TransGrid

2023-28 Expenditure Forecasting Methodology

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1. Introduction

This Expenditure Forecasting Methodology outlines the methodologies that we propose to use to prepare our operating expenditure (opex) and capital expenditure (capex) forecasts for our 2023-28 Revenue Proposal that we will submit to the Australian Energy Regulator (AER) in January 2022. This document has been prepared for submission to the AER in June 2021, as required under clause 6A.10.1B of the National Electricity Rules (NER)[1] and in accordance with the AER's Expenditure Forecast Assessment Guideline[2].

The purpose of this document is to inform stakeholders about our forecasting methodologies, and to consult with them about the application and the resultant forecasts, prior to submitting our regulatory proposals to the AER. Should this engagement lead to a change in the methodologies that we use to prepare our forecasts, the reasons for any change will be explained in our revenue proposal.

The details contained in this document are based on the information available at the time of publication.

1.1 About our network

We operate and manage the high voltage electricity transmission network in NSW and the ACT. Our network connects more than three million homes, businesses and communities to a safe, reliable and affordable electricity supply. Our transmission network transports electricity from generation sources such as wind, solar, hydro, gas and coal power plants to large directly connected industrial customers, and the distribution networks that deliver it to homes and businesses. Comprising 110 substations, over 13,051 kilometres of high voltage transmission lines, underground cables and five interconnections to Queensland and Victoria, our network is instrumental to the National Electricity Market (NEM), supporting a 14 GW maximum demand, and providing an annual energy throughput of 68 TWh[3].

Operating a safe, reliable and efficient transmission network which delivers value to customers is at the heart of what we do. To continue doing this, we must maintain and prudently invest in our network. Our network is at the heart of the NEM and is therefore at forefront of the profound changes to the energy supply landscape. We must respond and remain agile to change by continuously adapting and innovating. In this context, we have further improved and refined our methodologies to forecast capex and opex for the 2023-28 regulatory control period.

1.2 Our engagement with stakeholders

Engagement is integral to our business. Ongoing dialogue with our customers and other stakeholders is essential to ensure we continue to provide services tailored to suit their needs in a rapidly changing energy system. We actively listen to our community stakeholders, our customers and our industry partners on all aspects of our business including strategic, project and operational matters. The insights we gain from this engagement inform our strategic direction, our asset management approach, our investment priorities and options and a range of other considerations.

Our ongoing engagement program includes, but is not limited to, formal and informal engagement with:

> TransGrid's Advisory Council (TAC)

1 https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current
2 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-forecast-assessment-guideline-2013
3 The 2019/20 financial year recorded NSW region demands of 13,957 MW / 67,700 GWh with a 10% and 50% PoE weather-adjusted maximum demand of 14,380 MW and 13,360 MW respectively.

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> individual customers
> Federal, New South Wales (NSW) and Australian Capital Territory (ACT) Governments
> regulatory bodies including the Australian Energy Regulator (AER), the Australian Energy Market Operator (AEMO), the Australian Energy Market Commission (AEMC), the Energy Security Board (ESB), the ACT Independent Competition and Regulatory Commission (ICRC) and the NSW Independent Pricing and Regulatory Tribunal (IPART)
> local communities and councils
> almost 17,000 landowners who host current or potential future infrastructure, and
> registered participants and interested parties through the Regulatory Investment Test (RIT-T) market consultation process. Through this process, we work closely with third parties to consider potential non-network solutions to network constraints or limitations noting that non-network alternatives are increasingly providing viable alternatives to network solutions.

Our ongoing business engagement provides us with rich and constructive feedback around all elements of our service offering, and our future challenges in providing transmission services. This feedback is critical to informing our 2023-28 Revenue Proposal.

Over the last 18 months, we have undertaken extensive engagement particularly on major ISP Projects such as Project EnergyConnect (PEC), HumeLink, the Queensland to New South Wales Interconnector (QNI) and the Victoria to New South Wales Interconnector (VNI Minor).

We have, and will continue to engage with, the TAC on a broad range of issues impacting our business operations and relating to our 2023-28 Revenue Proposal, such as:

> our Network Vision, which is our views of the future network required to deliver prescribed transmission services that has regard for current energy market context and drivers for change.
> the key external drivers of our investment in the next regulatory period, and
> the key projects and programs we propose to deliver in response to these drivers and to build our Network Vision.

For the purposes of engaging on the development of our 2023-28 Revenue Proposal, we have expanded our TAC's membership to include a broader range of stakeholder organisations to facilitate more balanced and independent views. **Attachment A** sets out member details of our expanded TAC.

The TAC will also meet more regularly to focus on reset issues including through targeted deep dive workshops on specific matters such as our 2023-28 opex and capex forecasts. These workshops are open to a broader range of stakeholders than our TAC, such as generators and battery owners / providers, to attend. We are also undertaking surveys and other formal research through focus groups issues, which are important to inform our 2023-28 Revenue Proposal.

