Transgrid

People. Power. Possibilities.

Repex Overview Paper

2023-28 Revenue Proposal

Contents

List of Tables

List of Figures

1. Purpose, structure and scope of this document

1.1. Purpose and scope of this document

This document explains and justifies at a high level our Replacement capital expenditure (Repex) for our prescribed transmission network for the next regulatory control period from1 July 2023 to 30 June 2028. This document supports our Revenue Proposal and references other supporting documents for further detail.

All capex is presented in real 2022-23 dollars and is expressed in total costs (i.e., direct costs plus escalations and excluding overheads).

This document explains and justifies our capex forecast for Repex only. We explain and justify our:

- opex step change forecast in a separate opex step change overview document, and
- other categories of capex, including Augex, Non-network ICT and Non-network Other, in separate capex overview documents.

1.2. Structure of this document

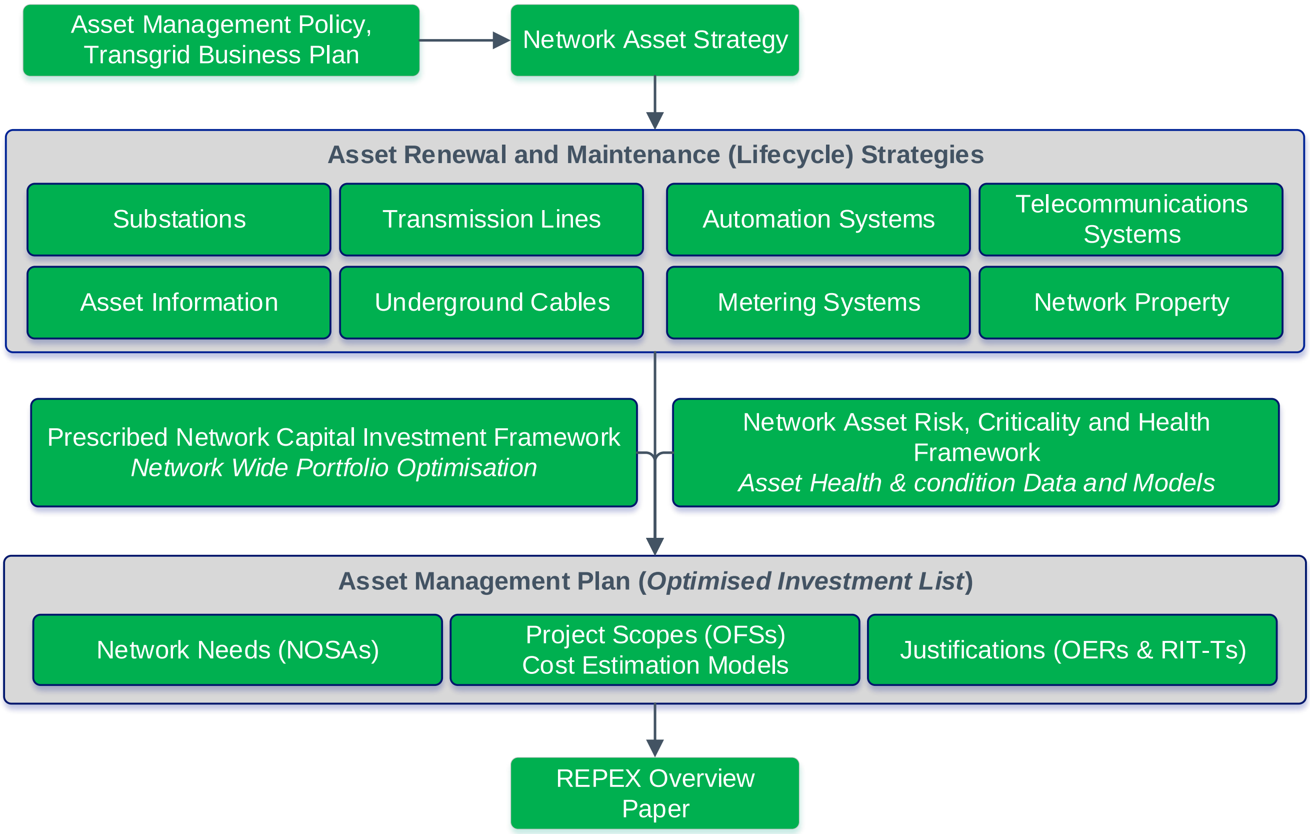
This Repex Overview Paper is structured as follows:

- chapter 1 sets out the hierarchy of supporting documents that underpin our Repex forecast
- chapter 2 discusses the nature and key external drivers of Repex
- chapter 3 overviews our Repex profile for the previous, current and forthcoming regulatory periods
- chapter 4 overviews our 2018-23 Repex and customer outcomes
- chapter 5 explains and justifies our 2023-2028 Repex forecast and customer outcomes
- chapter 6 overviews our asset management framework other obligations and explains our forecast method, inputs and assumptions used to develop our 2023-2028 Repex forecast
- attachment 1 lists the supporting documentations and models
- attachment 2 summarises the outcomes of the portfolio optimisation process

1.3. Supporting documents and models

Figure 1-1 illustrates the hierarchy of documents and models that support our Repex forecast, which we have submitted to the AER with our Revenue Proposal.

Figure 1-1 Hierarchy of Repex documents and models



This Repex Overview Paper is supported by our:

- **Network Asset Strategy** detailing our overarching Asset Management Policy, Strategy & Objectives,
- **Asset Management System Description** supporting our ISO 550001 Asset Management System certification,
- **Asset Renewal & Maintenance (Lifecycle) Strategies** comprising strategies for Substations, Transmission Lines & Cables, Digital Infrastructure – Automation, Telecommunications, Metering, Network Property, and Asset Information,
- **Prescribed Network Capital Investment Framework** detailing our capital governance framework and our approach to the portfolio optimisation of network-wide capital expenditure to demonstrate prudency,
- **Network Asset Risk, Criticality & Health Frameworks** which describe the risk-based, data-driven approach and models we use to identify and forecast network asset replacement and refurbishment needs, and to quantify risks for project and program justification, utilising our asset health and condition models,
- **Optimised Investment List** comprising a list of projects and programs (including costs, risks, benefits, and timing), and
- **Options Evaluation Reports** (OER) and/or **Regulatory Investment Test for Transmissions** (RIT-T) – Repex project and program economic evaluation business case and regulatory justifications which apply cost-benefit analysis utilising cost-estimates and quantified risks, to economically assess each credible option - to demonstrate prudency and optimum timing of the proposed investment. OERs should be read in conjunction with the outcomes of the portfolio review and optimisation process summarised in Attachment 2.

While the focus of this Paper is on Repex, our Asset Management System and Investment Governance Framework provides an integrated, holistic, optimised approach to network capital and operating expenditure. It considers the optimisation of Repex and Augex projects and programs, and the assessment of capex to opex trade-offs (including viability of non-network alternatives). Our approach ensures there is no double counting of expenditure, and maximises the value of net benefits for our customers.

2. Nature and external drivers of Repex

Transmission networks will continue to play a central role in providing energy to load centres and supporting the transmission to a low carbon future. Our transmission network will remain essential in serving customers who rely on the existing network for reliable and cost effective energy, now and into the future.

Progressive renewal of our portfolio of aging assets as they reach the end of their serviceable lives will therefore remain critical. Our fundamental approach to Repex expenditure balances the cost of replacing assets with the cost of continuing with our existing assets, including future risk costs and escalating reactive maintenance costs.

This chapter explains:

- the nature of our Repex to:
  - comply with applicable regulatory obligations
  - maintain the quality, reliability and security of supply
  - maintain the safety of the transmission system
- the key external drivers of Repex.

2.1. Nature of Repex

Our electricity transmission network forms the physical connection between regions in the National Electricity Market (NEM). It is essential for the connection of new low-cost renewable generation and stronger interconnection across the NEM to ensure the safety, security and reliability of supply and to enable customers to access affordable electricity.

Repex is required to replace or refurbish existing assets which are a required part of the transmission network into the future to ensure the continued safety, reliability and security of the network. Our investment framework provides that we only undertake investments that deliver demonstrable customer benefits, or are required to meet a statutory obligation.

Customer benefits

We assess customer benefits through our risk and investment analysis process, where the impacts of our proposed investments are given a defensible monetary value[1], to enable the relative benefits and costs to consumers to be compared. Our investment framework only supports investments for which the present value of the costs is less than the present value of the economic benefits, by avoiding the risk that would exist without investment, or by providing market benefits in excess of the costs of the investment.

Compliance obligations

We undertake investments to meet our statutory or regulatory obligations as set out in legislation, regulations, codes, rules and our licence conditions.

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[1] The valuation of non-monetary impacts has drawn on the most relevant independent estimates from credible government, academic or industry publications (such as federal government cost-benefit guidance on the Value of a Statistical Life, AER determinations on Value of Customer Reliability / Maximum Market Price and Bushfire & Natural Hazard CRC research into quantifying catastrophic bushfire consequence). The likelihood of the impact has been calculated by Transgrid based on our best analytical estimates with the methodologies subject to independent review.

These investments are driven by technical justification and are subject to economic efficiency tests, consistent with our Prescribed Network Capital Investment Framework. Our investments reflect the least-lifecycle cost solution which offer the most technically effective solution to meet the compliance obligation.

2.2. Key external drivers of our Repex forecast

Repex is required to replace or refurbish our existing assets, and is typically driven by asset condition and related risks, including technical obsolescence. The key drivers for Repex are:

- **Safety, security and reliability**, including:
  - **Aging assets and maintaining asset condition -** replacement projects and programs to address an identified condition issue which could lead to asset failure with risks to bushfire starts, public and workforce safety, the environment, and to reliability of supply. This encompasses meeting our safety and other regulatory obligations and managing technical obsolescence risks.

    Managing these risks has been the key driver of our expenditure in the previous 2014-18 period, the current 2018-23 period, and it will continue to be our main driver for repex in 2023-28. As our composite asset age continues to increase and the condition of assets decline, we are seeing increases in fault rates, particularly in our transmission line and digital infrastructure fleet as described further in Chapter 4.5.

    We must in invest to maintain the long-term condition of our assets. During the 2014-18 period we developed and implemented our enhanced risk based asset management approach which we applied during the 2018-23 period and will continue to apply in the 2023-28 period. While our approach in 2023-28 remains the same as 2018-23, we have refreshed the inputs to our risk modelling to reflect the latest industry practice as described in Chapter 6.
  - **Climate change and network resilience** – our network was impacted by a marked increase in extreme weather events (floods, storms and bushfires) in the 2018-23 period compared with the prior 2014-18 period and climate change is resulting in the frequency and intensity of extreme events increasing. In the 2023-28 period we will continue to manage these escalating hazards and maintain network risk and resilience in the long term by replacing assets with more resilient alternatives when we undertake planned condition-based replacements.
  - **Increasing cyber security threats to critical infrastructure** – new obligations are being introduced by the Australian and NSW Governments that we will need to comply with in the next regulatory period to ensure that our network is protected against cyber and physical infrastructure threats. We must invest in response to these new obligations to maintain the security and reliability of our network expected by our stakeholders and customers. This driver is a continuation from the 2018-23 period, where we experienced an increase in our cyber security obligations compared with the 2014-18 period.
- **Energy transition**, including:
  - **Changing generation mix** – the transition to a new energy market is happening quickly, as renewable costs fall, technology advances and governments commit to decarbonisation. The change in the generation mix is increasing the operational complexity of maintaining network safety, stability and security where generators are connecting to parts of the network they did not previously. In the 2023-28 period we will continue renewal of digital infrastructure (secondary systems and communications) to enable our operations to adapt as well as rectify low ground clearances on transmission lines which are now present due to increased utilisation as a result of generation changes.

The overall REPEX program aims to maintain asset portfolio risk and performance at current levels, manage emerging issues in the external environment and meet our obligations and commitments as a business.

3. Repex profile

This chapter overviews the Repex profile for the previous, current and forthcoming regulatory periods.

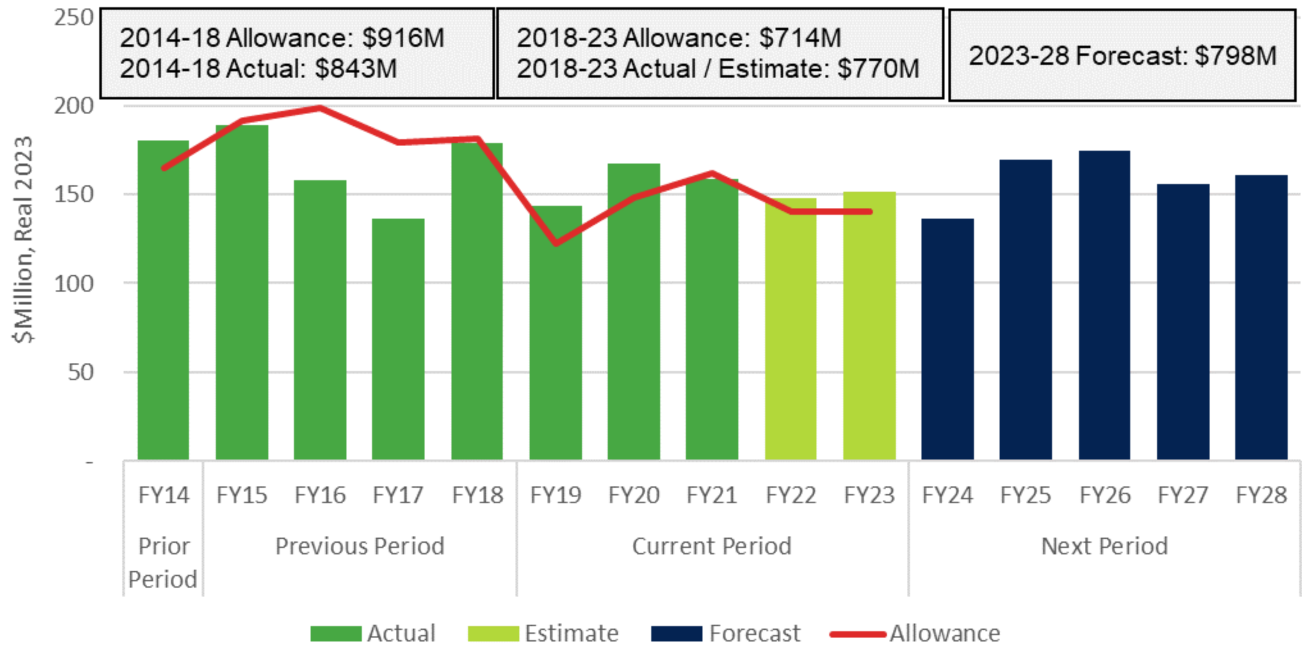
3.1. Previous, current and forthcoming period expenditure

Figure 3-1 shows our Repex for the 2014-18, 2018-23 and 2023-28 regulatory periods, and compares our 2014-18, 2018-23 Repex with the AER's allowance.[2]

Figure 3-1 shows that our outturn Repex of $770.2 million in the current period is expected to be $56.5 million or 7.9 per cent higher than the AER's allowance of $713.7 million in its 2018-23 Decision and around 8.6 per cent lower than outturn Repex for the 2014-18 regulatory period. The key driver is the reprioritisation of Repex versus other network capital expenditure to ensure we maintain the safety, security and reliability of the network in response to increasing replacement unit costs and responding to emerging issues, such as expenditure to restore assets following severe weather events.

Our 2023-28 Repex forecast of $797.6 million is $27 million or 4 per cent higher than 2018-23 actual/estimated Repex of $770.2 million and is slightly lower, $45.4 million or 5 per cent, than our outturn Repex for the 2014-18 regulatory period.

Figure 3-1: AER allowance vs actual / estimates for previous, current and next regulatory period ($Million, Real 2022-23)



The key driver of our Repex in the previous and current periods has been maintaining a safe, secure and reliable network. Improvements in our risk based asset management approach has meant that we have been able to maintain our strong network safety and reliability performance while expending less Repex in the current period compared to the previous period. Our risk based asset management approach is the basis for our Repex forecast in the next period, as described in Chapter 6. Chapters 4 and 5 present our Repex for the current and forthcoming regulatory period by detailed sub-category and driver.

2 This information is presented in accordance with clause S6A.1.1(6) of the Rules

Table 3-1 sets out our forecast Repex of $797.6 million for the 2023-28 regulatory period by key sub-category. Overall, our 2023-28 Repex forecast reflects a 3.6 per cent increase over our expected Repex in the current period. The key drivers for the increase are outlined in Chapter 3.2.

Table 3-1: Total Repex for the 2023-28 regulatory period ($Million, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Transmission Lines	48.8	59.6	86.0	54.5	85.7	**334.5**
Substations	35.5	37.6	41.9	45.9	38.7	**199.7**
Digital Infrastructure	52.2	72.4	46.6	55.6	36.6	**263.4**
Total Repex	**136.6**	**169.5**	**174.5**	**156.0**	**161.0**	**797.6**

3.2. Variance in forecast and actual capex

Table 3-2 shows our Repex for the previous (2014-18), current (2018-23) and forthcoming (2023-28) regulatory periods compared to the AER allowance and the variances.

Table 3-2: Historical and forecast Repex ($Million, Real 2022-23)

	2014-2018[3] (A)	2018-2023 (A) & (E)	2023-2028 (F)
AER allowance	915.6	713.7	
Actual Repex	843.0	770.2	797.6
Variance (Actual minus AER allowance) $ Million and %	(72.7) (7.9%)	56.5 7.9%	

Key drivers of the increased Repex between the 2018-23 and 2023-28 regulatory periods are discussed in Chapter 5.

3 Four-year regulatory control period. Values presented are for five years 2013-14 to 2017-18 for comparison purposes.

4. 2018-23 Repex and outcomes

Key messages:

Over the 2018-23 regulatory period we:

- delivered asset replacement and refurbishment projects in alignment with our 2018-23 proposal, prioritising delivery in accordance with the benefit it delivers to our customers and to maintain compliance with our obligations. Key programs delivered include those relating to:
  - transmission lines (representing 38.5% of Repex - where we invested $95.9 million in refurbishing steel tower transmission lines, including removing asbestos paint, as well as $115.6 million replacing deteriorated wood poles with poles made from concrete or steel. As part of these programs, significant investment in insulators ($58.6M) and overhead conductors ($26.4M) was completed.
  - substations (representing 26.3% of Repex) - where we invested $149.4 million replacing substation switchbay equipment, and a further $53.1 million replacing or refurbishing transformers and reactors
  - digital infrastructure (representing 35.2% of Repex), including:
    - $88.2 million replacing substation protection systems
    - $51.4 million replacing control systems
    - $39.6 million on network property and security systems
    - $42.7 million for metering and communication systems (including OPGW)
    - $30.5 million on SCADA systems replacement
    - $18.7 million on supporting AC/DC systems
- continued to deliver a safe network as a mission critical priority and have seen a decreasing number of fire starts, decreasing levels of trespass events and very low levels of public injury incidents
- maintained our network safety, reliability and security, utilising our robust asset management system to optimise our investments
- experienced and responded to extreme climate driven weather events impacting our network (bushfires, storms and floods), causing unprecedented levels of asset damage, while minimising disruptions to the community
- strengthened the cyber and physical security aspects of our network in response to increasing government concern regarding the security of critical infrastructure
- remained agile to change by investing in emerging asset issues as they arose, reprioritising our investment portfolio to do so, to ensure we continue to maximise the benefit we deliver to customers throughout the regulatory period,
- implemented innovative strategies, such as our digital substation, to ensure we leverage the latest technologies and continue to deliver value in the best long term interest of our customers.

4.1. Current period Repex compared to the AER's allowance

Our Repex for the current regulatory period is expected to be $770.2 million. This comprises

- actual Repex in the first three years of the 2018-23 regulatory period is $470.3 million, and
- expected Repex of $299.8 million in the final two years.

Table 4-1 shows that our total Repex of $770.2 million is $56.5 million or 7.9 per cent higher the AER's allowance of $713.7 million.

