather than later in the regulatory process.

3.1.6 Incorporating CWG and Consumer Panel feedback

The CWG have been clear that cost discipline is a core consumer expectation we must address and have asked us to apply cost levers to place downward pressure on expenditure. We have responded to this feedback by systematically applying these levers alongside refinement of our underlying analysis – both at the project and portfolio level.

While we have continuously sought to constrain costs, new information continues to become available and additional analysis is completed. In several cases this has also led to upward revisions of our expenditure forecasts. This has occurred as we receive new demand forecasts from distribution networks with higher (or different) load forecasts, we refine and improve cost estimates and additional needs for investment are identified.

We provide a high-level summary of program movements in Figure 3-4 below of both our base and data centre future scenarios. Further movements are likely as we refine our program to be included in our January Revenue Proposal.

Figure 3-4 Total Capital Expenditure movement between v1.5, v2 and v3 expenditure forecasts

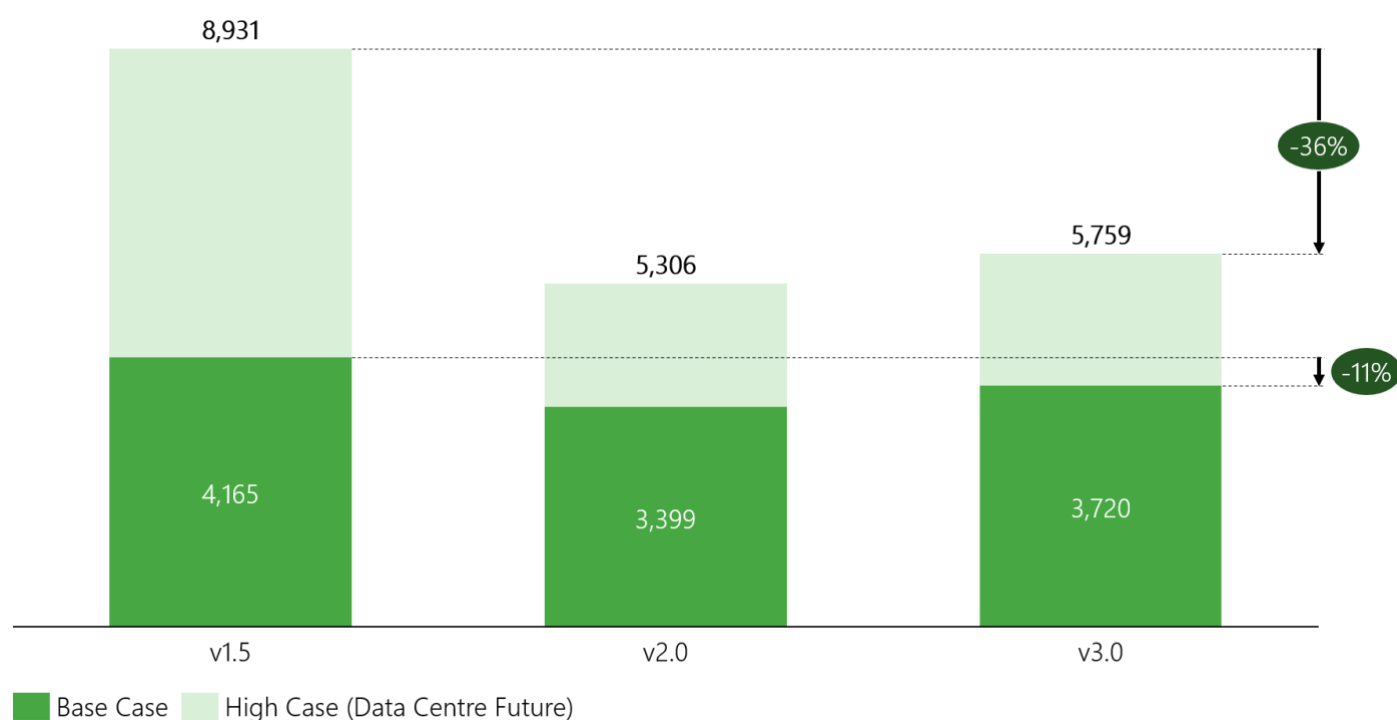


Table 3-2 below outlines examples of how we have reduced our expenditure forecast over time by expenditure category to illustrate how we have applied cost constraint wherever possible.

Table 3-2 Examples of cost levers applied

Expenditure category	Examples of cost levers applied
Augmentation	System security projects were reclassified as contingent projects, reducing base augmentation forecasts by \$1 billion. Certain projects were reduced in scope, including the Maintain Reliable Supply to Sydney West project, where components were deferred to the subsequent 2033-38 period, reducing costs from \$161 million to \$119 million. Duplicate scope was removed, including the Maintaining Reliable Supply to Beaconsfield Area project, which overlapped with the Powering Sydney Future Phase 2 project, reducing costs by \$99 million. Projects were delayed where feasible, including Maintaining Reliable Supply to Holroyd (reduction by \$86 million) and Supply to Tamworth (reduction by \$38 million).
Replacement	Volumes of transmission lines, substations and digital infrastructure were reduced by 20%, 45% and 32% respectively in the high case, with a portion of these reductions achieved through rephasing works to the subsequent 2033-38 period. Resilience and net zero expenditure was reduced by retaining only a single targeted resilience project from the high case scenario. However, these changes did not fully offset increases due to the introduction of firmer bottom-up cost estimates and newly identified investment needs.

Expenditure category	Examples of cost levers applied
ICT	Optimisation of forecast operational expenditure through further analysis of base, step and trend to remove duplication. Reduction in application investment requirements by maximising the use of existing platform capabilities, selectively descope initiatives, and pursuing self-funding opportunities where appropriate. These measures resulted in an approximate 23% reduction in ICT expenditure.
Property	Internal review of condition assessment programs removed lower-priority works and bundled activities, significantly reducing expenditure. Independent warehouse assessment identified opportunities to improve utilisation of existing facilities through storage redesign and operational improvements, enabling staged delivery, deferral of some new investment and a more efficient forecast. Additional reductions were achieved through scope refinement, prioritisation, deferral, and reallocation of non-critical investments. Collectively, these initiatives support a reduction of \$63m to our property renewal project.
Fleet	Establishing fleet growth assumptions that are closely tied to our Workforce Plan (which is approaching completion) to ensure vehicle requirements consider utilisation improvements and are correlated to training requirements, capital projects and maintenance work program. Implement safeguards to ensure the forecast only includes fleet required for the prescribed transmission network and kept separate from fleet funded through the NSW EII.

In addition to applying the cost levers developed with the CWG, we have made a number of other changes in response to feedback received from the CWG and Consumer Panel. In particular:

- We have refined the narrative, analysis and underlying assumptions through multiple rounds of engagement with consumers, their advocates and our Board. The Draft Plan provides a further opportunity to test and refine the analysis and key messages, while also ensuring key issues and trade-offs are communicated clearly. We are seeking CWG feedback on the issues that matter most to consumers.
- We are broadening the scope of our bill impact analysis beyond this Revenue Proposal in isolation. While the focus of this process remains on expenditure and outcomes funded through this Revenue Proposal process, we recognise that consumers experience the cumulative impact of multiple investment programs over time. We therefore provide greater transparency on the bill impacts associated with Transgrid's broader investment portfolio, including projects arising from the ISP and EII frameworks.
- In response to CWG feedback, we have committed to clearly distinguish between investments that are essential ("must do") with limited ability to influence and those that involve the exercise of judgment in the scope or timing. We are applying this framework across all CWG engagement to support more targeted discussion of trade-offs and priorities.
- We have reviewed and updated our business case templates to strengthen their consumer focus, including a clearer articulation of the benefits delivered to consumers. We also intend to share the draft business cases with the CWG to seek their feedback and input.
- We are reviewing our pricing methodology in response to ongoing concerns about the equity of cost recovery, particularly in the context of large load connections.

- Seeking, where possible, to use the contingent project (rather than cost pass through mechanism) for system security and operability projects.
- We have strengthened collaboration with distribution networks on key areas, including data centre demand forecasts in NSW and major projects such as Powering Sydney Future Phase 2, reflecting feedback from the CWG.
- Reflecting early feedback from Consumer Panel engagement, we have included targeted resilience expenditure in the low case forecast, recognising that consumers expect a proactive approach to resilience while managing cost impacts. We note that these trade-offs will be revisited with consumers later in the process, when consumers have greater visibility of the full program and associated costs.

These are examples of where feedback from consumers and their representatives has directly influenced the development of our approach. Further feedback and its application are discussed throughout the capital and operating expenditure chapters where relevant.

Figure 3-5 Snapshot from our consumer panel #4 session held 8 August in Sydney



3.2 Capital expenditure overview

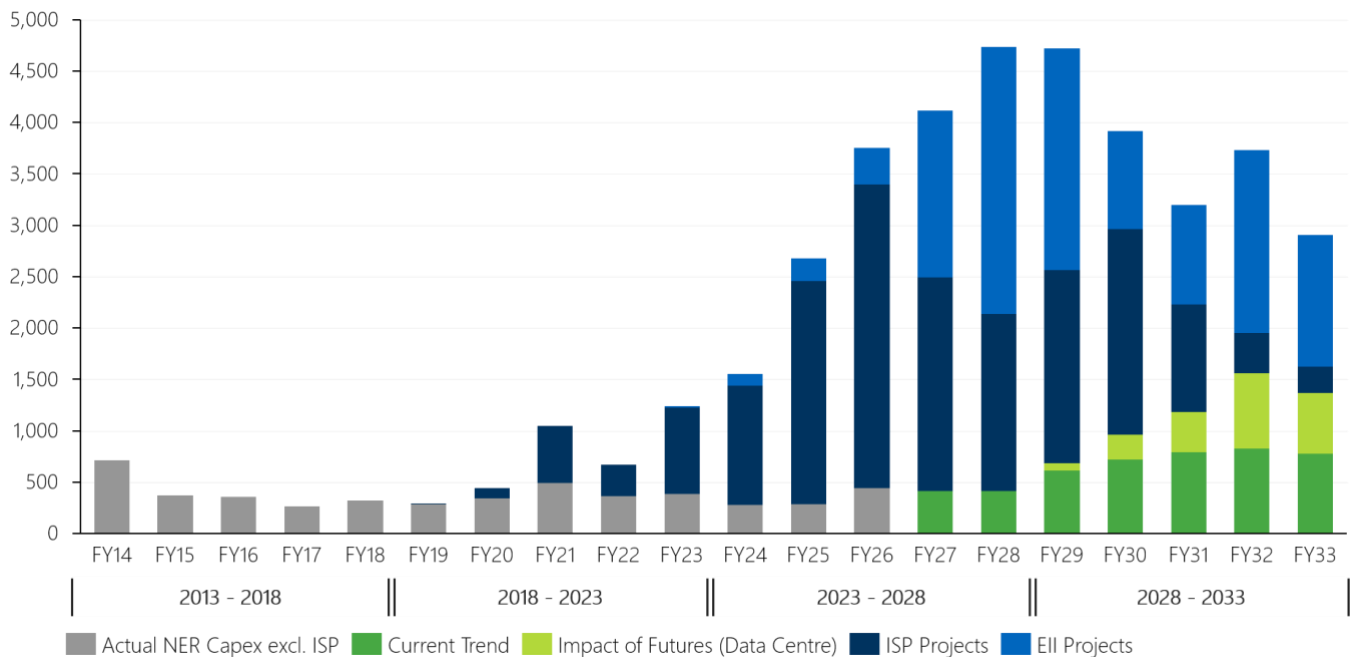
Our investments can be divided into two broad categories. The first are the investments identified by the NSW Energy Roadmap and the ISP which support the energy transition by enabling more renewable generation and in turn reduce consumer bills over the longer term. These investments are funded through the EII mechanism (in the case of the NSW Energy Roadmap) or the contingent project mechanism (for ISP projects) – and sit outside of this Revenue Proposal process.

The second set of investments are those required to continue providing our shared transmission service – prescribed services. These investments comprise the costs of augmenting our network to respond to consumer demand, replacing deteriorated assets, protecting existing assets from physical and cyber security threats, and maintaining supporting ICT platforms, property and fleet. These investments are the focus of this proposal.

A view across all of these elements, consistent with CWG guidance, is set out in Figure 3-6. We identify EII and ISP project expenditure together with the Draft Plan forecast (based on our current trend scenario) as well as the data centre scenario. The data centre scenario moves five data centre related contingent projects into our base expenditure.

The figure shows the significant step up in investment we are delivering which largely commenced in the 2023-28 period and which will continue into the 2028-33 period – the deep transition phase of the energy transition. The bulk of our investments relate to EII and ISP projects.

Figure 3-6 Total Capital Expenditure FY2014 to FY2033 (\$m, Real 2027-28), incl. EII & ISP Projects



Note: EII Projects include Waratah Super Battery, Synchronous Condensers Phase 1, Hunter Transmission Project and Central West Orana. ISP Projects include Project Energy Connect, HumeLink, VNI-West and Sydney Ring South.

Our expenditure program is substantial and will increase consumer bills (regardless of whether funding is provided through the EII or National Electricity Rules framework). This is in line with the expectations of policymakers that the infrastructure required to support the energy transition will put upward pressure on electricity bills in the short term before renewable generation reduces bills in the longer term.

The uplift in expenditure is also comparable to what is being experienced by other networks which are undergoing a similar transition. For instance, Ofgem projects that investment, across the electricity transmission businesses it regulates, will increase from £18b in the previous 2021-26 period to up to £70b in the 2026-31 period, an almost 4-fold increase (in 2023/24 prices). Similarly, Ireland's Commission for Regulation of Utilities, is expecting transmission to increase from investment from €1.5b to between €3.6b and €6.2b (in 2024 prices) between the 2021-25 and 2026-30 periods – more than doubling even at the low end.

We expect that expenditure will be lower in the 2028-33 period, as shown in Table 3-3 below. This comparison does not include the QNI Connect or the New England REZ ISP Projects which are currently in early planning.

Table 3-3 Period on period expenditure by funding mechanism (\$b, Real 2027-28)

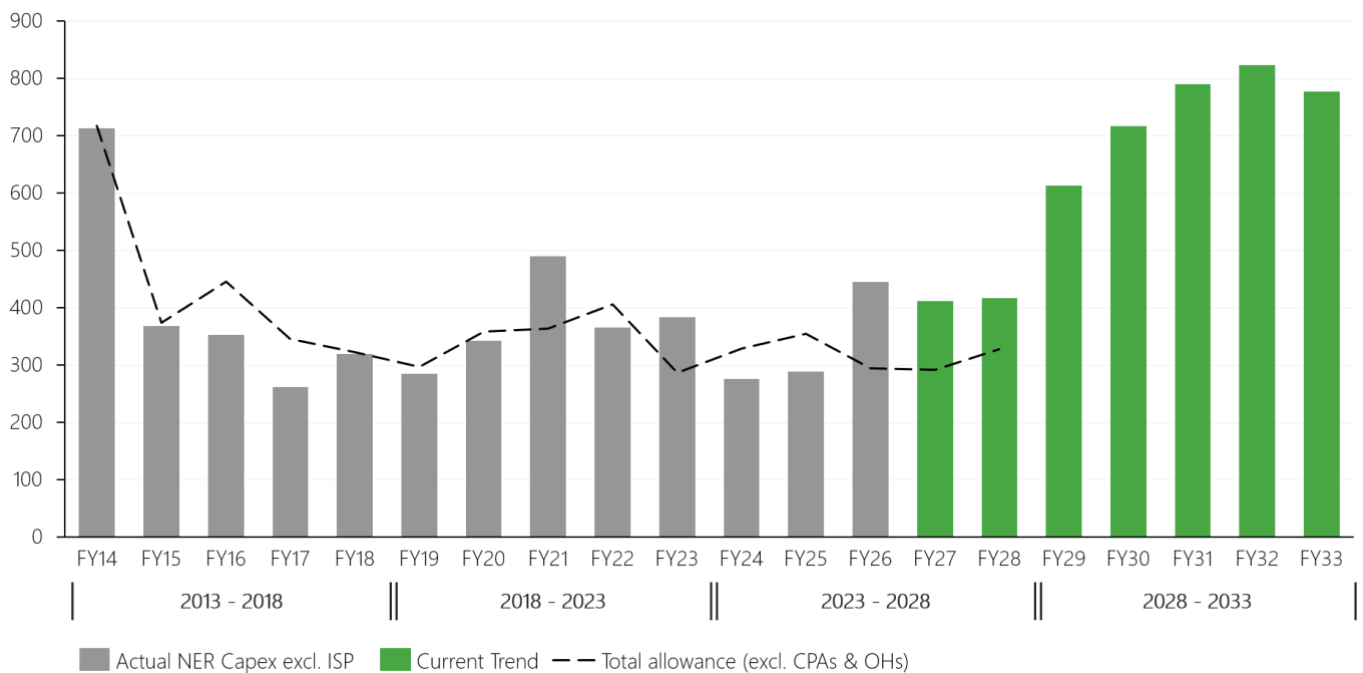
Category	2023-28 Actual/estimate	2028-33 Forecast	Change (\$)	Change (%)
EII Act Projects	4.1	2.1	-2.0	-49%
ISP Projects	10.1	5.6	-4.5	-45%
Prescribed service capex (including overheads)	1.8	3.7	1.9	+103%
Total	16.0	11.4	-4.6	-29%

3.2.1 Prescribed service capex (excluding ISP projects)

We are forecasting expenditure to increase in the 2028-33 period primarily due to growing and changing demand requiring an uplift in augmentation requirements together with increased investments in replacement expenditure to address increasing asset failure, resilience and cyber security risks.

Our forecast reflects our assessment of what is necessary to deliver on our obligations and meet the expectations of consumers. We trust that the regulatory framework will, over the long life of these investments outlined in this plan, provide a sufficient rate of return to enable these investments to occur. We have not considered the concurrent development of the AER's 2026 rate of return instrument which we have separately raised concerns with.

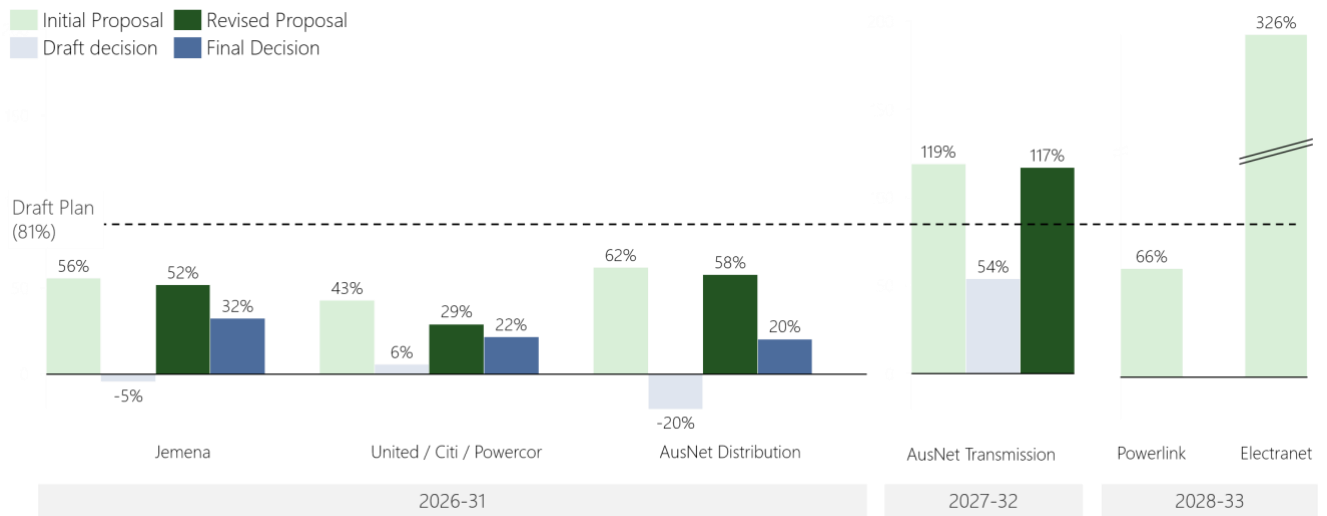
Figure 3-7 Total Capital Expenditure FY2014 to FY2033 (\$m, Real 2027-28), excl. EII & ISP projects



While Figure 3-6 includes expenditure forecast under both our Current Trend and Data Centre futures, we have not applied this forecast in our Draft Plan. Instead, we have applied the Current Trend in this Draft Plan.

Overall, in this Draft Plan we are forecasting an increase in net capex of ~81% (noting this excludes direct ISP capex). This compares to 119%, 66% and 326% recently proposed by AusNet Transmission, Powerlink, and ElectraNet in their recent revenue proposals. This trend of capital growth between regulatory periods has also been seen from regulated electricity networks worldwide, with Ireland's CRU, UK's Ofgem and France's CRE approving capital growth of 98%, 144% and 173%, respectively.

Figure 3-8 Net capex growth of network service providers between periods (%)



Category differences in expenditure between the current 2023-28 period allowances and actuals/estimated costs as well as the difference between current and forecast period expenditure are provided below in Table 3-4.

Table 3-4 2023-28 allowance versus actuals/estimated (\$m, Real 2027-28)

Category	Allowance	Actual/estimate	Change	Change (%)
Augmentation	368	349	-18	-5%
System security	87	87	-	-
Replacement	848	1,012	164	19%
ICT	89	136	47	53%
Cyber	14	10	-4	-29%
Property	30	46	16	56%
Fleet	60	84	24	41%
ISP Projects	7,436	8,795	1,359	21%
Overheads	188	329	141	75%
Gross capex – including ISP Projects	9,120	10,850	1,730	19%
Gross capex – excluding ISP Projects	1,683	2,054	371	22%

Note: Table does not include EII projects. ISP project capex excludes overheads. Note Cyber only includes ICT cyber costs.

Table 3-5 2023-28 Actual versus 2028-33 forecast (\$m, Real 2027-28)

Category	Actuals/estimate	Forecast	Change (\$)	Change (%)
Augmentation	349	1,190	841	241%
System security and operability	87	104	16	18%
Replacement	1,012	1,885	873	86%
ICT	136	109	-27	-20%
Cyber	10	18	8	80%
Property	46	76	30	65%
Fleet	84	86	2	2%
Overheads	329	252	-77	-23%
Gross capex – excluding ISP Projects	2,054	3,720	1,666	81%
ISP Projects	8,795	-	-	-
Gross capex – including ISP Projects	10,850	3,720	-7,130	-66%

Note: Table does not include EII projects. We are not also including any ISP Project spend in our Revenue Proposal forecast, other than what has already been approved through as part of an already approved contingent project. ISP project capex excludes overheads. Note Cyber only includes ICT cyber costs.

In the following sections, we provide a more detailed overview of each category of expenditure, our forecasting approach and the drivers for change.

3.2.2 Augmentation

Demand across NSW and the ACT is entering a period of sustained structural growth with a 6x increase from the current period. The expansion of data centres in particular are reshaping both the scale and location of electricity consumption. Over the 2028–33 regulatory period, this growth is expected to progressively absorb the remaining capacity of the existing transmission network, particularly in Western Sydney, the Sydney CBD and regional growth areas.

This places the network at an investment inflection point. Once available capacity is exhausted through increasing levels of utilisation, new transmission infrastructure will be required to maintain reliable supply and enable further economic and population growth. Because transmission augmentations are large, discrete and relatively infrequent, expenditure does not increase gradually, it steps up materially as capacity thresholds are reached. This dynamic change underpins the forecast increase in augmentation expenditure from \$349 million in the current period to \$1.2 billion in 2028–33.

Two key trends are driving the need for change in this regulatory period.

- **Operational complexity** which is increasing as renewable generation grows from 46% of supply in FY26 to 90% by FY33. As generation shifts from a small number of large coal-fired power stations to hundreds of geographically dispersed renewable generators, the network is experiencing new technical challenges, including voltage unbalance and harmonic compliance issues.
- **Demand growth** which has fundamentally changed. Driven by data centres, electrification and population growth, maximum demand is forecast to increase by 23% between FY26 and FY33, following more than a decade of flat maximum demand.

We have also identified nine potential contingent projects, including five associated with data centre loads. These projects have not been included in the base forecast because there remains material uncertainty regarding their timing, need and cost. However, they represent credible additional investment requirements and reinforce the need to preserve flexibility, monitor emerging demand closely and maintain readiness to respond as customer commitments and network needs become clearer.

Why augmentation is needed

Augmentation expenditure (augex) increases the capacity or capability of our transmission network. It enables us to respond to changing customer and power-system needs while maintaining network reliability and security and complying with our regulatory obligations.

The need for augmentation is principally driven by changes in electricity demand and in the way electricity is generated and transported across the network. These changes affect each location differently, depending on the capacity and configuration of the existing network, equipment ratings and the voltage, security and reliability requirements that must be maintained.