Our engagement approach for our 2023-28 Revenue Proposal will leverage our extensive ongoing engagement activities to provide stakeholders and the AER with information, and seek their views, on our Revenue Proposal as efficiently as possible.

Table 1 provides a high level overview of the consultation approach to our 2023-28 revenue proposal.

Table 1: Engagement approach for our 2023-28 Revenue Proposal

Channel	Form of use	Frequency out to Feb 2022
TAC (expanded to include a broader range stakeholders)	The TAC will be the primary channel for high-level reset engagement. It has been expanded to include additional members to ensure we receive a broad cross section of views and input. Attachment A sets out member details of our expanded TAC. Other stakeholders including the AER and AER Consumer Challenge Panel (CCP) members will be invited to attend TAC meetings from time to time.	Monthly
Deep dive workshops (part of the TAC meetings)	Deep dive workshops will facilitate detailed discussions on key aspects of our 2023-28 Revenue Proposal including our expenditure forecasts.	2+
One-on-one	One-on-one meetings will allow us to tailor our engagement to the needs, interests and characteristics of our customers including large energy users and other stakeholders such as industry, government and customer group representatives.	As required
Surveys and formal research	Surveys, focus group research and interviews will allow us to better understand the views of end customers on specific aspects of our proposal.	To be determined
Annual Transmission Planning Report forum	The Transmission Annual Planning Report (TAPR) forum provides an opportunity to present to industry and stakeholders, and seek feedback on, our Network Vision and 10 year planning horizon. In particular, the forum provides a valuable opportunity to discuss the future needs of the network and to collect feedback on our process and assumptions to improve our planning. Our TAPR is published on our website.[4]	1

[4] TransGrid's Transmission Annual Planning Report

2. Our investment drivers approach, and key inputs

This Chapter explains:

> the key external drivers of our expenditure in the 2018-23 regulatory period
> our investment governance process, which ensures that we are making prudent and efficient investment decisions
> how we identify and assess substitution possibilities between capex and opex to ensure the lowest cost solutions are adopted in order to deliver maximum value to our customers, and
> the key inputs used in developing our expenditure forecasts.

2.1 Drivers of Expenditure

Over the 2023-28 regulatory period, the power system will continue to transform due to:

> the retirement of thermal generators and their replacement with renewables, leading to the increasing penetration of intermittent generation
> the uptake of distributed energy resources (DER)
> the electrification of vehicles and industry
> climate change, driving amongst other things more intense and longer weather events, and
> an increasing expectation on business focus on reducing carbon emissions.

As a result, significant changes are occurring the National Electricity Market (NEM) and regulatory reforms are underway to facilitate these changes including:

> the Energy Security Board's (ESB), though its 2025 market design review (ESB 2025 project)
> Australian Energy Market Operator's (AEMO's) ISP which sets out the optimal development path for the NEM to ensure that NEM is planned and coordinated to provide the best value for customers, and
> the NSW Government, through the NSW Electricity infrastructure roadmap.

The key external drivers of our expenditure in the 20123-28 regulatory period include:

> AEMO's ISP and NSW Energy Infrastructure Roadmap
> economic conditions
> increasing renewable generation and change in generation mix
> climate change and resilience
> maintaining long term asset condition
> increasing cyber security threats to critical infrastructure
> technology change and consumer choice, and
> health and safety, maintaining compliance.

In responding to these drivers our forecast expenditure focuses on delivering value for money services including by leveraging new technology and innovation where possible to meet customers' needs.

2.2 Investment Approach

We have clear and accountable expenditure governance arrangements (our Prescribed Network Capital Investment Process) which set out the process by which our investments are identified, evaluated and delivered. This process includes five steps to ensure a prudent and efficient investment portfolio that maintains the provision of prescribed network services. Our Governance arrangements deliver value for money for customers by ensuring that the works are no more than is required to meet the need at the lowest sustainable cost:

1. **Identify the need or opportunity:** we assess emerging trends and issues, such as asset condition data and demand forecasts, to determine needs and associated risk to meet the NER capex objectives. We also identify opportunities to reduce costs and/or deliver benefits to consumers, such as reducing network congestion, which results in lower market costs. Where possible, we consider how new and innovative technologies, processes and systems could be used to deliver environmentally sustainable, value for money services to meet customers' needs. These needs and opportunities align with our strategic direction and policies, such as our Network Vision and Network Asset Strategy as part of our ISO 55001 accredited asset management system.
2. **Evaluate options:** we identify options to address each need and opportunity, including any credible technological innovations and maintenance options and prepare feasibility studies for each option based on an engineering review of the scope. We then undertake an economic assessment of the options, which includes a cost benefit assessment against the base case and optimal investment timing analysis. Opportunities are assessed against the economic benefits they are expected to provide to customers. A preferred option is selected for each need.
3. **Investment portfolio:** where the preferred option to address a need requires an investment or an opportunity delivers net benefits, it is added to the investment portfolio. The portfolio is then assessed and optimised, ensuring each investment is justified and prioritised to maximise the benefits we deliver to our customers - this is discussed in section 4.4. Our investment portfolio is submitted annually for endorsement by our Executive Investment Review Committee, which oversees the prudence and efficiency of expenditure, prior to approval by our Board. Applicable projects proceed to the RIT-T process.
4. **Project approval and delivery:** the individual projects, which make up the approved investment portfolio proceed to concept scoping, following which each project is approved by the appropriate financial delegate. The business case and justification is re-confirmed at this stage before the project is approved for delivery. This is overseen by the Executive Investment Review Committee.
5. **Project performance monitoring:** the operational and financial performance of projects is monitored through specific performance metrics. The efficient delivery of projects is monitored monthly by senior management in forums including the Works Program Executive Committee and Delivery Review Committee.