Table 4-1: 2018-23 Repex ($Million, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
AER Decision	122.5	148.4	162.2	140.2	140.5	**713.7**
Actual / Estimated	143.9	167.6	158.9	148.0	151.8	**770.2**
Variance ($)	21.4	19.2	(3.3)	7.8	11.3	**56.5**
Variance %	17.5	13.0	(2.0)	5.6	8.1	**7.9**

The key driver of our repex over the current period was overwhelmingly to continue to provide a safe and reliable network. However, we also undertook Repex to continue to meet our compliance obligations (notably compliance with safety obligations and to address cyber security concerns) and to repair our network following more frequent extreme weather events. Over the 2018-23 regulatory period we:

- delivered asset replacement and refurbishment projects in alignment with our 2018-23 proposal, prioritising delivery in accordance with the benefits delivered to our customers and to maintain compliance with our obligations. Key programs delivered include those relating to:
  - transmission lines, where we invested:
    - $95.9 million (12.4 per cent of total repex) refurbishing steel tower transmission lines, including removing asbestos paint
    - $115.6 million (15.0 per cent) replacing deteriorated wood poles
    - $58.6 million on replacing insulators (7.6 per cent)
    - $26.4 million in overhead conductors and $0.3 million in underground cables
  - substations, where we invested:
    - $149.4 million (19.4 per cent) replacing substation switchbay equipment
    - $53.1 million (6.7 per cent) replacing or refurbishing transformers and reactors
  - Digital infrastructure, where we invested:
    - $88.2 million (11.4 per cent) replacing substation protection systems
    - $51.4 million (6.7 per cent) replacing control systems
    - $39.6 million (5.1 per cent) on network property and security systems
    - $42.7 million (5.5 per cent) for metering and communication systems (including OPGW)
    - $30.5 million (4.0 per cent) on SCADA systems replacement

> $18.7 million (2.4 per cent) on supporting AC/DC systems

- continued to deliver a safe network as a mission critical priority, which has resulted in a decreasing number of fire starts, decreasing levels of trespass events and very low levels of injury incidents. Over the period we incurred $20.4 million (2.6 per cent) in compliance expenditure. These are primarily safety related, but also include small proportion relating to AEMO and NER requirements,
- spent $5.3 million (0.7 per cent) responding to extreme climate driven weather events impacting our network (bushfires, storms and floods), causing unprecedented levels of asset damage, while minimise disruptions to the community,
- invested $43.7 million (5.7 per cent) to strengthen the cyber and physical security aspects of our network, in response to increasing government concern regarding the security of critical infrastructure,
- remained agile to change by investing in emerging asset issues as they arose, reprioritising our investment portfolio to do so, to ensure we continue to maximise the benefit we deliver to customers throughout the regulatory period, and
- implemented innovative strategies, such as our digital substation, to ensure we leverage the latest technologies and continue to deliver value in the best long term interest of our customers.

Table 4-2: 2018-23 Repex by subcategory and driver ($Million, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Transmission lines	**54.5**	**73.4**	**63.4**	**49.4**	**56.1**	**296.8**
Safe and Reliable Network	48.2	69.3	58.0	42.3	54.5	272.4
Compliance	6.3	4.1	1.9	5.2	1.6	19.1
Climate change and resilience	-	-	3.5	1.8	-	5.3
Substations	**36.9**	**39.2**	**48.5**	**40.6**	**37.4**	**202.5**
Safe and Reliable Network	36.9	39.2	48.5	40.6	37.4	202.5
Digital Infrastructure	**52.6**	**55.0**	**47.0**	**58.0**	**58.4**	**270.9**
Safe and Reliable Network	48.2	44.0	39.6	49.4	44.7	225.9
Cyber/physical security	4.3	10.1	7.2	8.5	13.6	43.7
Compliance	0.1	0.8	0.2	0.2	-	1.3
Total	**143.9**	**167.6**	**158.9**	**148.0**	**151.8**	**770.2**

Table 4-3 details our 2018-23 Repex by subcategory and key program.

Table 4-3: 2018-23 Repex by subcategory and key programs ($Million, Real 2022-23)

	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Transmission lines	**54.5**	**73.4**	**63.4**	**49.4**	**56.1**	**296.8**
Transmission poles	37.8	45.5	31.0	1.2	-	115.6
Transmission towers	8.3	15.6	16.3	32.0	23.8	95.9
Insulators	5.2	10.0	15.4	12.7	15.3	58.6
Overhead conductors	3.1	2.4	0.7	3.2	17.0	26.4
Underground cables	0.0	0.0	0.0	0.2	-	0.3
Substations	**36.9**	**39.2**	**48.5**	**40.6**	**37.4**	**202.5**
Power Transformers	7.4	9.9	14.1	5.0	3.2	39.6
Reactive plant	1.9	1.9	3.2	5.3	1.1	13.5
Site Establishment and supporting assets	1.3	2.4	2.3	5.2	13.5	24.7
Switchbay Equipment	26.2	24.9	28.8	25.2	19.6	124.7
Digital Infrastructure	**52.6**	**55.0**	**47.0**	**58.0**	**58.4**	**270.9**
Protection systems	16.5	16.0	15.6	20.3	19.7	88.2
Control systems	9.6	9.6	8.1	13.2	10.9	51.4
Market metering systems	1.4	1.9	2.3	2.2	2.4	10.2
Communications systems	1.1	1.5	2.6	3.9	4.8	13.8
SCADA	6.7	10.9	7.6	1.3	4.0	30.5
OPGW	9.6	7.9	1.1	0.1	-	18.7
AC/DC & Auxiliary systems	1.9	2.7	4.4	6.7	3.0	18.7
Network Property & Security	5.6	4.6	5.3	10.5	13.6	39.6
Total	**143.9**	**167.6**	**158.9**	**148.0**	**151.8**	**770.2**

Each of our major Repex programs in the current period is discussed in more detail in the following sections, with the outcomes delivered to customers discussed in section 4.5.

4.2. Transmission lines

4.2.1. Steel tower transmission lines – refurbishment program

We have spent $95.9 million refurbishing steel tower transmission lines, including removing asbestos paint, delivering bushfire and public safety risk mitigations through addressing issues on key components such as insulators, fittings, tower members and footings which could cause conductor drop or tower collapse. This program primarily supports delivering a safe, reliable network.

The steel tower refurbishment program manages bushfire and public safety risk to as low as reasonably practicable. It also contributes to maintaining network reliability. The scope of the program is selected on the basis of the asset condition and the relative bushfire and public safety risk at each location on the network.

A number of steel tower refurbishment programs in coastal environment were progressed during the period. The scope of work at each structure is tailored to the individual asset condition and risk using data collected through our condition assessments and includes a mix of replacement or refurbishment on 946 towers across more than 18 transmission lines around the state of the following items, as required to maintain network safety:

- tower members and fasteners,
- conductor and earthwire fittings,
- foundations,
- earthwire,
- earthing systems, and
- addressing specific issues with buried steel grillage foundations due to corrosion to ensure structural integrity on approximately 1,125 towers.

The following specific compliance based programs were also progressed:

- asbestos paint removal across 1,185 of the highest priority steel towers to meet community safety expectations, and
- addressing conductor low clearance spans to manage public safety risk.

Unforeseen expenditure of $5.3 million was required to be included in the program due to multiple tower failures on two lines during extreme weather events. Whilst the costs associated with climate change and resilience in this period are reasonably low, the increased prevalence of this driver in the current period highlights the need for additional initiatives in this area in the 2023-2028 period and beyond.

The total expenditure on steel tower transmission lines is shown in Table 4-4.

Table 4-4: Transmission lines – steel tower refurbishment expenditure ($Million, Real 2022-23)

Transmission lines	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Steel tower refurbishment	8.3	15.6	16.3	32.0	23.8	**95.9**

4.2.2. Wood pole transmission lines – replacement program

We have spent $115.6 million replacing deteriorated wood poles, delivering bushfire and public safety risk mitigations through replacement of wood poles suffering from rot and termite attack. This program primarily supports delivering a safe, reliable network.

The wood pole program manages bushfire and public safety risk to as low as reasonably practicable. It also contributes to maintaining network reliability. Through the wood pole program we are aiming over the longer term to replace all wood poles with modern concrete or steel alternatives at the optimum time to manage risk.

Wood poles experience decay and / or termite damage which compromise the structural integrity of the structure. Condition information from inspections and forecast pole defect rates are used to identify the scope of the program. Our approach is to replace wood pole structures which are past a threshold for wood decay, in consideration with the bushfire and public safety risk at each location on the network.

We expect to replace 1659 wood pole structures in the current regulatory period across the state.

We were also required to address a number of conductor low clearance spans to manage public safety risk whereby the wood pole was replaced to achieve the required ground clearance.

The total expenditure on replacing wood poles in the current period is shown in Table 4-5.

Table 4-5: Transmission lines – wood pole replacement program expenditure ($Million, Real 2022-23)

Transmission lines	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Wood pole replacement	37.8	45.5	31.0	1.2	-	**115.6**

4.2.3. Insulators

We have spent $58.6 million replacing 1352 sets of insulators, delivering bushfire and public safety risk mitigations through addressing insulators at end of their serviceable life which could cause conductor drop.

Porcelain insulators in coastal environments suffer from corrosion of the insulator pin, eventually leading to failure and conductor drop. Testing has also shown that certain vintages of porcelain insulators have deteriorated through internal micro-cracking of the porcelain, which will lead to electrical puncture and failure, also causing a conductor drop. We have experienced conductor drop events from both of these causes. This program primarily supports delivering a safe, reliable network.

Insulator replacements manage bushfire and public safety risk to as low as reasonably practicable. It also contributes to maintaining network reliability. The scope of the program is selected on the basis of the asset condition and the relative bushfire and public safety risk at each location on the network and is undertaken in conjunction with the steel tower refurbishment and wood pole replacement projects described above.

4.3. Substations

4.3.1. Switchbay Equipment

We have spent $124.7 million replacing substation switchbay equipment to maintain network reliability and mitigate worker and public safety risks in the event of a catastrophic failure. This program primarily supports delivering a safe, reliable network.

Switchbay equipment, including circuit breakers, gas insulated switchgear (GIS), disconnectors and instrument transformers provide for the connection and control of network equipment and so are key contributors to reliability outcomes. In addition, for assets in poor condition, explosive failures may occur and we are obligated to manage this risk for both our staff and the public to as low as reasonably practicable.

We utilise a health index methodology to evaluate the condition of assets and determine their probability of failure into the future. This is combined with the consequence of failure in order to identify those assets which present the highest risk. The health analysis for switchbay equipment takes into consideration:

- natural age
- number of operations,
- defect counts and costs,
- diagnostic test data, oil sample analysis,
- targeted condition assessments
- types issues, and
- reactive plant switching duty.

We expect to replace around 875 items of switchbay equipment in the current regulatory period across the state.

The total expenditure on substation switchbay equipment is shown Table 4-6.

Table 4-6: Substation switchbay equipment ($Million, Real 2022-23)

Substations	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Substation switchbay equipment	26.2	24.9	28.8	25.2	19.6	**124.7**

4.3.2. Transformers and Reactive Plant

We have spent $53.1 million replacing 5 and refurbishing 20 transformers as well as replacing 5 items of reactive plant. We also decommissioned 3 transformers which were at end of life but were no longer required. This expenditure was undertaken to mitigate network reliability risks and safety risks in the event of a catastrophic failure. This program primarily supports delivering a safe, reliable network.

Power transformers play a vital role in the network by changing and controlling the voltage and current at key points in the transmission network and at customer supply points. The performance of power transformers is one of the most significant drivers of network reliability.

Reactive plant contribute to a reliable network through enabling voltage control under different system conditions and loads. They are critical to maintaining operating voltages between the maximum and minimum levels required under the voltage management requirements of the National Electricity Rules (NER). The program includes oil-filled reactors, air-cored reactors and capacitor banks.

We utilise a health index methodology to identify those assets with the highest risk of failure. The analysis for transformers and oil filled reactors takes into consideration:

- deterioration of insulating paper quality,
- combustible gases in insulating oil,
- tap changer condition,
- transformer loading

- bushing degradation, and
- defects including corrosion and paint system degradation.

A similar approach is taken for other reactive plant with different condition based factors considered as appropriate.

The program consists of replacements, complete refurbishments and strategic replacement of critical components. The total expenditure on transformers and reactive plant is shown in Table 4-7.

Table 4-7: Substation transformers and reactive plant ($Million, Real 2022-23)

Substations	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Transformers	7.4	9.9	14.1	5.0	3.2	39.6
Reactive Plant	1.9	1.9	3.2	5.3	1.1	13.5
Total	**9.4**	**11.8**	**17.4**	**10.2**	**4.3**	**53.1**

4.3.3. Site establishment and supporting assets

We have spent $24.7 million on substation assets which are required to support other critical high voltage assets to ensure a safe, reliable network.

The largest portion of this as spent on refurbishing substation gantry steelwork and holding down bolts at three sites. This involved replacing steelwork and fasteners as well as modifying foundations to install new holding down bolts.

These steelwork structures and the foundations facilitate the overhead electrical connections between transmission lines and high voltage equipment within the substation and are critical to the operation of the site. Extensive corrosion of the steelwork has occurred and a failure leading to collapse of the steel gantries is likely to cause extensive damage to high voltage equipment at the site resulting in long restoration times and resulting in significant network reliability consequences.

We have performed detailed condition assessments of substation steelwork to inform detailed engineering assessments. These assessments identify which sites have steelwork with elevated probability of failure.

In addition to substation gantry steelwork, we have also invested in:

- targeted renewal of substation earth grids to ensure the ongoing safety of our workers in accordance with earthing standards,
- replacement of air core reactors at the end of their useful life,
- purchase of strategic capital spares to support in service high voltage equipment, and
- replacement of auxiliary transformers (for powering local substation digital infrastructure) at the end of their useful life as part of power transformer replacement projects.

The total expenditure on site establishment and supporting assets is shown below in Table 4-8.

Table 4-8: Substation site establishment and supporting assets ($Million, Real 2022-23)

Substations	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Substation site establishment and supporting assets	1.3	2.4	2.3	5.2	13.5	**24.7**

4.4. Digital infrastructure

4.4.1. Substation protection systems

We have spent $88.2 million replacing substation protection systems delivering network reliability risk mitigation through the replacement of end of life and obsolete technology. This program primarily supports delivering a safe, reliable network.

Protection systems are critical within the transmission network. They ensure that electrical faults are cleared within NER compliance timeframes to prevent potential major grid events, and also prevent life ending failures of high voltage assets. We are moving to the replacement of all electro-mechanical and solid state relays in the longer term by targeted replacement with modern equivalents where the investment is justified.

We utilise a health index methodology to identify those protection assets with the highest risk of failure. The analysis for substation protection systems takes into consideration:

- manufacturer support,
- spares availability,
- forecast defect rate, and
- cost of corrective maintenance.

We expect to have replaced 874 protection relays in the current regulatory period across the state.

The total expenditure on substation protection systems is shown in Table 4-9.

Table 4-9: Substation protection systems ($Million, Real 2022-23)

Digital Infrastructure	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Protection systems	16.5	16.0	15.6	20.3	19.7	**88.2**

4.4.2. Substation control systems

We have spent $51.4 million replacing control systems, including 208 control units, through the replacement of end of life and obsolete technology, and managing worker safety risks from legacy systems and unsafe wiring. This program primarily supports delivering a safe, reliable network.

Control systems provide real time data and remote operation capability across our substation sites. They assist in operating a reliable system through enabling fast detection of alarm conditions and failures and allow for emergency remote operation and overall system monitoring.

We consider a range of factors in determining the optimum replacement mix. The analysis takes into consideration:

- manufacturer support,
- microprocessor and operating system obsolescence, and
- defect rates.

The program includes major whole of site replacement works and a number of targeted fleet replacements for key control assets have been completed due to obsolescence and failure rates.

The total expenditure on substation control systems is shown in Table 4-10.

Table 4-10: Substation control systems ($Million, Real 2022-23)

Digital Infrastructure	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Control systems	9.6	9.6	8.1	13.2	10.9	**51.4**

4.4.3. Network Property

We have spent $39.6 million on network property and security systems to provide for the protection of our assets and ensure the safety of the public. This program primarily supports delivering a safe, reliable network.

Our secondary assets are housed in buildings to provide safe, stable atmospheres for their operation and longevity. Our sites are protected using a range of security devices including swipe card, CCTV, motion sensing, alarms and lighting. These security systems are aimed at both reducing the risk of malicious damage to our assets through targeted attacks and keeping the public clear of dangerous areas for their safety.

These assets are replaced as required based on:

- outcomes of detailed building dilapidation reports,
- review of defect rates and costs,
- results from security assessments and threat advice, and
- risks to a safe working environment.

The program over the current period includes significant upgrades to two major operational sites and distributed works across our substation sites. Upgrades of card access, CCTV and other miscellaneous security system components to replace obsolescent technologies with modern technologies that meet expectations for protecting critical infrastructure have been completed.

The total expenditure on network property is shown in Table 4-11.

Table 4-11: Network buildings and security systems ($Million, Real 2022-23)

Digital Infrastructure	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Network Property	5.6	4.6	5.3	10.5	13.6	**39.6**

4.4.4. Metering and Communications Systems

During the current period, we have spent $42.7 million on metering and communication systems (including OPGW) to effectively and reliably operate the power system. We expect to replace 147 market meters, 225 communications units and installed 143km of OPGW this regulatory period. This expenditure primarily supports delivering a safe, reliable network.

Metering systems allow us to meet our NER requirements at our customer connections points. Communication systems interconnect both control, protection and metering devices back to central control and data storage points. These assets also allow for on-site data to be sent and stored in appropriate systems for the power system for monitoring and analysis.

These assets are replaced as required based on:

- accuracy and other diagnostic testing,
- obsolescence and manufacture support,
- corrosion, physical condition and performance (in the case of OPGW), and
- defect rates and costs.

The metering program consists of targeted replacements of obsolete and unsupported devices, and replacements of meters as part of broader site-based replacements at numerous sites. The communication systems program includes 4 fleet-based programs (PLC, VF intertrips, multiplexer and protection intertrips) and improvements in data capacity through adoption of modern terminal equipment. The OPGW program primarily supported the establishment of major connecting rings across our network to allow route diverse paths and the retirement of end-of-life microwave equipment.

The total expenditure is shown in Table 4-12.

Table 4-12: Metering and Communications Systems ($Million, Real 2022-23)

Digital Infrastructure	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Communications systems	1.1	1.5	2.6	3.9	4.8	**13.8**
Market metering systems	1.4	1.9	2.3	2.2	2.4	**10.2**
OPGW	9.6	7.9	1.1	0.1	-	**18.7**
Total	**12.2**	**11.3**	**6.0**	**6.1**	**7.2**	**42.7**

4.4.5. SCADA systems replacement

During the current period, we have spent $30.5 million on SCADA systems replacement to ensure timely and accurate information is available for the network. The key drivers for this expenditure are both to support delivering a safe, reliable network as well as enhancing cyber and physical security.

The SCADA network connects each operational site to our operations team and then on to the Australian Electricity Market Operator (AEMO). A key outcome for this asset class is meeting the expectations of AEMO, Government and other key regulators on maintaining appropriate cyber security protections for our critical infrastructure. Expenditure includes the following major programs:

- cyber security upgrades to core SCADA systems,
- replacement of the Network wide SCADA system, and
- replacement of substation secure LAN networks and devices (including cyber security upgrades).

The total expenditure on SCADA systems is shown in Table 4-13.

Table 4-13: SCADA systems replacement ($Million, Real 2022-23)

Digital Infrastructure	2018-19	2019-20	2020-21	2021-22	2022-23	Total
SCADA systems replacement	6.7	10.9	7.6	1.3	4.0	**30.5**

4.4.6. Supporting AC / DC systems

We have invested $18.7 million through the replacement of end of life and obsolete technology, and managing worker safety risks from legacy systems and unsafe wiring. This program primarily supports delivering a safe, reliable network.

The AC and DC systems power the essential protection, control, metering and communication devices at each operational site. They support the high level of availability and resilience required for these critical systems.

Expenditure includes the following major programs covering 162 units:

- 50 and 110V Battery Charger replacements,
- 415V AC distribution system replacements at 8 sites, and
- 50V Rack Power Supply replacements.

The total expenditure on supporting AC / DC systems is shown in Table 4-14.

Table 4-14: Supporting AC / DC systems ($Million, Real 2022-23)

Digital Infrastructure	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Supporting AC / DC systems	1.9	2.7	4.4	6.7	3.0	**18.7**

4.5. Benefits of our Repex to customers

Our expenditure during the current regulatory period has delivered beneficial outcomes which are valued by our customers – a safe, secure and reliable energy supply. In particular, we have:

- maintained network risk at an acceptable level, as described in section 4.5.1,
- met network security and reliability requirements, as described in section 4.5.2,
- met the needs of our customers by responding and adapting to change to maximise the benefits we deliver, as described in section 4.5.3,
- responded to emergencies and increased our focus on the emerging risks of climate change and ensuring appropriate resilience, as described in section 4.5.4, and
- applied technology and innovation to maximise value, as described in section 4.5.5.

We have also maintained our focus on delivering customer outcomes through:

- vigilant governance of our program development and ongoing expenditure, via the relevant board, executive and regulatory committees and associated business processes,
- ongoing engagement with stakeholders throughout the regulatory period via our Transgrid Advisory Committee (TAC) and project-specific consultation through our RIT-Ts, and

- independent audits of our asset management system and electricity network safety management system to ensure we are delivering value and managing safety risk to as low as reasonably practicable. We publish annual performance reports in accordance with our regulatory obligations and to provide clear and transparent information to consumers on how we effectively manage network safety (including bushfire) risk.