The following sections explain the changing network needs driving this increase, how we have challenged the underlying forecasts and how we have limited the base program to investment currently expected to be required during 2028–33.

How consumer feedback has shaped the plan

The CWG has emphasised the need to avoid over-investment and asset stranding, rigorously challenge distribution networks and data centre forecasts, consider non-network alternatives and clearly demonstrate the benefits of the proposed investment. It has also sought greater confidence in the deliverability of the program and an equitable approach to allocating the costs created by large new users such as data centres.

This feedback has directly shaped the approach and outcomes described above. In particular, we have strengthened the challenge applied to demand forecasts, planned only for transmission-connected data centre demand supported by project-level evidence, removed projects whose expected benefits did not justify their costs, deferred and staged investment where possible and increased the use of contingent project mechanisms for uncertain needs.

We have also identified projects that may instead be delivered through the NSW Roadmap, including potential upgrades between Parkes and Wellington and between Wellington and Orange. The value of these projects must be confirmed and, at this stage, have been excluded from our augmentation forecast to avoid double recovery.

How we develop our program

Our augmentation program is developed through an established, evidence-based planning process. The process develops location-specific forecasts, challenges the underlying assumptions and then tests whether the resulting network conditions create a reliability, compliance or economic need for intervention.

Developing and challenging demand forecasts

Demand forecasts prepared by distribution networks for each Bulk Supply Point are an important input. Distribution networks have detailed visibility of the changing requirements of the customers and communities supplied through each part of the transmission network. Their forecasts consider weather-normalised underlying demand, population and economic growth, electrification, energy efficiency, CER, network load transfers and major new loads, including data centres and industrial developments.

We do not accept these forecasts at face value or mechanically convert them into augmentation projects. Through our annual planning process and regular (typically fortnightly) joint planning discussions, we:

- reconcile forecast growth with actual and weather-corrected historical demand;
- compare previous forecasts with actual outcomes to identify potential bias;
- test assumptions concerning population growth, electrification, energy efficiency, CER and load transfers; and
- assess major loads against customer commitments, connection progress and delivery milestones and compare the results with AEMO forecasts, independent market assessments and other available evidence.
- Where the evidence does not support a forecast, we work with the relevant distribution networks to revise it. Where uncertainty remains, we test alternative scenarios rather than assuming that all forecast demand will proceed.

Figure 3-9 and Figure 3-10 show how distribution networks demand forecasts are progressively tested and converted into Transgrid's augmentation program. Forecasts provided by Ausgrid, Endeavour Energy, Essential Energy and Evoenergy are reviewed against historical demand and emerging customer loads, independently validated where material uncertainty exists, and refined through ongoing joint planning. Only after this challenge process are the forecasts incorporated into network modelling to determine whether, when and where investment is required.

Figure 3-9 Transgrid's forecasting approach derived from distribution networks

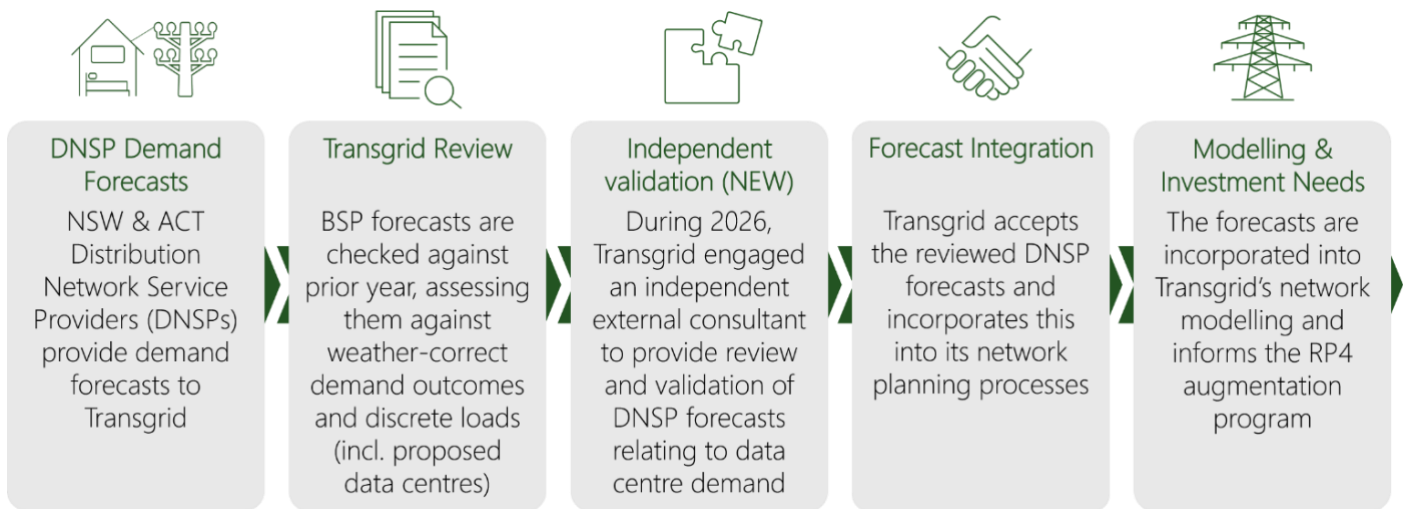
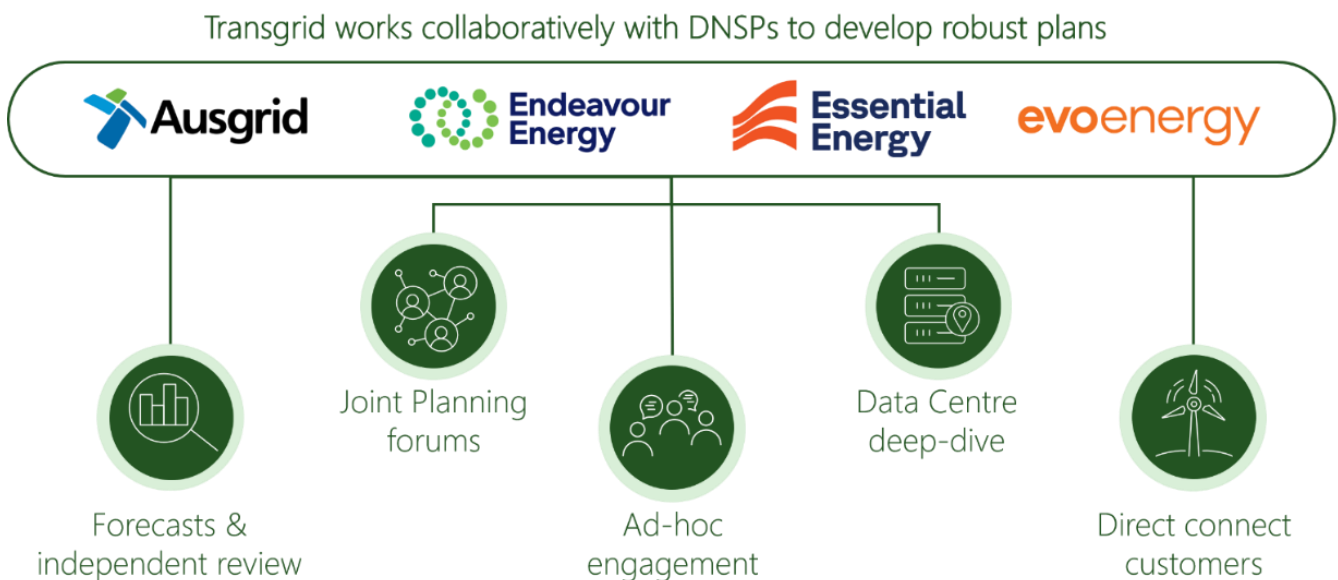


Figure 3-10 Network Service Provider collaboration and joint planning



Additional scrutiny of data centre forecasts

Data centre forecasts require additional scrutiny because proponents may investigate multiple sites and connection options before committing to a development. Aggregating all enquiries could therefore materially overstate the demand likely to proceed.

To provide an additional level of assurance, we engaged Baringa Partners to assess the NSW data centre market and development pipeline independently. We used this work to challenge distribution networks forecasts at both the Bulk Supply Point and network-wide levels.

Where possible, Baringa assessed the pipeline at the proponent and project level. This included distinguishing growth at existing facilities from proposed new facilities, removing outdated, cancelled and duplicated enquiries, assessing project maturity and timing, and testing whether multiple projects are likely to proceed concurrently. This also considered coincidence and diversity between loads and compare the resulting forecasts with independent market information.

The Baringa analysis proved valuable in challenging distribution networks data centre forecasts and subsequently resulted in material changes to the projects in our base program.

Modelling the network need

We use the updated demand and generation forecasts in our network models to determine whether existing capacity will be exceeded and whether intervention is required. The modelling assesses whether forecast conditions would result in:

- a forecast breach of technical requirements under the National Electricity Rules;
- a forecast breach of the applicable NSW and ACT transmission reliability requirements;
- increased expected unserved energy, valued using the AER's value of customer reliability; or
- increased transmission constraints affecting the efficient operation of the wholesale electricity market.

This distinguishes needs arising from mandatory reliability or compliance obligations from discretionary opportunities to deliver economic or market benefits. For mandatory needs, we identify the prudent and efficient response that meets the applicable obligation. For economic projects, investment proceeds only where the assessed benefits are expected to exceed the costs.

How we select the efficient response

Identifying a network need does not automatically result in traditional network augmentation. For each proposed project, we consider network and non-network responses, including storage and other demand or generation-side solutions. Technical and economic assessments determine whether a non-network response, alone or in combination with network investment, can address the need at a lower overall cost.

Potential solutions are coordinated with distribution networks, EnergyCo and AEMO through regular joint planning. At a portfolio level, the Sydney Plan coordinates demand-driven projects across the Sydney Basin so that related needs and investments can be considered together rather than through isolated, project-by-project decisions. This supports efficient sequencing and helps avoid duplicated or premature investment.

We have also excluded approximately \$291 million of generation-driven market-benefit projects, after preliminary assessment indicated that the estimated benefits of relieving the relevant constraints would not outweigh the costs. Projects that can reasonably be delivered later have been deferred, while others have been staged, reduced in scope or identified for potential treatment as contingent projects.

The preferred response for each project remains subject to the applicable project-development and approval gates. This allows the need, timing, scope, cost and delivery strategy to be reassessed as better information becomes available and before significant capital commitments are made.

Our response to a changing network operating environment

Rising and increasingly localised peak demand

Rapid growth in large loads, particularly data centres, is increasing peak demand and accelerating the exhaustion of network capacity in parts of Sydney. Other sources of growth include population and economic development, electrification of homes, businesses and transport, new suburbs and regional industrial developments.

Demand growth is not uniform across the network:

- **Western Sydney** is the principal location of demand-driven augmentation. Electricity demand is forecast to increase by 59% over the next ten years, with data centres accounting for approximately 45% of that growth. The population is also expected to continuously grow with a 37% increase forecasted from 2021 to 2041. This includes the new City of Bradfield, Australia's third largest and fastest-growing economy, home to more than 2.5 million people as well as developments such as the Western Sydney International Airport.
- **Inner Sydney and the eastern suburbs** are experiencing a combination of underlying demand growth and expansion of existing and new data centres. This growth is expected to exhaust the capacity available under the more stringent reliability requirements applying to Inner Sydney.

- **The ACT and surrounding area** are forecast to experience demand growth of 21%, driven by data centres, electrification, new suburbs and commercial developments. This is supported by the ACT Government’s Net Zero 2045 policy to electrify gas appliances and transport.
- **Regional NSW** generally has flat or declining underlying demand as CER and distribution-connected renewable generation offset other growth. However, localised industrial developments, including Special Activation Precincts (Parkes, Moree and Wagga Wagga) and gas and mining projects, are creating pockets of significant demand growth. In these areas, augmentation may be required to address both thermal capacity and voltage constraints.

Figure 3-11 shows a material increase in forecast NSW summer maximum demand between historical growth and our 2026 TAPR forecasts. Our 2026 forecast has been updated based on the process set out above and to reflect an additional 2 GW of data centre interest in connecting to the distribution networks by 2034-35.

This growth brings forward the point at which capacity is expected to be exhausted at affected Bulk Supply Points, strengthening the need for targeted augmentation while reinforcing the importance of continuing to validate and stage investment as data centre commitments become clearer. The delivery, scope and cost recovery arrangements for certain augmentation projects may evolve, as policy and regulatory frameworks continue evolve, including the data-centre related policies emerging from the Federal and NSW Governments, as outlined previously in Section 1.4.

Figure 3-11 Actual and projected NSW Region 50% POE - Summer as generated maximum demand (GW)

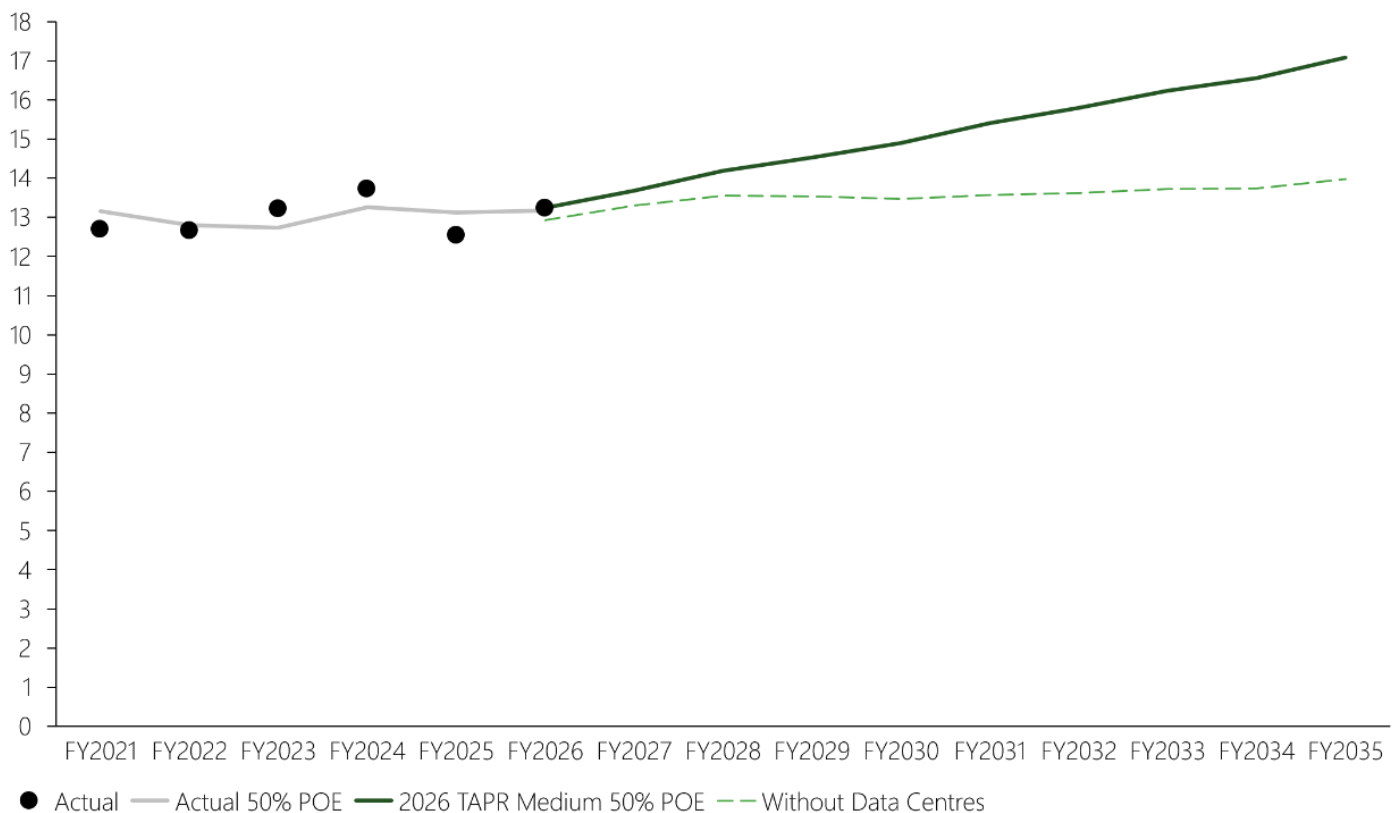
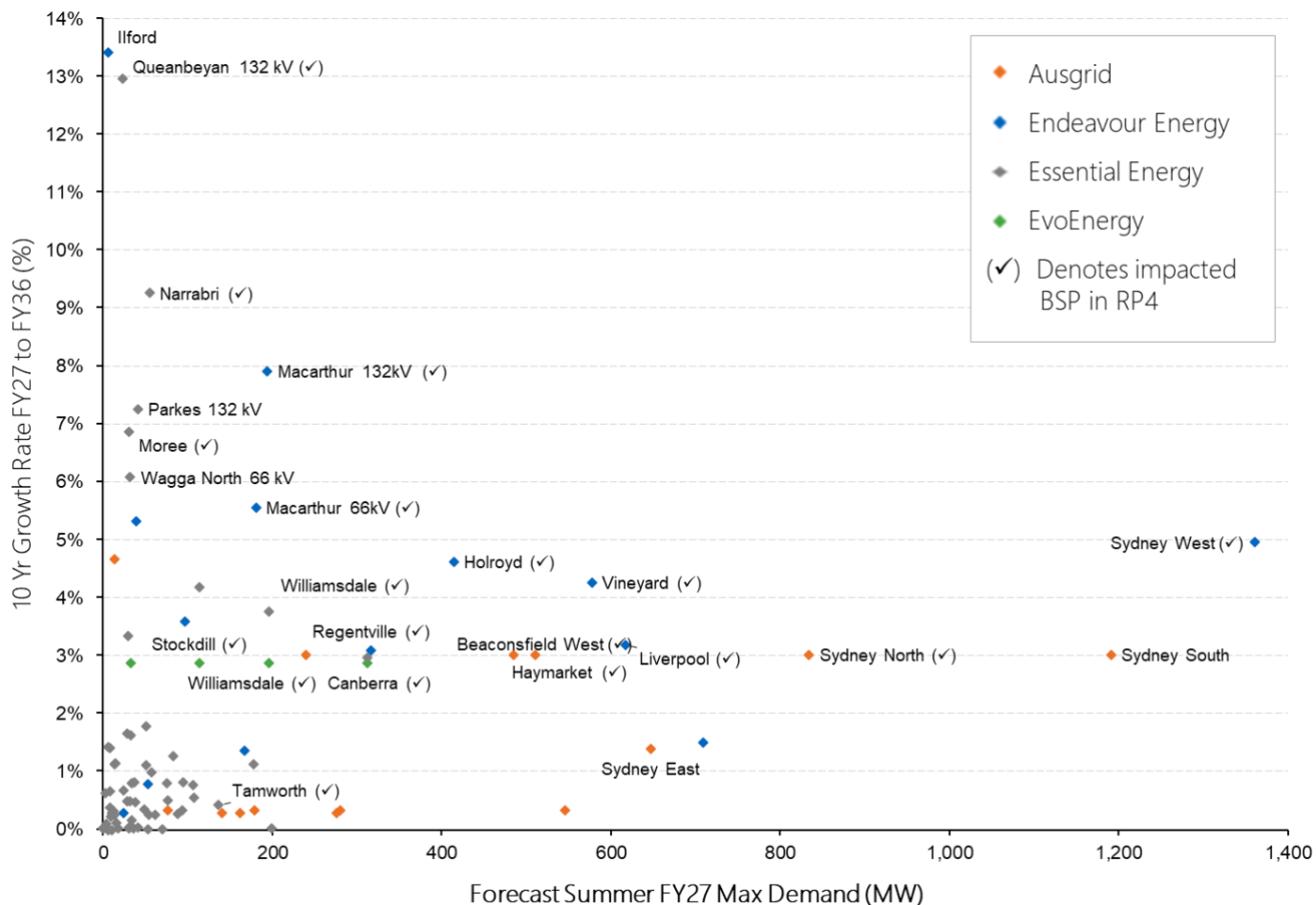


Figure 3-11 utilises a top-down POE-50 demand forecast produced by Baringa Partners, which is suitable for broad system planning activities. For the purposes of identifying the RP4 portfolio of projects, Transgrid utilises the forecasts provided by the distribution network service providers.

Figure 3-12 shows that forecast demand growth is modest for the whole NSW network apart from localised pockets of growth caused by data centre demand and regional spot loads¹. While most Bulk Supply Points are clustered at relatively low growth rates, several smaller regional locations are forecast to grow rapidly, while large metropolitan Bulk Supply

Points such as Sydney West combine a substantial existing demand base with sustained growth. The marked Bulk Supply Points identify locations affected by proposed 2028–33 augmentation projects. Importantly, the need for investment is determined not by demand size or growth rate alone, but by how forecast demand compares with the available capacity and reliability requirements at each location. The figure therefore reinforces the need for location-specific planning and targeted augmentation rather than a uniform network-wide response.

Figure 3-12 Bulk Supply Point (BSP) Summer maximum demand growth rates FY27 (% per annum)



Several Bulk Supply Points that have historically had adequate spare capacity are consequently expected to reach their limits during 2028–33. The current analysis indicates that forecast demand in Inner Sydney will reach approximately 109% of the existing transfer-capacity by FY2033. For the other Bulk Supply Points represented in the analysis, capacity exceedances begin from FY2031 and forecast demand reaches approximately 110% of the relevant transfer-capacity measure by FY2033.

Figure 3-13 Bulk Supply Points requiring augmentation - Demand versus current capacity (MW, FY2033)

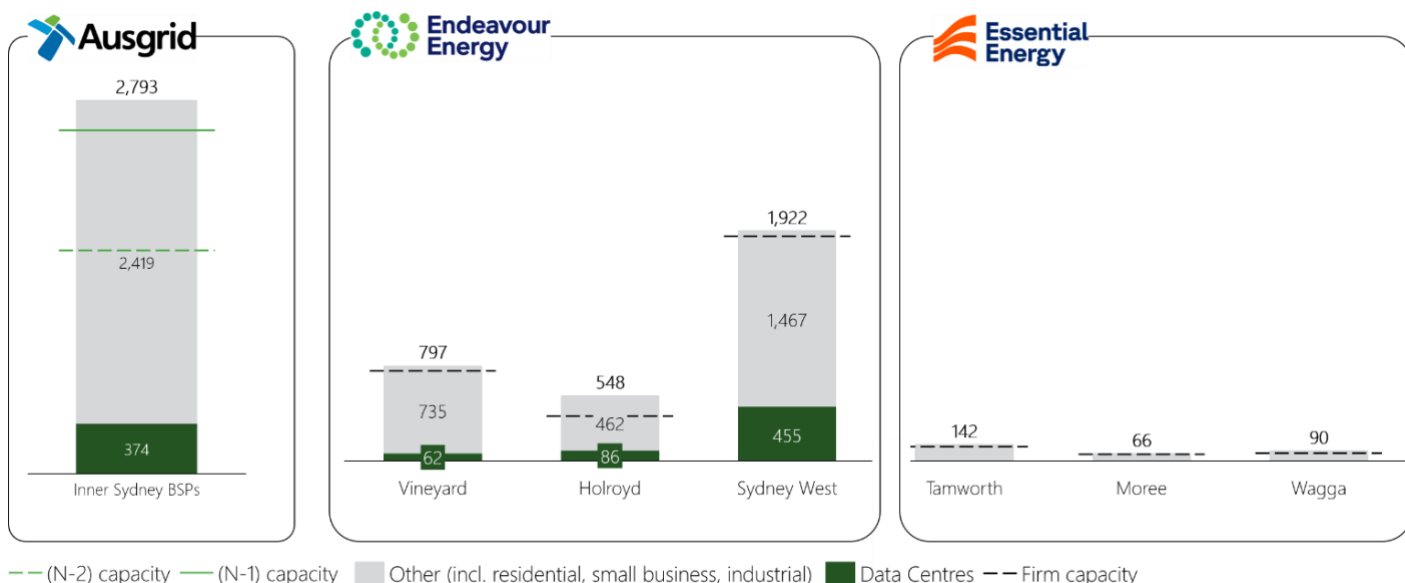
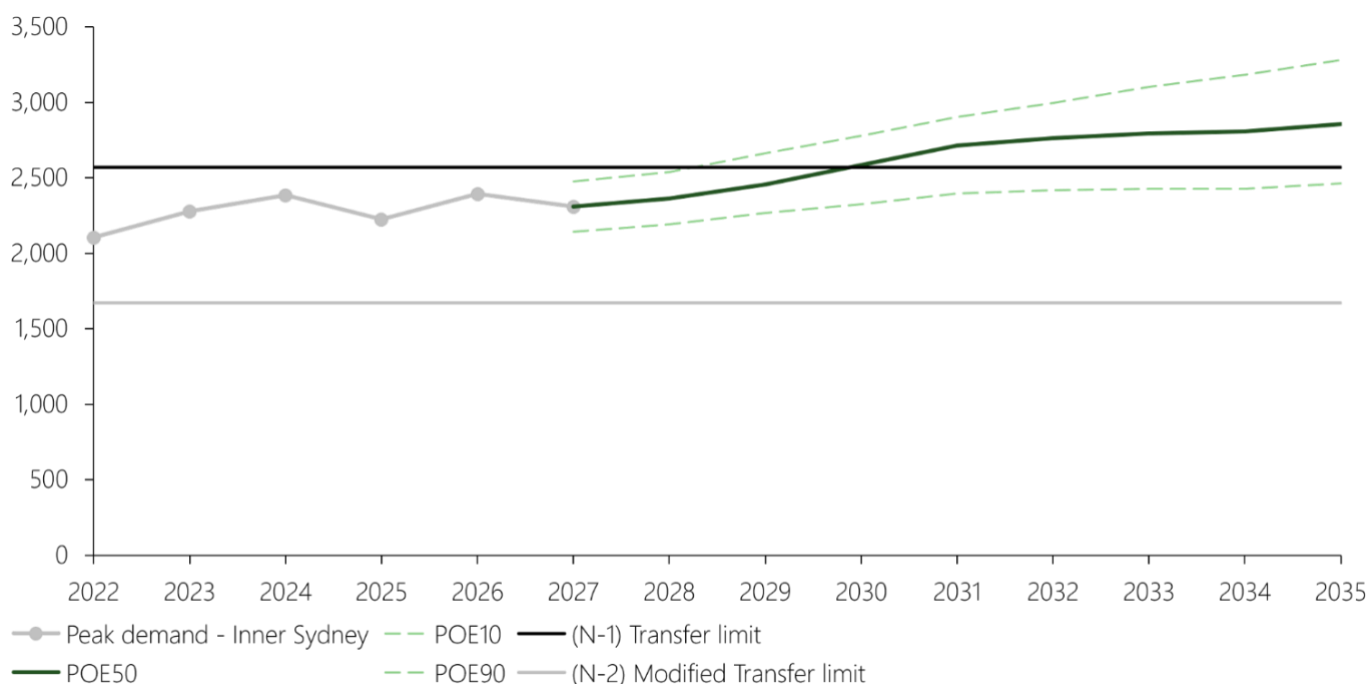


Figure 3-14 shows forecast utilisation of the existing transmission network by comparing peak demand with the relevant transfer-capacity limits. They demonstrate our approach of making fuller use of existing capacity before building more.