2.3 Opex-capex trade-offs

Throughout the expenditure forecasting process we seek to identify capex/opex trade-offs to minimise total asset life cycle costs for the long-term interests of our consumers. Our investment approach described in section 2.2 includes consideration of capex/opex trade-offs during the needs identification and options evaluation stages, including new technologies which may influence this trade-off. We systematically consider trade-offs between opex and capex in the following ways:

> assessment of maintenance options as part of asset renewal and replacement evaluations
> demand management programs including application of the RIT-T to seek non-network and competitive alternatives to network-based capital projects
> investment in assets that will function in longer-term climate change scenarios, and
> appropriate equipment, design and maintenance standards.

This approach ensures that the efficient trade-off between opex and capex has been considered at the asset component level (e.g. design specification), at need level (e.g. replacement decisions) and at a network level (e.g. non-network options).

2.4 Key inputs

Table 2 sets out the key inputs that are used in developing our expenditure forecasts.

Table 2 – Key inputs

Item	Description
Customer engagement	Our engagement approach is described in Chapter 1. We will use the feedback and views from this engagement, including on matters such as service level performance, reliability and investment, to inform our positions and shape our expenditure forecasts and plans.
Demand, energy and customer numbers	Demand forecasts at connection points are used as the basis for load driven Augex. We receive demand forecasts from relevant distribution network service providers (DNSPs) (and we verify these forecasts). Customer numbers and energy are used to inform our opex forecasts.
Base year (opex)	Opex for the 2021-22 regulatory year will be used as the base year to determine our 2023-28 opex forecast using the base-step-trend approach, which is the AER's preferred forecasting methodology.
Cost escalators	Real cost escalators are applied to reflect changes in in the cost of inputs (i.e. labour and material) above or below the consumer price index (CPI) in the forthcoming regulatory period. An independent expert will forecast labour cost escalators over the 2023–28 period. We expect that real price growth in materials will escalate at CPI in the forthcoming regulatory period (i.e. there are no real price changes for materials)
Forecast inflation	Forecast inflation will be based on the AER's revised approach for estimating expected inflation as set out in its Final Position Paper in December 2020[5].
Unit rates and project estimates	Project and program costs are based on cost estimates from our MTWO estimation database or competitively sourced panel contractor rates. An independent expert will be engaged to review the cost estimates underpinning our expenditure forecasts to

[5] AER, Regulatory Treatment of Inflation, Australian Energy Regulator, December 2020

Item	Description
	ensure that they are reasonable and reflect the prudent and efficient costs of delivering prescribed transmission services.
Asset information, condition reports and network performance data	Asset information, condition assessment data and asset performance outcomes are used to calculate asset health indices. Asset performance data is also used to develop probability of failure curves using statistical models (e.g. Weibull curve). Our asset health index and probability of failure inform our risk quantification models.
Risk quantification models	Risk models quantify the risk to the community for key risk areas, including public safety, worker safety, bushfire, environment and reliability. These quantified risk values inform our business case analysis of investment needs. These models consider the likelihood and consequence of risks occurring. Inputs to these models, such as AER's Value of Customer Reliability (VCR) for unserved energy are independently derived.
Environmental and Safety obligations	The *Electricity Supply (Safety and Network Management) Regulation 2014* (NSW) and *Utilities (Technical Regulation) (Electricity Transmission Supply Code) 2016* (ACT) set out the requirements we must comply with to ensure electrical safety across the asset lifecycle to the community and our workers and contractors. We also undertake activities to comply with our environmental obligations under the *Environmental Planning and Assessment Act (NSW)* and *Planning and Development Act (ACT)* for development planning approvals, as well as other environmental legislation such as the *Protection of the Environment Operations Act (NSW)* in relation to air, water, noise and land pollution.
Compliance obligations	There are numerous compliance obligations, in addition to our environmental and safety obligations, which we factor into the development of our expenditure forecasts. These include, amongst other things, obligations such as meeting IPART's reliability. As a critical infrastructure owner and operator we also have obligations to adopt a prudent approach to managing security risks and threats impacting on our network assets, information and associated facilities and infrastructure.
Network Transformation Opportunities	We are committed to developing and implementing new ways to manage our business and respond to challenges, as well as opportunities for innovation, to increase productivity and improve customer outcomes. Our expenditure forecasts will reflect new approaches, technologies and opportunities to provide prescribed transmission services where possible.