4.5.1. Maintain network risk at an acceptable level

The safety of our communities, customers, employees and delivery partners is our top priority. During the current regulatory period we have continued to prioritise our expenditure in favour of Repex projects related to compliance with our safety obligations. This has allowed us to maintain our network risk to an acceptable level as we have continued to deliver our strong network safety and reliability performance.

We measure our total network risk in the form of a 'risk index', which is a multi-dimensional measure for safety, environmental, bushfire and reliability risk. The risk index is the sum of the residual risk of each individual asset, which is then baselined, so that we can monitor relative changes in network risk over time. A higher risk index represents a relative increase compared to the 2018-19 baseline risk and a lower risk index represents a relative decrease compared to the 2018-19 baseline risk.

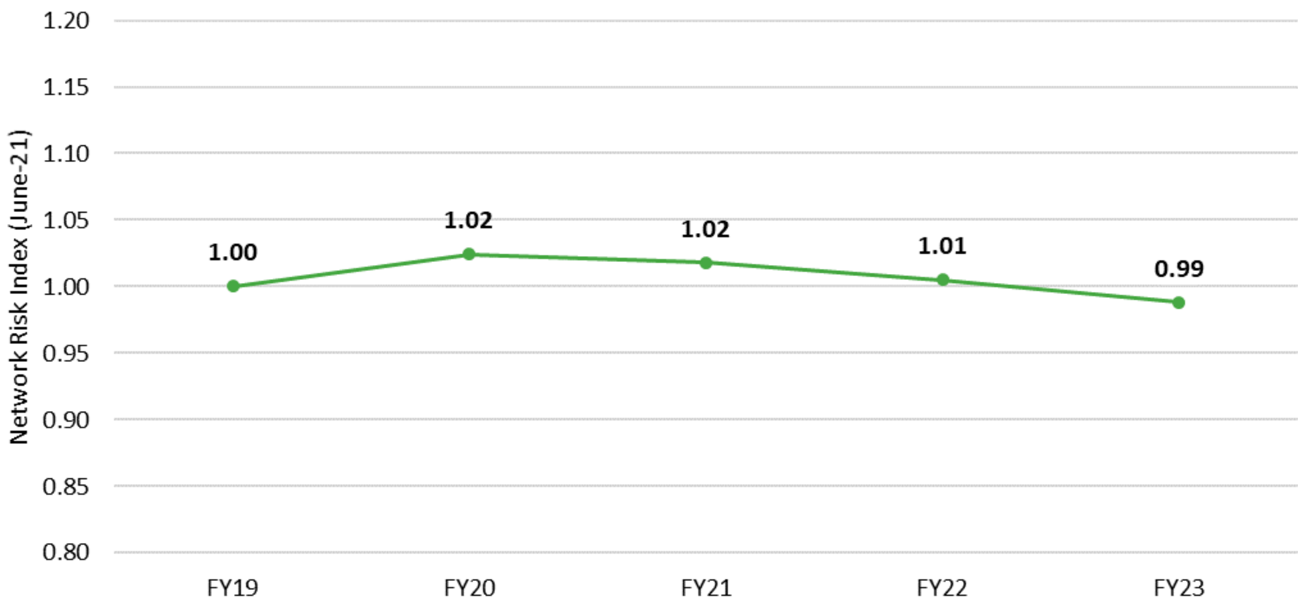
We use our network risk assessment methodology and network capital investment procedure to quantify risks and prioritise our investment portfolio accordingly. The risk index measures the effectiveness of our capital works program to mitigate network risk, taking into account:

- asset condition data collected through inspections and testing,
- probability of failure curves,
- consequences of a failure from a community perspective, considering all of our statutory, regulatory and legal obligations and the consequences for safety, bushfire, environmental and reliability outcomes. This considers:
  - Value of Statistical Life,
  - Value of Customer Reliability as estimated by the AER,
  - Bushfire and Safety Consequence, as required to meet the requirements set out in IPART (NSW) and UTR (ACT) Licence obligations and Electricity Supply (Safety and Network Management) Regulation 2014, and
  - other regulatory and statutory obligations
- the inherent asset risk, applying risk treatments (our asset management strategies and plans) to calculate the residual asset risk.

Figure 4-1 shows that by the end of the current period, we expect our network risk index to be in line with the risk index at the start of the regulatory period. We have achieved this by continually reviewing and reprioritising our expenditure works programs to focus on the delivery of key projects driven by our compliance obligations. In particular:

- we prioritised replacement of deteriorated wood poles and refurbishing steel towers on transmission lines in high risk areas (including high bushfire risk) to meet our network safety obligations,
- we focused on replacing substation transformers and switchbay equipment to mitigate safety and network reliability risks, and
- we invested in replacing control and protection systems which are critical to maintaining the safety, reliability and security of the network.

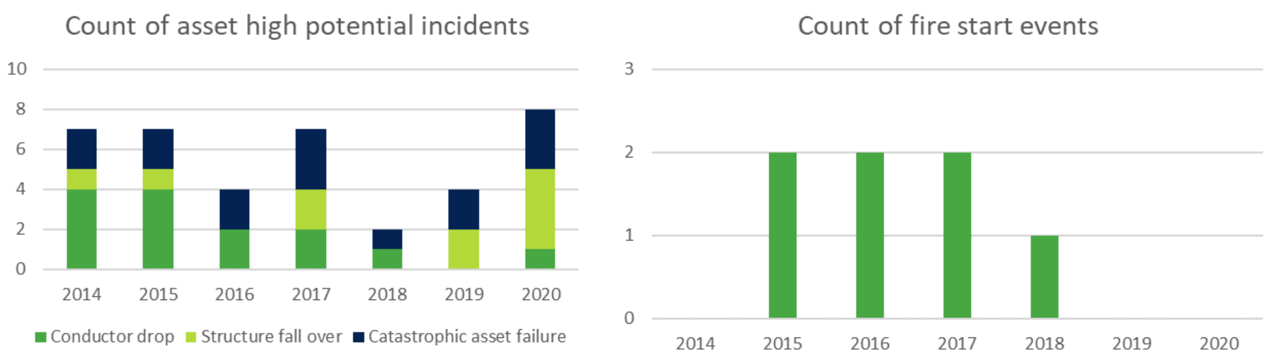
Figure 4-1: Network Risk Index



We also measure a number of key indicators of our network safety performance outcomes. Figure 4-2 provides a trend which shows:

- catastrophic asset failures (i.e those which result in an explosion or fire) have remained steady,
- conductor drops (i.e. events where the conductors has detached from the structure) have decreased,
- there has been an increase in structure collapse events due to high wind conditions, and
- actual fire start events have reduced.

Figure 4-2: Network key hazard metrics



This demonstrates that we are supporting the community by preventing bushfires and reducing fire-start risks. This is as a result of our investment approach whereby we have targeted assets with elevated probabilities of failure that can lead to hazardous events (e.g. conductor drops, which we have reduced) in combination with locations of high criticality (e.g. bushfire criticality, we have targeted high bushfire consequence areas resulting in reduced fire starts).

We have and will continue to prioritise our portfolio of Repex investments to meet our safety and compliance obligations. To achieve this we have had to defer or cancel other projects that were in our 2018-23 revenue proposal, and to accept a higher level of service risk as a consequence. Some of these risks have eventuated in the current period, for example:

- we proposed the replacement of wood poles on 330kV transmission line 86 (Tamworth to Armidale), part of the QNI power transfer path, due to a widespread decline in pole condition requiring other lines to be prioritised to mitigate the risk of asset failure. We were not able to accommodate the investment within our allowance due to the size. In April 2020 a wood pole structure failed catastrophically, and
- we proposed the renewal of secondary systems at Tenterfield substation but had to defer this out of the current period. In January 2021 a protection relay failure caused the loss of all load at Tenterfield.

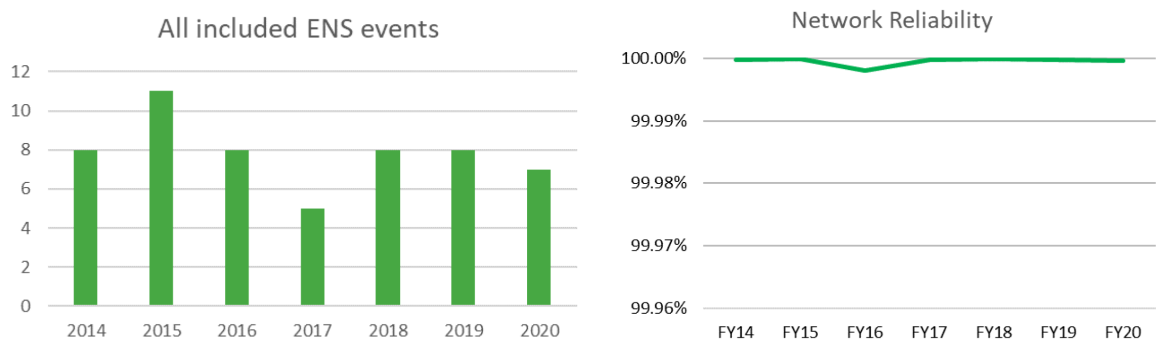
These examples give confidence that our investment process is accurately, and in a timely manner, identifying the highest risk assets to address each regulatory period.

4.5.2. Meet network security and reliability requirements

We have continued to invest in the network during the current regulatory period where necessary to meet our reliability standard obligations, although we have also sought to defer major Repex investments where possible to remain within our overall capex allowance.

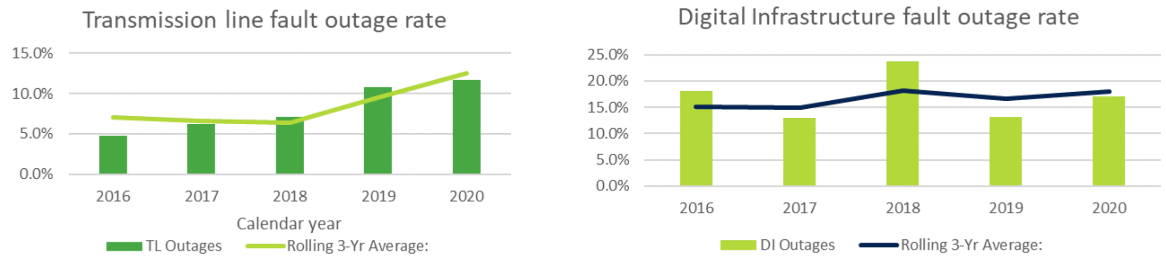
Reliability as seen by the end user across our network has remained steady during the current regulatory period, as evidenced in Figure 4-3 where energy not supplied event counts and overall system reliability have remained constant.

Figure 4-3: Network reliability Performance metrics



Resultantly, with an increasingly aging network and significant network elements dating back to the 1950s and 1960s, equipment faults are becoming more common as shown in Figure 4-4. The fault outage rate for transmission lines & cables and digital infrastructure have increased, and transformers remained steady in the current period. While we have prudently invested in these assets to mitigate safety risks, these increasing trends are lead indicators of additional network reliability risk and the need for additional investment in these areas going forward. These include failures related to assets which had proactively been identified for replacement, but which we were not able to progress in the current period due to the lower regulatory allowance.

Figure 4-4: Network reliability leading metrics



4.5.3. We have responded and adapted to change

We have been agile and adaptive to change, re-optimising our investment portfolio annually to ensure we continue to maximise benefits to our customers throughout the regulatory period. Key changes we have responded to in the current period are:

- climate driven extreme weather events,
- emerging asset issues and compliance obligations not known at the time of our revenue proposal, and
- portfolio variances including:
  - new asset information resulting in some project scopes increasing, but allowing others to be deferred or cancelled compared to what we knew at the time of our revenue proposal,
  - projects which carried over from the previous regulatory period, and
  - changes in the costs of delivering our Repex portfolio.

4.5.4. Respond to emergencies

In the current period we have had to respond to extreme weather events, including bushfires, floods and storms and extreme winds.

We have experienced six events in the current period to date where our transmission structures have collapsed due to extreme winds. We incurred additional Repex of approximately $5.3 million to restore these structures, including a rebuilding an entire 5.6km section of transmission line damaged in a storm. This is in contrast to the 2014-18 period where we had only four events.

Our response to the damage to our network caused by bushfires and floods has been funded via Opex (including our cost pass through event for the 2019/20 bushfires). However, the increased frequency of these extreme climate driven natural hazard events requires us to build our network resilience in the upcoming period to maintain our network safety, reliability and security.

Resilience is an increasing focus for us as the impacts of climate change become more apparent over time. Over the 2018-23 regulatory period, we have explored and adopted opportunities to improve asset resilience. For example, we are currently modelling network resilience for transmission lines, including assessing strategies for:

- critical asset resilience assessment of multiple transmission lines in common easements,
- prevention of bushfire starts,
- resilience against bushfires impacting against our assets, and
- long-term strategy for climate change.

We are using the findings and recommendations of the National Natural Disaster Arrangements Royal Commission[4] and the NSW 2019-20 Bushfire Inquiry[5] as inputs into these strategies.

We sustained a high level of reliability through an unprecedented bushfire season during the period. The 2019-20 year's extreme bushfire activity had a significant impact on our network, damaging transmission lines, disconnecting substations from the network and destroying communications infrastructure. Our network resilience and rapid emergency response meant our customers experienced minimal disruption. After the fires, we engaged an outside expert to undertake a strategic review of our bushfire risk controls. Their report indicated our controls and practices are keeping impacts to the community as low as reasonably possible.

In 2019-20, we continued to develop our first network climate change adaptation strategy, including completing our network resilience assessment using current climate data and reviewing our engineering design standards. The climate change strategy will allow us to estimate physical impacts that climate change will have on the NSW and ACT transmission network over the next 30 to 50 years and beyond. It will help our business to understand how to adapt our substations and transmission lines to withstand climate change, and guide planning of the potential steps required to maintain network reliability as Australia faces a more volatile and potentially hotter climate.

In 2021, we continued to assess the impact of climate change on our network, including by undertaking:

- modelling of future bushfire risk using data from the Electricity Sector Climate Information (ESCI) project,
- modelling the impact of forecast temperature rise on our transmission line ratings through an ESCI project case study,
- modelling the resilience of our most critical transmission lines to natural hazards, including extreme winds, lightning and snow/ice, and
- development of options which could mitigate the increasing network risks identified in the modelling described above, including:
  - strengthening of transmission line structures located in high exposure public safety areas,
  - strengthening of transmission line structures on critical line with parallel route paths,
  - strengthening of transmission line structures in high wind exposure areas,
  - remediation of transmission line structures on critical lines designed to lower legacy design criteria,
  - hardening of susceptible bushfire assets (wood poles and non-ceramic insulators),
  - replacing hook design insulators,
  - improving lightning performance of critical interconnectors through surge arrestors or improved earthing, and
  - the replacement of some standard SF6 equipment with low greenhouse alternatives as a trial.

Engineering consultancy GHD undertook a review[6] of the actions we have taken to assess and mitigate the risk posed by climate change and found that we are leading the way amongst network operations when it comes to assessing and implementing options to improve network resilience to climate change.

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[4] https://naturaldisaster.royalcommission.gov.au/
[5] https://www.nsw.gov.au/nsw-government/projects-and-initiatives/nsw-bushfire-inquiry
[6] GHD, Climate change and extreme weather event resilience, September 2021.

We continue to look to ensure our long term strategy to ensure the transmission system remains fit for purpose and can perform as required under increased extreme weather, bushfire and flood events associated with climate change. We have only proposed Repex related to network resilience in the next regulatory period where they meet our investment criteria. We will continue to assess this in future regulatory periods.

4.5.5. Technology and innovation

We have adopted new technologies and innovations during the 2018-23 regulatory period to improve our ability to identify asset issues and risks before they cause network interruptions, including:

- during transmission line inspections, we began using sub-millimetre resolution data capture and deep learning algorithms to better understand the condition of conductors,
- we deployed high-resolution photography and infrared and ultraviolet cameras to identify issues outside the visual spectrum and in a single flight. This helps us to identify emerging defects before a failure occurs and helps to optimise our network capital replacement investment, and
- we also deployed a real-time monitoring system on our Sydney CBD underground transmission cable to identify unauthorised activities in the vicinity of the cable. This is expected to reduce the risk of cable strike and major repair costs.

We have used these and other innovative asset condition assessment and monitoring techniques to inform our investment needs for the 2023-28 regulatory period.

During the 2018-23 regulatory period, we have demonstrated substantial innovation in our secondary systems including:

- our 'Digital Substation' strategy, including the installation of IEC 61850 compliant sites at some of our substations. This innovation results in
  - reduced cabling and trenching requirements
  - reduced building size
  - faster commissioning
  - reduction in system drawings
  - simplified maintenance,

  It is included as an option in secondary system replacements in the 2023-2028 period and used where there are benefits over traditional replacement,
- the implementation of a number of cyber security initiatives to respond to increasing government and agency concerns around security of critical infrastructure. We are required to increase our security requirements and therefore have undertaken investment to target level 2 maturity level for the Australian Cyber Security Centre[7] (ACSC) maturity model in the current regulatory period, and
- Commencement of transitioning the existing packet-switched SDH multiplexer communications network to a modern MPLS-TP Ethernet based network. This increases the bandwidth of our communications systems, allowing us to enhance our real time monitoring of assets and our operational capabilities in the increasingly complex energy system.

[7] https://www.cyber.gov.au/acsc/view-all-content/publications/essential-eight-maturity-model

5. 2023-28 Repex Forecast

This chapter sets out our Repex forecast for the 2023-28 regulatory period, and the associated outcomes we intend to deliver. Further details relating to each of the programs discussed is then provided.

We provide further details on the basis on which we have forecast our Repex in Chapter 6.

Key messages:

- Our Repex forecast is split into three major categories: Substations, Transmission Lines and Digital Infrastructure.
- The key driver for our Repex forecast is the continuing delivery of a safe and reliable network, as assets in our network age and their condition declines.
- However other drivers are emerging, in particular climate change and resilience and cyber/physical security.
- Transmission lines programs account for 42 per cent ($334.5 million) of our Repex forecast to maintain network safety. Key programs include:
  - $63.9 million on pole replacement – deteriorating wood pole assets are reaching end of life and are at increased risk of failure, including addressing low ground clearances on specific transmission lines which are now highly utilised due to the location of new renewable generation
  - $128.1 million on steel tower refurbishment and replacement - improved asset condition monitoring and information has identified significant corrosion on transmission towers and their components. This also includes the safety and compliance based programs to remove asbestos paint on our towers and upgrade of climbing deterrents to manage public safety risk.
  - $78.2 million on insulator replacement – these assets are experiencing a deterioration in performance as they age and are at an increased risk of failure.
  - $57.8 million on conductor replacement – these assets are experiencing a deterioration in condition as they age and are at an increased risk of failure.
- Substation programs account for 25 per cent ($199.7 million) of our Repex forecast to maintain network reliability. Key programs include:
  - $82.2 million on site establishment and supporting assets, where improved asset condition monitoring has identified significant steelwork corrosion requiring refurbishment.
  - $40.6 million on replacement of power transformers, to address increasing failure risks associated with deteriorating asset condition.
  - $5.2 million to address a significantly aged population of capacitor banks
  - $71.7 million on switchbay equipment – to address the increasing failure risks associated with deteriorating asset condition.
- Digital infrastructure programs account for 33 per cent ($263.4 million) of our Repex forecast to maintain network reliability, as well as network safety. Key programs include:
  - $156.8 million to replace control and protection equipment with new schemes to manage end of life and obsolesce risk, which managing the increasingly complex generation mix.
  - $36.8 million to replace operational technology equipment to align with cyber security requirements under new legislation.

5.1. Forecast Repex for the 2023-28 period

Table 5-1 presents our forecast Repex across the three major categories of Repex (Substations, Transmission Lines and Digital Infrastructure), by the key Repex drivers (ie, provision of a safe and reliable network, climate change and resilience, compliance, cyber/physical security and change in generation mix). The table shows that the key driver for our Repex forecast is the continuing delivery of a safe and reliable network.