Figure 3-14 Utilisation: Peak demand versus transfer capacity limit – Inner Sydney Bulk Supply Points (MW, 2022-2036F)



Ten projects in the base portfolio respond to maximum-demand growth and associated capacity constraints at ten Bulk Supply Points. The largest of these projects aim to address existing capacity limitations in the network in Inner Sydney and Western Sydney, respectively. These are outlined in Table 3-6 below:

Table 3-6 Large demand projects in augex forecast (\$m, Real 2027-28)

Project name	Project description	Estimated 2028-33 Capex
Maintaining reliable supply to Inner Sydney – Powering Sydney’s Future Stage 2	Strengthens the network in Inner Sydney to maintain reliability as demand grows and ageing transmission cables reduce the areas’ ability to withstand major network outages.	230
Maintaining reliable supply to Sydney West	Increases network capacity in Western Sydney to accommodate continued residential, industrial and demand growth while maintaining reliability standards.	207
Maintaining Reliable Supply to Holroyd	Maintains secure supply to by addressing transformer capacity constraints at Holroyd under contingency conditions, ensuring reliability can be maintained as demand increases	113

Note: We define a large project as more than 5% of the forecast first year maximum allowed revenue as per the AER’s Regulatory Information Orders.

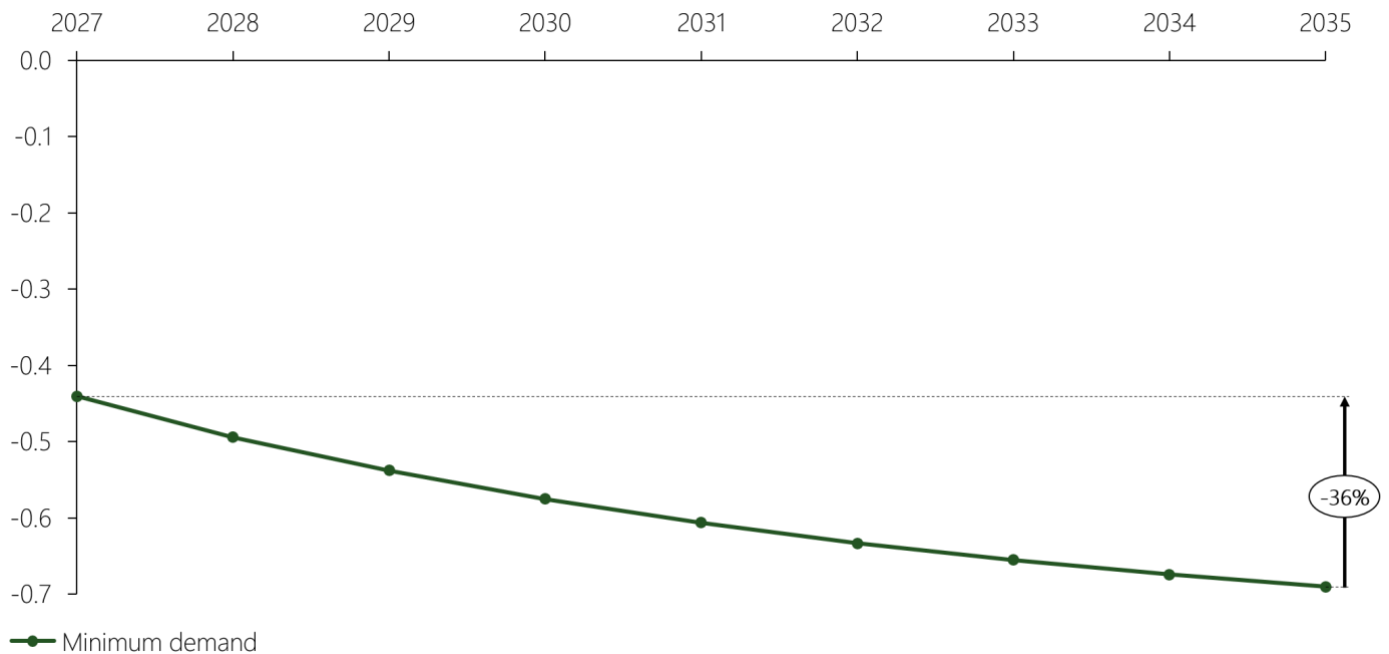
Falling minimum demand

The changing nature of demand is also creating investment needs at the other end of the load profile. Increasing CER penetration is reducing daytime minimum demand, particularly in regional NSW. Lower minimum demand can create voltage-management and other system-security challenges even where annual or peak demand is flat or declining.

Figure 3-15 shows minimum demand across Essential Energy’s Bulk Supply Points becoming progressively more negative through to 2035–36, representing a forecast decline of approximately 36%. This reflects increasing periods in which output from CER exceeds local consumption and electricity flows back from the distribution network into the transmission network.

These deeper reverse flows can make voltage control and secure network operation more challenging, creating a need for targeted investment even where peak demand is flat or declining. Figure 3-16 provides an indicative view of the trend rather than a coincident regional minimum.

Figure 3-15 Forecast minimum demand - Essential Energy Bulk Supply BSPs (GW, 2026/27-2035/36)



Two projects in the base portfolio respond to issues associated with declining minimum demand in the Essential Energy supply area: **Supply to Moree Area** and **Maintaining voltage levels in the North Coast**.

Changing generation flows and power-system characteristics

The transition to renewable generation is changing both the direction and magnitude of power flows across the transmission network. Increasing exports from regional areas contrast with the network's traditional pattern of transferring electricity from large coal-fired generators in the Hunter Valley to Newcastle and Sydney.

These changes are increasing or reversing flows through lines and transformers that historically supplied relatively small loads. Together with growing levels of inverter-connected generation, inverter-based loads and CER, these changing operating conditions are contributing to forecast risks involving voltage unbalance, harmonics, fault levels and other system-security and power-quality requirements. The effects may arise from the aggregation of many changes across the network rather than from a single identifiable source.

Our current base augex portfolio contains five compliance projects, primarily addressing forecast voltage, frequency, impedance and power-quality requirements under the National Electricity Rules. The most material of these projects are outlined in Table 3-7 below:

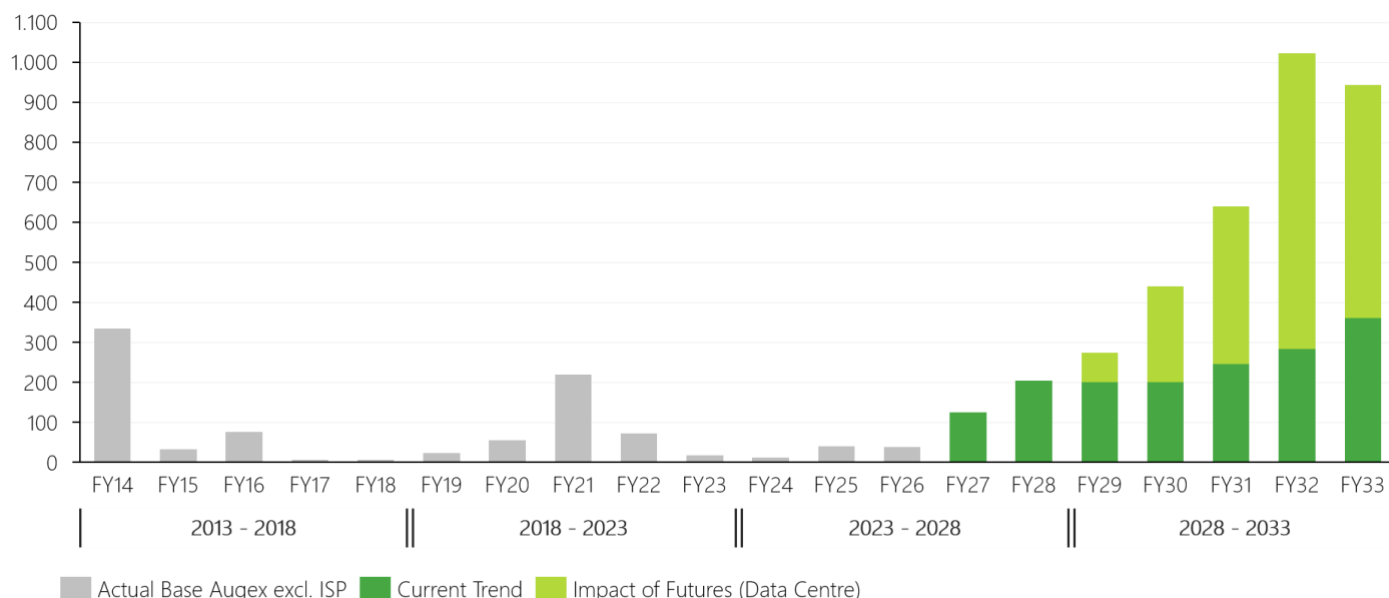
Table 3-7 Large compliance projects in augex forecast (\$m, Real 2027-28)

Project name	Project description	Estimated 2028-33 Capex
Supply to Moree Area	Provides additional voltage support in the Moree area to accommodate forecast demand growth and maintain reliable network performance.	93
Address voltage unbalance and harmonic issues	Remediates power quality issues on the transmission network to ensure compliance with NER and protect network performance and reliability.	98

Overall augex forecast

Following the forecasting, challenge and option-assessment process described above, our current base augex forecast is \$1.2 billion for 2028–33 as shown in Figure 3-16. We note that our forecast may change as we complete option selection and cost development. As this work is completed, projects may be staged, deferred, removed from the program or reclassified as contingent projects before our proposal is finalised.

Figure 3-16 Total augex FY2014 to FY2033 (\$m, Real 2027-28), excl. ISP Projects



Managing uncertainty and protecting consumers

The base forecast and contingent project pipeline provide complementary ways of managing uncertainty. The base forecast contains projects currently expected to be required during 2028–33, while the contingent project mechanism preserves a pathway for credible projects with uncertain needs or costs.

The contingent project pipeline proposed for 2028–33 is larger than in previous regulatory periods, reflecting the unusually high level of uncertainty associated with forecast augmentation needs. The uncertainty is driven by both the scale of forecast demand growth and the concentration of that growth in a small number of locations, particularly in areas experiencing strong data centre development.

We have identified nine potential contingent projects that are excluded from the \$1.2 billion base forecast. Table 3-8 shows the four projects that relate to regional load growth or changes in generation and system conditions, while Table 3-9 shows the five projects driven wholly or partly by potential data centre demand. Excluding data centre related projects, the number of contingent projects is broadly consistent with the number of contingent projects in previous regulatory periods.

These projects represent credible potential needs, but material uncertainty remains over their timing, scope or cost. If the defined trigger occurs, Transgrid may apply to the AER for the associated revenue allowance. Meeting a trigger would not itself authorise investment as a subsequent assessment would still need to confirm the network need, preferred solution and efficient cost.

Table 3-8 Augmentation contingent projects (\$m, Real 2027-28)

Project name	Project description	Estimated capex total all periods
Supply to North West Slopes - Stage 2	Upgrades to lines in the North-West Slopes region to supply demand growth. This project will be required if the Narrabri Gas project becomes committed.	400
Meeting demand growth in Macarthur area	Establishment of a new substation at Appin to supply load growth in Endeavour Energy's network. The project will be required if anticipated residential, commercial and industrial developments in the Macarthur area eventuate with a transmission option selected with the preferred option to address through a joint planning process with Endeavour Energy.	198
Address voltage unbalance and harmonic issues phase 2	Network upgrades to maintain compliance with voltage unbalance and harmonics requirements. This project will be required if an external audit of substation telemetry data at identified high risk sites shows exceedance of NER compliance limits. The underlying cause of an exceedance can be complex, but changes in power flows and increases in the volume of inverter connected loads are key sources of harmonics issues.	594
Managing increased fault levels	Upgrade equipment ratings due to increased fault level at multiple substations. This project will be required if proposed network augmentations, inverter-based resources and synchronous condensers that have been linked to the fault level issue at each site become committed.	321

Data centres have increased the scale and locational uncertainty of potential future demand. There is also additional cost uncertainty related to the data centre reforms discussed in section 1.3.1. The contingent project mechanisms ensure that, if required, we can deliver the projects without requiring these costs to be included in the ex-ante forecast – and customers paying for projects which may not be required.

Table 3-9 Data centre driven contingent projects (\$m, Real 2027-28)

Project name	Project description	Estimated capex total across all periods
Meeting demand growth in Northern Sydney	Establishment of a new Bulk Supply Point at Macquarie Park and associated 330 kV lines to supply load growth in Ausgrid's network. The project will be required if anticipated data centre connections in Macquarie Park enter into connection agreements.	1,018
Meeting demand growth in the Queanbeyan and ACT areas	Establishment of a new Bulk Supply Point at Queanbeyan with associated rebuild of line 977 to supply load growth in EvoEnergy's network. The project will be required if anticipated data centre connections, residential or commercial developments enter into connection agreements.	216

Project name	Project description	Estimated capex total across all periods
Maintaining reliable supply to Regentville	Upgrades to the Regentville substation with a new transformer to supply demand growth in the Western Sydney Region. This project will be required if the data centres, residential and commercial developments in the region become committed.	118
Increasing transfer capacity to the Sydney area	Upgrades to substations in Sydney to supply demand growth. This project will be required if the data centres connections become committed.	638
Meeting demand growth in the Newcastle area	Upgrades to Newcastle substation with an additional transformer and busbar upgrade to supply demand growth. This project will be required if the data centres connections become committed.	94

Next steps

Before finalising our proposal, we will:

- complete the remaining project assessments and outstanding studies to confirm the need, preferred option, delivery timing and cost of each project;
- update the base and contingent forecasts to reflect the outcomes of that work;
- further test the deliverability of the overall portfolio; and
- continue engaging with government, industry and consumers on capacity allocation and equitable cost-recovery arrangements for large new loads.

3.2.3 System security and operability

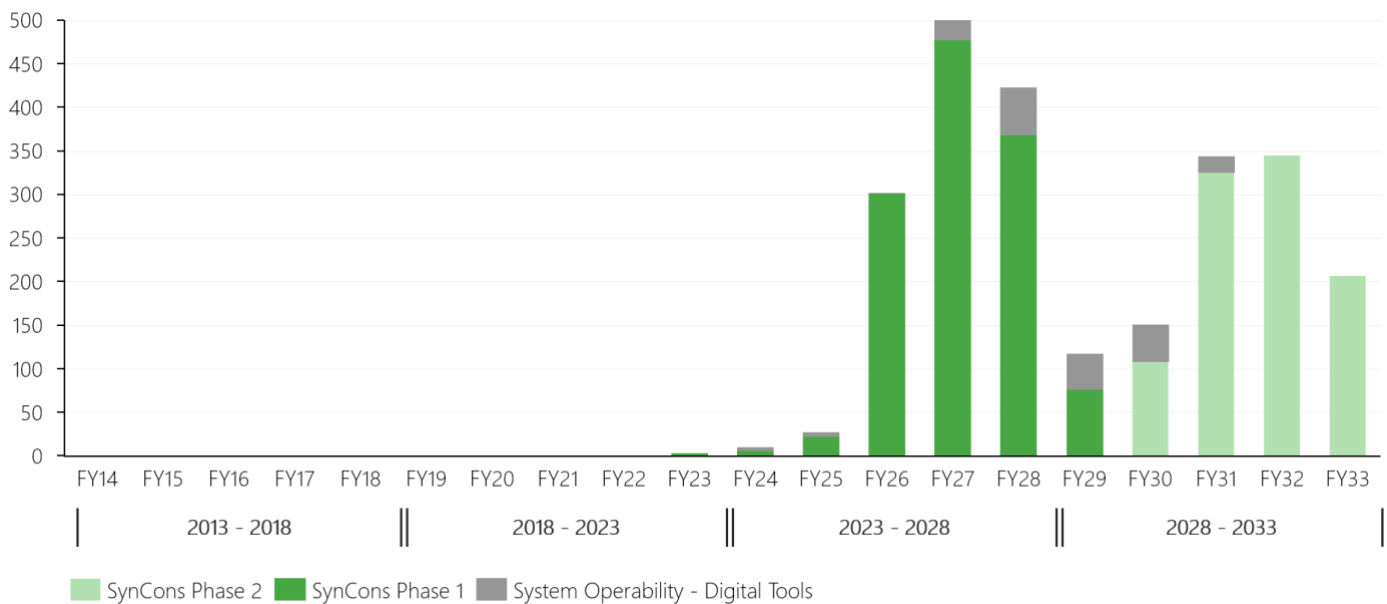
The transition to a renewable, inverter-based power system is fundamentally changing how the transmission network operates. Services that were previously provided inherently by synchronous generation, such as system strength and inertia, are diminishing, while new and more complex system security risks are emerging.

At the same time, the increasing integration of weather dependent inverter-based resources, changes in power flow patterns, and growing interactions between network elements are creating a more dynamic and less predictable operating environment. Ensuring the system remains secure and operable under these conditions requires new forms of investment.

In the current 2023-28 period, given the pressing need to maintain system security as coal generators retire, we have commenced a project to deploy synchronous condensers (SynCons) across 5 Transgrid locations (Phase 1).

This project was declared a Priority Network Infrastructure Project by the NSW Government and is being funded under the EII framework. In addition, we are deploying non-network, operating expenditure solutions. These include signing a non-network support agreement with a NSW hydro generator to provide system strength in synchronous condenser mode, when required by AEMO. We are also evaluating tender responses from up to 2 GW of grid-forming batteries to support system strength in NSW.

Figure 3-17 Identifiable system strength and operability capex FY2014 to FY2033 (\$m, Real 2027-28)



We are also intending, in this current 2023-28 period, to start our System Security Roadmap Operational Technology initiative. This will improve situational awareness in our control room, support real-time decision-making by system operators, avoid reducing the output of lower-cost generation and mitigate the increased risk of emergency outages and disruptions.

We lodged a contingent project application for this initiative in May 2026. The contingent project covers both the opex and capex components of this project across the 2023-28 and 2028-33 periods. The 2028-33 capex related to this project is included in this Draft Plan capex forecast. These costs are shown in the grey bars in Figure 3-17.

System security and operability needs in the 2028-33 period

In the upcoming 2028-33 period, we have considered whether further capital investment is likely to be required – in addition to the procurement of non-network solutions – across three areas. 1) maintaining system security, 2) voltage support as coal retires and 3) ensuring that our control room and system operability capabilities keep pace with increasing system complexity.

The first area of spend relates to system strength. Our initial system strength RIT-T identified the need for the deployment of 5 additional SynCons. Since then, unforeseen changes to factors outside our control have impacted the outcome of our earlier system strength RIT-T assessment, including:

- The anticipated cost of delivering Phase 2 synchronous condensers had increased by more than 30% due to additional supply chain impacts associated with the conflict in the Middle East.
- An expected delay to the delivery of Phase 2 synchronous condensers caused by additional regulatory processes and longer manufacturing lead times.
- Later than expected coal generation replacement outlined in AEMO's 2026 ISP Step Change scenario.

These changes satisfy the NER requirements of a Material Change of Circumstance (MCC) which enable us to reassess and resubmit a report on the optimal solution, taking into account updated information and stakeholder feedback. Given these changes we have reassessed the optimal solution, taking into account updated information and stakeholder feedback. Our updated Major Change in Circumstances report was published in August 2026 and found that the optimal portfolio would include only three SynCons to deliver the largest consumer benefit.

While the driver for these investments is likely to emerge, a defining feature of these investments is that the timing, location and technology solution remain inherently uncertain.

This uncertainty reflects the way system security needs emerge in practice. System strength requirements are updated regularly through AEMO's annual system security assessments, while generator retirement dates, operating behaviours, new generator connections and demand patterns continue to evolve. As a result, system risks and required responses tend to arise progressively, rather than as discrete and predictable events. At the same time, the available solutions, particularly for inverter-based systems and advanced grid-forming technologies, are developing rapidly.

The second area relates to emerging needs, specifically the need to deploy dynamic reactive support and equipment to manage system voltages as coal retires, as well as potential upgrades to protection systems and network controls to ensure they operate correctly under evolving system conditions, including periods of low fault current.

Our preliminary analysis found that these needs would require a project in the order of \$220m to address. However, we have since undertaken additional studies and tested our underpinning assumptions and found that this project can be avoided.

Lastly, we are considering the need to further enhance control room systems and digital tools may become required, beyond our current System Security Roadmap Operational Technology initiative, to provide more advanced predictive capability to further improve situational awareness and support real-time decision-making by system operators as complexity of the network increases. While the cost of this project is not in our current forecast, we are currently preparing a business case and are considering whether to include it in our Revenue Proposal.

Regulatory arrangements for SynCons

We have considered available mechanisms – upfront 'base' capex, contingent projects, cost pass-throughs and regulatory change – to determine which is most appropriate for each element of our 2028-33 system security and operability expenditure.

Including capex in our base forecast requires a level of certainty around scope, timing and location. At this stage, we have not identified any element which is sufficiently certain to be included, given the inherent uncertainty as generation patterns and retirement dates change, technologies develop, and system conditions are updated through ongoing analysis and operational experience. This may change as we continue to develop our Revenue Proposal.

The contingent project pathway allows funding to be provided if specific events or conditions occur. There are several requirements, including that the event or condition must be such that it is all that is required for a contingent project to be triggered and the condition or event must relate to a specific location.

This pathway is suitable for several projects including additional system strength remediation project as well as the synchronous condensers included in our system strength RIT-T (indicative costs for SynCons Phase 2 are shown in Figure 3-17). At this stage, we intend to propose a contingent project for each individual location, consistent with the approach adopted by Powerlink in its Revenue Proposal.

We will also include a contingent project to be triggered if an additional SynCon is required as a result of AEMO changing the minimum fault level requirements or its forecast of inverter-based resources, which could trigger the need for additional SynCons.

While we are intending to include a series of contingent projects for the SynCons Phase 2, we are concerned that the actual cost of funding these projects is higher than the compensation provided in the AER's rate of return instrument (RORI). This creates an investability issue with no clear solution in the regulatory framework.

We will continue to engage with the AER to assess our options, including any flexibility that the AER may have when making a contingent project determination, to improve the investability of these projects. Consistent with our approach for past large projects, we will work with the AER and various government agencies to close this gap through additional support or alternative funding pathways.

Regulatory arrangements for other system security and operability projects

The upfront specification in the contingent project mechanism means that it is not always suitable for other system security projects, such as emerging network needs, especially given that the power system is in a state of constant transition toward an uncertain future state. The challenge is that the need typically arises from a combination of evolving factors rather than being triggered by a single, clearly defined, location-specific event. These factors can interact and progress in ways that are difficult to predict or isolate, with risks only becoming apparent once system conditions collectively deteriorate.