3. Our opex forecasting methodology

This Chapter explains the methods that we propose to use to forecast our prudent and efficient opex for prescribed transmission services for the 2023-28 regulatory period. It:

- explains the opex categories used
- overviews the opex forecasting approach, and
- explains the key forecasting steps.

3.1 Opex Categories

We categorise opex as either controllable or non-controllable.

Controllable opex includes:

- **maintenance and operations** – system recurrent costs directly attributable maintaining and operating the transmission network including maintenance, system operations and grid planning and other costs such as insurance, property management and environmental;
- **support costs** – non-system recurrent costs that encompass activities and services which are not directly related to maintaining or operating the network including corporate governance, customer relations, regulatory, finance, information technology, and human resources and payroll; and
- **benchmark costs** – which are other cost, such as debt raising costs, that are typically set based on benchmarks rather than our actual costs. These costs are generally excluded from our opex reported for regulatory purposes.

Non-controllable costs include insurance, rates, taxes and charges, and network support. These costs items must also be included in the forecast opex.

We intend to forecast opex using the base-step-trend approach discussed in section 3.2.

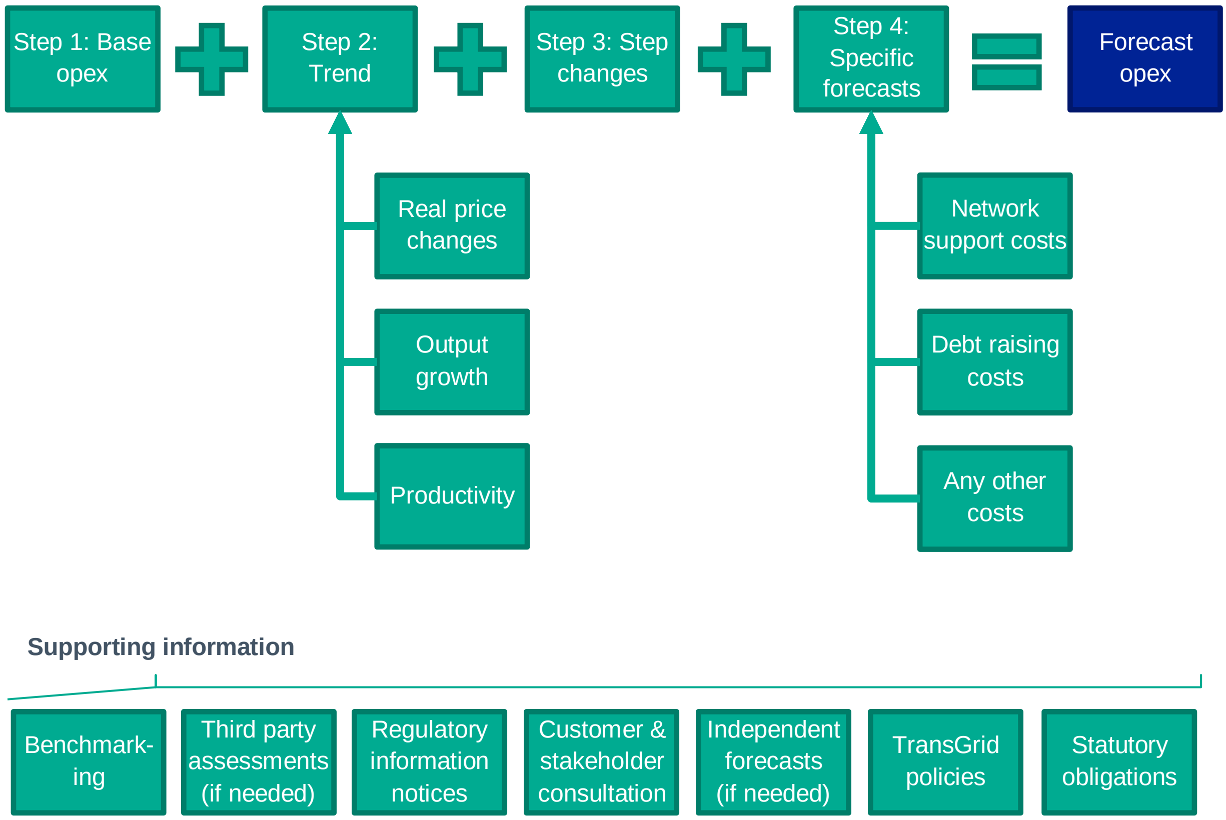
3.2 Overview of Opex Forecasting Approach

Consistent with the approach accepted by the AER for the 2018–23 period and the AER's Expenditure Forecast Assessment (EFA) Guideline, we will forecast opex over the 2023–28 period using the base-step-trend approach. The base-step-trend approach involves a forecast developed at an aggregate level, rather than for each of the 'operating expenditure categories' detailed in the AER's Economic Benchmarking Regulatory Information Notice (RIN).