Table 5-1: Repex by key driver for the 2023-28 regulatory period ($Million, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Transmission lines	**48.8**	**59.6**	**86.0**	**54.5**	**85.7**	**334.5**
Safe and Reliable Network	36.5	41.3	59.8	40.7	79.0	257.3
Compliance	12.1	9.0	22.9	13.8	6.7	64.5
Change in Generation Mix	0.2	9.2	3.3	-	-	12.7
Substations	**35.5**	**37.6**	**41.9**	**45.9**	**38.7**	**199.7**
Safe and Reliable Network	35.5	37.6	41.9	45.9	38.7	199.7
Digital Infrastructure	**52.2**	**72.4**	**46.6**	**55.6**	**36.6**	**263.4**
Safe and Reliable Network	40.2	58.6	39.3	49.0	30.0	217.0
Cyber / Physical Security	7.2	9.0	7.4	6.6	6.6	36.8
Compliance	4.8	4.8	-	-	-	9.7
Total	**136.6**	**169.5**	**174.5**	**156.0**	**161.0**	**797.6**

Table 5-2 presents our forecast Repex across each of the three major categories broken down further by sub-category.

Table 5-2: Repex by category 2023-28 ($Million, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Transmission lines	**48.8**	**59.6**	**86.0**	**54.5**	**85.7**	**334.5**
Transmission poles	7.3	18.1	17.3	15.7	5.5	63.9
Transmission towers	21.9	18.1	20.9	16.0	51.4	128.1
Insulators	10.2	13.0	29.1	12.4	13.5	78.2
Overhead conductors	7.7	7.6	18.1	9.8	14.6	57.8
Underground cables	1.7	2.9	0.6	0.6	0.6	6.4
Substations	**35.5**	**37.6**	**41.9**	**45.9**	**38.7**	**199.7**
Power Transformers	2.0	7.9	15.4	10.4	4.9	40.6

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Reactive plant	1.0	0.2	1.1	1.4	1.5	5.2
Site Establishment and supporting assets	16.9	15.0	17.3	17.7	15.3	82.2
Switchbay Equipment	15.7	14.5	8.0	16.5	17.0	71.7
Digital Infrastructure	**52.2**	**72.4**	**46.6**	**55.6**	**36.6**	**263.4**
Protection systems	18.5	28.8	20.3	23.2	14.4	105.3
Control systems	5.9	11.9	11.8	15.2	6.7	51.5
Market metering systems	1.7	3.3	2.0	2.2	1.3	10.5
Communications systems	9.3	10.6	2.6	4.2	4.4	31.1
SCADA	-	-	-	-	-	-
OPGW	-	-	-	-	-	-
AC/DC & Auxiliary systems	1.3	2.7	2.2	1.9	0.8	8.9
Network Property	15.6	15.1	7.6	8.9	9.0	56.1
Total	**136.6**	**169.5**	**174.5**	**156.0**	**161.0**	**797.6**

Each of our major Repex programs in the 2023-28 regulatory period is discussed in more detail in the following sections, together with the outcomes delivered to customers.

The major programs (and associated key drivers) of our Repex forecast are:

- $334.5 million to be spent on transmission lines during the 2023-28 regulatory period. This represents 42 per cent of our total forecast Repex:
  - The predominant driver for transmission lines Repex is maintaining the safety of the network as assets age and their condition deteriorates, as well as maintaining compliance with our safety obligations. Key programs include:
    - $63.9 million on pole replacement – deteriorating wood pole assets are reaching end of life and are at increased risk of failure. This is discussed in section 5.2.1.
    - $128.1 million on steel tower refurbishment and replacement - improved asset condition monitoring and information has identified significant corrosion on transmission towers and their components. This also includes the safety and compliance based programs to remove asbestos paint on our towers and upgrade of climbing deterrents to manage public safety risk. This is discussed in section 5.2.2.
    - $78.2 million on insulator replacement – these assets are experiencing a deterioration in performance as they age and are at an increased risk of failure. This is discussed in section 5.2.3.
    - $57.8 million on conductor replacement – these assets are experiencing a deterioration in performance as they age and are at increased risk of failure. This is discussed in section 5.2.4.

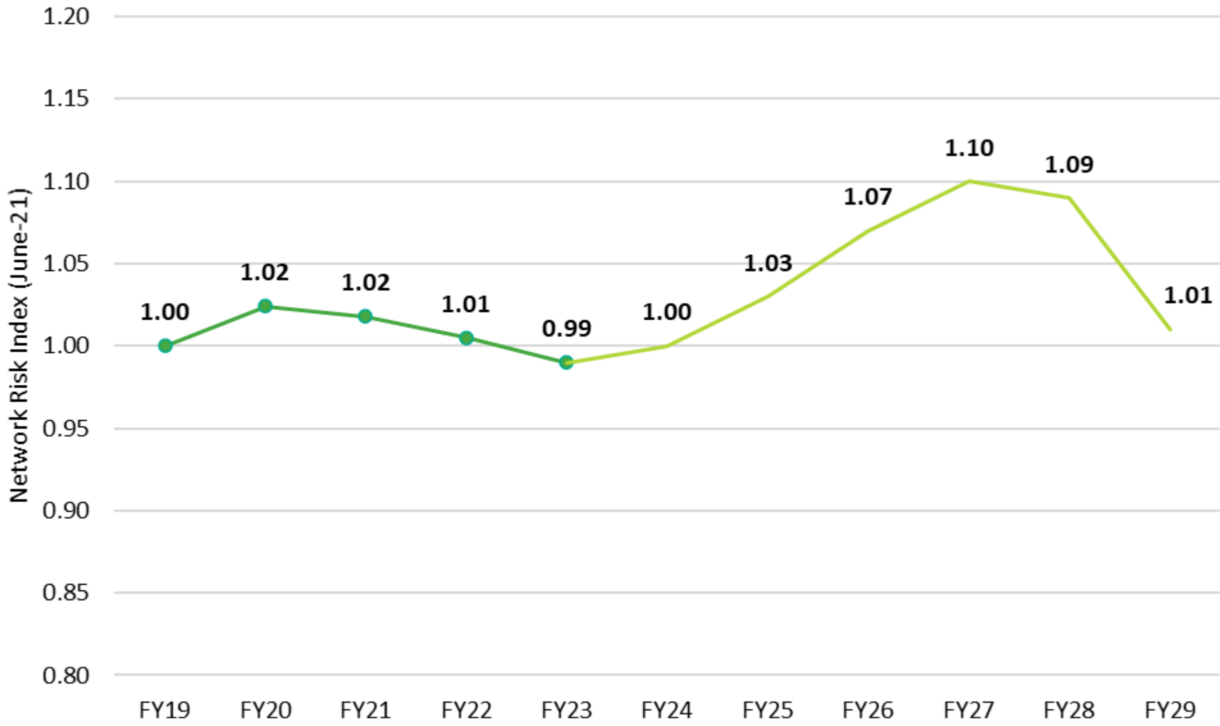
- The changing generation mix is driving the need to spend $12.7 million to address low ground clearances on specific transmission lines which are now highly utilised due to the location of new renewable generation. This is discussed in section 5.2.1.
- Increasingly our transmission lines are being influenced by the need to build network resilience and maintain network risk associated with increasing climate driven extreme weather events. While we assessed options[8] to mitigate this risk (as discussed in Section 4.5.4), we have not included any network resilience specific expenditure in our Repex forecasts. Some of our forecast programs do however include measures which will also provide network resilience benefits as part of undertaking condition-based replacements which is discussed in Section 5.2.1.

- $199.7 million to be spent on substation programs during the 2023-28 regulatory period. This represents 25 per cent of our total forecast Repex,
  - The key driver of substation Repex is maintaining the reliability of the network, as condition-related issues and the average age of the legacy assets continues to grow. Key programs include:
    - $82.2 million on site establishment and supporting assets, where improved asset condition monitoring has identified significant steelwork corrosion. This is discussed in section 5.3.1.
    - $40.6 million on replacement of power transformers, to address failure risks associated with deteriorating asset condition. This is discussed in section 5.3.2.
    - $71.7 million on switchbay equipment, to address the increased risk of failure associated with deteriorating asset condition. This is discussed in section 5.3.3.
    - $5.2 million to address a significantly aged population of capacitor banks. This is discussed in section 5.3.4
- $263.4 million to be spent on digital infrastructure programs during the 2023-28 regulatory period. This represents 33 per cent of our total forecast Repex.
  - The key driver for expenditure on digital infrastructure is maintaining the safety and reliability of the network, as these assets are central to providing a safe, reliable and efficient transmission service. The key digital infrastructure programs included in our Repex forecast are:
    - $167.3 million to replace control, protection and metering equipment with new schemes to manage end of life and technology obsolesce. This will also allow capability to manage the increasingly complex generation mix. This is discussed in sections 5.4.1, 5.4.2 and 5.4.3.
    - $56.1 million to replace or refurbish network property assets which are experiencing end of life, performance or obsolesce issues. This is discussed in section 5.4.4
    - $31.1 million to replace communications systems which enable data transfers across sites and facilitate NEM market operations new schemes to manage end of life and technology obsolesce. This is discussed in section 5.4.5.
  - We must also meet our obligations under new cyber and physical security requirements set out in new legislation. Our forecast includes $36.8 million to replace operational technology equipment to align with cyber and physical security requirements under this new legislation. This is discussed in sections 5.4.2 and 5.4.4.

[8] GHD's independent climate change adequacy review of our network found that we are leaders in assessing and implementing options to improve our network resilience to climate change.

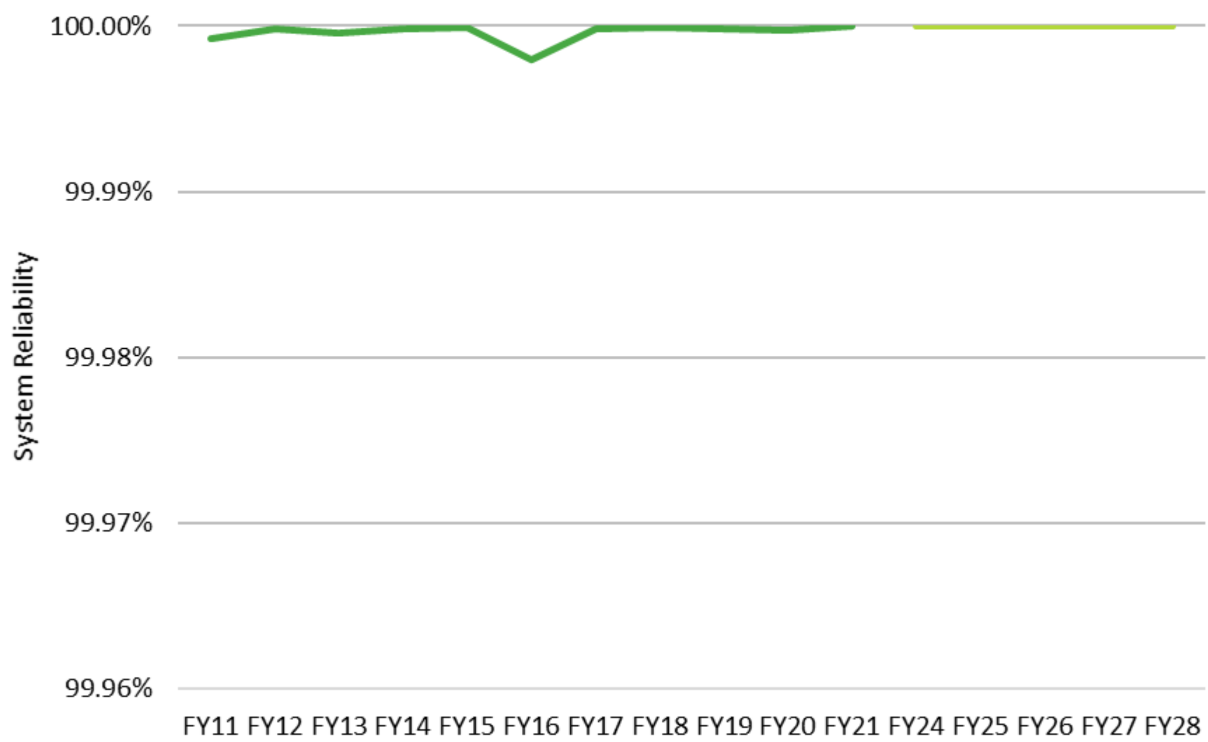
Our repex forecast for 2023-28 will allow us to maintain our network risk index as shown in Figure 5-1 and contribute to maintaining network reliability as shown in Figure 5-2.

Figure 5-1 Network risk index 2023-28 regulatory period



Note: Risk benefits from projects are realised the year following commissioning. E.g. for projects commissioned in 2027-28, risk benefits are realised in 2028-29.

Figure 5-2 - Expected annual network reliability 2023-28 regulatory period



5.2. Transmission lines

Our Repex forecast reflects $334.5 million to be spent on transmission line programs during the 2023-28 regulatory period. This represents 42 per cent of our total forecast Repex. The key sub-categories of forecast Repex for transmission lines relate to replacement or refurbishment of transmission poles, transmission towers, conductors and insulators.

The predominant driver for Repex on transmission lines is maintaining the safety of the network. Our transmission line and cable network is made up of assets dating back to 1940, with a significant share of lines being commissioned in the 1950s and 1960s. The aging asset base and the associated increase in condition issues on the network are presenting ongoing challenges in maintaining safety and performance outcomes from our transmission line assets:

- aging wood pole assets are causing increased corrective maintenance and replacement expenditure as the condition of the timber deteriorates, predominately due to rot and termites. We are forecasting expenditure of $63.9 million on pole replacement. This also includes addressing low ground clearances on specific wood pole transmission lines which have legacy low conductor ground clearances and are also now highly utilised due to the location of new renewable generation to manage public safety risks.
- improved asset condition information has identified significant corrosion of steel components (tower steelwork, buried steel foundations and conductor attachment fittings) on transmission towers for some transmission lines. We are forecasting expenditure of $128.1 million on steel tower refurbishment and replacement. This also includes the following safety and compliance based programs on our steel towers which are also planned:
    - some of our steel towers are coated in a legacy asbestos containing paint which is degrading and flaking off the towers. Asbestos paint removal is planned across the steel tower fleet where applicable to meet community safety expectations
    - upgrade of climbing deterrents in line with current industry guidelines to manage public safety risk, and
    - address low ground clearances on specific steel tower transmission lines which have legacy low conductor ground clearances to manage public safety risks.
- insulators are experiencing a deterioration in their performance as the component ages and the material properties degrade, and accordingly, are at an increased risk of failure which can lead to safety and bushfire risks. We are forecasting expenditure of $78.2 million on insulator replacement.
- conductors are experiencing a deterioration in their performance due to various factors including corrosion, annealing due to bushfire exposure, fretting and fatigue due to Aeolian vibration. They are at an increased risk of failure which can lead to safety and bushfire risks. We are forecasting expenditure of $57.8 million on conductor replacement.

Our Repex forecast for this sub-category will also support network resilience and maintain network risk associated with increasing extreme weather events impacting on transmission lines - such as that which affected our assets during the NSW Bushfires of 2019-20.

5.2.1. Transmission poles

Wood poles are critical assets in our network and are used to support conductors on overhead transmission lines. We have 12,956 wood pole structures on our network, predominately on our 132kV network. The wood pole structure population is amongst the oldest assets in the transmission line network.

Wood pole structures are replaced according to an asset risk evaluation, comprising of both condition and criticality assessments undertaken at the pole locality.

We have forecast replacement of 468 wood pole structures over the 2023 – 2028 regulatory period. Each replacement will be with either steel or concrete pole structures to current design standards. The forecast cost of the replacement program is $63.9 million. Design and installation will be managed by our construction teams using external resources sourced through a competitive tendering process.

This is lower than the 1659 wood pole structures we expect to replace in the current regulatory period due to the per unit cost increases we have experienced over the period meaning less replacements have their optimal timing falling in the 2023-28 regulatory period. Future regulatory periods are likely to see increasing rates of wood poles requiring replacement as the population continues to age, which we aim to manage in a stable manner.

Wood decay due to rot, fungi and/or termite damage reduces a pole's structural capacity and compromises its ability to withstand loads. As the level of decay increases the structural capacity of the pole is reduced. Once this capacity falls below a certain threshold, the wood pole structure is at an increased risk of failure and is deemed to have reached end-of-life. Our approach is to replace wood pole structures which are approaching the threshold for wood decay to minimise the risk of failure.

The proposed wood pole structure replacements are based on condition assessment information (field measurements and forecast defective pole rates) and the risk that condition presents to bushfire, safety and reliability.

Safety is the single most important driver of wood pole Repex. The structure and conductor drop event can result in potential fire ignition and/or present a safety hazard if exposed to the general public. Some lines have a higher network reliability criticality impact, and a failure event may potentially result in an unserved energy event. The proposed replacement volume is required to enable us to maintain our levels of risk and network performance for the benefit of customers.

Replacement of these deteriorated wood poles with modern concrete and steel poles inherently also improves the resilience of the network to extreme natural hazard events which are increasing as a result of climate change.

The energy transition is seeing new generation connect to our 132kV network which is increasing the utilisation of wood pole transmission lines. This is increasing the risk posed by legacy low conductor ground clearances. We plan to replace wood poles with new taller poles and modify insulator and cross-arm arrangements to rectify these ground clearances, where administrative controls are not adequate. This will mitigate public safety risk and compliance with design standards.

The program will result in the following benefits:

- avoiding increased bushfire risk,
- avoiding increased public and worker safety risk,
- avoiding increased reliability risk, and
- avoiding increased operating costs.

5.2.2. Transmission towers

Steel lattice towers are critical assets in our network and are used to support conductors on overhead transmission lines. We have 14,700 steel lattice towers predominately on our 330kV and 500kV network, with 12% of these located in coastal areas where they are more likely to suffer from corrosion. Of the towers in coastal areas, 58% are greater than 50 years old.

Steel lattice towers are refurbished or replaced according to an asset risk evaluation, comprising of both condition and criticality (bushfire, safety or reliability risks) assessments undertaken at the tower locality.

The 2023 – 2028 regulatory period will include the refurbishment and replacement of lattice towers, at a forecast cost of $128.1 million. These steel towers have experienced corrosion of the steel tower members, fasteners, attachments, and footings. The towers located in coastal areas have suffered the greatest deterioration, primarily due to their local atmospheric corrosion levels.

Corrosion of the key components of the tower and attachments can compromise its structural integrity. Corrosion related deterioration compromises the strength of the component, and accordingly, the structural capacity[9] of the tower or component is reduced. Once the level of corrosion reaches certain thresholds of deterioration, the tower or component is at an increased risk of failure and deemed to be in need for repair, or to have reached end-of-life.

We take the following approach when deciding on whether to refurbish or replace a tower:

- where corrosion is localised on specific tower components we aim to refurbish and extend the life of the tower through targeted activities such as replacing attachments/fasteners and painting steel, or
- where corrosion is widespread across a tower (typically only in high corrosion zones) it is often more efficient to replace the tower than refurbish it (applies to suspension towers, tension towers typically remain more efficient to refurbish).

We plan to replace 102 steel towers which are at end of life across coastal transmission Line 11 between Sydney and the Illawarra as well as Line 23 at the Central Coast. These steel towers have experienced the highest rates of steel corrosion on the network and present some of the highest bushfire and public safety risks on the network. Replacement of these towers is consistent with our strategy to refurbish tension towers (which we did in the current and previous regulatory period on these two transmission lines) and replace the suspension towers when they reach end of life.

We also plan to refurbish 266 steel towers across the state, with the scope of refurbishment tailored to the specific condition issues at each tower based on detailed condition assessments that we have performed.

Safety and bushfire are the most important drivers of steel tower refurbishment/replacement expenditure. A structure and conductor drop event can result in potential fire ignition and/or present a safety hazard if exposed to the general public. Some lines have a higher network reliability criticality impact, and a failure event may potentially result in an unserved energy event. The proposed refurbishment/replacement volume is required to enable us to maintain our levels of risk and network performance for the benefit of customers.

Future regulatory periods are likely to see steady rates of steel towers requiring refurbishment/replacement as the population continues to age, which we aim to manage in a stable manner.

Design and construction will be managed by our construction teams using external resources sourced through a competitive tendering process.

We also plan to address safety and compliance issues on our steel towers:

- Many of our steel towers also have legacy paint coatings containing asbestos. As these coatings have been in place for decades, they are deteriorating resulting in the paint flaking. This asbestos containing paint presents a safety risk to workers who need to perform work on or near the towers, as well as to the general public. We have engaged expert consultants to sample, assess and test the paint to

9 The structural capacity of the tower refers to its ability to withstand structural loads, as per its relevant design criteria.

prioritise remediation if it is required. Based on this expert advice, we expect that asbestos containing paint will need to be removed from 1,727 towers during 2023-28.

- Steel towers have climbing deterrent devices affixed to prevent unauthorised access. We have identified 2,733 structures that require modification to their climbing deterrents to align with the latest industry guidelines and Transgrid's standard. This will improve the effectiveness of the climbing deterrent, decrease the likelihood of unauthorised access to the tower and reduce the public safety risk.
- Where increased utilisation of steel tower transmission lines is increasing the risk posed by legacy low conductor ground clearances, we also plan to alter the towers or insulator arrangements to rectify these ground clearances, where administrative controls are not adequate. This will mitigate public safety risk and compliance with design standards.