We are concerned that we may need to undertake additional system security projects which are not sufficiently certain to be included in our Revenue Proposal expenditure forecast and do not meet the requirements of the current contingent project requirements in the Rules. For these projects, there are three alternative options.

The first is to include a specific nominated cost pass through event targeted at these kinds of costs. This would allow us to apply to the AER to seek additional funding mid-period if a pre-specified event occurs – which can have fewer constraints than a contingent project trigger event (i.e. not location specific requirement). The AER would then assess whether the event occurred and whether the additional costs (either actual or forecast) were prudent and efficient. While possible under the current rules, this approach is not consistent with regulatory practice. Regulatory precedent for cost pass through events outside the standard set the AER approves is scarce as the AER generally finds that additional events are unnecessary.

The second option would be to seek a Rule Change to allow the separate transitional contingent project mechanism for system security projects (which does not require projects to be probable, location specific etc.) currently in place only for the 2023-28 period, to become a permanent feature of the Rules.

The third option would be to include expenditure in our forecasts if we can be sufficiently certain regarding the need and cost of any particular project.

We are continuing to work through these options as we develop our Revenue Proposal.

CWG feedback and proposed approach

We have engaged the CWG on the challenge we face given the uncertainty around future system security expenditure. The CWG recognised both the importance of these investments for maintaining reliability and the limitations of the current regulatory framework in accommodating them.

The CWG indicated that the contingent project pathway is currently the most fit-for-purpose option, as it allows funding to be linked to emerging system needs while avoiding the need to commit consumers to costs before there is sufficient certainty. The CWG notes the challenges associated with defining a specific location for some contingent projects, where the future need remains uncertain (but will be clarified through a RIT-T process).

Consistent with this feedback and where the requirements of the contingent project framework can be met – in particular where the location and triggering event can be clearly identified – the contingent project pathway is our preferred approach.

Accordingly, we will include contingent projects for additional synchronous condensers anticipated to be required. These projects can be included as the technical solution and location are certain, with uncertainty relating to their timing and need.

This approach also recognises that some of these investments may be progressed through alternative regulatory or policy frameworks, such as the EII framework or a CPA in the current period – which may also be required given the associated investability concerns we have with these projects. We will continue to monitor developments and engage with stakeholders, including government and the AER, and will update our approach should a more appropriate or certain alternative pathway emerge. If an alternative funding pathway emerges then there will be no need to trigger any approved contingent project.

3.2.4 Replacement

As the energy transition is accelerating and demand is growing and changing, our existing network infrastructure is entering a period of increased renewal needs.

Three key trends are driving the need for change in this regulatory period.

- First, asset condition is deteriorating, as evidenced by a growing volume of defects across the network. At the start of the 2028-33 period, 30-40% of our substation and transmission line assets will be beyond their standard lives, while around 50% of shorter-lived digital assets (including substation monitoring, control and automation systems) will be approaching obsolescence.
- Second, operational complexity is increasing as the network is exposed to more frequent and severe weather events, as well as evolving physical and cyber security threats.
- Third, labour and equipment costs have increased significantly. Across the three main asset classes of transmission lines, substations and digital infrastructure, expenditure is forecast to increase in all categories. However, only digital infrastructure is expected to experience a significant increase in asset volumes.

Collectively, these factors are driving an increase in our replacement needs. Our bottom-up assessment has identified around \$3b of economically justified replacement expenditure. However, we have heard consumer concerns around the importance of reliability concerns around resilience and strong feedback on the need to constrain costs.

In response, we have undertaken several iterations of portfolio optimisation across a range of scenarios in order to balance risk, cost, network benefits and asset performance outcomes.

In summary, our Draft Plan includes \$1.9 b of replacement expenditure, up from \$1.1b this period. This is around 38% below our bottom-up assessment and is designed to broadly maintain network risk at current levels while constraining costs to consumers.

Our transmission network is made up of 14,314 km of high-voltage overhead lines and underground cables, 98 substations and thousands of digital assets. These assets will not operate indefinitely. Over time asset condition deteriorates leading to reduced performance, increasing defects and increasing the risks borne by the community, including reliability, bushfire, safety, and long-term costs.

The objective of our replacement program is to mitigate these risks by replacing assets (or taking other action) to ensure we can continue to comply with our regulatory obligations, maintain the quality, reliability and security of supply, and maintain the safety of the transmission system.

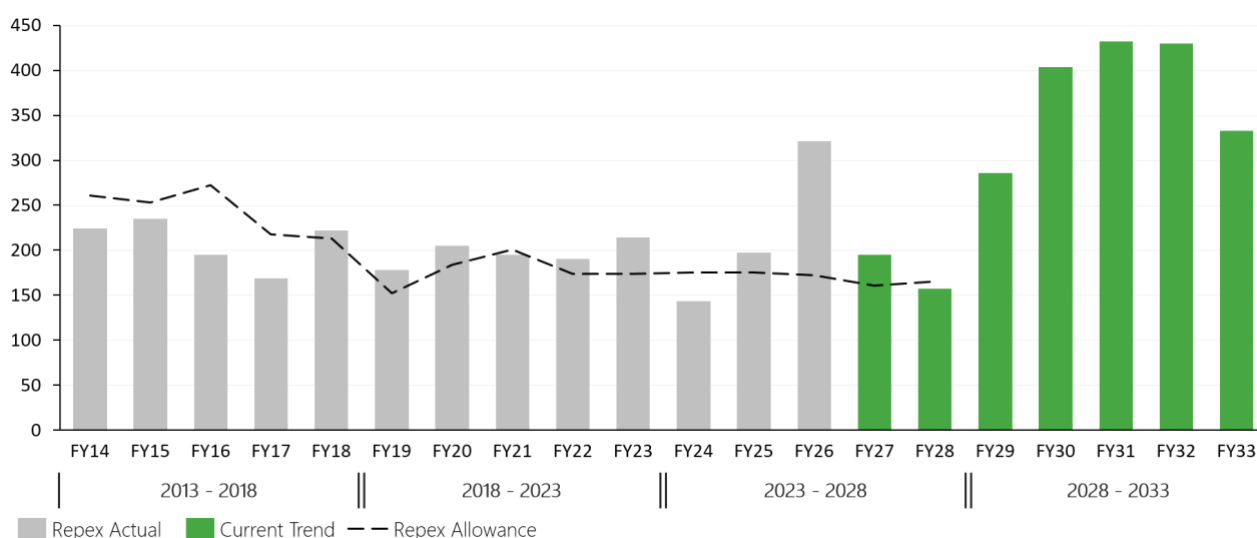
Most of our existing network was constructed between the 1950s and 1980s. We are now entering a period where a higher number of assets are operating beyond their design life, with an increasing likelihood of performance degradation and higher levels of risk.

Taking into account the outcomes of our economic risk analysis, consumer views, guidance from the CWG, our preliminary deliverability assessment, and longer-term implications of the 2028-33 portfolio, our Draft Plan is to deliver a portfolio of projects that broadly maintains the level of risk we expect at the end of the current 2023-28 period.

Keeping risk at this level, given the age and condition of our network, will require an increase in replacement expenditure to \$1.9b (up from \$1.1b) over the 2028-33 period. This program will deliver consumers at least \$6.4b in avoided risk costs, primarily by halting the growth in reliability, bushfire and safety risks.

While this program requires an uplift in expenditure, it is below the level identified through our bottom-up economic risk analysis. In developing our Draft Plan, we have balanced the benefits of further reducing risk against customer feedback on affordability and the need to constrain expenditure. The trade-off from this lower level of expenditure is that we do not reduce the increase in risk that has occurred over the current period. Instead, we forecast risk to marginally increase around 8% above 2018-23 levels.

Figure 3-18 Replacement Expenditure FY2014 to FY2033 excl. overheads (\$m, Real 2027-28)



How consumer feedback has shaped the program

We have presented this forecast and earlier versions to the CWG along with a number of case studies across the program to provide a detailed view of how we consider and forecast repex requirements. The feedback received to date has been focused on:

- **Clarifying the exercise of judgement:** the CWG recognise that much of the repex program is driven by compliance and reliability obligations but have requested greater clarity on the extent to which expenditure is mandated versus discretionary, and how Transgrid determines when investment is required.
- **Detailing the status quo:** the CWG wish to better understand the asset management practices used to maximise utilisation of existing assets and the justification for any increase in replacement volumes or costs. While recognising industry-wide cost pressures, they have also sought greater insight into whether current inflationary pressures are expected to persist and how this affects investment timing.
- **Applying constraint:** The CWG have consistently emphasised the importance of cost discipline. They expect project-level testing of options such as deferral, descoping and non-replacement, supported by a top-down challenge of the overall program through prioritisation and deliverability constraints.
- **Demonstrating risk and consumer outcomes:** The CWG have also sought greater transparency regarding the relationship between expenditure, asset condition and risk outcomes, including maintaining network risk broadly in line with the position approved by the AER in the current 2023-28 period, and stronger evidence that replacement, resilience, renewal and deferral options have been robustly assessed before investment is proposed.

This CWG feedback has directly informed both the content of this Draft Plan and the further analysis, business cases and supporting materials being developed for the Revenue Proposal.

Asset level needs analysis: an economic-risk based approach

Over time, asset condition and performance deteriorates and the risks associated with continued operation can increase due to a variety of factors. These include asset condition degradation (due to thermal ageing, electrical stress, moisture ingress, corrosion, coastal exposure and mechanical wear and fatigue), type issues (known defects for a particular asset), changes to operational conditions and needs (e.g. increased cyber security threats and changes to power flows) as well as obsolescence and declining vendor support.

Each asset is designed and is largely capable of withstanding these pressures for a period giving rise to a standard design or technical life. This can range from about 35-70 years for transmission lines, 30-50 years for substation equipment or shorter periods for digital assets. The design life depends on the individual component (e.g. wood poles don't last as long as steel towers), operating conditions and environmental factors.

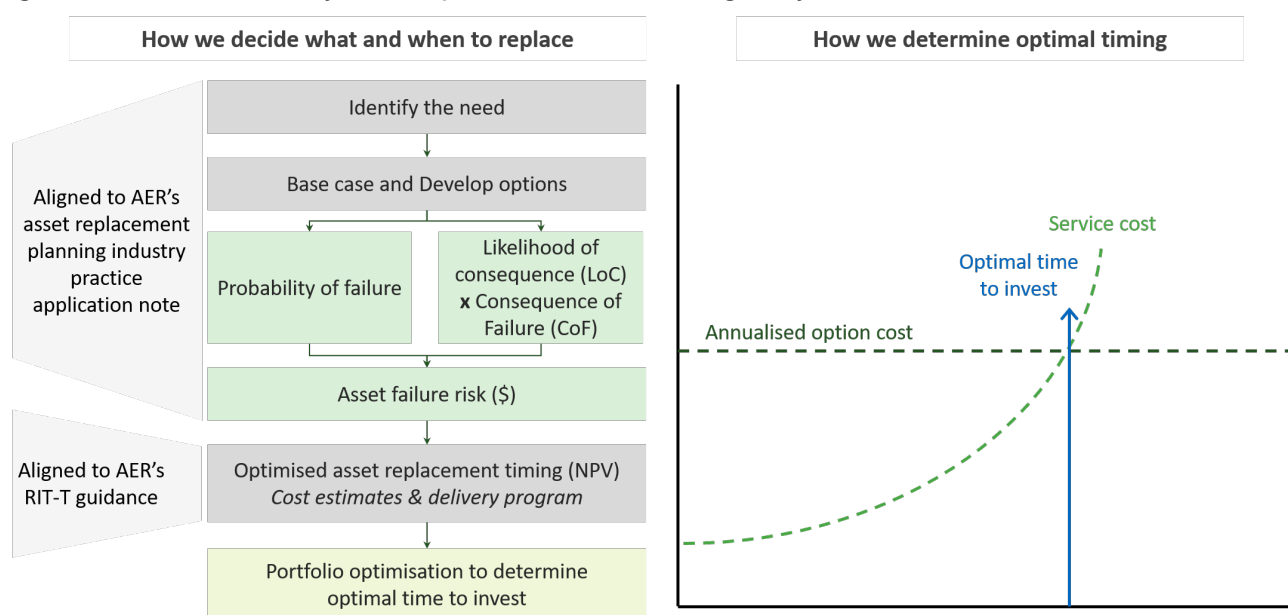
We don't replace assets based on age or whether they are operating past their design life. Instead, we monitor their performance informed by asset condition information and failure data. We continue to operate assets past their design life where there is no expected material reduction in performance or material increase in risk.

Where we expect to see an increase in risk, in terms of unreliability, safety, long-term costs etc., we quantify this risk by calculating:

- **The probability of failure** – which is determined by a health index applied to each asset class. These indices reflect condition data, defects and failure history, stress/usage, type issues and environmental factors.
- **The consequence of failure** – this represents the economic value (cost) of the identified detrimental outcomes to consumers and the community. This also assesses the potential impact and the likelihood that an asset failure will lead to that impact. We apply economic assumptions such as the AER's Value of Customer Reliability, which reflects the value consumers place on avoiding interruptions to supply, and the Value of Statistical Life published by the Australian Government.

We then compare this quantified risk borne by consumers and the community with the cost of mitigating that risk, which is ultimately recovered from consumers through tariffs. For each technically feasible option, we compare its economic costs and benefits to determine the most economic intervention and its optimal timing.

Figure 3-19 Asset level analysis: risk quantification and timing analysis



In a small number of cases, continued operation of an asset would no longer meet our regulatory obligations and technical standards. In these cases, our analysis is focused on identifying the lowest cost option to comply with our obligations, and the most reasonably practicable time to implement the option.

Our approach is consistent with the AER's Industry practice application note on asset replacement planning (which defines the principles and process for asset risk modelling and replacement planning) as well as our Network Asset Strategy, our ISO 55001 certified Asset Management system along with our Electrical Network Safety Management System (aligned with AS 5577 and ISO 31000).

We have made several changes to our approach to asset level analysis. This includes addressing themes identified from our 2023-28 revenue determination process (as outlined in Table 3-10). Further, based on CWG and AER feedback, we have also refined our options analysis to ensure we explore all feasible options (including the base case, additional maintenance and non-network options) not just those which address the identified need.

We have also applied a 4.9% WACC and 7% discount rate in comparing costs and benefits, compared with the 2026 ISP of 3% WACC and 7% discount. Applying this rate (rather than the regulated WACC typically applied by distribution networks) provides a conservative test of replacement expenditure because it places less weight on risk-reduction benefits that occur further into the future. We also acknowledge that we may need to align this assessment with the 2026 ISP in our preliminary proposal.

Table 3-10 Updates to our replacement expenditure forecasting approach

Themes from 2023-28 Determination	Updated approach
Improve clarity on risk methodology for asset replacements	Update Network Risk Assessment Methodology to be clearer and easier to interpret, including source and development of inputs to calculations
Application of disproportionality factors in risk modelling	Simplify calculations to apply these factors only to the safety component of risk
Demonstrate top-down network performance and risk aligns with bottom-up forecast	Present whole-of-network risk profile and calibrate with network performance
Review portfolio sensitivity to global factors, e.g. unit rates, discount rate	Develop scenario based repex portfolios and include sensitivity analysis in business cases
Additional evidence to justify operational avoided cost in business cases	Provide observed evidence along with a sensitivity analysis in business cases
Some investments have optimal timing sensitive to changes	Include optimal timing sensitivity analysis and justification in business cases
Compliance based investments not supported by adequate quantitative cost/benefit analysis	Include cost/benefit analysis in business cases and demonstrate economic net benefit
Demonstrate total capex package is suitable in addition to assessment of individual projects	Top-down analysis to be tested with bottom-up analysis

Replacement portfolio optimisation

Our bottom-up analysis results in a program in the order of \$2.5bn to \$3bn. This program reflects the value consumers place on reliability through assumptions such as the VCR, is supported by robust, quantitative economic analysis and developed with a risk-based methodology consistent with AER guidelines.

However, given the uplift in expenditure required, we have undertaken additional consideration and analysis. We have not applied a ‘mechanical’ approach where all economic projects are automatically included in our expenditure forecast.

Our top-down analysis has taken into account consumer views – who have told us that a reliable supply of electricity is a fundamental expectation for consumers and remains a high priority – as well as guidance from the CWG that they expect Transgrid to exercise discipline by actively constraining costs and demonstrating restraint wherever possible to put downward pressure on costs.

Our takeaway from this feedback is that we need to develop a replacement program that balances the need to manage network risk with the need to constrain the costs consumers pay through tariffs.

To do this, we have first considered how the aggregate level of risk is changing across periods. To evaluate programs at the portfolio level, we have developed a risk index that aggregates the residual quantified risk. A value of 1 represents the level of risk borne by the consumers and the community in 2018-19, allowing us to compare how aggregate risk changes over time under different expenditure scenarios. Over the 2018-23 period the level of risk held steady. We had planned to maintain the overall level of risk in the 2023-28 period; however, due to substantial increases in input costs and a lower expenditure allowance than proposed meant we reduced the scope of our program and deferred some investment to 2028-33.

We absorbed part of the impact of these higher costs by spending above our repex allowance by \$164m and, as a result, incurring a \$49m CESS penalty (repex overspend component only). By spending above the allowance, we limited the increase in risk to 8%. The resulting level of residual risk is equivalent to around \$700m in annual expected risk costs.

Figure 3-20 Risk index – historical and forecast (base year FY19)

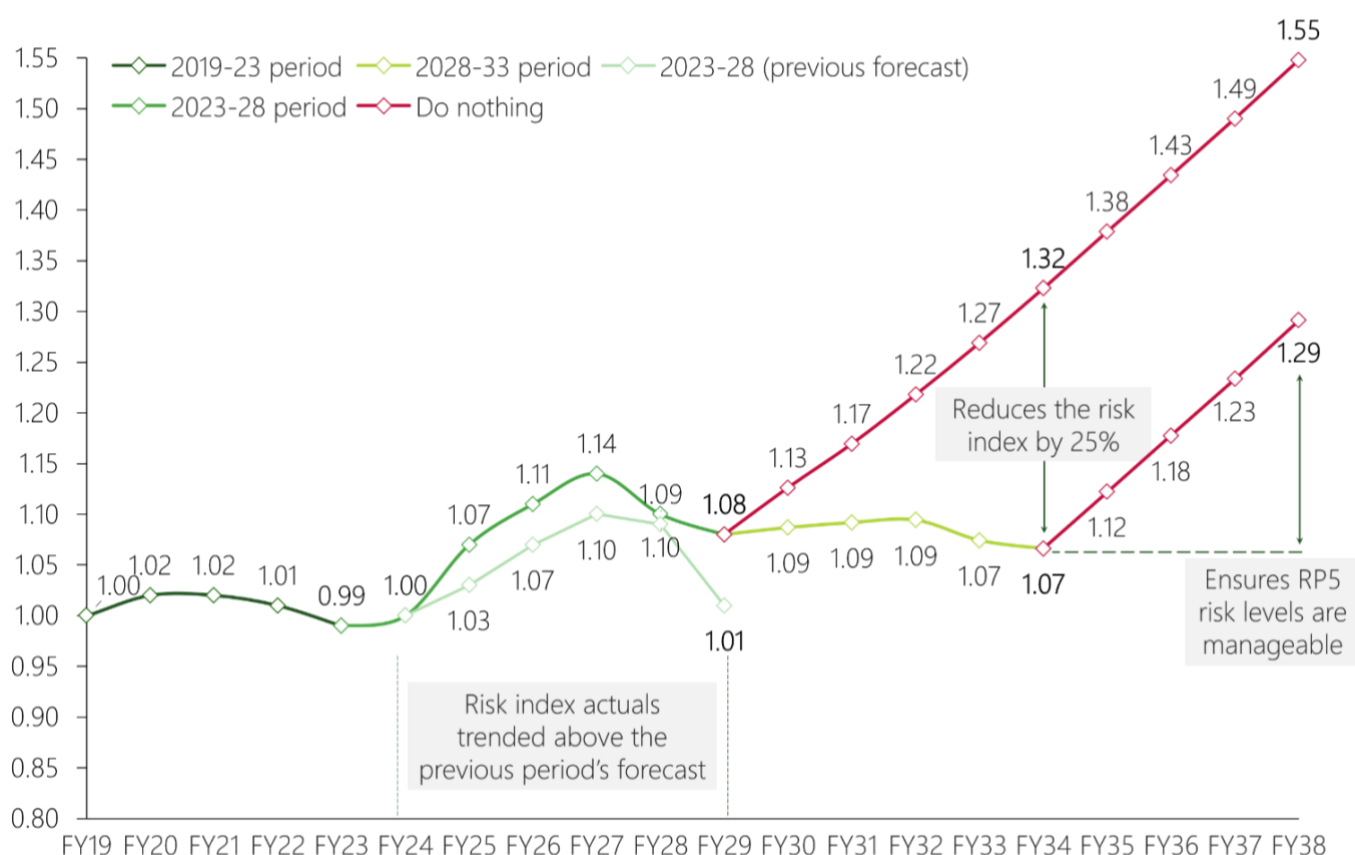


Figure 3 20 also shows how risk will change in both the 2028-33 and 2033-38 periods with no replacement expenditure. It illustrates how continued investment is required to mitigate growing risk. If we let risk rise, it will require a larger program in the subsequent 2033-38 period to arrest further increases and reduce risk back down towards previous levels.

We have identified a program that maintains risk at the level we anticipate we will achieve by the end of the 2023-28 period. This is 8% higher than 2018-19 levels and does not seek to reduce the increase in risk seen over the current 2023-28 period. As outlined in section 3.4, this program – in conjunction with the remainder of our Draft Plan – results in a small increase in consumer bills and, as outlined in the Overview section, is deliverable.

We consider that this level of investment achieves the twin objectives of managing risk while constraining expenditure and its impact on consumers. In our iterative portfolio development, we also considered alternative portfolios that further reduced risk below forecast FY2034 levels, but these were not adopted as our Base given the balanced consideration of cost and consumer impact.

To reduce expenditure relative to our bottom-up portfolio while keeping aggregate risk broadly stable, we have reduced the size of some programs (conductor and power transformer and reactive plant) and removed others. All resilience investment was removed (other than Line X2 Strengthening, shown in Case study 3 1 below), as was the mobile spare

transformer strategy. These specific program decisions were based on the key considerations outlined above, including the balance of risk, demonstrating cost constraint and enacting specific consumer feedback as appropriate.

The CWG have noted that our outturn reliability and compliance performance to date, which they suggest implies there is a risk buffer to draw down on, and asked how we are sure that we have got the balance right between on managing risk, cost and meeting customer expectations.

We intend to continue to consider how we get the balance right on the central trade-off between risk and cost – and will further engage the CWG on this topic. One complication is that risk reflects the expected costs to the community and consumers rather than the outturn costs or service levels that actually arise. While over the longer term outturn service levels and risk levels will align this will not always be the case in the short-term, particularly when risk is driven by low probability high consequence events. This means that while outturn performance is a good reasonableness cross check, current performance is not a good indication of future customer outcomes, especially in the context of assets increasingly being operated beyond their design life.

Case study 3-1 – Resilience: Line X2 Strengthening

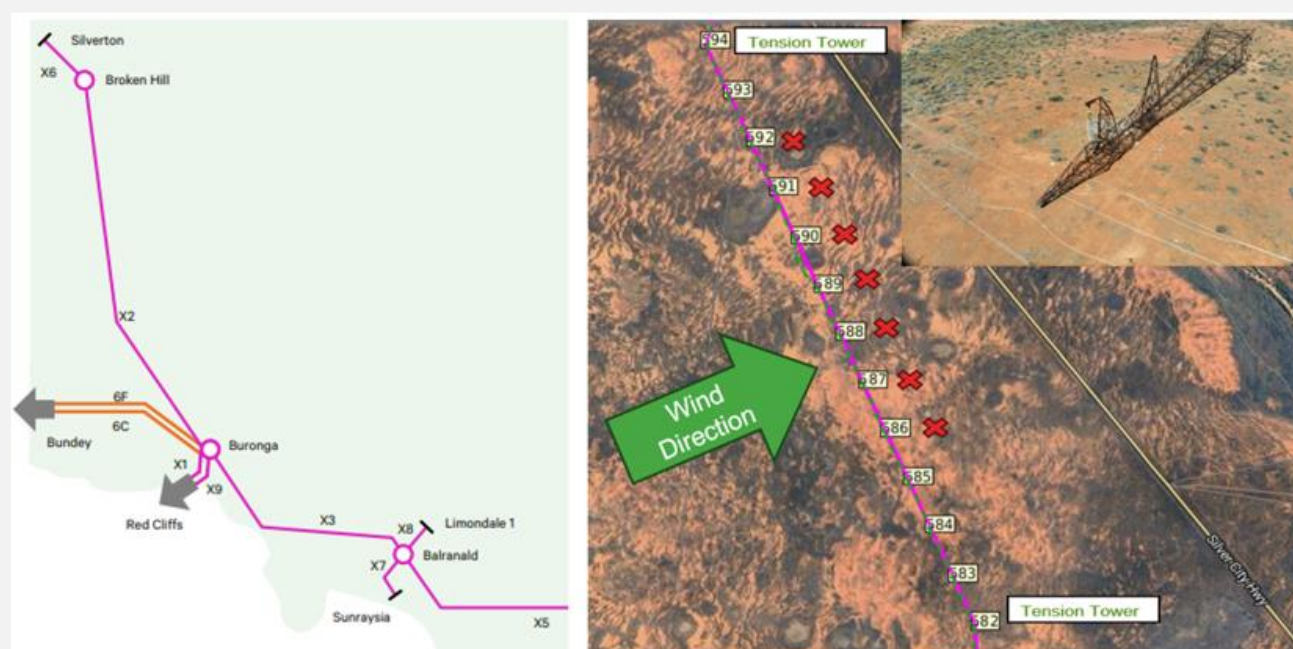
Our network is exposed to increasingly severe and frequent weather events where things like storms, high winds and bushfires increase the risk of low probability, high consequence events occurring.