Figure 1 overviews the four steps in the base-step-trend approach:

- **Step 1 –** nominate the efficient revealed cost base year (base opex)
- **Step 2** – apply rate of change adjustments
- **Step 3** – add or subtract step changes
- **Step 4** – add specific forecasts for any other costs that were not included within steps 1–3.

Figure 1: Opex forecasting approach



Each of the four steps is explained in detail below:

Step 1 – efficient base opex

The initial step in preparing a base step trend opex forecast is to select a base year that represents a realistic expectation of the efficient and sustainable on-going level of opex that is required to provide prescribed transmission services in the next regulatory period.

The AER has indicated a preference for using the most recent year for which audited data is available. As a result, we consider that 2021-22 will be the most representative base year to forecast prudent and efficient opex. Our initial Revenue Proposal, which is due to the AER by 31 January 2022 will reflect our board approved 2021-22 budget[6] and our revised Revenue Proposal, which is due to the AER to the AER in December 2022 will reflect our actual 2021-22 expenditure.

Step 2 – determine trend

The trend combines three elements into a rate of change:

> **real price changes** – expected changes in the cost of inputs (i.e. labour and material) will be higher or lower than CPI in the forthcoming regulatory period. We will engage an independent expert to forecast labour cost escalators over the 2023–28 period. We expect that real price growth in materials will escalate at CPI in the forthcoming regulatory period (i.e. there are no real price changes for materials).

> **output changes** – changes in the type and volume of services that we provide to efficiently meet consumer needs and our regulatory obligations. Our output growth forecast will be determined based

[6] Our 2021-22 actual expenditure will be available in August 2022.

on movements in customer numbers, ratcheted maximum demand, energy throughout, and circuit length, in accordance with the AER's preferred approach

- **productivity changes** – changes in productivity expected to be achieved in the next regulatory period. We will consider what productivity changes may reasonably be expected over the 2023–28 period, which may rely on outputs from econometric modelling.

The overall rate of change will be applied to base opex to trend that opex over the 2023–28 period.

Step 3 – step changes

Step changes are either (a) costs applicable to the next regulatory period that are not reflected in our base year costs and are not captured by the rate of change or (b) costs that are reflected in our base year costs but are not expected to persist over the next regulatory period. Step changes can include for example new costs that will be incurred in the next regulatory period and/or costs that will no longer apply.

We will explain and justify any step changes relevant to the 2023–28 regulatory period in our Revenue Proposal.

Step 4 – specific forecasts

We will forecast certain cost elements, such as network support costs and debt-raising costs, by adopting a category specific approach to forecast these items.

Network support costs are incurred in accordance with network support agreements, which allow us to procure network support and control ancillary services, to improve network capability through non-network solutions. Providers of network support services may include local generation, cogeneration, demand side response and services from a Market Network Service Provider (MNSP). We will review existing and potential contracts for the 2023-28 period to determine whether to include an allowance for these costs or rely on the network support through pass arrangements under the NER.

Debt raising costs are costs incurred over and above the debt margin when new debt is raised, or current lines of credit are renegotiated or extended[7]. We will engage an independent expert to calculate an appropriate debt raising cost benchmark. We will then estimate efficient debt raising costs by inputting the benchmark into the AER's Post-tax Revenue Model.

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7 These costs include arrangement fees, legal fees, company credit rating fees and other transaction costs.

4. Our capex forecasting methodology

This Chapter explains the methods that we propose to use to forecast our prudent and efficient capex for prescribed transmission services for the 2023-28 regulatory period. It:

- explains the capex categories
- overviews the overall approach to forecasting capex, and
- explains the specific forecasting method to be applied for each capex category.

4.1 Capex Categories

We are required to present our capex forecasts in the following categories for the purpose of the AER's Category Analysis RIN reporting, as described in Table 3.

Table 3 – Capex categories

RIN Category	Expenditure Elements	Service Description
1. Repex	> Network asset replacement > Physical security of network assets > Network asset compliance	Investment required to meet and maintain asset safety compliance obligations and performance levels through replacement of assets, triggered by assets that are approaching technical end of life
2. Augex	> Base Augmentation (compliance, demand, economic benefits) > Major Augmentation Projects > System Services > Strategic Property > NCIPAP	Investment required to meet and maintain power system compliance obligations and performance levels through augmentation of the network, triggered by changes in electricity demand, fault levels, or power flows (for example)
3. Connections	> Connections	A subset of Augex, this category relates to augmentation of the network to enable connection of new direct-connected customers or distribution system loads
4. Contingent projects	> NSW Government Energy Roadmap projects (to be confirmed once Electricity Infrastructure Investment Act 2020 (EIIA) has been finalised) > Major Augmentation Projects	Investment to augment the network when triggered by market or other needs. We do not include the costs of these projects in our ex-ante expenditure forecasts given the uncertainty around timing and costs of these projects.
5. Non-Network	> Information and communication technology, and cyber security > Fleet (motor vehicles, mobile plant and tools) > Property (depots and office buildings)	Investment required to support the business in providing its prescribed transmission services including IT systems, fleet, tools, depots and office buildings

We incur, and report, our capitalised network and corporate overheads as a separate category of capex in the AER's annual Category Analysis RIN.