The program will result in the following benefits:

- avoiding increased bushfire risk,
- avoiding increased public and worker safety risk, and
- avoiding increased reliability risk.

5.2.3. Insulators

Insulators allow the high voltage conductors to be attached to the transmission line structures. The insulators can either be "disc" insulators made of glass or porcelain, or polymer "non-ceramic" longrods. We have insulators of various vintages dating back to the 1950's and earlier and from various manufacturers.

The 2023 – 2028 regulatory period forecast includes the replacement of 1,746 porcelain insulator and non-ceramic insulator (NCI) sets. A "set" is the entire insulator string on every phase on one tower, inclusive of any pilot insulators. The forecast cost of the insulator replacement program is $78.2 million. The replacements will be spread over multiple proposed projects, primarily associated with steel tower/pole and wood pole refurbishment and replacement projects. Design and installation will be managed by our construction teams using external resources sourced through a competitive tendering process.

We expect to replace 1,352 insulator sets in the current regulatory period. Future regulatory periods are likely to see increasing rates of insulators requiring replacement as more insulators reach end of life. Insulators experience a deterioration in their performance as the components and materials ages. This deterioration varies by type:

- Porcelain insulators are subject to two modes of deterioration, namely porosity of the porcelain material and corrosion of the steel pins on the insulator disc. Porcelain insulators of a vintage dating to the 1950's have experienced a deterioration in electrical insulation performance due to increased porosity, and the manufacturer has advised they have reached the end of their serviceable lives and recommended their replacement following sample testing. Disc insulators located in coastal locations experience corrosion and metal loss on the steel pins from exposure to atmospheric conditions. These can both result in a failure of the insulator, and can lead to a conductor drop event.
- NCI or polymer insulators experience degradation with age as exposure to the atmosphere, UV radiation and electrical stresses progressively result in adverse deterioration of the matrix polymer compound. These condition issues are typically hidden, but manifest themselves by failure in service. Failure of the insulator will result in a line outage, and can lead to a conductor drop event. Sample test results have shown a large reduction in hydrophobicity (i.e. the ability of the insulator to resist moisture) and corona activity at the end fitting to housing interface after over 20 years in service. This is

consistent with current industry practise where the service life of NCIs at Extra High Voltage is expected to be 25 years due to corona ageing effects on the silicone housing.

We have experienced in service insulator failures on porcelain and NCI's for each of these failure modes.

Our approach is to replace these insulators which are approaching or have reached the end of their serviceable lives, and accordingly are at an increased risk of failure. Safety and bushfire are the most important drivers of the insulator replacement programmes. A conductor drop event can result in potential fire ignition and/or present a safety hazard if exposed to the general public. Some lines have a higher network reliability criticality impact, and a failure event may potentially result in an unserved energy event. The proposed replacement volume is required to enable us to maintain our levels of risk and network performance for the benefit of customers.

Our risk-based approach to managing forecast replacement volumes provides a method to manage to aging population of insulators in a stable manner by considering asset condition and economic evaluations based on risk quantification.

The program will result in the following benefits:

- avoiding increased bushfire risk,
- avoiding increased public and worker safety risk, and
- avoiding increased reliability risk.

5.2.4. Overhead conductors

Conductors are critical assets in our network and are used to transmit electrical energy across distances. We have over 12,953 km of conductors (three phase bundles) and the same of overhead earthwire on our network.

Our Repex forecast for the 2023 – 2028 regulatory period includes:

- the replacement of 138 km of conductor (circuit length) which have reached end of life due to various factors including corrosion, annealing due to bushfire exposure, fretting and fatigue due to Aeolian vibration.
- the replacement of 208 km of steel earthwire (circuit length) due to corrosion related deterioration.

The forecast cost if the conductor replacement program is $57.8 million. Design and installation will be managed by our construction teams using external resources sourced through a competitive tendering process.

There is 5 km of conductor replacement and 200 km of steel earthwire replacement in the current regulatory period. Future regulatory periods are likely to see increasing rates of conductor replacement as the population continues to age, which we aim to manage in a stable manner.

Various inspections, including Smart Aerial Image Processing (SAIP) in early 2020, have been carried out on selected lines, supported with sampling and material testing. These have confirmed that multiple spans within line segments have issues including broken strands, probable conductor corrosion, and probable annealing of conductor.

The main factors that impact conductor condition are:

- Bushfire exposures. High temperatures can impact the mechanical integrity of conductors in multiple ways such as annealing of the aluminium alloy reducing tensile strength or the loss of the grease/galvanising layer from the inner steel strands of conductor. Both of these reduce the corrosion performance.

- Corrosive operating environment. Conductors which are operating in the coastal regions are subject to harsher operating conditions and therefore higher rates of corrosion than conductors situated away from the coastline. In particular, corrosion and subsequent metal loss of the steel strands in ACSR/GZ conductor and galvanised steel earthwires reduces tensile strength. Once the level of corrosion has reached a certain threshold, the earthwire is at an increased risk of failure.
- Conductor type. Prolonged exposure to Aeolian vibration results in fatigue and/or fretting of conductor strands, and our earlier legacy fleet of conductor attachments utilise bolted suspension clamps which lack effective vibration control.

Analysis of inspection records, historical defects, line design information including conductor type and attachments, and bushfire burn areas have identified locations that have been exposed to the above conditions. Based on these factors, a risk priority ranking has been developed to consider those conductors at the greatest risk of failure.

Our approach is to replace the conductor and earthwire sections with the highest priority ranking and which meet the relevant replacement criteria.

Safety and bushfire are the most important drivers of conductor replacement expenditure. The conductor drop event can result in potential fire ignition and/or present a safety hazard if exposed to the general public. Some lines have a higher network reliability criticality impact, and a failure event may potentially result in an unserved energy event. The proposed replacement volume is required to enable us to maintain our levels of risk and network performance for the benefit of customers.

Our risk-based approach to managing forecast replacement volumes provides a method to manage the aging population of conductors in a stable manner by considering asset condition and economic evaluations based on risk quantification.

The program will result in the following benefits:

- avoiding increased bushfire risk,
- avoiding increased public and worker safety risk, and
- avoiding increased reliability risk.

5.2.5. Underground cables

We have 86km of underground cable up to 330kV, increasing to 106 km following the commissioning of the Powering Sydney's Future project.

The cable circuits operate as a system which includes joints and terminations and the surrounding environment on where the cables are situated, including trenches, backfill, and supporting structures such as bridges. Monitoring systems such as cable temperature and oil sensors are also critical in supporting the safe and reliable operation of the cables circuit.

Our Repex forecast includes replacement of condition monitoring systems and procurement of spares to enable continued reliable operation of our underground cables which supply inner Sydney, including:

- renewal of cable condition monitoring systems, which have much shorter functional lives than the cable itself. Asset lives are similar to microprocessor based protection and control equipment. All of our cable condition monitoring will reach end of life within the next regulatory period. These monitoring systems allow us to monitor cable temperature and oil pressures to ensure they are within operating limits, and
- cable spares for two types of cable technology:

- Self Contained Fluid Filled (SCFF) cable, which is an older generation of cable technology that is being phased out. By the end of the 2023 – 2028 regulatory period compatible cable and accessories will not be available for purchase. New spares in addition to the current holdings are required to enable continued operation of our existing SCFF cable network to reach the end of its technical life.
- Cross Linked Polyethylene (XLPE) cables, where the existing spare accessories have reached the end of their limited shelf life (due to the chemical nature of the rubberised material). Accordingly, XLPE spare accessories are required to be renewed to ensure that their condition remains acceptable for use.

The forecast cost of the replacement program is $6.4 million.

5.3. Substations

Our Repex forecast includes $199.7 million to be spent on substation programs during the 2023-28 regulatory period. This represents 25 per cent of our total forecast Repex.

The overwhelming driver for expenditure on substation assets is maintaining the reliability of the network, as condition-related issues and the average age of the legacy assets continues to grow.

We have specific challenges in maintaining safety and performance outcomes from our substation assets into the next regulatory control period. We are forecasting a need to spend:

- $82.2 million on site establishment and supporting assets,
    - improved asset condition monitoring and information has identified steelwork corrosion as significant issue across multiple sites. Projects have already been initiated to extend the life of steelwork, with this work needing to continue over the next regulatory period
- $40.6 million on replacement and refurbishment of power transformers is required to address failure risks associated with deteriorating asset condition.
- $71.7 million on switchbay equipment – to address issues associated with the increased risk of failure, along with increasing expenditure to maintain and repair the assets. $0.4 million of this expenditure will include a trial of equipment with SF6 alternative insulating gasses which will in the long term reduce the greenhouse gas emissions from our switchgear fleet.
- $5.2 million on replacement of reactive plant through the renewal of capacitor banks. A large number of capacitor banks are beyond their typical useful life and a portion require replacement in the 2023-28 regulatory period.

5.3.1. Site establishment and supporting assets

We have identified the need for increased expenditure on substation site establishment and supporting assets over the next regulatory period, driven in particular by substation gantry steelwork assets reaching end of life and having an increased risk of failure. In total we are forecasting expenditure of $82.2 million for this sub-category.

This category of assets is comprised of:

- substation gantry steelwork,
- auxiliary transformers to provide low voltage supplies to power secondary system assets,

- capital spares to ensure that network assets can be repaired or replaced to maintain network availability, and
- online condition monitor (OLCM) systems to continually assess asset condition and initiate remedial action where required.

There is an increase in the expenditure required for substation gantry steelwork in the 2023-2028 regulatory period, which is expected to further increase into the future. This increase is due to ageing steelwork which is now 50-60 years old having depleted galvanic protection systems and experiencing loss of metal through corrosion, which increases the probability of failure.

In the current regulatory period we undertook steelwork and holding down bolt remediation at three sites as well as site trials. This has provided significant input into our understanding of the complexity addressing this emerging need. We plan to replace key steelwork gantries at five sites in the 2023-28 regulatory period. Expenditure will continue to increase as more gantry steelwork reaches this critical end of life period.

The key drivers of expenditure are steelwork, where site specific condition data collection and structural modelling is used to determine the probability of failure, and capital spares, where expected requirements are based on historic usage and upcoming equipment procurement.

We have also included a forecast for replacement and acquisition of miscellaneous tools and test equipment which are required to facilitate network capital and maintenance works, which is not included as part of our non-network other capex forecast.

The program will result in the following benefits:

- avoiding increased safety risk,
- avoiding increased reliability risk, and
- avoiding increased operating costs.

5.3.2. Power Transformers

Expenditure in relation to the replacement of power transformers is required to address the risk associated with deteriorating asset condition due to asset age, which leads to increased probability of failure. In total we are forecasting expenditure of $40.6 million for this sub-category.

Power transformers play a vital role in the network by changing and controlling the voltage and current supplied to customers at points throughout the network. The performance of power transformers is one of the most significant drivers of overall network reliability.

We have a total of 215 individual units with primary voltages ranging from 500kV to 132kV. Our power transformers are predominantly oil insulated, with a small number of newer transformers SF6 insulated, where required to manage fire or environmental risks. Power transformer risks can be treated by installation of a new unit (replacement) or refurbishment (involving replacement and/or remediation action on specific components).

The 2023-2028 regulatory period will include replacement of 10 power transformers at a cost of $40.6 million, which is 2.3% lower than that expected for the 2018–23 regulatory period where we replaced 5, refurbished 20 and decommissioned 3 power transformers.

Power transformers are procured from a small number of pre-qualified manufacturers. This allows competitive pricing while standardising on a relatively small number of suppliers to reduce diversity, spares holdings and design effort. Design and installation is managed by our construction teams using external resources engaged through a competitive tendering process. The power transformer program has been validated through comparison and challenge using the top down Repex model, independent reviews of key building blocks (Asset Health and Criticality) and trending with past actual and future predicted replacement rates.

As power transformers are generally the most expensive single item of substation plant, significant maintenance and monitoring attention is directed to them and hence these plant items have the most comprehensive set of condition data. We utilise a transformer health index methodology to identify those transformers with the highest risk of failure. Detailed condition assessments are prepared for higher risk transformers.

The output of the health index methodology is an effective age which is then modelled to an individual probability of failure. The probability of failure is then combined with the consequence (criticality) values for each transformer to allow the optimum intervention strategy to be determined. Outage and other constraints are reviewed during the feasibility assessment for each project. The forecast expenditure in 2023-2028 is similar to the current period so no significant delivery challenges are expected.

The program will result in the following benefits:

- avoiding increased safety risk,
- avoiding increased reliability risk, and
- avoiding increased operating costs.

5.3.3. Switchbay equipment

Our proposed switchbay equipment expenditure program will address issues associated with the increased risk of failure, along with increasing expenditure to maintain and repair the assets. In total we are forecasting expenditure of $71.7 million for this sub-category.

Switchbay equipment includes high voltage circuit breakers (CBs), current transformers (CTs), voltage transformers (VTs) and disconnectors. These assets are essential for clearing electrical faults from the transmission network, enabling safe access to the network for our internal and other workers and measuring high voltage current and voltages for control, protection and metering functions.

CBs, CTs and VTs are assessed through a health index methodology (described in section 4.3.1) which combines relevant health data to determine an effective age and feed into our quantified risk methodology.

The 2023-2028 regulatory period includes replacement programs comprising:

- 137 CB replacements (three phase assets),
- 139 CT replacements (single phase assets),
- 311 VT replacements (single phase assets), and
- 121 disconnector replacements or refurbishments (three phase assets).

This represents a slight decline in the 875 items of switchbay equipment replaced in the current period.

Switchbay equipment is procured through bulk order agreements in order to achieve efficiencies from global suppliers.

The number of CBs, CTs and VTs proposed to be replaced in the 2023-28 period is similar to the number replaced in the current regulatory period as it represents the ongoing condition replacements.

The proposed disconnector renewal program is an increase from previous periods. Disconnectors present an ongoing challenge due to a significantly ageing population and increasing defects, which impact our ability to safely and efficiently access the network to perform required maintenance and project work.

Historically low replacement volumes and a corresponding increase in the large number of disconnectors which are beyond their nominal life necessitates the increase in the disconnector renewal program. The proposed renewal program combines refurbishment where practicable with replacement, to managing the ongoing risk of this asset type.

It is expected that the volume of renewals of this asset in future regulatory periods will further increase.

The switchyard equipment programs will result in the following benefits:

- avoiding increased safety risk,
- avoiding increased reliability risk, and
- avoiding increased operating costs.

A forecast of $0.4 million is planned to investigate and trial circuit breaker replacements with insulation mediums other than SF6. This will enable early trials of this technology which will contribute to the achievement of lower emissions targets in future regulatory periods.

5.3.4. Reactive Plant

Expenditure in relation to the replacement and refurbishment of reactive plant is required to address the risk associated with deteriorating asset condition, which leads to increased probability of failure. In total we are forecasting of expenditure of $5.2 million for this sub-category.

Capacitor banks and shunt reactors enable us to operate the transmission network within the defined voltage limits as required by the National Electricity Rules. Shunt reactors can be oil filled or air cored. Capacitor banks are comprised of capacitor cans (which provide reactive power support), as well as air cored reactors (to manage switching transients during energisation) and embedded current transformers (for fault detection). Capacitor banks are installed within specifically fenced areas to manage the safety risk associated with low electrical clearances and high magnetic fields.

The 2023-2028 regulatory period will include the replacement of 5 capacitor banks out of a total population of 184 capacitor banks. There are no shunt reactors included for replacement. In the current period we also replaced 5 items of reactive plant.

Capacitor bank expenditure has historically been limited due to low reliability impacts and has resulted in a large number of capacitor banks now operating beyond their nominal lives. This presents an increasing risk of failure and associated consequences. It is expected that capacitor bank expenditure will increase in the coming regulatory periods.

Capacitor banks and shunt reactors are procured using specifications ensuring each meets the technical requirements for the network location.

Capacitor banks are assessed on the basis of increasing age and the risk of failure which would result in load shedding to ensure we comply with the voltage limit requirements of the NER. The probability of asset failure is combined with the consequence (criticality) values for each capacitor bank to allow the optimum intervention strategy to be determined.

The key benefit from this program is an avoided increase in reliability risk.

5.4. Digital infrastructure

Our Repex forecast reflects $263.4 million to be spent on digital infrastructure programs during the 2023-28 regulatory period. This represents 33 per cent of our total forecast Repex.

Digital Infrastructure technology includes assets such as protection and control equipment, communications and metering equipment, and their associated power supplies. Digital infrastructure assets facilitate the operation of the transmission network, allowing automatic and remote operation of network elements to providing real-time and long-term trending feedback. The key sub-categories of proposed Repex relate to the replacement of protection systems and control systems.

The driver for expenditure on digital infrastructure is again predominantly maintaining the safety and reliability of the network, as these assets are central to providing a safe, reliable and efficient transmission service. We face key challenges in maintaining safety and performance outcomes from our digital infrastructure assets into the next regulatory control period. These include:

- adapting to increased network complexity as a result of the energy transition, including strengthening of digital infrastructure in areas which have not previously been critical to the operation of the transmission network. This is reflected through additional control system and communications expenditure as described in the relevant section
- adapting to the use of new digital infrastructure technologies and evolving digital infrastructure asset strategies, to keep pace with technology and realise benefits for customers. Due to their nature, these assets are subject to random failure and obsolescence (as distinct from age degradation of traditional electromechanical systems)
- enabling new technology to realise capital efficiencies through both convergence of functions and inter-operability into assets, and
- our fleet of substation buildings which have hazardous materials are increasingly requiring upgrades and repairs.

There is also a material amount of expenditure ($36.8 million) being driven by cyber security and physical security requirements. Cybersecurity has quickly risen as a critical risk to digital infrastructure assets. The risk presented from the unauthorised use of technology is increasing and coming under the scrutiny of external stakeholders, with new cybersecurity requirements expected to become mandatory during the next regulatory period.

An expected expenditure of $8.9 million is proposed to the AC/DC and auxiliary systems to maintain their safety and reliability to support the core secondary systems and High Voltage Equipment.

In identifying assets for replacement, we utilise a health index methodology to identify those assets with the highest risk of failure. The analysis takes into consideration manufacturer support, spares availability, forecast defect rate and age against nominal technical asset life. The output of the condition analysis is an effective asset age used to determine the probability of failure. The asset risk of failure is then combined with the consequence (criticality) values for each protection asset, to allow the optimum intervention strategy to be determined.

5.4.1. Protection systems

There are over 3,850 protection system devices on our network. These are critical assets within the transmission network ensuring electrical faults are cleared within NER compliance timeframes, mitigating not only potential grid destabilising events, but also preventing life-ending failures of high voltage assets. They are pivotal in providing a secure, reliable and compliant energy system.

Our deployed protection systems range in commissioning dates from 2021 back to the 1960’s, including electromechanical, discrete component and modern microprocessor based generational technologies.

Secondary systems are replaced according to an asset risk evaluation, comprising of condition, criticality and compliance assessments.

The 2023-2028 regulatory period will include the replacement of 962 protection relays, at a forecast cost of $105.3 million.

Protection assets are procured from a small number of pre-qualified manufacturers. This allows competitive pricing while standardising on a relatively small number of suppliers to reduce diversity, spares holdings and design effort. Installation is managed by our construction teams using a competitive tendering process.

We expect to replace 874 protection relays in the current regulatory period. Future regulatory periods are likely to see stabilisation of protection relay replacement volumes as we move strategically towards common site-wide technological upgrades.

Expenditure is identified to address one or more of the following condition related issues as detailed in each business case:

- technological obsolescence,
- withdrawn manufacturer support,
- spares depletion without ability to restock, or
- technical life.

The program will result in the following benefits:

- avoiding increased safety risk,
- avoiding increased reliability risk, and
- avoiding increased operating costs.

5.4.2. Control systems

There are over 1,940 control system devices on our network. These are critical assets within the transmission network that ensure that our SCADA Control Room is able to operate and monitor the status of unmanned substations and switching stations throughout the state. These assets also collect significant amounts of status and condition information to facilitate remote diagnostics during failures and defects. They are pivotal in providing a secure, reliable and compliant energy system.

Our deployed control systems range in commissioning dates from 2021 back to the 1960's. The fleet includes single site controllers, early generation microprocessor dispersed control and modern microprocessor type generational technologies.

Control (i.e. substation local) systems are replaced according to an asset risk evaluation, comprising of condition, criticality and compliance assessments.

The 2023-2028 regulatory period will include the replacement of 124 controllers, at a forecast cost of $51.5 million.