Line X2 is the sole transmission supply to the Broken Hill region, serving around 18,000 residents, critical services and mining operations. There is no back-up transmission line, but instead, two diesel-fuelled gas turbine generators.

Built in 1978, the line operates in one of the most severe weather environments on Transgrid's network and has experienced two major storm-related collapses in the last 20 years, most recently in October 2024 when seven towers failed and the region relied on local generation for 14 days. Analysis indicates an expected line failure approximately every 20 years, with each major failure costing around \$25 million to restore.

Transgrid proposes strengthening 609 of the highest-risk structures to withstand higher wind speeds. This targeted \$174.2 million investment would significantly reduce the likelihood of major weather-related failures, enhancing reliability and resilience for Broken Hill customers while avoiding costly emerging restorations and delivering a net benefit to consumers.

Figure 3-21 Line X2 location



Program detail

We divide our program into three parts: 1) asset condition and obsolescence 2) cyber operational technology and 3) resilience.

As outlined above, we are forecasting to increase spending in asset condition and obsolescence – largely due to the age and condition of our assets – as well as incurring expenditure in new areas related to resilience and strengthening our operational technology from increasing cyber threats.

Table 3-11 Replacement expenditure by driver excl. overheads (\$m, Real 2027-28)

Driver		2023-28	2028-33
Asset condition and obsolescence	Transmission lines	456	526
	Substations	190	540
	Digital infrastructure	366	645
Resilience: Line X2 Strengthening			174
Total		1,012	1,885

We are also planning on responding to the increasingly sophisticated cyber and physical security threats by improving the security of our network. These programs cover only network assets that support Operational Technology (OT) systems and the physical security of transmission sites, including substations, switching stations, and communications repeater sites. Separate programs address risks associated with ICT systems and non-network facilities, such as depots.

For the security-related expenditure forecast for the 2028–33 regulatory period, Transgrid has assessed its current cyber security capability, maturity gaps and evolving threat exposure across a range of credible investment options. The assessment considers Transgrid’s critical role in the NEM, its obligations under the SOCI Act and other applicable requirements, and the potential consequences for consumers and network operations if its critical systems were compromised.

The proposed investment represents the prudent and efficient option for maintaining cyber risk within Transgrid’s tolerance as the threat landscape and attack surface evolve. It would enable Transgrid to achieve and sustain AESCSF V2 Security Profile 3 maturity for the relevant OT environments and position its controls to align with the emerging direction of ASD guidance for operational technology.

3.2.5 ICT

Over the last 10 years we have overhauled and replaced many of our legacy core platforms. Our focus for the 2028–33 period is to make better use of the foundations already put in place before building more, while maintaining existing capability, and continuing to strengthen our cyber security defences.

We are forecasting ICT (excluding cyber security) capital expenditure of \$109m, \$26m less than the \$136m we incurred in the current period. We will focus on using making better use of our existing platforms, while undertaking targeted lifecycle, application, data, infrastructure, end-user and customer engagement work needed to maintain service capability.

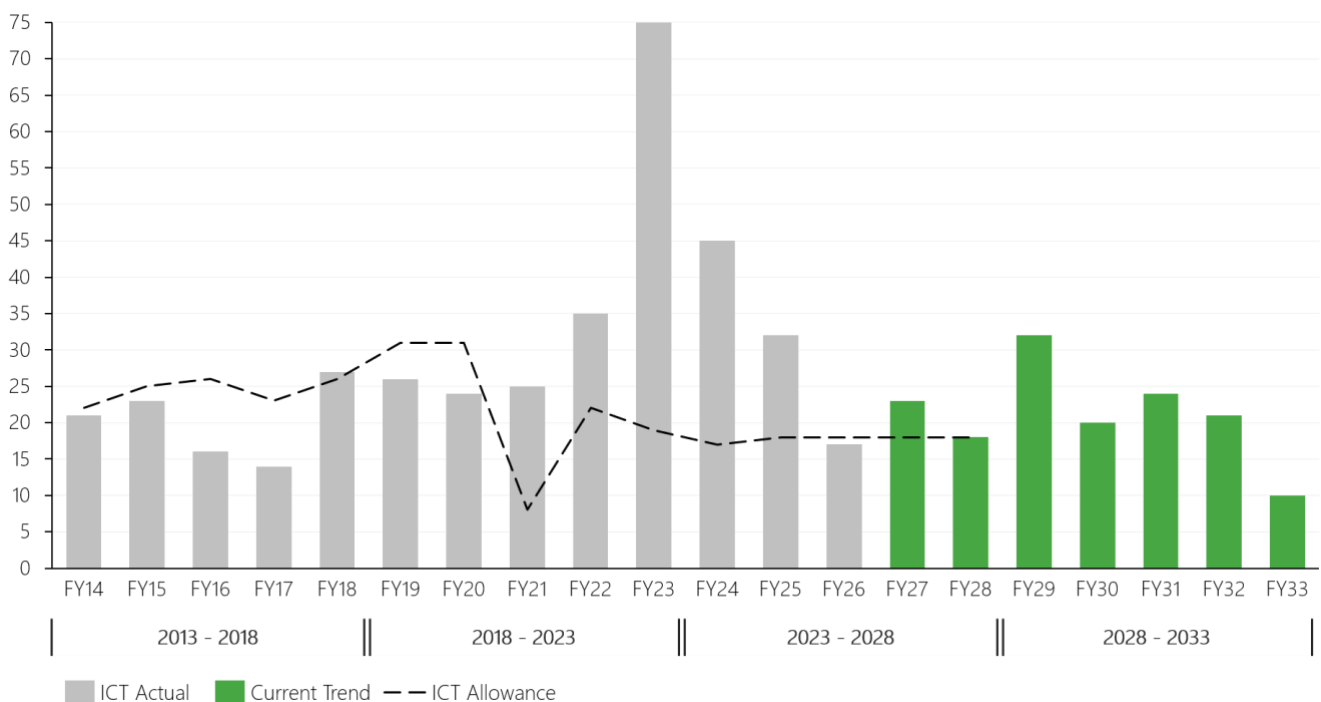
The reduction in capital spend also reflects the market-wide shift away from owned on-premise infrastructure towards externally provided solutions, such as cloud services, software subscriptions and managed services. These costs are treated as operating rather than capital expenditure. Given this capital-operating expenditure substitution we are also forecasting an ICT operating expenditure step change of \$38.1m.

Our ICT systems and platforms support the safe, reliable and secure delivery of transmission services. They enable us to operate and maintain the network, support our workforce and provide accurate and trusted information for planning and decision making.

The current regulatory period represented the peak of our technology transformation. We replaced or replatformed many of our core enterprise applications and supporting infrastructure, moving away from a fragmented mix of legacy and bespoke systems. By the beginning of 2028–33, much of this foundation will be in place.

We are forecasting lower ICT capital expenditure, with our program focused primarily on maintaining and making better use of the capability established through the current period. This is also consistent with consumer and stakeholder feedback to constrain costs. The reduction in ICT capex is shown in Figure 3-22.

Figure 3-22 ICT capital expenditure (excluding cyber) FY2014 to FY2033 excl. overheads (\$m, Real 2027-28)



Note: ICT cyber security is excluded from the 2023-28 and 2028-33 periods.

While our core platforms and systems are stable, looking ahead we expect substantial changes to both the operating environment and the kind of support our systems and platforms need to provide. In particular:

- an increasingly complex operating environment for the business as we provide new services (such as system strength), interact with a more complex generation environment and meet rapidly growing demand;
- a larger network, workforce and delivery ecosystem, which will continue to grow in line with our capital expenditure program, increasing demand for secure access, devices, licences, connectivity and support;
- greater requirements for integration between corporate systems, operational technology, field devices, suppliers and delivery partners;
- increasing volumes of data and greater reliance on digital systems in network planning, delivery, maintenance and operations;
- continued changes in the technology market, including cloud services, automation and artificial intelligence; and
- ongoing structural change in how ICT services are delivered from owned on-premise solutions towards cloud services, software subscriptions and managed services.

In developing our plans for the upcoming 2028-33 period we have considered consumer and stakeholder feedback, in particular, the importance of constraining expenditure while maintaining reliability. We have also considered more specific stakeholder feedback, such as feedback from landholders and communities about how we can improve our ongoing engagement.

We applied this feedback in developing each of our five ICT portfolios. We identified, tested, removed, de-scoped, consolidated and removed initiatives, reducing our initial list of 134 initiatives to 82, and developed strategic options for each portfolio.

Our preferred portfolio plans broadly focus on maintaining existing capability rather than undertaking a further major uplift in ICT capability. We will undertake lifecycle replacement, address obsolescence and supportability issues and ensure that our existing systems continue to provide the services on which our business, and, in turn, our consumers and the wider community, rely.

We considered a broader range of options at both the portfolio and initiative level. At the portfolio level this includes whether to extend the life of existing assets or implementing enterprise-wide platform consolidation. The analysis concluded that the preferred approach is to defer large-scale consolidation in the current period and focus on maximising the value, capability uplift, and return on investment from the organisation's core platforms before pursuing further consolidation opportunities. We are, however, positioning for consolidation in the 2033-38 period, as it could improve efficiency, reliability, interoperability and functionality – and therefore consumer outcomes – over the longer term.

Over 2028–33, our ICT investment will focus on five key areas:

- **End-user computing** – Continue to provide secure, reliable and fit-for-purpose technology for employees, contractors and delivery partners working across offices, sites and field environments. Expenditure will increase with the larger number of devices, licences and collaboration tools needed to support our growing workforce and delivery ecosystem.
- **Infrastructure and networks** – Maintain resilient, secure and scalable infrastructure and connectivity, including lifecycle refresh, monitoring, backup and disaster-recovery capability. We will undertake required lifecycle refreshes and improve system resilience through enhanced observability, backup and disaster-recovery capability. This will lower the risk of technology failures interrupting services and support faster recovery when incidents occur.
- **Applications** – Expenditure in this portfolio will fall significantly, reflecting the completion of our core transformation in the current period. We will focus on simplifying and modernising our application environment by making greater use of our core platforms, consolidating applications and retiring residual bespoke systems where efficient. This will reduce application complexity and improve process reliability and supportability.
- **Data and decisioning** – We will maintain appropriate data governance and increase capacity to accommodate growth in data volumes. This will support better reporting, asset insights and analytics, improving decision making as the scale and complexity of the network grows. Expenditure in this area is broadly steady across periods.
- **Customer engagement** – We will scale an integrated access-controlled engagement capability to support engagement with customers, landholders and local communities. This will support more transparent engagement, better tracking of commitments and improved privacy controls to help maintain the social licence required to operate across our large network footprint.

Table 3-12 sets out our forecast project spend across the 2023-28 and 2028-33 periods by portfolio. We set out both capital expenditure and project operating expenditure to provide transparency over the changing way ICT capability is delivered.

Historically, most ICT project spend was capital expenditure as we deployed and replaced ICT systems and platforms that we owned. Increasingly we are implementing services and platforms we do not own, including cloud, software and other managed solutions. The cost of implementing these solutions is treated as operating expenditure.

Table 3-12 ICT portfolio project expenditure

Portfolio	2023-28			2028-33		
	Capex	Opex	Total	Capex	Opex	Total
End User Computing	27	5	32	40	0	40
Infrastructure and Networks	20	1	21	24	1	25
Applications	79	31	110	25	4	29
Data and Decisioning	8	1	9	12	1	13
Customer Engagement	2	3	5	8	1	9
Total project expenditure	136	41	177	109	7	116

While the regulatory framework treats capital and operating expenditure differently, we have developed both our capital and operating expenditure forecasts using a total expenditure approach.

For each ICT portfolio, we developed a bottom-up build of forecast costs. Each cost element is identified as either capex or opex, project or ongoing, and recurrent or non-recurrent spend. The capital element of this forecast flows directly into our ICT capital expenditure forecast.

The approach is different for operating expenditure, given the top-down nature of the AER's base-step-trend forecasting approach. We have therefore:

- Compared our bottom-up build of ICT operating costs with the top-down forecast produced using the base-step - trend approach outlined in section 3.3.
- Identified incremental costs that are not already captured through the base year or trend and which may appropriately be treated as step changes. These relate to either:
 - a capex-opex substitution, where an opex-based service is replacing an alternative that would historically have been delivered through capital expenditure; or
 - new requirements arising from regulatory obligations or other external factors outside our control.

We have found that our ICT operating expenditure requirements are higher than the base-trend forecast. While we are forecasting project operating expenditure – the costs to implement new systems – to fall, this is offset by an increase in ongoing recurrent costs to operate and support the systems implemented in the upcoming period, including cloud services, software subscriptions and managed services.

After accounting for costs already captured through the base year and trend allowance, we have identified \$38.1m of incremental ICT operating expenditure that meets the AER's step-change criteria.

Given that we are forecasting a capital expenditure reduction of \$26m and a step change of \$38.1m, these two movements result in a net increase of \$12.1m relative to the current-period expenditure. We will continue to engage with the CWG on this forecast, current period performance and addressing whether the program contains any overlap with major project funding pathways (the latter in particular with respect to community engagement programs).

3.2.6 Cyber security

The cyber threat environment continues to evolve, increasing the importance of protecting both our corporate IT systems and the operational technology used to monitor and control the transmission network.

Over the current period we have seen malware-free (sophisticated) attacks up from 51% (2020) to 82% (2025), tracked adversaries up from 149 to 281, and eCrime break time down 70% from 98 to 29 minutes (fastest was 27 seconds). We are also seeing AI increasing cyber phishing attacks with a 1,200% surge (2025) since the rise of gen AI in late 2022.

Over 2028–33 we will improve our resilience against cyber threats. We will do this by strengthening our cyber security capability across protection, detection, response and recovery, including for operational technology, control systems, SCADA, remote access and connections with third parties.

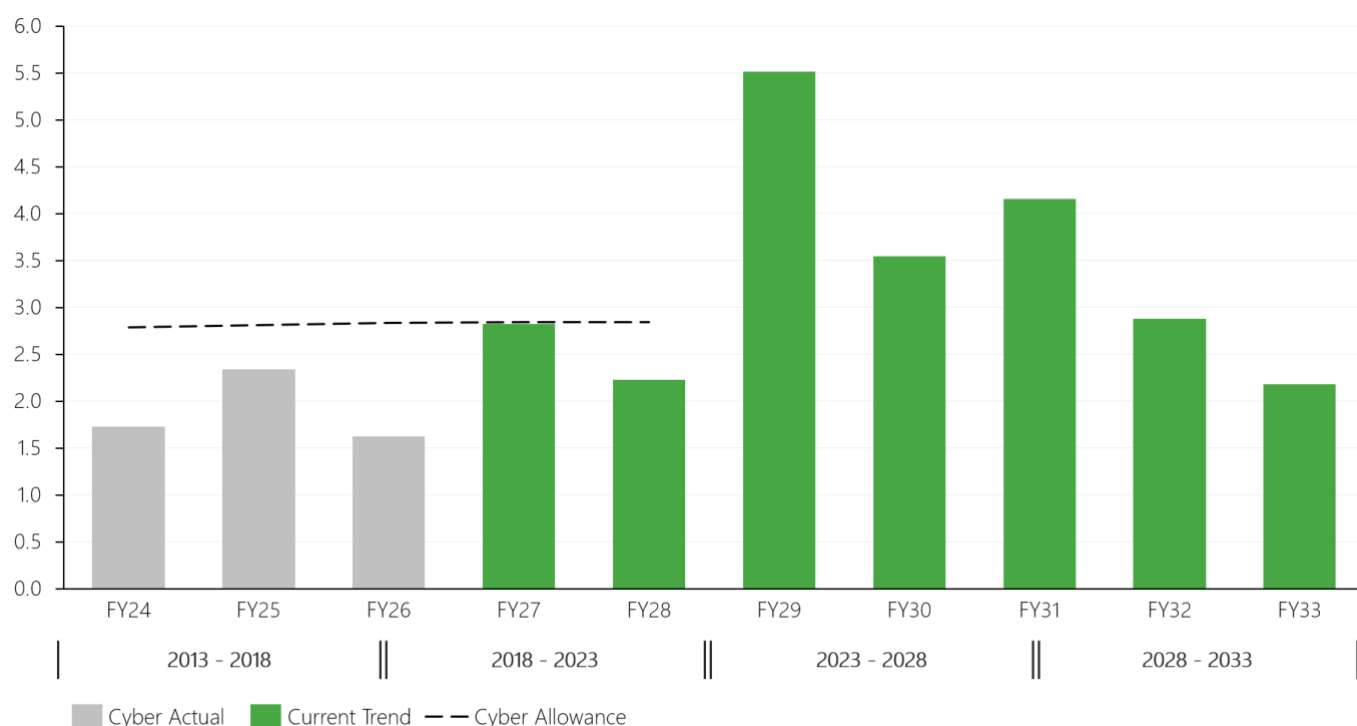
To ensure we exercise cost constraint, we are proposing to adopt a proportionate and risk-based approach focused on addressing identified capability gaps, material risks and evolving critical infrastructure obligations.

We are forecasting to increase ICT cyber security capital expenditure from \$10m in the current period to \$18m as well as a \$31.4 million cyber security step change across ICT and operational technology to maintain the ongoing capability needed to protect nationally significant transmission infrastructure.

Cyber security is critical to the safe, reliable and secure operation of the transmission network. Our cyber security capability protects both our corporate IT environment and the operational technology used to monitor and control the network, including control systems, SCADA, remote access and connections with suppliers and other critical infrastructure.

The cyber threat environment continues to evolve. At the same time, our increasing reliance on digital systems, greater connectivity between corporate and operational technology environments and increased use of third-party technology providers are increasing the potential exposure and consequences of a cyber incident. We also need to continue responding to evolving critical infrastructure and cyber security obligations, including relevant requirements under the Security of Critical Infrastructure framework.

Figure 3-23 Cyber expenditure FY2014 to FY2033 excl. overheads (\$m, Real 2027-28)



Note: Does not include Operational Technology cyber security which is included in replacement expenditure. Cyber ICT cyber security costs over the 2013 – 2023 period has not been excluded from broader ICT costs.

Over the 2028-33 period, we intend to maintain a proportionate, risk-based level of cyber security capability. Our objective is not to pursue unconstrained improvements in cyber capability, but to address identified capability gaps and material risks and maintain the protection appropriate for nationally significant transmission infrastructure.

This includes investment across both ICT and operational technology. For ICT cyber security, we are forecasting \$18m of capital expenditure in 2028-33 compared with \$10m in the current period. This increase reflects targeted investment required to strengthen our cyber security capability across our ICT environment. A component of our replacement program is also driven by the need to strengthen Operational Technology cyber security. This investment spans both ICT and Operational Technology (OT) environments.

Strengthening cyber security across the ICT environment reduces the overall attack surface available to threat actors, thereby helping to protect the operational systems and reducing the risk of threats impacting critical network operations. Similarly, OT cyber investment is necessary to maintain security of our operational technology environment.

In addition to this capital expenditure, maintaining the required cyber security capability increasingly requires ongoing operating expenditure. We are therefore proposing a \$31.4 million cyber security opex step change across ICT and operational technology over the 2028-33 period.

The combination of capital and operating expenditure is intended to reduce both the likelihood and consequences of cyber compromise, including the potential for disruption to transmission services, increased recovery costs and failure to meet relevant regulatory obligations.

In developing the program, we have considered the capability we already have in place, identified gaps and risks, and the alternative ways those risks could be addressed. Consistent with our broader approach to ICT, we have sought to avoid duplication with existing capabilities and focus expenditure on areas where additional investment is required to maintain an appropriate level of protection.

3.2.7 Property

After a period of relatively low spend our workplaces now require refurbishment to address deterioration and ensure they remain safe, compliant and fit-for-purpose. We also intend to undertake targeted works to address identified physical security vulnerabilities.

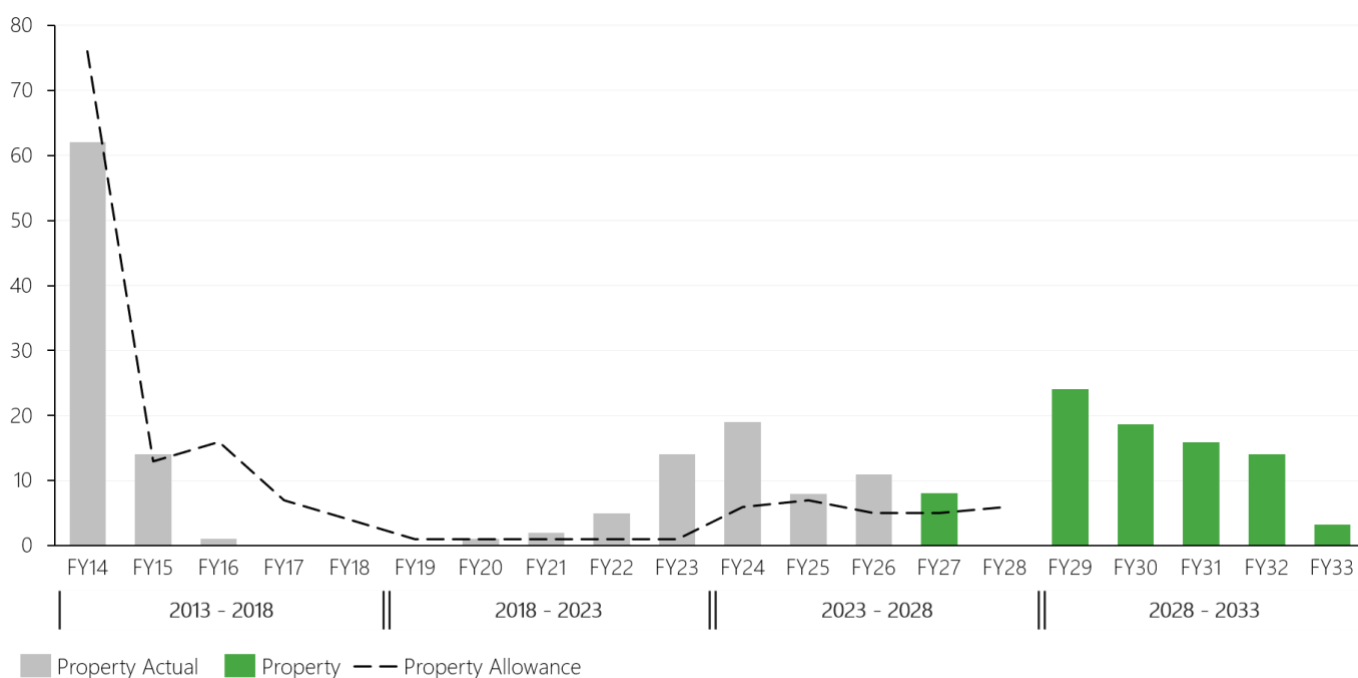
We will also establish new high-voltage regional field training hubs which will remove the primary training constraint we face: network outages to allow team members to train on de-energised assets. These facilities will alleviate our technical training backlog and allow us to increase the internal supply of specialist skills, reducing our reliance on external suppliers in a market expected to remain tight over the long-term and in turn lower costs.

We are forecasting property spend to increase from \$46m in the current period to between \$76m and \$134m in the 2028-33 period, with the higher investment pathway still under consideration. We have received feedback to investigate alternative options to maintain our existing portfolio, to share costs fairly with major project initiatives and to apply constraint.

Property expenditure covers the cost of maintaining and operating our workplaces including offices, depots, warehouses and satellite facilities. We have 7 main workplaces made up of our Sydney central office, 3 regional depots and 3 area centres which include offices, warehouses, and workshops. We also have leased offices and a small number of satellite workplaces. The age and condition of our workplaces vary.