4.2 Changes to our forecasting methodologies

We continuously review our capex forecasting methodologies to ensure they remain accurate, reliable, robust and fit for purpose. This ensures that our capex forecasts derived using these methodologies are prudent and efficient.

We have built on our robust investment process and made changes to our forecasting methodology to address the AER's feedback in its 2018-23 Revenue Determination, which it subsequently reflected in its guidance notes[8]. These changes include:

> implementing a new Asset Analytics and Investments Tool to calculate network asset risk, prioritise investments and analyse the resultant network investment portfolio. This replaces our previous Investment Risk Tool

> reviewing and updating our risk quantification and cost of consequence inputs to address concern that our potential consequence values were too high. This includes using novel inputs (such as human movement data for public safety modelling) and the latest industry approaches to modelling the range of potential consequence outcomes (such as bushfire propagation models).

> modifying our assessment of the optimal timing of network investments so that it aligns with the AER's preferred approach. Our assessment also demonstrates that our forecast investments offer net benefits and/or are required to meet compliance obligations

> introducing changes to how we assess the overall forecast for efficiencies and deliverability, and

> broadening our top down assessment techniques to challenge our forecast investments. These are listed in Table 4.

We have also made general process improvements which include:

> streamlining the documents which make up our Prescribed Network Capital Investment Process.

> incorporating our 'As Low As Reasonably Practicable' (ALARP) compliance assessment into the net benefits calculation, to provide a more transparent view of the value our investments will deliver to consumers, and

> applying the latest cost estimate inputs to our forecasts

> aligning our economic justification template with industry best practice.

4.3 Overview of capex forecasting approach

Our total forecast capex is derived by aggregating expenditure forecasts developed by sub-category of capex. Table 4 summarises the methodology used to derive forecast capex by sub-category. We apply top down validation techniques to ensure our forecast capex is prudent and efficient and meets the NER requirements to:

> meet the expected demand for prescribed transmission services over the period

> comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services

> maintain the quality, reliability and security of supply of prescribed transmission services, and

[8] Including the AER's asset replacement planning application note (released January 2019)

- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

We apply our Prescribed Network Capital Investment Process discussed in section 2.2 to determine our forecast capex for all categories of capex.

Table 4 summarises our forecast method by capex category including the top down assessments that we apply.

Table 4 – Our capex forecasting methods

RIN Category	Key inputs	Our bottom-up forecasting method	Top down tests applied
Repex	> Asset information > Asset condition reports > Network performance data > Electricity Network Safety Management System	> Calculate a Health Index using condition indicators relevant to each specific asset type and determine an Effective Age of the asset > Apply probability distributions to determine the expected probability of failure > Calculate the Risk Cost based on the expected likelihood of consequence and consequence of failure > Identify assets which may form part of a need for investment > Identify credible options to address the identified need and estimate the cost of these options, including new technology options > Perform cost-benefit analysis of the risk cost (and any other benefits) against the cost of feasible options in Net Present Value terms, demonstrating the value and benefit provided to our customers > Determine the optimal timing of the investment	> Trend analysis of asset replacement volumes and asset age profiles > Predictive model of forecast asset replacements, including the AER's Repex model > Benchmarking against other TNSPs > Sensitivity testing and scenario analysis
Augex	> AEMO's ESOO > NSW transmission reliability standard published by IPART > Load forecasts	> Identify existing or emerging constraints, needs and opportunities related to reliability standard compliance, demand growth, economic benefits and system services. > Calculate the forecast expected risk or lost opportunity cost associated with the constraint, taking into account the probability	> Comparison to AEMO regional load forecasts > Comparison to DNSP load forecasts > Trend analysis of historical augex expenditure > Sensitivity testing and scenario analysis