Control assets are procured from a small number of pre-qualified manufacturers. This allows competitive pricing while standardising on a relatively small number of suppliers to reduce diversity, spares holdings and design effort. Installation is managed by our construction teams and/or corporate IT teams using a competitive tendering process.

We expect to replace 208 controllers in the current regulatory period. Future regulatory periods are likely to see stabilisation of controller relay replacement volumes as we move strategically towards common site-wide technological upgrades.

The following Control and SCADA assets are being worked on during the 2023-2028 period:

- remote terminal unit (RTU, i.e. the local substation gateway) assets are being renewed, and
- the Human Machine Interface (HMI, i.e. the on site connection to the SCADA system) assets are being replaced.

Expenditure is identified to address one or more of the following condition related issues as detailed in each business case:

- technological obsolescence,
- withdrawn manufacturer support,
- spares depletion without ability to restock,
- technical life, or
- cyber security requirements.

The program will result in the following benefits:

- meet cyber security compliance obligations,
- avoiding increased safety risk,
- avoiding increased reliability risk, and
- avoiding increased operating costs.

5.4.3. Market metering systems

There are over 870 metering system devices on our network. Metering systems installed throughout the network are utilised for the purposes of market settlement and are at the core of the economic component of the NEM.

Our deployed metering systems range in commissioning dates from 2021 back to the 1990's. The fleet includes discrete component and modern microprocessor type generational technologies.

Metering systems are replaced according to an asset risk evaluation, comprising of condition, criticality and compliance assessments.

The 2023-2028 regulatory period will include the replacement of 152 meters, at a forecast cost of $10.5 million.

Metering assets are procured from a small number of pre-qualified manufacturers. This allows competitive pricing while standardising on a relatively small number of suppliers to reduce diversity, spares holdings and design effort. Installation is managed by our construction teams using a competitive tendering process.

We expect to replace 147 meters in the current regulatory period, and so our forecast reflects a small increase due to a higher population reaching obsolescence. Future regulatory periods are likely to see stabilisation of metering replacement volumes as we move strategically towards common site-wide technological upgrades.

Expenditure is identified to address one or more of the following condition related issues as detailed in each business case:

- technological obsolescence,
- withdrawn manufacturer support,
- spares depletion without ability to restock,

- technical life, and
- compliance.

The program will result in the following benefits:

- meet compliance obligations, and
- avoiding increased operating costs.

5.4.4. Network property

Our Network Property asset class consists of a number of different asset types including operational buildings, fire systems, physical security systems, Heating, Ventilation and Air Condition (HVAC) systems and more. Property assets are critical in providing housing for secondary systems equipment within a controlled environment, physically securing nationally significant assets, and providing a safe working environment for all parties performing work at our sites.

Network Property assets are replaced according to asset risk evaluation, comprising of condition, criticality and compliance assessments.

We are forecasting Repex of $56.1 million over the 2023-2028 regulatory period across 332 buildings and property systems, which will include investments in:

- building capital works,
- physical security (CCTV, access control and motion detection), and
- fire systems.

Generally, network property assets and services are procured from a large pool of contactors within the industry, allowing competitive pricing. For specialised assets such as those related to physical security, a small pool of pre-qualified vendors are utilised, allowing a balance between competitive pricing and standardising on a relatively small number of product manufacturers to reduce diversity, spares holdings and design effort. Installation is managed by our construction teams using a competitive tendering process.

Our forecast Repex in this sub-category is an increase on expenditure in the current regulatory period.

Expenditure is identified to address one or more of the following condition related issues as detailed in each business case:

- technological obsolescence,
- withdrawn manufacturer support,
- spares depletion without ability to restock,
- functional performance degradation,
- technical life, or
- critical infrastructure physical security obligations.

The majority of Network Property related investments utilise third-party dilapidation information to assess assets with the highest risk of failure and those that present compliance-based risks. Investment decisions are based on this analysis criteria against the dilapidation report to form the optimum intervention strategy.

Physical security (less fences and gates) assets are more akin to electronic based asset analysis, and the following factors are taken into consideration: manufacturer support, spares availability, forecast defect rate and age against nominal technical asset life.

The asset risk of failure is then combined with the consequence (criticality) values to allow the optimum intervention strategy to be determined.

The program will result in the following benefits:

- meeting compliance and critical infrastructure security requirements,
- avoiding increased safety risk,
- avoiding increased reliability risk, and
- avoiding increased operating costs.

5.4.5. Communications systems

There are over 1,700 telecommunication devices on our network. These are critical assets within the transmission network providing both essential communication paths for high speed protection services, operational data and telephony, and other bulk carrier services. They are pivotal in providing a secure, reliable and compliant energy system.

Our deployed communications systems range in commissioning dates from 2021 back to the 2000's, including a broad mixture of functional and technology types.

Communications systems are replaced according to an asset risk evaluation, comprising of condition, criticality and compliance assessments.

The 2023-2028 regulatory period will include the replacement of 320 telecommunication assets at a forecast cost of $31.1 million.

Telecommunication assets are procured from a small number of pre-qualified manufacturers. This allows competitive pricing while standardising on a relatively small number of suppliers to reduce diversity, spares holdings and design effort. Installation is managed by our construction teams using a competitive tendering process.

We expect to replace 225 telecommunication assets in the current regulatory period. Future regulatory periods are likely to see stabilisation of telecommunication assets replacement volumes as we move strategically towards common site-wide technological upgrades.

Expenditure is identified to address one or more of the following condition related issues as detailed in each business case:

- technological obsolescence,
- withdrawn manufacturer support,
- spares depletion without ability to restock, or
- technical life.

The program will result in the following benefits:

- avoiding increased safety risk,
- avoiding increased reliability risk, and
- avoiding increased operating costs.

5.4.6. AC/DC and Auxiliary Systems

AC/ DC and auxiliary system are vital supports for the core protection, control and high voltage equipment at each substation. The AC systems provide a low voltage supply to building and switchyard lighting, general purpose outlet, air condition and battery charger systems. The DC systems provide battery back-up for prolonged outages to deal with major system disturbances and black start situations. Expenditure on these systems is vital to retain their reliability and also address worker safety hazards as the cabling and insulation systems age.

The 2023-2028 regulatory period will include work on the following systems:

- battery chargers,
- site AC electrical systems, and
- uninterruptable power supply systems.

The 2023- 2028 regulatory period will include a forecast cost of $8.9 million on 79 of these systems. This is down from 162 systems replaced in the current regulatory period.

The program will result in the following benefits:

- avoiding increased safety risk,
- avoiding increased reliability risk, and
- avoiding increased operating costs.

6. Forecasting method, inputs, models and assumptions

6.1. Introduction

The purpose of this chapter is to explain our forecasting methodology, the inputs to that methodology and the key assumptions that are reflected in our 2023-28 Repex forecasts.

Before discussing our forecasting methodology, we briefly describe our network risk management framework, and how it encompasses our asset condition assessments and our compliance obligations.

6.2. Asset management framework

Our Asset Management System has been ISO55001 accredited and aligns the management of the network assets with our corporate policies, frameworks and management systems. Commensurate with this, the key inputs to our capital program include board direction through the business' risk statement, oversight and guidance, and business plans. This input is provided alongside the ongoing stakeholder views are tested and refined as we develop and manage our capital program.

The following Asset Management framework and business case documents support our Repex forecast and methodology:

- Asset Management System Description
  - provides an overview of our asset management system, detailing the scope of the asset management system, its boundaries, interfaces with other management systems, and presents how key elements and criteria applied throughout the system are derived and aligned
- Asset Management Policy
  - we commit to applying an effective asset management system over the entire asset life cycle to efficiently manage cost, risk and asset performance for the benefit of consumers and security holders
- Network Asset Strategy
  - The Network Asset Strategy converts organisational objectives into asset management objectives and specifies the approach of the Asset Management System in the development of the Network Asset Renewal and Maintenance (Lifecycle) Strategies and Plans. This is achieved through the application of the risk management framework and through application of the Asset Management Policy.
- Network Asset Renewal and Maintenance (Lifecycle) Strategies and Plans
  - The network asset lifecycle strategies and plans consider attributes of the asset portfolio including current age, condition, and capability, actual and forecast performance, to highlight key areas that need to be addressed.
- Network Asset Risk, Criticality and Health Frameworks
  - These documents set out our internal policies, including for example in relation to capital investment and delivery, governance, asset management, risk management, security, health and safety, emergency, environment and sustainability. They form the basis for our expenditure forecasting methodology as detailed in section 6.8.
- Prescribed Network Capital Investment Framework

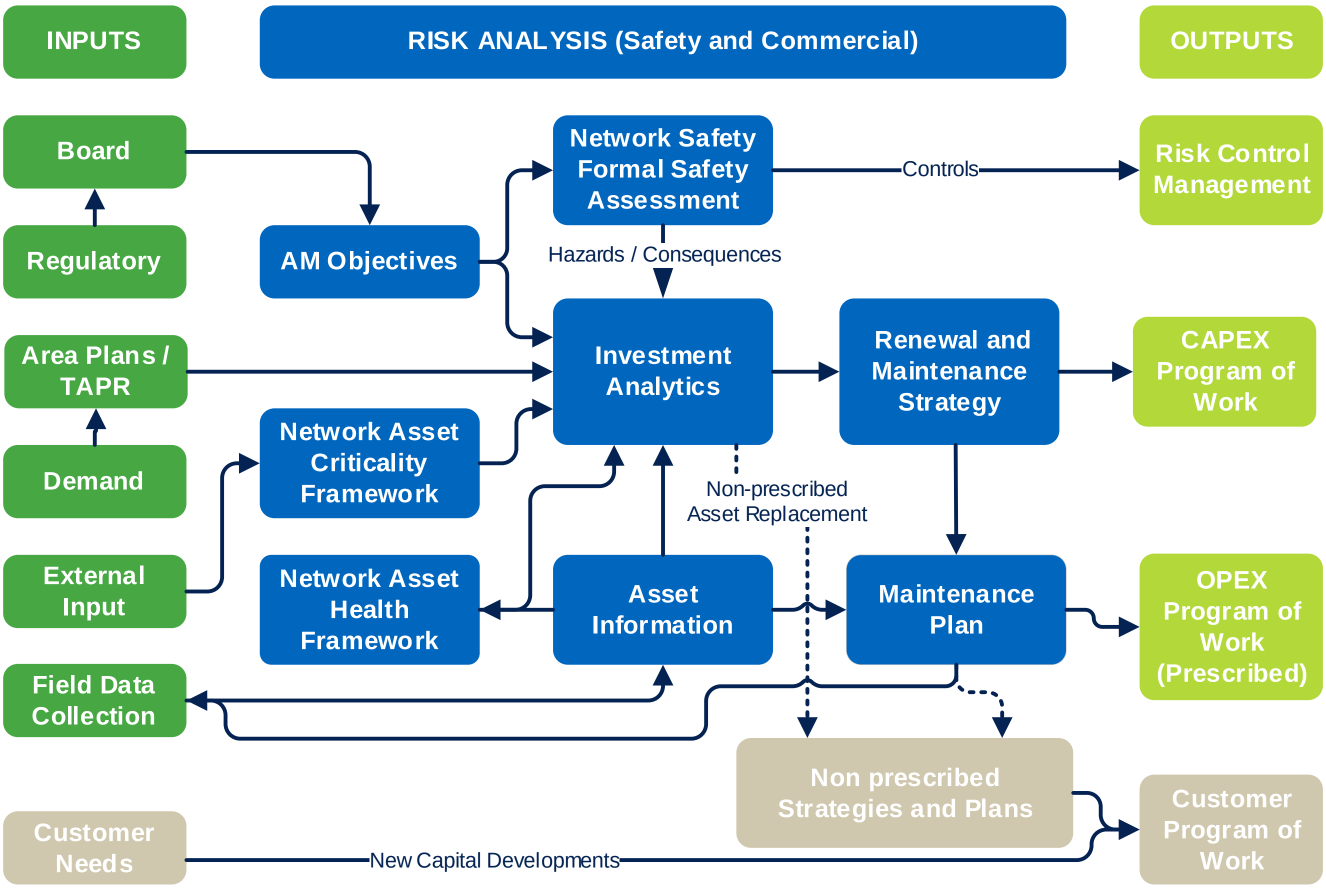
- sets out our end to end process for capital investment governance used to identify, deliver, justify and govern investments in assets that deliver prescribed transmission services.

- Need and Opportunity Screening Assessment (NOSA)
  - sets out why a particular asset-related investment is being proposed, and briefly summarises potential options to address the need and/or opportunity.
- Option Feasibility Study (OFS)
  - desktop engineering review and cost estimate (typically to an accuracy of +/- 25%) for the options nominated in the NOSA.
- Options Evaluation Report (OER)
  - summarises the need and/or opportunity, the options available to address that need and/or opportunity and the technical and commercial evaluation (cost-benefit assessment) of those options, and need date (optimal replacement timing). In doing so, all practical options are considered, such as increased maintenance (opex), asset replacement and/or refurbishment, and non-network solutions (where applicable).

6.3. Network risk management framework

Our investment decisions are increasingly data-driven (based on asset condition monitoring and data analytics) to optimise investment solutions, utilising asset health and pre-emptive failure modelling, to optimise investment timing. Figure 6-1 illustrates this framework.

Figure 6-1: Network Risk Management Framework (Asset Risk, Criticality & Health)



6.3.1. Asset Condition

We apply an established, consistent risk-based process across each of our asset classes. Our risk-based process comprises:

- asset performance and condition assessment,
- health indices monitoring,
- criticality risk assessment,
- quantification of the risk, and
- co-ordination with other asset classes.

Deteriorating asset condition increases failure rates, which can manifest in increased public safety, occupational safety, environmental and bushfire risks. Asset failures can also lead to reduced security and reliability of supply.

Consequences of unplanned failures can be catastrophic, including failures that trigger bushfires or failures that are explosive in nature. We therefore actively monitor condition, quantify risks, and manage risks through prudent use of controls across our asset classes to ensure materialisation of such risks are minimised. We consider a range of risk consequences and their likelihoods in all our asset risk assessments to model and calculate expected, moderated risk costs.

Accelerated deterioration of asset condition is expected towards the end of an asset's technical life and assessed through condition monitoring and asset health and criticality modelling. We forecast asset replacement programs that optimise cost, safety and performance for our customers and the community. Risk monetisation of safety and performance risks allow us to minimise the lifecycle cost of the asset.

We identify prudent deferral opportunities to optimise the timing of our replacement programs and target expenditure in areas that provide the most value for our customers through the use of:

- technology, which allow us to continually improve our understanding of asset condition, and
- monitoring and data analytics which enable us to pre-empt increased likelihood of emerging potential failures.

6.3.2. Compliance Obligations

Our key compliance obligations include our safety requirements, licence conditions, the National Electricity Rules (NER) and other relevant legislation, regulations and codes.

We apply a consistent compliance-based process across each asset class. This comprises:

- a list of our current compliance obligations and material changes that require investment,
- evaluation of least cost solutions, and
- assessment of our safety obligations against our As-Low-As-Reasonably-Practicable (ALARP) test in accordance with our stakeholders expectations.

We manage and mitigate bushfire and safety risk to ensure they are below risk tolerance levels or ALARP in accordance with our obligations under the New South Wales Electricity Supply (Safety and Network Management) Regulation 2014, and our approved Electricity Network Safety Management System (ENSMS).

To meet our compliance obligations, we monetise risk to represent economic cost to consumers with appropriate disproportionality used to value our safety impacts. Under the ALARP test, a predefined gross disproportionality factor would typically be applied to the risk costs, to identify the preferred option.

Asset spares availability is a consideration in our replacement decisions, particularly when existing assets are technically obsolete, where vendor or manufacturer support has been withdrawn, and stocked spares are depleted. This can present major risk in relation to maintaining security and reliability of supply if outage times are extended due to lack of spare parts. These issues particularly impact our secondary systems assets where technology advancements in digital equipment quickly supersede in-service equipment. Our compliance obligations under the NER require us to maintain a level of protection coverage within a prescribed time following a failure of an asset in a protection scheme. This can generally only be achieved in cases when spares are available.

6.4. Forecasting method – Condition Based Risk

Condition and risk driven replacement (Repex) is primarily driven by asset condition and related risk assessments, with assets only replaced if their condition and the related risk-cost demonstrates economic benefits that exceed the value of the investment. The forecasting approach for condition and risk-based expenditure is summarised below.

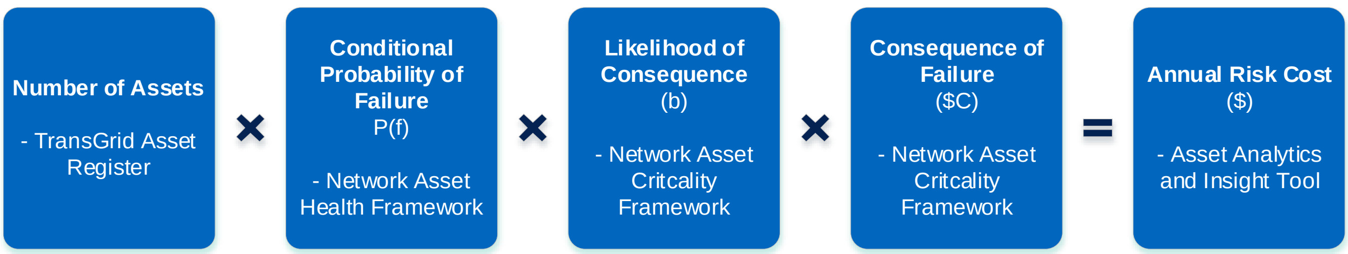
Our forecasting method is aligned with the AER's Asset Replacement Planning guideline[10] and its Principles. In demonstrating this alignment, we seek to ensure we are forecasting according to good electricity industry practice with a program of works that is based on prudent and efficient expenditure decisions, in a consistent manner that provides greater levels of transparency for stakeholders.

Section 6.5 to 6.8 outline the end to end approach to Condition Based Risk.

6.5. Risk cost calculation

The monetary value of risk (per year) for an individual asset failure resulting in an undesired outcome, is the likelihood (probability) of failure (in that year with respect to its age), as determined through modelling the failure behaviour of an asset (Asset Health), multiplied by the consequence (cost of the impact) of the undesired outcome occurring, as determined through the consequence analysis (Asset Criticality). Figure 6-2 illustrates the base risk equation applied to our assets, to determine our forecast expenditure.

Figure 6-2 Risk cost calculation



6.6. Risk types

Economic justification of Repex expenditure to address an identified need is supported by risk monetised benefit streams, to allow the costs of the project or program to be assessed against the value of the

10 Industry practice application note - Asset replacement planning, AER January 2019

avoided risks and costs. The major quantified risks we apply for Repex justifications include asset failures that materialise as:

- **Bushfire risk** - This refers to the consequence to the community of an asset failure that results in a fire-start. Assessment work has recently been completed with the University of Melbourne to improve our quantification of this risk including the moderation of risk costs. Our new model uses an electricity industry-developed approach to ensure more consistency with other networks, modelling the potential spread from a fire started by each asset in the network using recognised fire modelling software, calculating the consequence based on the number of houses, agricultural and forestry land use (and other infrastructure in the predicted burn area), and moderating the consequence using a statistical distribution of fire conditions across the year to come up with a most likely consequence to be used in the investment decision.
- **Safety risk** - This refers to the safety consequence to our workforce, contractors and/or members of the public from an asset failure whose failure modes can create harm. The monetary value takes into account the cost associated with a fatality or injury including compensation, loss of productivity, litigation fees, fines and any other related costs. Our safety model has been developed in conjunction with asset management specialist consultancy AMCL. The main changes to the model relate to consequence and likelihood quantifications with our safety risk now considering a range of consequences from fatality where possible ranging down to a minor injury, and the likelihood of each (rather than just a fatality) based on historical events, human movement data and land use.
- **Environmental risk** – This refers to the environmental consequence to the surrounding community, ecology, flora and fauna of an asset failure that can create environmental damage. The monetary value takes into account the cost associated with damage to the environment including compensation, clean-up costs, litigation fees, fines and any other related costs.
- **Reliability risk** – This refers to the system reliability and security consequence of an asset failure. The monetary value takes into account the expected load-at-risk and duration of loss-of-supply (MWh of lost load) due to the failure and any subsequent actions, and a customer value of reliability (VCR) for the customer type impacted. We have updated our reliability risk model to consider the quantity of load that can be restored through the distribution system following an asset failure. The consequence modelling has also been updated to a weighted-scenario basis using low and high load scenarios to reflect variations in load throughout the day and the year. The unavailability and return-to-service time assumptions have been reviewed to ensure unusual historic outage events (where there was no urgent need for restoration) are not factored into the typical outage durations assumed.
- **Financial Risk** - This refers to the financial consequence of an asset failure. The monetary value takes into account the cost associated with the financial impact not covered in any of the other areas of consequence such as disruption to business operations, any third party liability, and the cost of replacement or repair of the asset, including any temporary measures. The financial consequence includes the market impact, which considers the monetary impact associated with generator/interconnector constraints due to an asset failure.