Property expenditure is cyclic and dependent on the age, condition and utilisation of our workplaces. Expenditure requirements are driven by the need to maintain safe, compliant, and operationally suitable workplaces and to address condition-related risks as they emerge over time. Expenditure over the last 5 years has included the refit of our Sydney head office to accommodate workforce growth together with targeted site renewals and remediation works across the portfolio.

Figure 3-24 Property capital expenditure FY2014 to FY2033 excl. overheads (\$m, Real 2027-28)



We have undertaken condition assessments, risk and utilisation assessments, and considered future needs to forecast expenditure for the 2028-33 period. We have identified three main areas of property expenditure.

The first relates to maintaining the functionality and safety of existing workplaces. Following condition audits, prioritisation and criticality assessments, we have identified the need to undertake works to keep our workplaces safe, compliant and operationally suitable for continued use. Several of these workplaces were originally constructed in the 1960s. Maintaining and making better use of these existing facilities avoids the need to build or lease additional workplaces.

These works focus on identified safety, compliance and condition issues, including asbestos and cladding, water ingress affecting building integrity, fire safety systems, electrical compliance and other critical building defects identified through our condition assessments. Where practical, these works also enable reconfiguration of existing workplaces to improve functionality and accommodate workforce growth, further reducing the need for new buildings or sites.

Second, we will address physical security vulnerabilities across our depots. Recent security incidents, evolving threat assessments, updated Security Management Plans and independent security assessments have identified a number of physical security risks across our operational sites. To address these vulnerabilities, we have developed a proportionate, risk-based program to implement additional physical security controls.

Third, we intend to build additional regional field training capacity to address a training backlog, reduce our reliance on external suppliers and lower delivery costs over the long-term. As outlined in section 3.1.2, over the current 2023-28 period, we experienced significant increases in costs in part due to persistent shortages of, and increased competition for, highly skilled labour. We have considered alternatives, including greater use of external training providers but found that these alternatives are generally not feasible, given the specialised high-voltage transmission training required.

Our initial assessment of identified property needs produced a forecast of approximately \$236m. We then undertook an additional review to identify which elements can be avoided, delayed, bundled, de-scoped or funded through other avenues. This included seeking feedback from the CWG which encouraged us to constrain costs and explore alternative options.

At this stage we are considering two investment options. The first is a \$76m essential works pathway, comprising safety and compliance works, targeted physical security upgrades and regional field training facilities, which constrains costs in the short term and focuses only on works necessary to address short-term operational, safety and compliance requirements. The second is a \$134m pathway where we would undertake additional works at our oldest regional workplaces where earlier investment will reduce whole-of-life costs, avoid more expensive future intervention, or improve the functionality and utilisation of our existing workplaces to accommodate workforce growth.

In this Draft Plan we have only included the costs of the \$76m essential works pathway. However, we are continuing to assess the impact of workforce growth and whether deferring elements of the higher investment pathway would result in higher costs or operational consequences over the longer term. We will continue to explore the trade-offs and consumer implications of each option and are now developing business cases for each element of our forecast before determining what, if any, additional expenditure should be included in our Revenue Proposal.

3.2.8 Fleet

Fleet is essential to supporting the safe and efficient delivery of capital works and maintenance activities. Our fleet comprises light commercial vehicles, passenger vehicles, all-terrain vehicles, trucks, plant and elevated work platforms. These assets operate across regional and remote locations, travel long distances, carry specialised equipment and support access to transmission infrastructure.

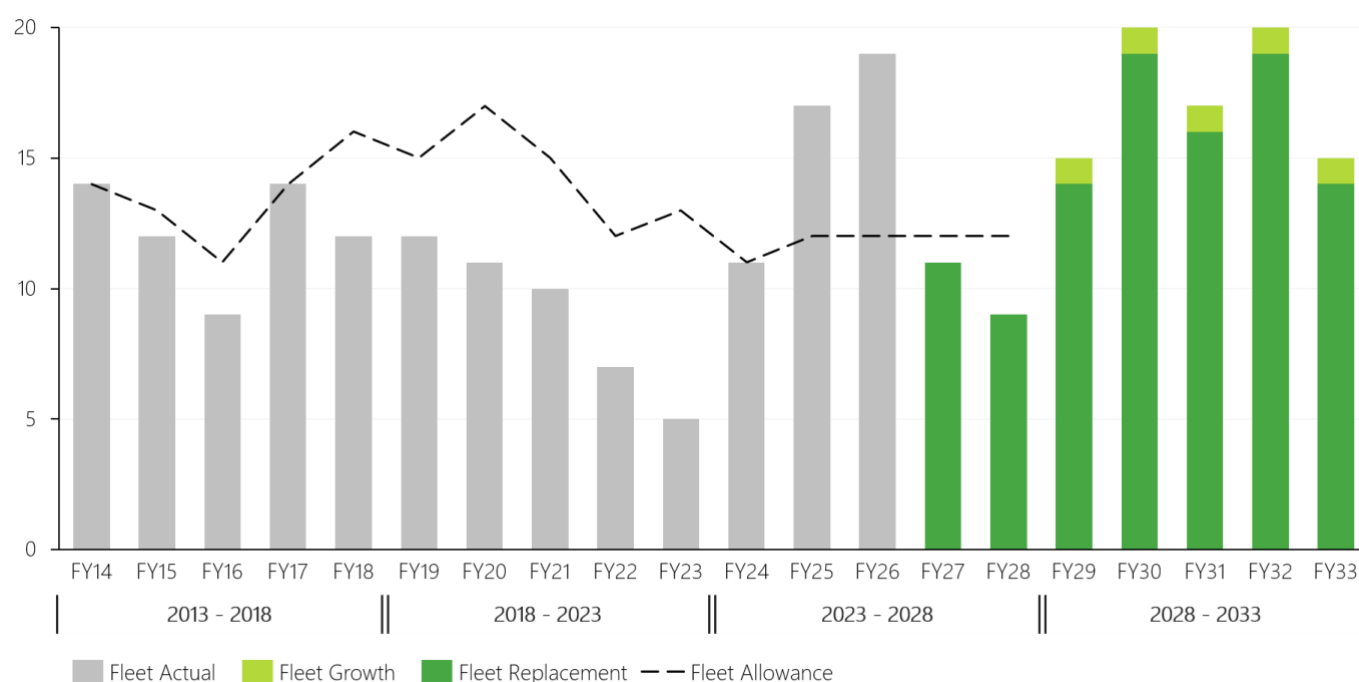
During the current regulatory period, our fleet has grown from approximately 550 to around 750 motor vehicles as our workforce, delivery task and operational requirements have increased. Including plant and trailers, we have approximately 1,200 assets. To constrain costs in the short term, we have also retained vehicles when their replacements have arrived rather than purchasing additional vehicles to meet fleet growth requirements.

In the next period, we intend to catch up on this backlog and move back to replacing fleet items in accordance with our established replacement criteria. This will avoid higher maintenance costs, maintain fleet reliability and ensure our fleet is equipped with the latest safety technology. This forecast is based on the age, condition and utilisation of our existing fleet.

We expect fleet expenditure in the 2028-33 period to be higher than in the current period largely due to the increased size of our fleet as well as higher vehicle costs.

In addition to replacement expenditure, we have included forecast expenditure for fleet growth in line with our workforce and delivery requirements. In this Draft Plan we have included a placeholder of \$4m per year; however, our preliminary assessment indicates that this could be as much as \$39m over the period, depending on our final workforce and delivery forecast.

Figure 3-25 Fleet capital expenditure FY2014 to FY2033 excl. overheads (\$m, Real 2027-28)



We intend to update this estimate following the completion of our updated workforce growth projections. Before including additional fleet expenditure in our Revenue Proposal, we will assess the operational need for additional vehicles and opportunities to increase utilisation, redeploy existing vehicles or otherwise meet the requirement without expanding the fleet.

3.2.9 Overheads

Capitalised overheads include the costs which support the delivery of our capital program. They are made up of corporate and network support, control and management costs. We intend to forecast these costs using the AER's standard approach where we project forward historical costs adjusted for the change in the scale of our overall program.

3.3 Operating expenditure

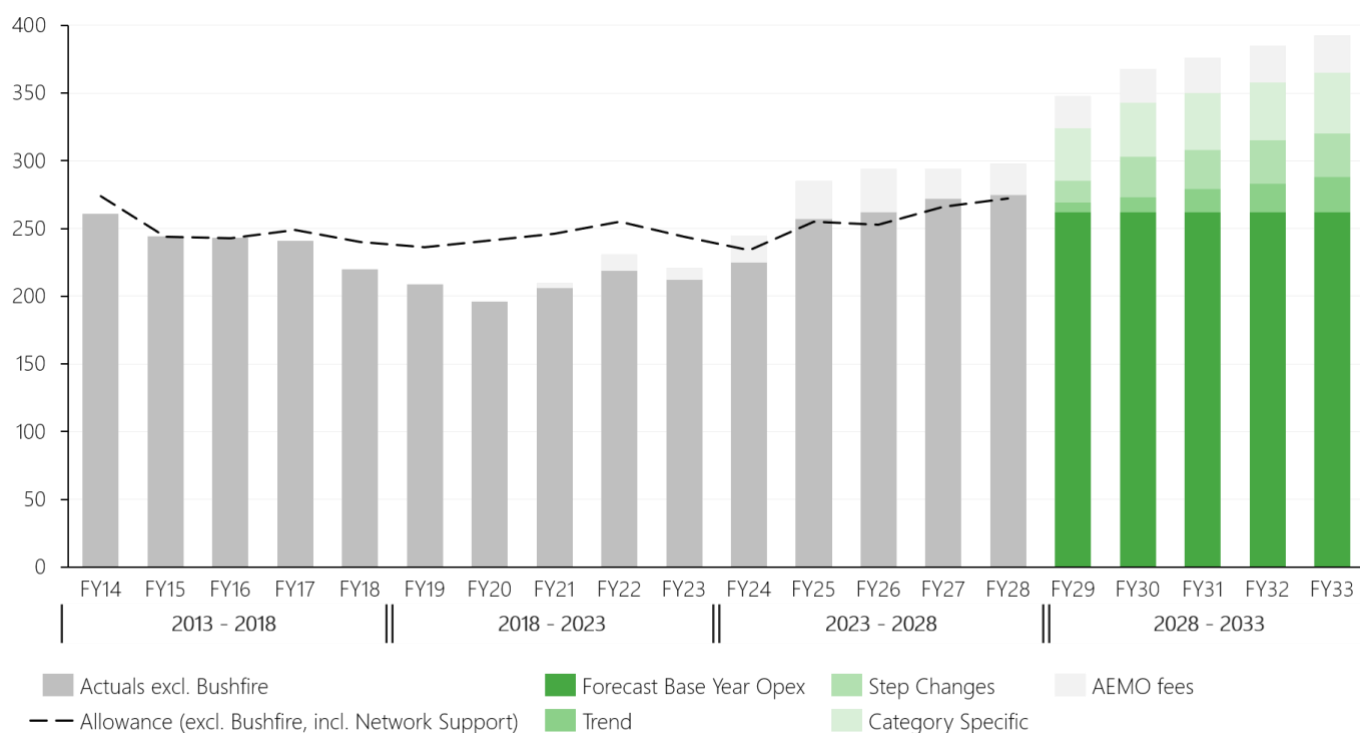
Historically, operating expenditure has been stable year-to-year with changes aligned to wages, efficiency gains and growth in our network size. However, it is not business-as-usual as we adapt the network for the deep transition. There have been substantial changes to our role, the scale of the transmission system, and the complexity of our operating environment. Despite these changes, we have been able to constrain costs and keep expenditure in line with the AER's allowance for the current 2023-28 regulatory period.

For the upcoming 2028-33 regulatory period, our intention is to apply standard operating expenditure forecasting methods, consistent with guidance provided by the AER in its 'Better Resets Handbook' and regulatory precedent. Broadly, this consists of a base-step-trend forecasting approach, with step changes, and category specific forecasts where a base-step-trend forecast would not produce a realistic estimate of efficient costs.

Operating expenditure, or opex, funds the day-to-day costs of keeping our network running. It includes maintenance, emergency response, system planning, asset management, the costs of third-party non-network solutions, land tax and soon AEMO participant fees.

We are forecasting opex to increase consistent with the increasing scale and complexity of our role in Australia's energy system. We will need to uplift our capabilities to maintain system strength as coal exits to sustain the 'heartbeat' of the grid, while also defending against increasing cyber risks. In parallel, we will leverage our existing ICT systems to maximise value for consumers, pay higher statutory charges, and procure third-party non-network solutions where this results in a lower cost or improved outcomes for consumers. A comparison of our forecast to historical costs is shown in Figure 3-26.

Figure 3-26 Operating Expenditure FY2014 to FY2033 (\$m, Real 2027-28)



While we provide a long-term trend of opex, we note that opex over time is not directly comparable on a like-for-like basis. Opex in 2028-33 includes substantial costs not reflected in prior periods, including AEMO participant fees (\$109m) and network support costs (\$27m). We have also seen increases in land tax (which is outside of our control) while ICT costs are increasingly being reported in opex rather than capex, due to movement from on-premise to software as a service (SaaS) solutions.

If we exclude all of these factors, we are forecasting that controllable opex at the end of the next period will be equivalent to what we incurred in 2013-14 – with effectively no real increase over 20 years. This outcome reflects our efforts to drive efficiencies and constrain costs in the initial phase of the energy transition and through the changes in both the scope and complexity of our role.

From the consumer feedback we have received, we recognise the importance of placing downward pressure on operating costs, particularly in the current cost-of-living environment. We are also conscious that opex has a more immediate impact on consumer bills because, unlike capex, it is recovered in the year it is forecast to be incurred.

In the course of developing our opex forecast, we have engaged with the CWG and reviewed the scope, timing and cost of each proposed step change. This has resulted in the reduction of step changes from \$188 million to \$138 million from the prior version of our forecast. This reflects further portfolio refinement, the removal of duplication with costs already captured through the base year and trend, and a stronger focus on ensuring that the remaining step changes are genuinely incremental.

As we continue to develop our opex forecast, we continue to further test and refine each proposed step change. We have heard the CWG's advice to avoid duplication, focus on consumer outcomes and clearly demonstrate the consumer value delivered by any additional expenditure. We will also continue to explore whether cost pressures can be managed through internal efficiencies, including by delivering activities in-house, consolidating or reprioritising work, or adjusting its scope or timing.

Our intention is to include only costs that cannot reasonably be avoided or absorbed through efficiencies, or that deliver sufficient consumer benefits to warrant their inclusion. For each proposed step change, we will clearly demonstrate the underlying need, the capability gap being addressed and why the expenditure is not already captured through the base year or trend. We look forward to further engagement as we continue to refine our Revenue Proposal.

3.3.1 Base year

The starting point for our opex forecast is the selection of an efficient and representative base year. For this Draft Plan, consistent with regulatory precedent and the AER's long-standing expenditure forecast assessment guidelines, we have retained 2026/27, the fourth year of the current regulatory control period.

The AER has asked that we consider using an earlier year, such as 2025/26, as we will have actual, auditable data available for it to consider in its draft decision. Using this data would allow the AER to determine if the base year is not materially inefficient and avoids changes between the draft and final decisions.

While we did not have time to make this change for this Draft Plan, we are considering adopting the third year. We agree that there are merits to the potential – subject to AER acceptance – of locking down the opex forecast at the draft decision stage. This will allow us, the AER and stakeholders to focus on a smaller number of outstanding elements (if any) in our revised proposal and the AER's final decision.

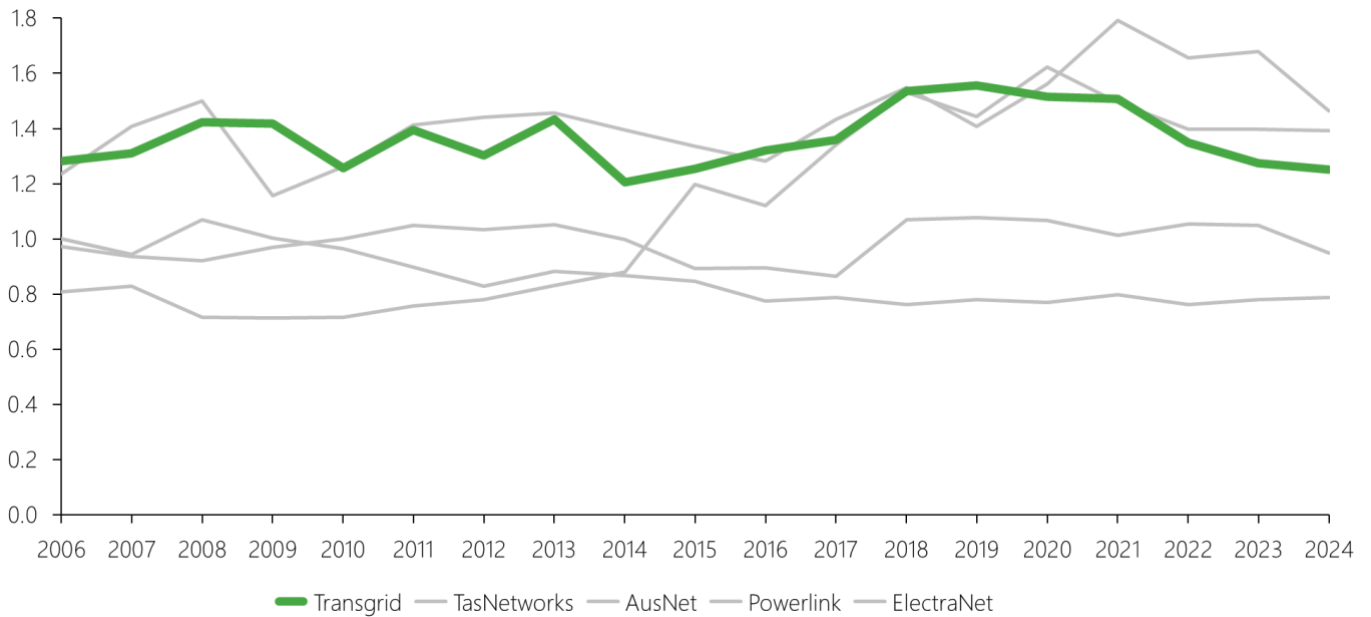
There are also drawbacks to this approach. In particular, the forecast may not reflect the best estimate of costs given that it would rely on older information from 2025/26, even though more up to date information for 2026/27 will be available for both our revised proposal and the AER's final decision. We also need to consider implications for the calculation of EBSS carry-overs in both the 2028-33 and the subsequent 2033-38 periods.

Regardless of whether we adopt year 3 (2025/26) or year 4 (2026/27), we consider that actual revealed costs provide an appropriate basis because:

- We have operated under, and responded to, the EBSS, which provides a continuous incentive to reveal efficient costs.
- Despite substantial changes in our operating environment, we expect our expenditure over the 2023–28 period to be broadly consistent with the AER's allowance.
- We have been able to constrain cost increases over the long term, including during a period of material growth in the scale and complexity of the transmission system.
- Our benchmarking performance provides supporting evidence that our opex is efficient relative to other Australian transmission businesses.

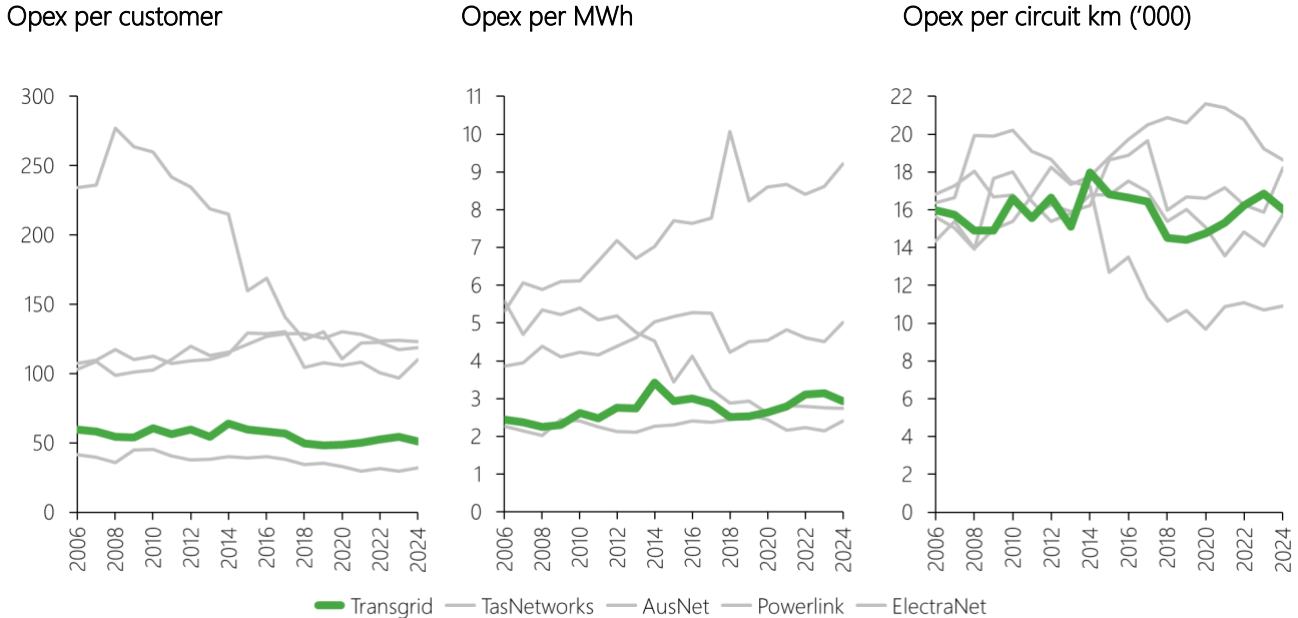
In respect of our opex benchmarking performance, Figure 3-27 compares our multilateral opex partial factor productivity with other transmission networks. Our productivity has consistently been above the industry average and, despite recent reductions, remains in the top three of Australian transmission networks.

Figure 3-27 Transgrid multilateral operating expenditure partial factor productivity versus other networks



We have also reviewed partial performance indicators, including opex per customer, opex per MWh and opex per circuit kilometre. These measures are shown in Figure 3-28. While these indicators do not, by themselves, establish the efficiency of our base year, they provide useful cross-checks and indicate that our opex remains relatively low compared with peers.

Figure 3-28 Opex Partial Performance Indicators \$2024



We are forecasting our base year expenditure to be \$271.5 million in 2026/27. We then adjust the base year to remove elements we are forecasting separately, such as land tax and network support costs (see section 3.3.4 for further details).

3.3.2 Trend

The second component of our opex forecast is the trend, which captures the expected annual rate of change in costs arising from output growth, real price growth, and productivity growth. Output growth captures changes in the scale of our network. Price growth captures above-inflation growth in labour costs. Productivity growth captures expected cost savings over time.

Conceptually, the output growth factor is intended to capture changes in the services we provide to consumers. However, in practice, the rate of change is limited to changes in the scale of our network – it only takes into account customer numbers, circuit length, ratcheted maximum demand and energy delivered – and does not reflect ongoing changes in the scope of our service or how we are managing an increasingly complex power system to enable consumers to benefit from distributed, lower-cost generation.

We considered developing an alternative output measure to capture these changes but ultimately decided against it. We made this decision primarily based on stakeholder feedback provided to Powerlink. Stakeholders considered that changes of this nature should be implemented via a network-wide review rather than through an individual reset. We agree that there is merit in a network-wide review, especially considering the data and analytical challenges that need to be resolved (for example, how to identify and quantify new output measures). Accordingly, we have instead captured costs related to the increased system complexity through two separate step changes, as outlined below.

Our current approach is to forecast the trend in our operating expenditure consistent with the standard AER-accepted methodology. Specifically, we intend to forecast:

- **Price growth:** based on the average of two consultant forecasts: draft July 2026 labour price growth forecast prepared by Oxford Economics for Transgrid and the Australian Utilities Wage Price Index forecast prepared by Deloitte Access Economics (DAE) for the AER's AusNet Services 2027-32 transmission determination. The Oxford Economics forecast will be updated prior to submission of the Revenue Proposal and the latest DAE forecast available at that time will be incorporated.
- **Output growth:** by applying output 'weights' together with the latest forecasts of customer numbers from AEMO, as well as maximum demand and energy throughput forecasts per our 2026 Transmission Annual Planning Report (TAPR), and our forecast for circuit length (which takes into account planned augmentations).
- **Productivity growth:** based on the most recent estimate from the AER's 2025 annual transmission benchmarking report of 0.4%. We do not expect the AER's 2026 annual transmission benchmarking report to be available in time to make any changes to this factor in our January Revenue Proposal.

The cumulative impact on operating expenditure from the rate of change is set out in Table 3-14.