RIN Category	Key inputs	Our bottom-up forecasting method	Top down tests applied
		and consequence of the risk materialising > Identify credible options to address the identified need and estimate the cost of these options, including new technology options > Perform cost benefit analysis of the avoided risk cost and/or economic benefits against the cost of the feasible options in Net Present Value terms, demonstrating the value and benefit provided to our customers > Determine the optimal timing of the investment	
Connections	> Distribution Network Service Provider joint planning > Load forecasts	> Identify existing or emerging constraints and needs through the joint planning process > Calculate the forecast expected risk associated with the constraint, taking into account the probability and consequence of the risk materialising > Identify credible transmission and distribution network options to address the identified need and estimate the cost of these options, including new technology options > Perform cost benefit analysis of the avoided risk cost and/or economic benefits against the cost of the feasible options in Net Present Value terms as a joint assessment with the DNSP > Determine the optimal timing of the investment	> Comparison to AEMO and DNSP load forecasts > Trend analysis of historical augex expenditure > Sensitivity testing and scenario analysis
Non-Network ICT	> Cyber security requirements > ICT infrastructure and application life > Business processes	> Identify needs, such as applications at end of life > Assess ongoing business need, performance and market trends to develop options to address the need	> Trend analysis of past expenditure > Benchmarking

RIN Category	Key inputs	Our bottom-up forecasting method	Top down tests applied
		> Apply a cost model based on unit rates and project specific estimates to each option > Perform cost benefit analysis of the benefits against the cost of the feasible options in Net Present Value terms	
Non-Network Other	> Fleet vehicle/plant usage and age > Property/building condition assessments > Property standards such as Building Code of Australia > Property legislation and council orders	> Identify needs, such as fleet vehicles at end of life or property condition > Assess ongoing business need and develop options to address the need > Apply a cost model based on unit rates and/or project specific estimates to each option > Assess business support need for the investment to proceed	> Trend analysis of past expenditure
Network and corporate overheads	> Corporate support and management services by the corporate office that is not directly attributable > Maintenance support, Network monitoring and control, Asset management support that is not directly attributable	> Apply an assumed mark up to forecast direct internal labour based on current regulatory period experience and outturn costs	> Assume that 25 per cent of capitalised overheads vary with direct capex and that 75 per cent is fixed at current levels.

4.4 Forecasting Steps

Step 1 – identify the need

All of our investments address a need or opportunity. Needs typically address risks requiring management within tolerable levels whereas opportunities typically deliver a benefit such as reduced costs to consumers. We focus on identifying needs and opportunities that efficiently support the continued delivery of a safe, reliable and secure power system. We consider both traditional infrastructure and new and innovative technologies, processes and systems to ensure we continue to provide value for money services to meet customers' needs.

The process for identifying needs in three broad capex categories are:

> Repex: we use asset attribute and condition data to calculate the expected risk of asset failure (the ‘do nothing’ base case). When we consider the risk may require mitigation through capex investment, these assets are captured in a need and options proposed to address the need (e.g. altered maintenance, refurbishment or replacement). We assess and benchmark the inputs to our risk calculations against independent and industry reference sources, where available.

> Augex: our Augex forecast will consist of load driven and non-load driven expenditure:

  – Load driven expenditure relies on demand forecasting. We forecast demand by considering the underlying non-weather sensitive demand, make adjustments to this based on the trends for energy efficiency and DER, factor in planned changes to spot loads and correct for prevailing weather conditions in the region for each season. We consider multiple demand scenarios in our assessments, validate connection point forecasts with the DNSPs and compare our forecasts with AEMO’s forecasts.

  – Non-load driven expenditure addresses compliance obligations that we must comply with for reliability of supply as well as network constraints that offer opportunities for economic benefits to the market and consumers if relieved.

  – we calculate the value of risk associated with the network thermal and stability constraints that are driven by load or non-load factors as well as the benefits of pursuing opportunities and identify options to address these needs and opportunities, including network and non-network solutions.

> Non-network capex: this expenditure addresses business support needs including:

  – ICT investment to keep our ICT assets protected and secure, replace assets at the end of their useful life and update applications, which support the business. ICT also considers opportunities to deliver improvements in safety, customer experience and efficiency through digital solutions.

  – Fleet investment in vehicles and plant to allow us to efficiently build, operate and maintain the network. The forecast capex for fleet is typically based on the usage and age of the vehicles and plant, and replacing these at the end of their useful life subject to ongoing business need.

  – Property investment to ensure the property and facilities for our business and workforce are safe and up to standard. The forecast for property is based on condition assessments, which identify the required works to keep the sites operational.

Step 2 – option estimate and feasibility studies

We prepare cost estimates for each credible option for each need as follows:

> Repex and Augex: we undertake an engineering review of each option, including credible new technology options, to determine the scope of work to implement it. This assesses whether the scope of works are feasible, the timeframe required to implement it and a bottom up estimate of the cost using the unit rates in our estimating database.

> Non-network capex: we apply appropriate cost models to suit the specific nature of the option, such as unit rate estimates or project specific estimates.

Step 3 – options evaluation

Other than for non-network other, we evaluate each need by considering the expected benefits to our customers (e.g. risk reduction of a need or benefits of an opportunity) and costs for each feasible option by preparing an economic cost benefit analysis business case compared against the base case. The preferred option is typically the one that offers the highest positive benefits in net present value (NPV) terms. We also consider the sensitivity of the business case outcome by varying key parameters, apply weighted scenarios and check the optimal timing of the investment to ensure we have a robust business case before proceeding to add the investment to our forecast expenditure.