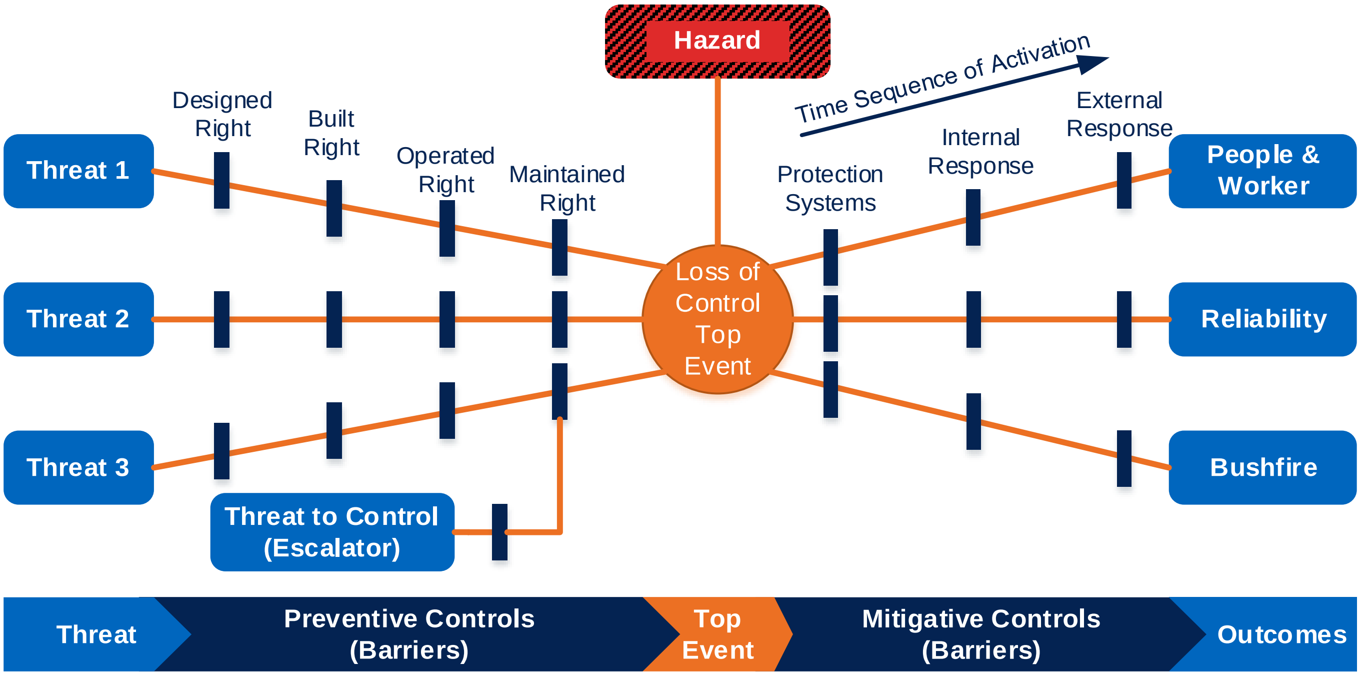
6.7. Risk models

We commence our risk-cost assessment by utilising the Bow-Tie failure mode risk modelling method as illustrated in Figure 6-3 for identifying:

- hazards and the threats that may lead to the loss of control of the hazards,
- the consequences that may occur from the loss of control, and

- the preventive and mitigative controls required to prevent or minimise undesired consequences.

Figure 6-3 Risk identification



In our risk modelling, we consider different failure modes for each asset class, the relevant range of consequences and the likelihood of each. This provides moderated, expected quantified risks which are then used in economic evaluation assessments to justify our Repex forecast.

The process we use for risk monetisation involve the following elements:

6.7.1. Asset health modelling

Our asset health modelling is aligned with Chapter 5.2 of the AER's Asset Replacement Planning guideline. Condition information for each asset is assessed to generate an Asset Health Index which is calculated by the method described in our Network Asset Health Framework document. Assets reaching the end of technical life as identified through the Asset Health Index, are candidates for a replacement or refurbishment intervention.

Asset Health is used to estimate the remaining life of an asset, and forecast the associated probability of failure of the asset now and into the future. The modelling takes input from current and historical asset information including, failure, defect, maintenance and condition data, and operational/performance/fault information. The inputs to the Asset Health model are given weightings according to their significance to overall longevity of the asset. The failure behaviour of these assets is modelled using a Weibull statistical distribution and parameters that best fit the time to failure (or any other indicator of failure) of past failures, as determined by examining historical failure data.

Failure modes associated with the key hazards are identified. Each failure mode that could result in the occurrence of a key hazard is examined. We consider the range of the asset components, their failure modes and associated root causes that have the potential to result in a functional or conditional failure. Of particular concern is the combination of components, failure modes and root causes that could lead to the occurrence of an undesired outcome due to asset failure. For example, a transformer may fail in a number of ways including a bushing or tap changer failure, a winding failure, or a tank failure, all of which result in different consequences. The probability of each failure mode is calculated using reliability engineering techniques that take into account conditional age (chorological age moderated by asset health), failure and defect history, and industry benchmarking studies. We screen out failures that are not related to end-of-life when quantifying risk for Repex because such risks are not addressed by Repex programs.

6.7.2. Asset criticality modelling

Our asset criticality modelling is aligned with Chapter 5.3 of the AER's Asset Replacement Planning guideline. Each failure mode has an identified range of consequences from most-likely through to worst-case and is determined consistently across each asset class. The range of consequences are moderated by the likelihood of that particular outcome occurring. Our Network Asset Criticality Framework documents the method we use to identify the financial value of the moderated consequences.

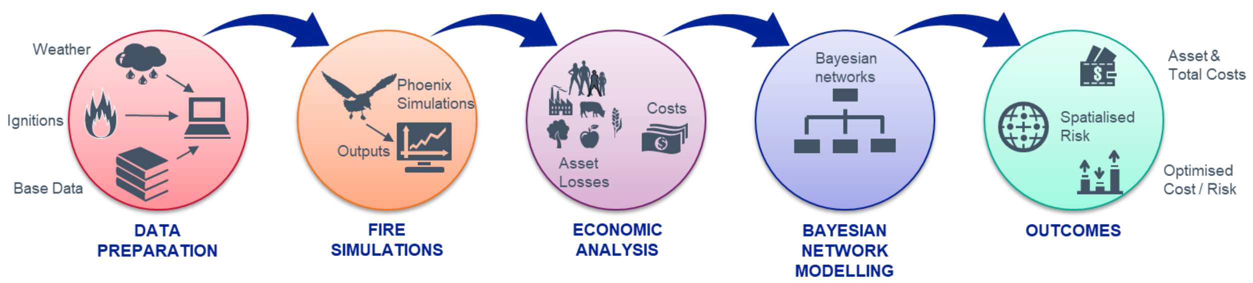
Our consequence models for each of the risk categories have been updated in consultation with wider industry. For example, we worked with the University of Melbourne to complete improvements to our bushfire consequence risk model.

We have developed four key asset criticality models to help quantify our risk costs.

6.7.2.1. Bushfire Consequence Model

The Bushfire model is shown in Figure 6-5 and consists of the following phases:

Figure 6-4 Bushfire model conceptual diagram



- phase 1 consists of data collection and preparation including weather data, location of ignitions and range of base date inputs,
- phase 2 involves fire simulations using Phoenix Rapidfire, to determine the expected area burnt and assets impacted under a range of weather scenarios. Phoenix RapidFire Simulator models fires starting from each asset location (eg transmission line structure or substation) across our network, applying various scenarios and weather conditions. These scenarios represent the distribution of fire intensity and burn areas at each asset location. Land use data, number of dwellings and other spatial information is used to model the quantity and type of impact within the boundary of the burn area to calculate the dollar value consequence per asset.
- phase 3 involves economic analysis with cost assigned to each asset,
- phase 4 combines weather and ignitions, fire simulation data and estimated costs per asset in a Bayesian network. The Bayesian network generates a series of outputs, including cost of damage per asset and total costs, and
- phase 5 using the outputs from phase 4 to determine the probable dollar consequence at each asset on our network is calculated.

6.7.2.2. Public Safety Consequence Model

The Public Safety Model is applied to a number of hazards which could impact public safety, including conductor drop, unauthorised access to our assets and asset explosion. The model is adjusted for the hazard being assessed and has the following key components:

- where available, human movement data from mobile devices is used to estimate the expected number of exposed people hours within the “calculated impact area” for the hazard being assessed (eg asset explosion blast area or conductor drop zone),
- at all asset locations, using the exposed people hours to calculate a likelihood of the public being on site, should a hazard occur. For some hazards, proximity to populated areas, land usage or historical incidents are considered in determining the likelihood,
- injury likelihood factor, to denote that an exposed person may escape injury, and
- a probability distribution of the injury consequence (from minor injury to fatality) has been assessed based on the “calculated impact area”.

6.7.2.3. Reliability Consequence Model

The Reliability Consequence ($/hour) for the catastrophic failure of an asset has been assessed through evaluating its level of redundancy within the NSW High Voltage (HV) network and an estimate of the potential load at risk. The modelling consists of:

- a network load flow model of NSW with 10 levels of demand were analysed to determine the probabilistic load at risk for each of our transmission line and cable, transformer, reactive plant and substation switchbay equipment assets,
- the network load flow studies examined up to two contingencies after the catastrophic failure of the asset, to determine the load shedding required to maintain power system security, operate within network limits or due to network topology,
- other external parameters such as the interconnector flows and generators were monitored and adjusted to simulate the operations of the NEM,
- Value of Customer Reliability (VCR) ($/MWh) is the value customers place on a reliability supply of electricity, and
- the VCR multiplied by the probabilistic load at risk is used to determine the Reliability Consequence $.

6.7.2.4. Worker Safety Model

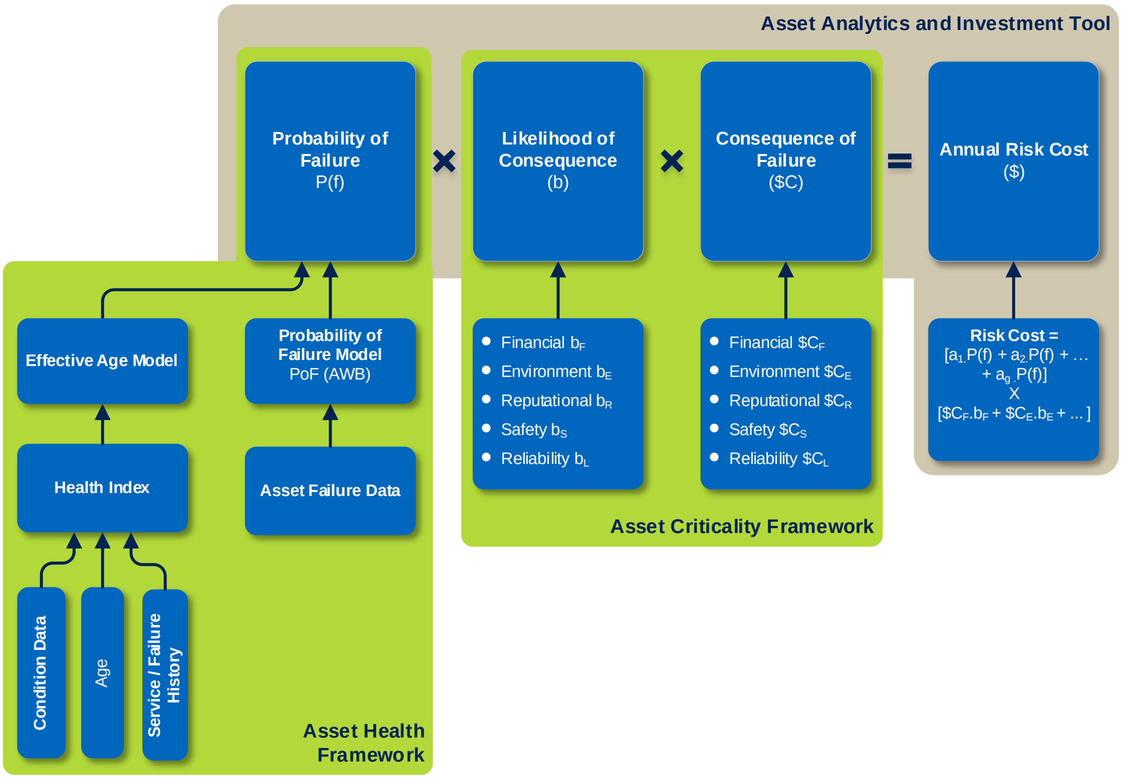
The Worker Safety Model is applied to a number of hazards which could impact worker safety, primarily explosive failure. It uses historical data to calculation the likelihood of workers being in the vicinity and a blast radius model to calculate a probability distribution for the consequence of an explosive failure.

6.7.3. Overall risk for investment decisions

Our risk cost modelling is aligned with Chapter 5.4 of the AER’s Asset Replacement Planning guideline. The monetary value of risk (per year) for an individual asset failure resulting in an undesired outcome is quantified by multiplying the probability of failure (in that year with respect to its condition) as determined through modelling the failure behaviour of an asset (Asset Health), with the consequence cost and the likelihood of that consequence, as determined through the consequence analysis (Asset Criticality).

Where multiple key hazards are applicable to an asset, the value of risk for each of these are summed to give the total value of risk associated with an asset as shown in Figure 6-5.

Figure 6-5 Aggregated quantified risk model



Options for reducing probability of asset failure or likelihood of a consequence are identified and costed. A Need and Opportunity Screening Assessment (NOSA) initiates the costing and scoping which is undertaken using our MTWO estimating database, and documented in an Option Feasibility Study (OFS).

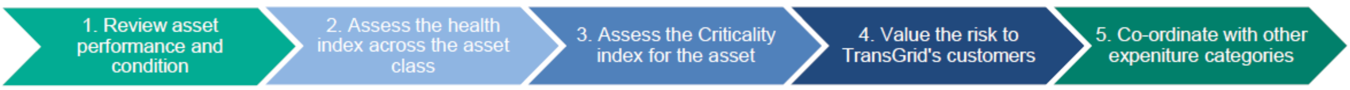
A subset of quantified risks associated with the safety of our workforce and the public, and bushfire is tested against the ‘As Low as Reasonably Practicable’ (ALARP) threshold by the use of disproportionality factors. A factor of three is used for safety consequences and six for bushfire consequences. This ensures that we meet all our regulatory obligations with respect to safety.

The overall net present value of benefits for consumers is calculated using the quantified risk reductions and capital expenditure to determine the economic viability of the investment and the optimum timing that maximises the net present value. The output of this modelling is documented in our Options Evaluation Report (OER) and Regulatory Investment Test (RIT-T) documentation.

6.8. Application of Risk Frameworks

To forecast our Repex volumes for both unitised programs and the scope-of-work for non-united projects, we apply risk-condition modelling for every asset class which is informed by the routine collection and analysis of asset condition data. We undertake a number of key steps in forecasting Repex and these steps are illustrated in Figure 6-6.

Figure 6-6 Repex forecasting steps



The Repex forecasting method requires an understanding of the condition of the asset, determining a probability of failure time series and expected risk cost over the expected service life.

6.8.1. Step 1 – Review Asset Health and Condition

Determining Asset Health and effective age considers the following:

- An asset consists of different components, each with a particular function, criticality, underlying reliability, life expectancy and remaining life. The overall health of an asset is a compound function of all of these attributes.
- Key asset condition measures and failure data provides vital information on the current health of an asset.
  - ‘Current effective age’ is derived from asset information and condition data.
- The future health of an asset (health forecasting) is a function of its current health and any factors causing accelerated (or decelerated) degradation or ‘age shifting’ of one or more of its components. Such moderating factors can represent the cumulative effects arising from continual or discrete exposure to unusual internal, external stresses, overloads and faults.
  - ‘Future effective age’ is derived by moderating ‘current effective age’ based on factors such as, external environment/influence, expected stress events and operating/loading condition.

6.8.2. Step 2 – Assess the health index across the asset class

The Probability of Failure (PoF) is the likelihood that an asset will fail during a given period resulting in a particular adverse event. E.g. Equipment failure, pole failure, broken overhead conductor.

The outputs of the Probability of Failure (PoF) calculation are one or more probability of failure time series which provide a mapping between the effective age, discussed above, and the yearly probability of failure value for a given asset class. This analysis is performed by generating statistical failure curves, normally using Weibull analysis, to determine a PoF time series set for each asset that gives a probability of failure for each further year of asset life. This establishes how likely it is that the asset will fail over the next regulatory control period.

6.8.3. Step 3 – Assess Criticality Index for the Asset

Asset criticality is the relative risk of the consequences of an undesired outcome. Eg fatality, loss of supply, property damage. Asset criticality considers the severity of the consequences of the asset failure occurring and the likelihood the consequence will eventuate.

The analysis of the severity of the consequence assigns an economic value (cost of consequence) to the likely worst case impact in respect of the areas of consequence, including people, environment, system impact and financial. The analysis of the likelihood of the consequence is used to determine the probability of the impact eventuating for the safety, environment, and system impact areas of consequence. The combination of and economic value of consequences varies with and is dependent on the nature of the undesired outcome. These vary from asset to asset and site to site.

A number of factors are considered in determining the likelihood of consequence of an undesirable event, including:

- expected frequency and duration of people being at a site or structure,
- probability that equipment will fail and fail explosively,
- effectiveness of preventative controls,
- location of site, structure or line route and the sensitivity of the area around the site,

- bushfire proneness of the land and the likelihood of a flashover causing a major bushfire event, and
- anticipated load restoration time following an outage event.

6.8.4. Step 4 – Determine the asset risk cost

The Risk Cost takes account of how critical an asset failure would be for our customers, to provide an indicator of the potential consequence of an asset failure, moderated by the probability-of-failure and the likelihoods of each consequence. The Cost of Consequence (CoC) establishes the dollar value of the potential consequences that could be avoided by investing during the next regulatory control period. The Risk Cost establishes the expected stakeholder value that would be realised by the investment, moderating the CoC by its associated likelihood.

Comparing this risk cost against the cost of feasible options to replace or refurbish the asset using an economic evaluation and portfolio optimisation to provide economic volumes. This evaluates the cost of the reasonable network and non-network options that are available to address the risk and select the option that delivers the highest net value to stakeholders. In some cases, 'As-Low-As-Reasonably-Practicable' (**ALARP**) may be triggered as an expression of the safety expectation of customers as required by relevant safety regulation.

6.8.5. Step 5 - Option Analysis and Investment Decision

All identified feasible options (including non-network) are identified and scoped for input into investment decision. The preferred option is determined using the calculated Net Present Value (NPV) using the following criteria.

- The base case is established – usually continuing to operate and maintain the asset to keep it in service
- The avoided risk or cost is calculated for each project (being the difference in risk between that option and the base case)
- Disproportionality is applied to safety related risks to ensure ALARP principles are met in the NPV calculation
- Cost benefit completed through a weighted NPV calculation of mitigated risks and / or benefits. This NPV considers a range of sensitivities on the key parameters
- An appropriate discount rate, modelling period and terminal value are applied, and
- The preferred option has the highest NPV (highest net benefits).

The output of the analysis is presented in the Options Evaluation Report (OER).

6.8.6. Step 6 - Investment Optimal Timing

Only projects which are optimally timed in the next period, or are required to have expenditure to achieve the optimal timing are included the Repex program.

As per the AER Replacement Planning Guideline the optimal timing is where annual service cost of the existing asset (e.g. risk costs, operational expenditure) exceeds the annualised capital cost of the preferred option.

The preferred options are all tested for optimal timing criteria to determine the unconstrained timing for that investment.

6.9. Forecasting method – Compliance and “Duty of Care” (Non-quantified ALARP)

Whilst the majority of our REPEX program is justified on positive NPV benefit programs, a small part of our program is driven by compliance and non- quantified ALARP.

Projects such as fire system and market metering replacement are driven by the need to comply with specific regulatory requirements (WHS and NER legislation). Other projects such as low spans, asbestos and climbing deterrent upgrades are based on “duty of care” ALARP principles where risks cannot be fully quantified. This is assessed using the following process consistent with AS 5577:

- where reasonably practicable the hazard has been eliminated, or where this is not reasonably practicable
- all risk good industry practise treatment options have been considered
- a risk treatment option has not been implemented only if the cost in doing so is grossly proportionate to the benefit gained, and
- opportunity for further safety improvement has been assessed.