Table 3-13 Forecast trend operating expenditure (\$m, Real 2027-28)

	2028-29	2029-30	2030-31	2031-32	2032-33	Total
Output growth	6.1	9.6	14.0	17.7	21.6	69.1
Price growth	1.8	3.9	6.0	7.8	9.7	29.2
Productivity growth	-1.1	-2.1	-3.2	-4.2	-5.3	-15.9
Total	6.9	11.4	16.8	21.3	26.0	82.4

Note: Totals may not sum precisely due to rounding.

3.3.3 Step

The third component of our forecast is the step changes that account for material cost movements not included in the base or trend. Generally, step changes relate to regulatory obligations, capex-opex trade-offs (or re-allocations), changes driven by external factors outside of a business's control, or opportunities to increase the activities to deliver greater consumer value. That is, step changes reflect an uplift in our capability, activity, or function, required to continue to deliver transmission services.

Our approach to developing step changes has three steps:

1. Identify where costs are likely to increase beyond what is included in our base year.
2. Filter out costs which do not relate to a new capability, activity, or function. This includes cost increases already reflected in the base-step-trend methodology (in particular the final year incremental and trend adjustment) as well as those activities implicitly included in our 2023-28 allowance.
3. Develop detailed business cases and cost estimates. This includes testing whether activities can be avoided, delayed or descope, verifying that the expected consumer value warrants the cost, and ensuring there is no duplication with the base year, trend, or other step changes.

In developing our Draft Plan, we have further refined our assessment, including a detailed review of cost estimates, treatment of final-year funding, interaction with trend allowances, delivery timing and scope. This process has resulted in a reduction in the total value of proposed step changes and greater confidence that only incremental costs not otherwise captured in our forecast are included. Several are also linked to broader investment programs that include both capital and operating expenditure. The proposed step changes are summarised in Table 3-14.

Table 3-14 Draft Plan step changes (\$m, Real 2027-28)

Category	Forecast
System Security Roadmap Operational Technology Contingent Project	32.6
System strength & complexity	21.2
ICT: SaaS, cloud & data	38.1
Cyber Security: IT & OT	31.4
Critical Infrastructure Security – Physical Security	15.4
Fleet electrification	-0.6
Total	138.1

System Security Roadmap Operational Technology Contingent Project 2028-33 costs

As outlined in section 3.2.3, the NSW energy system is undergoing a transition from a small number of large thermal generators to many smaller, distributed, variable generation and storage resources. These changes create a more complex and dynamic transmission network to manage and reduce the operational 'buffer' in the power system.

To respond to these changes, we plan to deliver a project across 2023-28 and 2028-33 to ensure that we can proactively plan for, and respond to, operational issues. This will require upgrades to our core operational technologies and introduction of several new capabilities. Consumers will benefit as we will be able to avoid the need to apply more conservative limits in how we operate the system, which would otherwise reduce the output of lower-cost generation, and mitigate the increased risk of emergency outages and disruptions.

To ensure we can deliver this project, on 1 May 2026 we submitted a Contingent Project Application seeking an adjustment to our 2023-28 capex and opex allowances.

In considering our application, the AER is required under the National Electricity Rules to determine the additional capex and opex required in 2023-28. The AER is also required to determine the total capex required to undertake the project across both 2023-28 and 2028-33. There is no equivalent Rule for 2028-33 opex.

As additional capex and opex is required across 2023-28 and 2028-33 to deliver the project, we provided a complete picture of all costs in our contingent project application. While the AER can only make a decision on 2028-33 opex as part of this revenue determination process (and not as part of the contingent project process), we requested that the AER undertake a provisional assessment of the 2028-33 incremental opex to inform its determination for 2028-33. This approach avoids the AER having to assess the prudence and efficiency of the costs twice and provides us, if our application is accepted, with a reasonable degree of confidence that sufficient opex will be provided allowing us to proceed with the initial capital investment required in the current period.

We recognise that a decision on opex requires a broader assessment and understand that the AER must test that there is no duplication of costs across our overall opex forecast, separate from assessing the merits of the incremental costs in isolation. We confirm that there is no duplication with the trend, which does not capture increasing system complexity, or with our other step changes which focus on separate items.

In developing our proposal, we have updated our estimates to align with the AER's approach for approved contingent projects and pass through events. Specifically, the proposed step change reflects the forecast operational technology costs required in 2028-33, less the amount already reflected in the final year of the current regulatory period and the associated rate of change that would continue into the subsequent period. This ensures that only the incremental costs required above those already provided for are included in the step change.

Based on our current estimates, the total 2028-33 operational technology expenditure associated with the project is \$37m, of which approximately \$5m will be reflected through the final year allowance (if the Contingent Project Application is approved) and ongoing trend growth. Accordingly, the proposed step change has been reduced to \$32 million over the 2028-33 period.

Table 3-15 System Security Roadmap Operational Technology Project costs (\$m, Real 2027-28)

Category	2023-28	2028-33
Capital expenditure	86.9	102.9
Incremental operating expenditure	0.9	37.2

System complexity: network and operational planning & system strength support

Separate from and in addition to the System Security Roadmap Operational Technology project, we have identified two areas where we need to expand our current capabilities to adapt to increased system complexity and implications for our operations.

The first is a targeted uplift in our network and operational planning capability. Increasing inverter-based generation and storage, data centres and Renewable Energy Zone development, together with the reduction in synchronous generation, is increasing the volume and complexity of the work required to securely plan and operate the network.

By 2030 there will be a 100% increase in external operators interfacing with our control room while over the last 2 years we have seen 2.8 GW in new connections and 250% increase in control room monitoring points.

This requires additional and more complex power system studies to manage outages and contingencies, assess new stability and voltage-management risks, and provide more frequent advice on operational limits. These activities are beyond what is captured in the output growth trend. Without sufficient capability, studies may be delayed or more conservative operating limits applied, potentially resulting in unnecessary constraints on renewable generation and storage.

While EnergyCo now coordinates aspects of strategic transmission planning in NSW, this has not reduced Transgrid's planning costs. Transgrid retains responsibility for planning its network, connections, the TAPR, joint planning, and its system strength and inertia service provider activities. The additional coordination, review and technical input required to support EnergyCo largely offset any reduction from transferred activities.

The second area relates to our enduring role as the System Strength Service Provider for NSW. To meet our obligations at the lowest overall cost to consumers, we must continually assess system strength requirements, engage the market, evaluate and procure efficient solutions, manage contracts and monitor technical performance as the system evolves.

During the current 2023-28 period, our system strength function supported the delivery of capital projects, such as Synchronous Condensers. The costs of this function have been included within the cost of delivering these projects and capitalised.

In 2028-33, system strength is increasingly expected to be delivered through non-network solutions, including grid-forming batteries and synchronous machines. The delivery of these solutions will require ongoing planning, procurement and contract-management activities. The costs of these non-network solutions will be recovered through the annual pricing process rather than in forecast capital or operating expenditure.

We will need to maintain our system strength function in 2028-33. However, because these costs have historically been capitalised, they are not reflected in the base or trend components of our opex forecast. This step change includes, as operating expenditure, the ongoing cost of the capability that previously supported capital projects and will now be required to plan, procure and manage non-network solutions.

At this stage, we expect these two elements to increase opex by approximately \$21 million across the 2028-33 period, comprising around \$16 million for system strength activities and \$5 million for a targeted system analysis capability uplift.

We have excluded existing base and trend funding and any project-specific activities expected to be capitalised in the 2028-33 period, recovered through contingent projects or pass-through mechanisms, ensuring costs are only recovered once. We are continuing to refine the business case, including validating the incremental activities and costs, quantifying consumer benefits and confirming that only costs incremental to existing funding are included.

ICT: SaaS, cloud and data

As outlined in section 3.2.5, Transgrid is transitioning to cloud-based platforms, SaaS solutions and enhanced data and decisioning capabilities as part of its ICT strategy. These changes are necessary to modernise our technology environment, improve scalability and resilience, and support more efficient delivery of services across the business.

This step change captures the operating expenditure associated with these initiatives, including software subscription costs, cloud hosting services and ongoing support for new data and analytics capabilities. These costs are incremental to the base year because they reflect changes in software delivery models and new capabilities that are not captured through the trend forecast or existing ICT expenditure.

Cyber Security (IT & OT)

As outlined in section 3.2.6, we need to improve cyber security protections across our information and operational technology environments. We are assessing the additional initiatives and activities required, including improved monitoring, incident response, vulnerability management, asset oversight and cyber resilience capabilities.

The proposed step change will provide the specialist capability needed to maintain visibility and control across these environments, respond to evolving cyber threats and support compliance with critical infrastructure security obligations. These capabilities are essential to identify and mitigate cyber risks in a timely manner, reduce the likelihood and impact of incidents, and support the safe and reliable operation of the transmission network.

Critical Infrastructure Security – physical security

As Transgrid's network expands, increasing alarm volumes and incidents of theft, vandalism and unauthorised access are increasing the need for effective physical security monitoring and response.

Monitoring is currently undertaken as a secondary function within our network operations control room, limiting proactive monitoring and coordinated incident response. We propose to establish a dedicated security control room and progressively build a 24/7 monitoring capability during the 2028-33 period, allowing the network operations control room to remain focused on operating the network.

This will enable earlier detection and response, improve protection of critical assets, and support network resilience, public safety and compliance with critical infrastructure security obligations. We are refining the scope and costs to ensure the uplift is scalable and aligned with increasing monitoring demand.

Fleet electrification

We currently operate a fleet of around 1,200 vehicles to support maintenance activities and the delivery of capital works. Almost half of the fleet comprises light commercial vehicles, primarily utes. The remainder includes trucks, excavators, mobile elevated work platforms, all-terrain vehicles and other specialist equipment.

We have recently completed the transition of our passenger vehicles from a mix of diesel and hybrids to electric vehicles. We are seeing cost savings from maintenance costs and fuel usage which will be fully realised in our base year. We also trialled electric utes to understand real world field use; however, these vehicles were subsequently discontinued. There are no electric vehicles (aside from passenger vehicles) which are currently available and fit our broader fleet needs.

However, we expect the market for electric commercial vehicles to develop over the next three to five years. We have assumed that 10% of our commercial fleet can be electrified from 2031–32, despite no viable electric equivalent currently being available. Our forecast includes the estimated opex savings for these vehicles from 2031–32, based on the expected reduction in operating costs compared with conventional vehicles. This assumption remains uncertain and will be refined as the market develops. We have not included any corresponding capex uplift for the higher purchase cost of electric vehicles.

Step changes identified and not progressed

We have identified a number of cost increases that we expect to incur in 2028-33. Examples include:

- Digital and technology initiatives intended to improve the efficiency and efficacy of our planning, delivery and other business activities (\$17m).
- Additional operating cost increases to support the uplift in training capacity (\$12m).
- Expected increases in multi-year service contracts that reset after the base year (\$3m-\$6m).
- New technologies and systems to improve SF6 reporting and support our net-zero strategy (\$1-\$2m).
- Social licence programs in regional areas (\$1.5m-\$4.5m).
- Live line costs to support the delivery of our capital and maintenance programs (with costs remaining uncertain at this stage).
- Increased maintenance costs as major new transmission lines are commissioned (\$10m-\$12m).

We are not proposing step changes for these items. Each potential step change was assessed against whether there was a clear and material change in activity or capability, whether the expenditure was already captured in base opex or the rate of change, and whether the need, costs and consumer benefits could be supported by sufficient evidence.

We also considered dependencies with other expenditure proposals and the risk of double counting. For some items, we consider the costs are implicitly captured in the base year or trend. For others, including selected digital and technology initiatives, we intend to avoid, defer, reprioritise or self-fund activities within our broader expenditure allowances. This assessment has helped ensure that our proposal only includes step changes that are demonstrably incremental, prudent and efficient, and cannot reasonably be accommodated through existing funding.

3.3.4 Category specific forecasts

The final component of our opex forecast is category specific forecasts for items that are not forecast using the base-step-trend approach. We are currently considering three category specific forecasts (outside of debt raising costs, which are forecast in the Post Tax Revenue Model) related to land tax, AEMO participant fees and network support agreement costs.

Table 3-16 Draft Plan category specific forecasts (\$m, Real 2027-28)

Category	Forecast
AEMO participant fees	109.0
Land tax	72.6
Network support agreements	27.2
Total	208.8

Land tax and AEMO participant fees

In providing services to consumers we expect to incur as part of regulated opex:

- **Land tax** – a long-standing jurisdictional charge based on the value of unimproved land we own. These costs have increased by about 10.5% a year (in some years more than 20%) over the last 20 years. Given this, we have removed land tax from our estimated base opex and instead forecast this cost on a category specific basis, consistent with the approach the AER has accepted for other material jurisdictional taxes and levies, such as Evoenergy’s Utilities Network Facilities Tax and AusNet’s easement land tax. The net effect of the base year adjustment and category specific forecast is \$12m.
- **AEMO participant fees** – fees payable to fund AEMO’s core NEM functions. These fees commenced in 2023 and were expanded from 1 July 2025 to also fund AEMO’s cyber security roles and responsibilities. These fees have been applied via TUOS to date, consistent with transitional rule arrangements, and will transition to recovery via our opex allowance for the 2028-33 period onwards.

Unlike other programs and investments, we have no discretion over whether to incur these fees. The costs we pay are driven by the services provided by the NSW Government and AEMO (to NSW residents and electricity consumers and the market) together with policy decisions from these bodies on how to recover their costs. These costs are not a fee for service that we can directly control or influence.

How we recovered land tax and AEMO participant fees in the current 2023-28 period

Regulatory treatment of these costs has differed in the current 2023-28 period. While we have historically incurred land tax as part of opex, AEMO participant fees have been recovered directly through Transmission Use of System (TUOS) charges and not included in forecast or reported opex or as part of the overall regulated revenue requirement.

The difference in treatment has arisen because AEMO decided to recover its costs of operating the NEM from transmission network service providers for the first time in 2021.

The cost recovery of these new charges was considered as part of a subsequent Rule Change process. The AEMC determined that these AEMO participant fees should be recovered through our opex allowance. The AEMC made this determination on the basis that, under existing regulatory mechanisms, we will be provided with a reasonable opportunity to recover efficient costs, that we have some ability to manage the inevitable ups and downs in costs and that the risk associated with the volatility in fees will be shared through the EBSS. The AEMC had assumed that we would bear 30% of differences between forecast and actual costs, with consumers bearing the balance.

As a transitional measure, over the current 2023-28 period AEMO participant fees are recovered through TUOS, rather than through the opex allowance. This approach was applied due to insufficient information available to produce a reasonable cost forecast and to provide time to align how AEMO sets fees with our opex forecasting processes.

A summary of the cost recovery and materiality of each of these levies and charges is provided in Table 3-17 below.

Table 3-17 Regulatory charges and fees approach and amounts (\$m, Real 2027-28)

Regulatory charge and fee	2023-28	2028-33	Estimated base year costs	As a percentage of the base yearA
Land tax	Opex	Opex	11.4	4.3%
AEMO participant fee	TUOS	Opex	18.8 ^B	7.1%
Total			30.2	11.4%

Note: A - Base year amount adjusted to include fees. B - Costs not included in the base year.

Options for the 2028-33 period

Under the base-step-trend framework there are two broad options for these costs. Either costs are included in a category specific forecast (and excluded from the EBSS) or costs are included in base and escalated by the rate of change (and are subject to the EBSS). This is due to the link between the EBSS and the base-step-trend revealed cost forecasting method.

In the Framework and Approach process, the AER acknowledged that we do not have direct control over some costs, including AEMO participant fees and other government charges, but noted its long-standing position that uncontrollability is not a reason to exclude cost elements from the EBSS. The AER considered that cost variances should be shared between businesses and consumers in the same way as any other cost variances: 30:70 between businesses and consumers.

We have also engaged the CWG on this issue; however, the CWG noted the AER's commentary in its Framework and Approach and decided not to focus on this issue.

Following our First Look, the AER has provided feedback on category specific forecasts. Specifically:

- In deciding whether to include costs as category specific forecasts, the AER will determine what provides a better forecast of total opex.
- Uncontrollable costs should not be excluded from the EBSS. Rather unexpected variances should be shared through the EBSS, consistent with the treatment of other costs (i.e. 30:70 sharing, or where they exceed the materiality threshold, the cost pass through mechanism).
- Where it has accepted category specific forecasts (for example Evoenergy's Utilities Network Facilities Tax and AusNet's easement land tax) these formed larger shares of total opex.
- Cost growth above the rate of change alone is not a justification for a step change, as not all costs increase at the same rate. Some will increase faster or slower than others.

We welcome this feedback and consider that this provides a useful framework to guide whether costs should be treated as a category specific forecast. This framework works well with the Rules, which set out that a better forecast of total opex is the one which best meets the opex criteria: broadly, a forecast which reasonably reflects efficient, prudent and realistic cost inputs.

A category specific forecast provides a better forecast of total opex

We recognise that the AER is generally reluctant to separately forecast individual cost elements as this could lead to an upwardly biased forecast. This is why we are not proposing step changes for several known cost increases. However, there is also a risk that by not forecasting costs separately the overall forecast does not provide a realistic estimate of efficient costs and in turn leads to a biased underestimate of total opex.

The question is whether classifying specific costs as category specific costs provides a better – in terms of more reasonable, efficient, prudent and realistic – forecast of total opex. To answer this, we need to determine whether it is reasonable and realistic to assume that a known cost increase would be offset by cost reductions (or slower cost growth) in other elements of total opex.

While it is reasonable to assume that a small cost increase could be offset by other elements of total opex, as cost movements become larger the potential that other elements can offset an increase becomes implausible and unrealistic. In these circumstances, a category specific forecast (or a step change) must be applied to ensure that the total opex forecast meets the opex criteria.

Importantly, it is materiality in the context of total opex that matters. This is a function of both the size of a cost element as well as its growth and variance. A large cost element that moves closely with the trend is less material to the forecast of total opex than a smaller cost element which is growing at a substantially faster rate.

We have compared the materiality of the cost elements which the AER has previously accepted to be category specific forecasts against the materiality of the AEMO fees and land tax we face. Table 3-18 compares the forecast total opex outcome if a category specific forecast is applied or not and the overall materiality.

In our forecast of total opex, applying a category specific forecast for AEMO fees and land tax or not leads to a total opex difference of 1.3% over the period. The year-by-year difference can be more material. By the end of the period, the inaccuracy rises to 1.9% of opex.

Table 3-18 Materiality of proposed and accepted category specific costs

Business	Uncontrollable cost elements	Total opex		Difference	
		With category specific forecasts	No category specific forecasts	\$	%
Evoenergy	Utilities Network Facilities Tax and Energy Industry Levy	171.0	169.0	1.9	1.1%
AusNet	Land tax	2,149.2	2,157.5	-8.3	-0.4%
Transgrid	AEMO fees and land tax	1,788.3	1,764.9	23.5	1.3%

Note: Evoenergy and AusNet costs presented in \$2025-26 to align with their opex models. Transgrid costs are presented in \$2027-28.

While the AEMO fees and land tax we pay make up a smaller proportion of total opex compared to Evoenergy's Utilities Network Facilities Tax and Energy Industry Levy or AusNet's land tax the costs are more material. Applying a category specific forecast changes total opex by 1.1% for Evoenergy and by 0.4% (in absolute terms) for AusNet, both of which the AER accepted. For Transgrid the difference is 1.3% over the period, rising to 1.9% by its end – larger than in either accepted case.

This outcome is unsurprising given that our AEMO fees and land tax costs are increasing much faster than the rate of change. This is because AEMO fees and land tax cost movements are driven primarily by factors outside the rate of change: movements in NSW land valuations and the NSW Government's tax settings, and AEMO's budget and fee-setting decisions. Growth in our land holdings has been a minor contributor to overall land tax costs.

In turn it is not reasonable or realistic to assume, in preparing a forecast of total opex, that these costs will move in line with the rate of change (especially when there is evidence to the contrary) or that other cost elements will increase at a slower rate to offset these known cost increases (when there is no evidence this is possible, particularly in the increasingly complex environment we are operating within).

Given the materiality of AEMO fees and land tax to the forecast of total opex, we consider that these costs should be forecast on a category specific basis.

Interaction with the EBSS

The AER and AEMC both assume that the EBSS will ensure that AEMO fee cost variances are shared 30:70 between us and consumers.

In contrast to the CESS (which ensures that the difference between forecast and actual costs is split 30:70 between networks and consumers), the EBSS provides a continuous incentive linked with the operating expenditure forecasting approach. Networks retain any movements in opex for five years, after which cost increases (or savings) ultimately flow through to consumers.

A critical assumption in the application of the EBSS is that a base-trend forecast approach provides an unbiased forecast of future costs. However, as outlined above, applying the base-trend forecast approach does not result in an unbiased forecast as, based on AEMO's forecast and expert advice received on land tax values, these costs will increase at a rate higher than the rate of change.

If these costs are forecast using the base-trend approach and subject to the EBSS, in each regulatory period going forward we will incur:

- 100% of the cost difference between forecast and actual costs.
- A negative carry-over amount in the subsequent period.

That is, we will incur 100% of the cost difference plus an additional penalty for cost movements which are entirely outside of our control.

If this approach were to be applied in the upcoming 2028-33 period, we would expect to spend \$23.5m above our total opex forecast and would bear 100% of these costs. We would then incur an additional \$12.1m EBSS penalty in the subsequent 2033-38 period due to the 'efficiency loss' over the period from costs increasing faster than the allowance. After accounting for the time value of money (using the 6% real discount rate assumed in the AER's EBSS explanatory statement), we would incur 144% of the difference between expected costs and the allowance. This is significantly higher than the 30% share the AEMC assumed we would bear when it determined that AEMO participant fees should be recovered through the opex allowance.

This is not a one-off outcome. We expect AEMO fees and land tax to continue to grow faster than the rate of change, which creates a new gap between forecast and actual costs and a new EBSS penalty in every subsequent period. The EBSS assumes that resetting the base corrects any gap between forecast and actual costs. For these costs it does not: although the base does increase each period the forecast growth rate remains too low, so the opex under-forecast will continue to occur.

An outcome where we incur 144% of cost differences – where the differences are forecastable and entirely outside of our control – is not consistent with the EBSS objective of providing a fair sharing of efficiency gains and losses over a period.

We also note that efficiency gains and losses, under the rules, relate to the difference between outturn opex and the allowance (which are assumed to be set on a reasonable and realistic basis). The EBSS is not a mechanism to share movements in uncontrollable costs between transmission businesses and consumers more broadly.

Our proposed approach for the 2028-33 period

We recognise the AER's standard positions to both avoid category specific forecasts (to avoid an upwardly biased total opex forecast) and to not exclude uncontrollable costs from the EBSS (to ensure cost variances are shared 30:70 like other cost variances).

However, in the case of AEMO fees and land tax, the AER's stated aims are not achieved by its standard approach to forecast these costs as part of base opex and apply the EBSS as:

- A base and trend forecast of AEMO fees and land tax does not produce a reasonable or realistic forecast of total opex. These costs have, and will continue to, increase much faster than the rate of change resulting in a material cost difference that cannot be absorbed by savings elsewhere in opex.
- If the EBSS is applied to a forecast that is materially below expected costs, we will bear 144% of this cost difference. This is contrary to the objective of the EBSS which, under the Rules, is intended to be designed and implemented so that the difference between forecast and actual costs are fairly shared. That is, we should only bear 30% of deviations away from a reasonable forecast of efficient costs not 144% of the difference between expected costs and what the base and trend forecasting approach produces.

The alternative approach is to apply a category specific forecast. This approach would allow a more accurate forecast – based on AEMO's own forecasts as well as expert advice on land value movements – to be applied resolving the issues identified above.

We recognise that category specific forecasts are generally not applied to preserve the incentive properties of the framework – to provide a continuous incentive to reduce opex. However, in this case, there is limited risk for three reasons. First, the costs are uncontrollable: incentives will have no impact on the efficiency of these costs. Second, we are still subject to an incentive to reduce costs (as we will bear 100% of the cost difference in period). Third, the forecast is based on material prepared by third parties (AEMO’s own fee forecasts and independent land valuation advice), which limits any risk that the forecast is set above efficient costs.

To summarise, our proposal is not based on the uncontrollability of these costs. We are proposing a category specific forecast as it will produce a materially better forecast of total opex. Consistent with the interaction between the forecasting methodology and the EBSS, these costs should therefore be excluded from the EBSS. This avoids applying an efficiency penalty to a systematic and forecastable difference created by the forecasting methodology itself, and better preserves the fair-sharing objective of the EBSS.

Network support costs

Network support costs are payments made to third parties who help us to address network constraints and issues. We procure these services generally where this results in lower costs to consumers than traditional network solutions, such as network augmentation.

We forecast these costs by applying a category specific forecast based on the payments we expect to make, rather than through the base-step-trend forecasting methodology, consistent with the AER’s decision for the current 2023-28 period and AER decisions for other transmission networks.

Our forecast is currently based on known contracts. As we progress the development of other elements of our forecast, we will update this forecast to include costs for additional services we expect to procure over the 2028-33 period. To be clear, our forecast does not include any system security network support payments which we will instead recover through the annual pricing process rather than the building block revenue requirement.