At this stage we also consider any obligations we may have in relation to the need, such as compliance. For example, we apply a 'disproportionality test' where the benefits relate to bushfire and safety risk reductions to ensure we are fulfilling our obligations to manage network safety risks to As Low As Reasonably Practicable (ALARP).

For non-network other, we assess the business support need for the investment to proceed on a case by case basis.

Step 4 – top down assessment

Once we have the forecast of our proposed investments, we test and challenge this against top down assessments to check the prudency of our forecast and investigate material differences. Some key top down checks we apply are:

- predictive models: we use asset information to predict long term replacement trends, including using the AER's Repex model, and compare this against our bottom up forecast.
- trend analysis: we assess our past expenditure in key areas against our forecast expenditure to ascertain any material changes in trend.
- benchmarking: we assess key metrics and performance outcomes against others in the industry, both in Australia and internationally.
- input validation and sensitivity testing: we validate our inputs against industry references and test the sensitivity of the overall portfolio to changes in key input parameters.

Step 5 – network investment portfolio optimisation

Once we establish the portfolio of network investments and the timing of these investments, which make up our proposed forecast, we review the portfolio for optimisation opportunities. This includes considering the deliverability of the portfolio, appropriate scheduling and bundling of works, and any overlap between Augex and Repex projects to ensure the portfolio represents an efficient forecast of our expenditure.

We rank our investments based on their NPV, whether they address a compliance obligation, the network safety risk they mitigate and the consumer benefit (opportunity) they provide. We use this ranking to assess expenditure scenarios and the resultant impact on asset and network risk profiles. This portfolio optimisation process ensures that we maximise the benefit that we deliver to our customers.

4.5 Network and Corporate Overheads

Overhead activities support the delivery of our capital program. They include corporate support and management costs not directly incurred in producing output, and shared costs that we cannot directly allocate to a particular business activity or cost centre

When developing our project and program costs we apply an assumed mark-up to cover the costs of such activities based on our past experience and outturn costs. Our capitalised network and corporate costs for the 2023-28 regulatory period is the sum of these costs across our entire capital program.

We test and validate this forecast by comparing it to a top-down forecast which assumes:

- 75 per cent of capitalised overheads are fixed at current levels, and
- 25 per cent of capitalised overheads vary with direct capex.[9]

[9] This approach was adopted by the AER in its April 2021 decisions for the Victorian electricity distribution networks.

We also apply labour escalation where appropriate. If the top-down forecast differs materially from our internal forecast, then we will adopt the top-down forecast.

Glossary

Abbreviations/acronyms	Definition
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
ACT	Australian Capital Territory
AER	Australian Energy Regulator
ALARP	As Low As Reasonably Practicable
Application	Contingent Project Application
Augex	Augmentation Capital expenditure
BCA	Building Code of Australia
Capex	Capital expenditure
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer Price Index
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
GW	Gigawatt
GWh	Gigawatt Hour
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
ISO	International Organisation for Standardisation
ISP	Integrated System Plan
kV	kilovolt
M	Millions
MAR	Maximum Allowed Revenue

Abbreviations/acronyms	Definition
MTWO	TransGrid's cost estimation database system
MW	Megawatt
MWh	Megawatt Hour
NCIPAP	Network Capability Incentive Parameter Action Plan
NEL	National Electricity Law
NEM	National Energy Market
NEO	National Electricity Objective
NER (Rules)	National Electricity Rules
NPV	Net Present Value
NSW	New South Wales
Opex	Operating expenditure
PADR	Project Assessment Draft Report
PACR	Project Assessment Conclusions Report
PTRM	Post-Tax Revenue Model
RAB	Regulatory Asset Base
Repex	Replacement Capital expenditure
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
ROE	Return on equity
SA	South Australia
SFARP	So Far As Reasonably Practicable
TAC	TransGrid Advisory Council
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
TWh	Terrawatt Hour

Attachment A - TransGrid's Advisory Council

Box 1 sets out our current TAC member organisations. This shows that the TAC represents a broad range of customers and energy consumers to ensure we receive a broad cross section of views and input from our customers and other stakeholders.

Box 1: TAC member organisations

- Australian Energy Market Operator (AEMO)
- Australian Industry Group (AIG)
- Australian National University (ANU)
- City of Sydney
- Clean Energy Council
- Energy Consumers Australia (ECA)
- Energy Users Association of Australia (EUAA)
- Environmental Resources Management (ERM) Advisory - Australian Renewable Energy
- Ethnic Communities Council NSW
- Goldwind Australia
- Public Interest Advocacy Centre (PIAC)
- Snowy Hydro
- St Vincent de Paul
- Tesla
- Tomago Aluminium