3.4 Revenue, RAB and consumer bills

Our forecast revenue requirement, to recover our efficient costs in delivering shared transmission services, for the 2028-33 period is \$8.8b. This has been calculated using the building block method. Forecast revenue and each building block is set out in Table 3-19 below.

Table 3-19 Building block revenue requirement, forecast revenue and x-factors (\$m, Real 2027-28)

Building block	2023-28 Total	2028-29	2029-30	2030-31	2031-32	2032-33	2028-33 Total
Return on capital	4,299	1,173	1,193	1,234	1,293	1,337	6,230
Regulatory depreciation	536	162	190	181	187	130	850
Operating expenditure	1,315	333	353	359	368	375	1,788
Revenue adjustments	-62	-34	-57	-45	-43	-45	-224
Cost of corporate tax allowance	70	23	25	29	27	23	128
Annual revenue requirement (unsmoothed)	6,157	1,658	1,705	1,759	1,831	1,819	8,772

Annual expected revenue (smoothed)	6,155	1,658	1,705	1,753	1,803	1,854	8,774
------------------------------------	-------	-------	-------	-------	-------	-------	-------

X factors	n/a	-6.42%	-2.84%	-2.84%	-2.84%	-2.84%	n/a
-----------	-----	--------	--------	--------	--------	--------	-----

In setting the x-factors we have sought to minimise volatility between periods and manage financeability, noting issues could arise if revenue recovery is deferred within period.

We note that in calculating the Draft Plan building block revenue requirement, consistent with prior regulatory practice, we have applied the expenditure forecast outlined earlier and made several assumptions with respect to other elements of our Revenue Proposal.

In particular, we have assumed the AER's draft 2026 RORI will apply, notwithstanding our concerns with the AER's draft decision. A comparison of the rate of return between the current 2023-28 and forecast 2028-33 periods is shown in Table 3-20 below. While applying the draft 2026 RORI includes a lower market risk premium and equity beta, the cost of debt and risk-free rate have increased since the 2023-28 determination, resulting in a nominal vanilla Weighted Average Cost of Capital (WACC) of 6.38% rather than 5.77%.

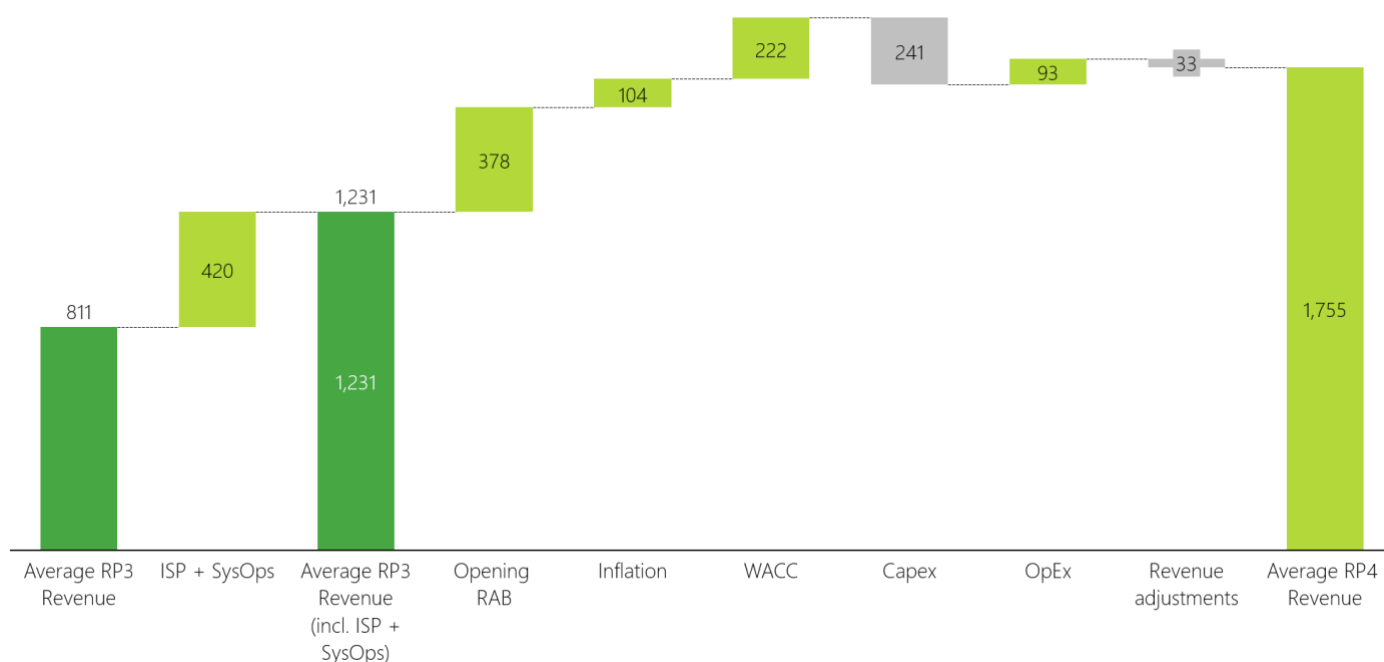
Table 3-20 Rate of return parameters applied in 2023-28 and in this Draft Plan

Component	2023-28	2028-33
Nominal risk-free rate	3.76%	5.01%
Market risk premium	6.20%	6.10%
Equity beta	0.6	0.55
Return on Equity (nominal post-tax)	7.48%	8.37%
Return on Debt (nominal pre-tax)	4.63%	5.06%
Gearing	60%	60%
Nominal Vanilla WACC	5.77%	6.38%
Expected inflation	2.92%	2.50%

We have also assumed that the AER will accept our applications to reopen the 2023-28 Revenue Determination as well as to trigger the System Security Roadmap Operational Technology contingent project.

The overall change in average revenue between what is allowed in the 2023-28 period and in our forecast for the 2028-33 period is set out below in Figure 3-29.

Figure 3-29 Changes in total revenue between 2023-28 period and 2028-33 period (\$m, Real 2027-28)



We note the figure identifies the revenue impact of:

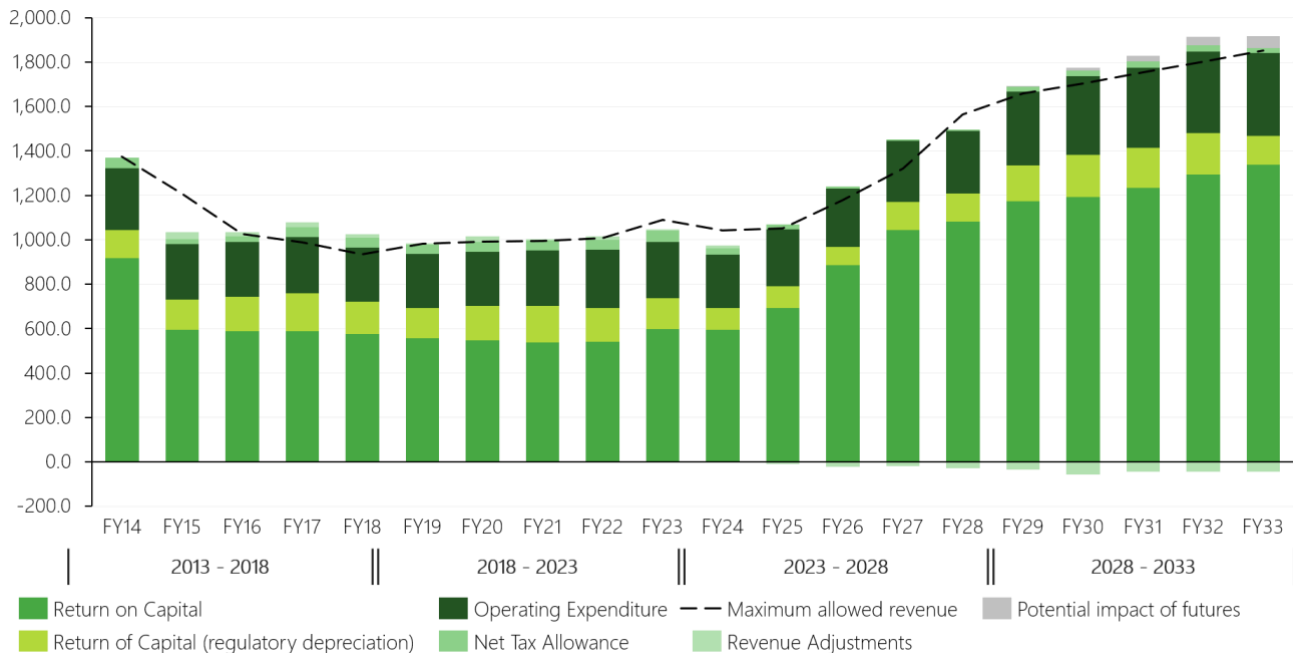
- **ISP** – ISP project capex included in the 2023-28 revenue amount, including Project Energy Connect, HumeLink and VNI West.
- **Opening RAB** – The increase in the Regulatory Asset Base (RAB) between regulatory periods.
- **Inflation** – Lower inflation assumptions increase revenue by driving a higher regulatory depreciation building block. This is because under the regulatory framework revenue is calculated using an RAB which is indexed by inflation each year and a nominal rate of return. To prevent double compensation for inflation, there is also a negative revenue adjustment to the depreciation building block based on the value of RAB indexation. Accordingly, a period on period reduction in inflation translates into lower RAB indexation, a smaller reduction to depreciation building block and in turn an increase in overall revenue.
- **WACC** – The increase in the rate of return identified above.
- **Capex** – Lower overall forecast capex. This reflects that capex (including ISP projects) is forecast to be \$3.7b, less than the \$9.1b allowed in the current period. We note that, if we exclude ISP projects in the current period, capex is increasing from an allowance of \$1.7b to a Draft Plan position of \$3.7b.
- **Opex** – Forecast opex increasing from an average of \$258m to \$348m to account for network growth, cost increases, productivity, increasing complexity, a larger proportion of ICT costs included in opex, and increasing taxes and fees.
- **Revenue adjustments** – A larger negative revenue adjustment of \$33m per year. This is driven by an increase in CESS penalties due to the expected capex overspend.

The increase in building block revenue over time is shown in

Figure 3-30 below. Revenue growth is primarily driven by the return on capital building block, reflecting the significant increase in the size of the RAB. Driven largely by ISP projects, the RAB is forecast to grow from \$7.6 billion (nominal) at the start of the 2023–28 period to \$21.6 billion (nominal) by the end of the 2028–33 period. As the RAB grows, the return on capital building block also increases, reflecting the application of a regulated rate of return to a larger asset base rather than an increase in the rate of return itself. The rate of return is determined under the AER's regulatory framework and is intended to provide a reasonable opportunity to recover efficient financing costs.

Figure 3-30 below also identifies the outcome if the data centre future arises.

Figure 3-30 Forecast Revenue Building Blocks (\$m, Real 2027-28)



While our regulated asset base, and building block revenues are growing, this increase is partly offset by the increase in energy volumes which lower average costs per customer.

We present a summary of the bill impacts associated with this Draft Plan in the Overview section. Figure 0 2 shows the indicative residential bill impacts over the current regulatory period and the next 2028-2033 regulatory period. Over the 2028-33 period, we are forecasting that the transmission component of residential consumer bills will be, on average, \$2 lower, compared to the last year of the current regulatory period (2027-28). This reduction is due to the increasing energy consumption over the 2028-33 period as well as our efforts to find opportunities to constrain cost increases.

These bill outcomes could vary for a variety of reasons: how much electricity a household or business actually consumes and how distributors and retailers allocate our costs for instance. This proposal includes a number of assumptions which, if varied, will result in a materially different pricing outcome.

This includes the AER's Draft RORI which we have applied in this Draft Plan. If market conditions, such as interest rates, or the AER's Final RORI includes changes to key parameters it will materially impact the revenue and bill outcomes included in this Draft Plan. For instance, a 50 bps increase in the WACC would increase the 2028-33 average bill outcome for the average residential consumer from \$179 to \$187 (or vice versa).

Further, the amount of energy consumed is a key input for translating our revenue forecasts into bill outcomes. Currently, this Draft Plan aligns with our assumptions for energy consumption in the 2026 TAPR. Again, revisions to this energy forecast, or in realised consumption, will materially change the bill outcomes quoted in this Draft Plan. For instance, a 10% reduction in energy consumed would increase the 2028-33 average bill outcome for the average residential consumer from \$179 to \$199 (or vice versa).

3.5 Other elements

In addition to our expenditure forecast, our Revenue Proposal must also set out how we propose incentive schemes to apply, any nominated pass through events and a pricing methodology. We provide detail on our current thinking on each element below as well as on emerging issues around large loads and data centres.

3.5.1 Incentive schemes

Our starting point for our 2028-33 Revenue Proposal, consistent with our letter to the AER on the Framework and Approach, is for the full suite of incentive schemes to apply, consistent with the AER's standard approach for all network businesses. This includes the Capital Expenditure Sharing Scheme (CESS), Expenditure Benefits Sharing Scheme (EBSS), Service Target Performance Incentive Scheme (STPIS) and Demand Management Innovation Allowance Mechanism (DMIAM).

As outlined below, we have identified some areas where adjustments to the standard approach could result in improved consumer outcomes. We are interested in CWG and AER views on these elements.

Data centre scenario risk

As outlined in section 3.2.2, under different future scenarios, the need for augmentation could significantly vary. Our approach is to adopt a conservative view on demand to ensure that we do not over-forecast our expenditure requirements.

However, there is a risk that demand outcomes require us to undertake additional projects to avoid breaching our licence conditions or to mitigate reliability risks, e.g. from higher peak loads in localised areas.

This risk can be partly managed through the contingent project mechanism. Rather than include expenditure for a project in our forecast, we can instead identify projects which will be required if certain conditions arise mid-period. Once these conditions arise, we can then apply to the AER for our expenditure allowances to be adjusted mid-period. However, risk remains, as the contingent project mechanism can only be used for projects which can be identified, probable, location specific, and exceed a cost threshold.

We recognise that the regulatory framework is designed so that we bear a degree of forecasting risk. The purpose of this risk allocation is to provide an incentive to spend efficiently. However, in the case of a material difference in demand, the opposite outcome occurs. If we respond to these demand outcomes and undertake additional projects, we will bear a significant financial penalty (30% of every dollar incurred). This creates a powerful incentive to defer projects or reduce spend elsewhere which, as the AER recognises, could result in poorer outcomes for consumers in terms of reduced service quality or higher longer-term costs.

More broadly, this raises the question of how the regulatory framework can support efficient and timely investment when demand growth exceeds forecasts. While regulatory incentives play an important role in promoting efficient expenditure, they should also support outcomes that are in consumers' long-term interests, including maintaining reliability, enabling economic growth and avoiding higher costs arising from delayed investment.

The AER, in its CESS guideline, has indicated that it may vary the application for the CESS for certain projects in limited circumstances at its own discretion. These adjustments will be made following an ex-post review – that is after expenditure is incurred.

This results in a mismatch between when clarity will be provided on how and whether the CESS will apply to these projects and when we need to make decisions. We note that we need to make two sets of decisions. First, on what demand forecast assumptions to apply in our Revenue Proposal and second, what projects to undertake mid-period.

Our initial thinking is that this mismatch could be addressed through greater clarity from the AER on how it will exercise its discretion at the end of the 2028-33 period, including whether projects driven by higher demand outcomes would be excluded from the CESS. Greater certainty would help support timely investment decisions and reduce the risk that regulatory incentives inadvertently discourage expenditure that is ultimately in the long-term interests of consumers.

Guidance of this nature could be similar to what the AER has set out for distribution networks for large bespoke connections. However, we note that it is relatively easier to identify whether a large bespoke connection is included in a demand forecast, relative to an augmentation project which is not directly linked to a specific customer connection. Accordingly, we are also interested in what information the AER considers would be helpful for us to provide in our Revenue Proposal to make future decisions on whether the CESS should apply to additional projects.

We also note, as discussed below, that there is an emerging issue relating to data centre-driven augmentation and cost recovery. Future policy developments may result in data centres contributing towards the costs of additional augmentation. However, even where such arrangements apply, Transgrid may still need to undertake substantial additional expenditure to support customer connections – just as the AER has recognised that distribution networks may incur substantial capex net of connection charges. We are interested in the AER and CWG views on how the regulatory framework should balance efficient investment incentives with consumer outcomes, including how the benefits and costs of accommodating large new loads should be assessed and allocated.

Interaction between the CESS and cost estimates

Our expenditure forecasts are based on a 'P50' cost estimate, which represents the median cost outcome with an equal probability of final costs being higher or lower. This includes cost components which can be largely uncontrollable and which have a high variance outcome, such as biodiversity credits.

An alternative approach could be to adopt a lower cost estimate for these components – e.g. the minimum we expect to incur based on the information that is currently available together with an adjustment mechanism (or CESS exclusion) for these costs.

We are currently reviewing our cost estimates of our larger projects where there is sufficient divergence between our minimum and median cost estimates to justify the additional complexity required to propose implementing a mechanism of this nature.

The Market Impact Component (MIC) of the STPIS

The MIC was originally introduced to provide incentives on transmission businesses to schedule planned outages at times which minimise the impact on spot market outcomes. However, with the shift in generation the number of binding constraints we are likely to incur maximum penalties under the MIC irrespective of what action we take.

Accordingly, the AER has found that the MIC is no longer working as intended and suspended its operation in the version of the STPIS which will apply to us in the 2028-33 period. We support the suspension of the MIC and look forward to continuing to work with the AER to develop an effective alternative.

Innovation allowance

We note that the AER has committed, in its August 2025 letter to the Commonwealth Treasurer, to consult on the introduction of a standard innovation allowance for all electricity network businesses with no ex-ante proposal and assessment under a use-it-or-lose-it funding arrangement.

We support the introduction of this kind of scheme as we consider that the consumer benefits from innovation, through cost reductions and service improvements, can be substantial. We note that the small-scale incentive scheme outlined in the Rules provides an avenue for any scheme developed to be implemented in the 2028-33 period.

We intend to work with the AER and the CAG to seek their views on whether and how an innovation allowance could be applied.

3.5.2 Cost pass through events

The regulatory framework is based on ex-ante incentives. This is primarily implemented by setting revenues based on forecast expenditure. Regulated businesses are then exposed to forecasting risk and in turn are given an incentive to reduce costs.

The cost pass through mechanism provides an alternative to including an expenditure forecast for specific items. It allows expenditure to be included if, and only if, pre-specified generally uncertain and uncontrollable events occur and result in a material change in cost.

To ensure that the mechanism works in consumer interests, we recognise that there is a balance to be struck between not undermining our incentive to manage forecasting risk and ensuring networks are not incentivised to under-invest to avoid financial penalties despite a material change in circumstances occurring.

There are two main controls which work to ensure that the incentives created work in consumers' interest. First, a materiality threshold applies to the events. Next period, this threshold will be about \$18m, one of the highest of all businesses regulated by the AER.

The second control is a general limit to on the number of cost pass through events. These events must be pre-specified in the Rules or as part of a Revenue Determination. In reviewing 53 recent AER decisions we have identified 38 unique events which have been proposed and not been accepted by the AER.

While we can nominate additional cost pass through events to apply (beyond those set in the Rules), our initial position is to limit these to the standard set of events that the AER usually accepts: the natural disaster, terrorism, insurer credit risk and insurer coverage events. We intend to define these events using the definitions previously approved by the AER. The one exception to this is the System Security cost pass through event which we discuss further in section 3.2.3.

3.5.3 Pricing methodology

As part of our 2028-33 Revenue Proposal, Transgrid is required to submit a Pricing Methodology for prescribed transmission services for the 2028-33 regulatory period.

Our Pricing Methodology must comply with:

- the pricing principles in clause 6A.23 of the NER, and
- the AER's Pricing Methodology Guidelines.

In accordance with this framework, the Pricing Methodology provides the rules-based approach used to:

- allocate the aggregate annual revenue requirement (AARR) across categories of prescribed transmission services,
- determine how this revenue is recovered from transmission customers, and
- establish the structure of transmission prices, including locational and non-locational components.

The regulatory framework prescribes key requirements for how transmission charges must be determined each year and, as a result, pricing methodologies across the NEM are broadly consistent.

Proposed take-or-pay pricing for large loads

We are proposing amendments to our 2028-33 Pricing Methodology to introduce take-or-pay pricing for certain large inverter-based loads, including data centres.

Under the existing pricing methodology, transmission charges are largely based on a customer's actual maximum demand in a billing month. This approach has historically worked well when demand growth and investment were both gradual and diversified across a broad customer base. In those circumstances, a customer's actual monthly demand provided a good measure of their footprint on the network and enabled the costs of network investments to be shared equitably across all customers.

The emergence of new very large loads, such as data centres, presents a different risk and investment profile for the network. These customers seek access to substantial amounts of network capacity, requiring significant network augmentation investment to accommodate their connection. However, their demand typically ramps up progressively over several years and there is a risk that their demand may not ultimately materialise at the level originally anticipated.

Because Transgrid's revenue is fixed under the regulatory framework, if the charges paid by large customers do not cover the costs they impose, the shortfall must ultimately be recovered from other transmission customers. This can result in existing customers facing higher charges to fund network investments driven by new large loads whose demand has not materialised. Under the existing approach, there is also an incentive for large loads to seek connection at a capacity beyond their likely requirements 'just in case', while paying charges based only on their realised demand. This can impact how we plan and invest to meet the future needs of all transmission customers and may mean that the network is not put to its best use.

The current approach to charging large loads such as data centres can also have efficiency and utilisation consequences beyond cost recovery. Given network capacity is scarce, connections sized around a level of demand that does not eventuate can delay or prevent the connection of other customers with genuine and more timely demand. Where this occurs, the network may not be put to its most efficient use, and customers forgo the lower network charges that better utilisation would have delivered.

To address these risks, we are proposing that eligible large inverter-based loads be charged on the basis of their contracted maximum demand rather than actual demand. The proposed approach would better align transmission charges with the level of network capacity a large load requires, and support more efficient network investment and utilisation. It would also reduce the risk of other customers bearing costs driven by large loads, or missing out on lower charges a better utilised network would have delivered.

The proposed reforms are consistent with broader policy discussions underway across the energy sector regarding the efficient integration of data centres, including work being progressed through NSW Government data centre reforms and the Australian Government's recent Rule Change proposal to the AEMC.

Through these reforms, Transgrid will continue to engage with governments, consumer representatives, distribution networks and other stakeholders to develop an equitable cost allocation across network users that is aligned to our key policy principles for data centres:

- It is a major economic opportunity and NSW should actively support it;
- Consumers must be no worse off; and
- Speed matters – rules must be practical to implement now.

This remains an active area of policy and regulatory development, and the proposed updates to our Pricing Methodology are just one way to manage the impacts of data centres. We will continue to progress the proposal through stakeholder engagement and regulatory processes, with any necessary refinements incorporated through future stages of the Revenue Proposal.

Other proposed updates to the 2028-33 Pricing Methodology

In addition to take-or-pay pricing, we have identified a set of other limited and targeted updates to the Pricing Methodology for 2028-33. The identified targeted updates are focused on:

- compliance with updated regulatory requirements,
- improving transparency and clarity, and
- managing stakeholder expectations regarding how the methodology operates in practice.

The proposed updates improve the clarity and robustness of the methodology and do not materially change the structure or operation of transmission pricing.

Table 3-21 Summary of 2028-33 Pricing methodology updates

#	Update	Description	Purpose
1	AARR description, interconnector cost allocation, and regulatory updates	Update the methodology to clarify how the total regional AARR is determined, including how interconnector transfer amounts are incorporated, provide illustrative examples under cost allocation agreements, and incorporate any other targeted amendments necessary to reflect recent changes to the regulatory framework.	Mandated (Rule changes and AER guideline updates)
2	Removal of redundant pricing objectives	Remove pricing objective statements that do not influence outcomes due to the prescriptive regulatory framework	Improve clarity and manage expectations
3	Transparency on data inputs and adjustments	Add explanatory guidance on when and how historical data may be adjusted, including application of materiality thresholds and supporting information requirements	Improve transparency and expectation management
4	Clarification of pricing methodology scope	Clarify that investments delivered under the NSW Electricity Infrastructure Investment (EII) framework are outside the NER pricing methodology	Improve scope transparency
5	Drafting improvements	Review and update wording to ensure the methodology is clear, consistent and robust over the regulatory control period	Document quality and usability



Contact details

For all enquiries regarding the
Draft Plan, contact:

your.voice@transgrid.com.au

© Transgrid 2026. All rights reserved. NSW
Electricity Networks Operations Pty Limited
(ACN 609 169 959), as trustee for NSW
Electricity Networks Operations Trust (ABN
70 250 995 390). Registered business
name is Transgrid (ABN 70 250 995 390).

transgrid.com.au