6.10. Key assumptions

Clause SA6.1.1(4) of the Rules requires us to list the key assumptions that underpin our capex forecast. The key assumptions applying across the Augex forecasts are summarised in Chapter 8 of the Revenue Proposal document and replicated in the following table.

Table 6-1: Summary of key assumptions

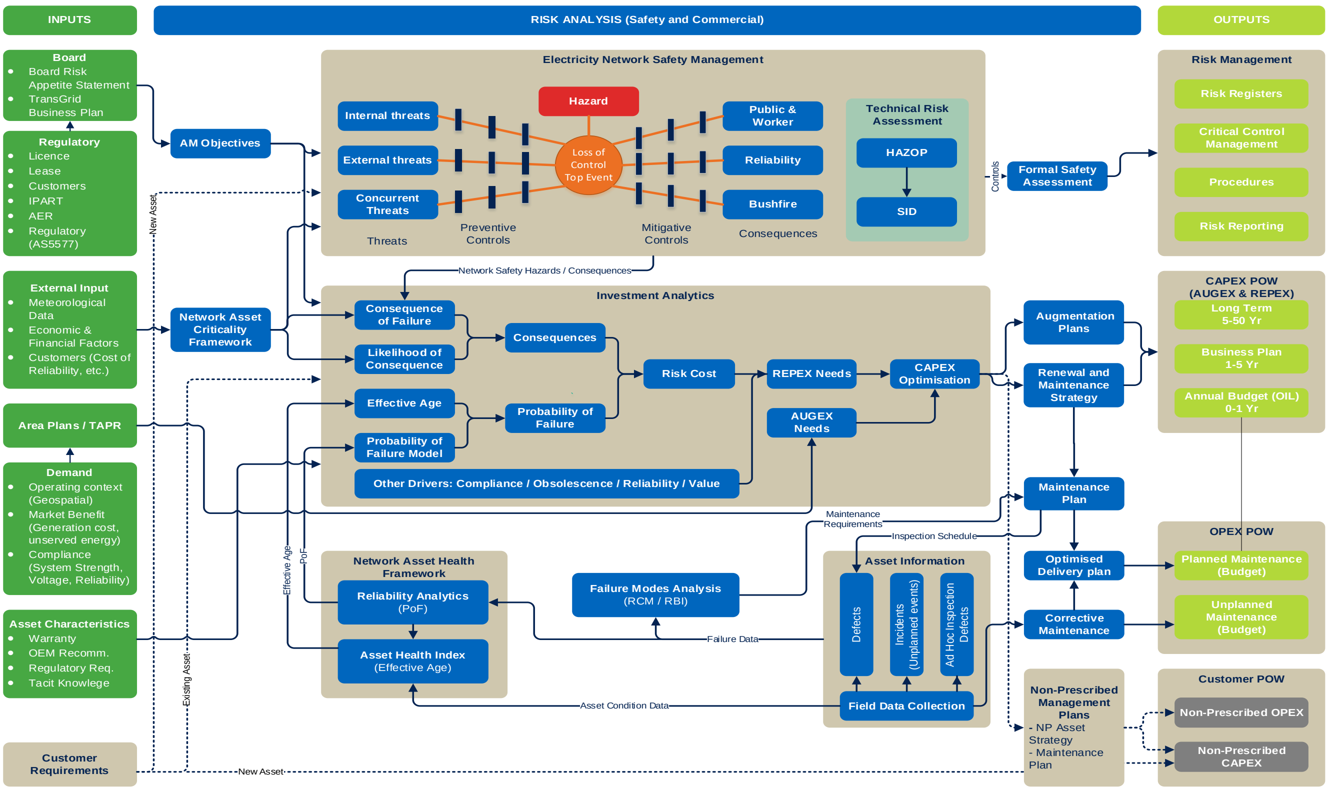
Assumption	Description
Legislative & regulatory obligations	Our capex forecasts are based on our current legislative and regulatory obligations and our licence requirements
Network reliability	Our capex forecast will maintain, but not improve, service outcomes consistent with clause 6A.6.7(a)(3)(iii) of the NER
Demand forecasts	Our forecasts are required to meet DNSPs’ connection point demand forecasts (published in our TAPR) reconciled to AEMO’s forecasts.
Value of customer reliability (VCR)	Our capex forecasts reflect AER’s VCRs, which represents the monetary value different types of customers place on having access to a reliable electricity supply. The VCR is a key input into how we determine when to replace assets on our network.
Unit rates and project costs	The unit rates and project costs that we have applied in developing our capex forecasts are representative of the costs that will be incurred in the next regulatory period.
Cost allocation and capitalisation	Our capex forecasts reflect our capitalisation policy and our CAM, which provides an appropriate basis for attributing and allocating costs to, and between, our prescribed transmission and other services.
Cost escalations	The cost escalations that we have applied in developing our capex forecasts are representative of the increased costs that we will incur in the next period
Inflation	The inflation that we have applied in developing our capex forecasts is representative of the inflation-related costs that we will incur in the

Assumption	Description
	next period and is consistent with the AER-preferred inflation forecasting method
Cost pass throughs and contingent projects	The AER will approve our nominated pass through events and contingent projects

6.11. Risk modelling tools

We utilise an integrated, data-driven risk modelling approach for Repex that allows co-optimisation with Augex programs. This is illustrated in Figure 6-7 below.

Figure 6-7 Risk monetisation modelling for Repex



We utilise sophisticated data analytics tools to manage our risk modelling for Repex. The systems that house the models which support the development of the Repex forecast include:

- Isograph Availability Workbench (AWB) for identification of failure modes of assets and calculation of probabilities of failure based on the failure modes of assets,
- Asset Analytics and Investment Tool (AAIT) for risk quantification, risk forecasting and register of risk assessments,
- Enterprise Resource Planning (Ellipse) system for management of work, and
- Asset Inspection Manager (AIM) for collection of asset inspection data from the field.

Our Asset Analytics & Investment tool (AAIT) calculates both the pre- and post-investment risk costs used as inputs into the economic assessment. The tool optimises the investment portfolio based on benefit/cost provided by individual projects and their alignment with our strategic objectives. The AAIT also provides an assessment of the likelihood and consequences for all hazards associated with the asset in question and to quantify the relevant risk cost in dollar terms. Projects that contribute directly to specific compliance requirements such as NER obligations or IPART reliability standards are also factored into the investment decisions.

A key focus for us in recent years has been on getting the inputs correct for our models so that they are aligned with the AER's Asset Replacement Planning Guideline. We use observed failure rates, inspection and condition data to inform input data for the models.

Our risk models described in section 6.7 utilise inputs from independent sources and experts, are assessed against industry sources where available, and are subject to independent audits and reviews.

6.12. Unit costs

Our Repex forecast comprises:

- Unitised programs – these programs are forecast using standardised unit rates, and
- Non-unitised projects – these are individually costed projects, which in some instances are also combined to form a larger program

All our network capital expenditure for both unitised and non-unitised works are estimated using our MTWO cost estimation database. The outputs of the estimates, adjusted as required to align with the nominated replacement unit quantities, feed directly into our Capex spreadsheet model which is included in our Regulatory Proposal. Associated with each estimate is an Option Feasibility Study (OFS) which documents the estimate and its key assumptions.

6.12.1. Unitised programs

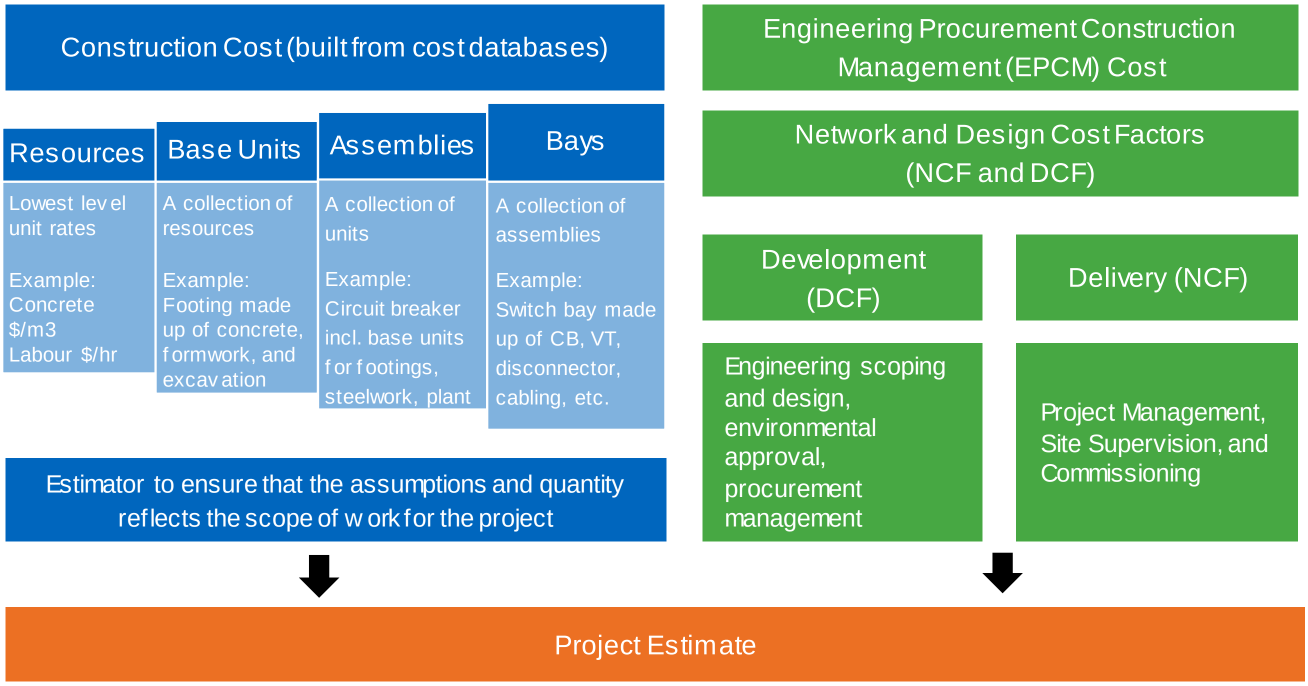
We forecast the costs of unitised programs by multiplying work volumes by unit costs. For unitised programs, our volumes are multiplied by unit rates which are based on:

- our historical costs with movement in unit costs determined from most recent costs as recorded in our MTWO cost estimating system, and
- contract unit rates from our service providers.

6.12.2. Non-unitised projects

Project costs are developed for work that has a higher level of complexity, which means that it cannot be costed upfront based purely on unitised rates. Our non-unitised projects require tailored cost estimates. For non-unitised scoped projects that typically involve the replacement of a number of different assets or components, and potentially across more than one location, we build up our Repex costs on a specific project-by-project basis. We generate a detailed scope of works including consideration of site specific features in line with our experience of delivery similar projects from which the estimate is compiled using itemised cost elements sourced from our MTWO cost estimating system. This system utilises historical costs, updated with the most relevant recently completed projects of similar scope. The estimates incorporate design and network cost factors to determine the internal labour support requirements and construction management costs as illustrated in Figure 6-8.

Figure 6-8 Non-unitised project cost estimation



6.12.3. Review and independent benchmarking of the estimate database

The rates within the MTWO cost estimate database are reviewed and updated on an annual basis. The review compares the existing database rates at the unit level against the most recent available rates from other sources to determine any movement which might have occurred. Rates may also be updated outside of the annual cycle in line with the latest relevant information as required.

Key sources of price data used in our estimates include:

- Primary plant – current period orders and other procurement strategies
- Other plant, equipment, materials – Ellipse ERP system for stock lined items, available tender/quote information, direct enquiries to manufacturers and Rawlinsons (Australian Construction Handbook)
- Construction Costs – All awarded contracts within the previous twelve months
- Labour rates – Updated with latest labour rates, and
- Design and network cost factors - percentages are determined based on analysis of actual costs from similar past projects.

Further, we undertake an independent benchmarking cost review of our MTWO unit costs database on an annual basis. Select work packages each year are independently priced using costs sourced externally, requesting an accuracy of ±25 percent for an OFS equivalent estimate, considering P50 risks. Reviews have utilised firms such as VScope Services, Jacobs, AECOM and Aurecon. Results of this benchmarking in recent years have provided an adjusted (after confirming like-for-like assumptions) cost differential to within +12 per cent to -6 per cent of our estimates for each work package as a whole. Larger variances are identified at a more granular level within each work package which are addressed through specific actions as a continual improvement to our database estimates.

6.13. Cost escalation

The costs we incur in delivering transmission services do not always increase in line with the basket of goods and services used by the Australian Bureau of Statistics (ABS) to calculate the consumer price index (CPI).

Therefore, in order to ensure that we are compensated for appropriate real cost increases that we will incur in acquiring the inputs necessary to provide services, we have engaged BIS Oxford Economics to forecast real increases in the cost of labour costs that we expect to incur during the 2023-2028 regulatory period.

Although we consider that real costs increases for materials are likely to grow faster than inflation over the 2023–28 period, we have not presently included any real materials cost escalation.

We have applied the labour cost escalators to our capex forecasts using appropriate weightings based on an estimated use of internal labour services to deliver work programs. While our Replacement capex forecasts include the impact of cost escalation, our analysis in preparing the forecasts is conducted without the effect of cost escalation.

For example, the detailed analysis in the OFS is conducted exclusive of cost escalators for the forthcoming regulatory period. To assist the AER, however, each of the capex overview papers includes a reconciliation table showing the escalated forecasts. The table below shows the aggregate impact of the cost escalators on our Replacement Capex forecast for the forthcoming regulatory period.

Table 6-2: Impact of labour and materials escalation ($Million, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Total un-escalated Repex	136.6	169.4	174.1	155.3	160.3	**795.7**
Escalation for material and labour	(0.0)	0.2	0.4	0.6	0.7	**1.9**
Total escalated Repex	**136.6**	**169.5**	**174.5**	**156.0**	**161.0**	**797.6**

Further details regarding our cost escalators are provided in the supporting document titled “BIS Oxford Economics - Labour Cost Escalation Forecast to 2027-28”

6.14. Overheads

Overhead activities, such as network planning, are needed to support Repex. The costs of those activities are capitalised in accordance with our Capitalisation Policy[11] and relevant accounting standards, including AASB 116.

Capitalised overheads are split between network and corporate overheads, consistent with the AER”s RIN definitions. We have forecast our overhead costs using the AER’s default approach based on:

- 75 per cent of capitalised overheads are fixed based on the most recent available year of actual capex (i.e. 2021-22), and
- 25 per cent of capitalised overheads vary with direct capex.[12]

[11] Expenditure Capitalisation Procedure, Transgrid, 2021.

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

The capitalised overhead forecast related to repex is set out below. As shown in the table, changes to total escalated Repex from one year to the next affects the level of capitalised overheads allocated to Repex.

Table 6-3: Addition of capitalised overheads ($Million, Real 2022-23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Total escalated Repex	136.6	169.5	174.5	156.0	161.0	**797.6**
Capitalised network overheads	19.1	20.2	22.7	22.4	19.7	**104.1**
Capitalised corporate overheads	2.6	2.9	3.2	3.2	2.9	**14.7**
Total escalated Repex with overheads	**158.3**	**192.6**	**200.4**	**181.5**	**183.6**	**916.4**

Capitalised overheads are forecast within our "2023-28 Capital Expenditure Model".

6.15. Capex-opex substitution

Opex-capex substitution opportunities are assessed at the project and program justification level, not at the portfolio level. This is because it is challenging to demonstrate opex-capex trade-offs for broad-based solutions, without considering the individual projects' costs and benefits.

We regularly screen projects for opex alternatives that have the potential to substitute capital costs – through either their deferral in the short-term or provide capital reductions over the long-term. This may be through the use of maintenance options to address a need rather than capital investment.

6.16. Portfolio Optimisation

Once all of the asset renewal investment needs have been evaluated, the Repex portfolio is assembled in order of the economic benefit delivered by the investment and reviewed on a top-down basis. At this point, total asset renewal expenditure can be optimised by removing, re-scoping or adjusting the timing and phasing of projects to maximise stakeholder value within a top-down expenditure constraint. This ensures that we can manage our future investment to moderate the impact of any step changes that Repex requirements may have on total expenditure on therefore customer prices.

The prioritisation of the asset renewal investment needs considered factors such as:

- compliance to regulatory obligations
- duty of care based safety projects such as low spans and asbestos removal
- duty of care in relation managing safety related risks (including bushfire) as low as reasonably practicable (ALARP), in accordance with the criteria set out in the Network Asset Risk Assessment Methodology document
- highest economic benefit to the consumer via highest capital productivity, that is NPV per dollar of capital expenditure
- alignment with strategic objectives
- ability to mitigate risk through other strategies, such as opex strategies, and
- timing requirements.

We have an established process to review and 'challenge' the forecast expenditure portfolio to ensure that it is aligned to strategic objectives and customer feedback with regards to cost and service levels. Our investment management team does this through reconciling our bottom-up build of Repex forecasts with a number of top-down reconciliation methods including:

- Top-down Repex model,
  - Our model is based on the principles of the AER's REPEX model. Fundamentally, it is a population age profile based model using probability (predominantly normal) distributions to forecast asset replacements and accordingly generate a long-term view of Repex expenditure.
  - It does not consider a risk based approach to asset replacement, so whilst the asset age is used as a proxy for condition, the consequences of an adverse asset condition are not modelled, and accordingly the top down model estimate was considered as an upper bound of the required repex for the upcoming regulatory period.
  - We reviewed the overall quantum of our proposed expenditure which is over 25% lower than the the expenditure predicted solely on the basis of typical replacement ages, and approximately 45% lower when compliance and duty of care safety project expenditure is removed from consideration.
  - Further, we for the reviewed the alignment of expenditure splits across the different asset classes and found alignment between the Digital Infrastructure and Substations asset classes, whilst there was a 9% step increase for the Transmission Lines asset class. The increase is attributed to the expenditure associated with the Line 11 replacement, such concentrated expenditure due to localised impacts cannot be accurately reflected in a top down repex model based on mean ages and standard deviations, and in removing this expenditure, there is alignment of the expenditure splits for all three asset classes.
- Historical expenditure trending,
  - We check our forecast of required Repex against our historical expenditure and trend based on linear extrapolation of historic data.
  - As our program is based on evolving condition information and a relatively consistent risk profile, our asset plan for condition and risk-driven replacement will usually align loosely with historical annual expenditure when smoothed over a five-year period. This provides customers with assurance that our routine replacement activities are consistent with historical levels and do not anticipate a step change in risk exposure for the network.
- Board and Executive top down challenge,
  - Our portfolio, asset performance and trends have been reviewed by our board and executive management. This review considers long term trends, asset performance expectations and price impact to consumers. Feedback from this process informs any prioritisation between projects with an NPV positive outcome to consumers, compliance and duty of care / ALARP driven projects.
- Sensitivity and Scenario analysis,
  - Sensitivity of the economic benefit evaluation is checked by developing suitable statistical distributions of key inputs both in relation to risks and costs and running Monte Carlo simulations to simulate the expenditure.
  - Key parameters that are tested include risk input parameters such as the value of customer reliability, value of statistical life, environmental consequence, probability of failure, repair duration and disproportionality factors for ALARP.

- Capital costs and the discount rates are also included in the analysis. These inputs are considered important as they predominantly drive the overall benefit evaluation.
- The review indicated that the proposed portfolio is largely insensitive to changes in the parameters, particularly the value of statistical life, ALARP disproportionately multipliers and the load at risk.
- None of the current proposed projects other than projects included for strategic reasons, namely Digital Infrastructure Capital Spares and Fire System Renewals, are impacted by an adverse 10% change on any single parameter tested.

- Deliverability Review – we have checked our proposed portfolio through the following lenses,
  - Reviewed the program for key outage clashes and project dependencies to adjust optimal timing dates as necessary. The primary focus was on the transmission line refurbishment and wood pole projects as they require extended outages to facilitate the works. In particular, there were two main areas where line outages could not be concurrent per our operating manuals:
    - Southern program including Wollongong, Southern Highlands and the Sydney metropolitan area on lines routed primarily into Sydney South Substation;
    - Northern program including Newcastle, Central Coast and the Sydney metropolitan area on lines routed from the north;
    - We identified a number of projects that would not be able to be readily delivered as a result of outage clashes, and accordingly prioritised those in these areas of the highest benefit. These include:
      - Conductor replacements on Lines 17 in the southern area. It is noted that some expenditure allowance has been included for the Line 17 conductor replacement in the upcoming regulatory period to enable the project to be initiated and ready for delivery in the subsequent period.
      - The Line 11 replacement project also could not have been entirely included within the upcoming regulatory period in consideration of reasonable levels of program contingency in the southern area. It is forecast to commence in the next regulatory period and conclude in the subsequent period.
      - Conductor replacements on Lines 25/26, 90, 93, 2M and 81 in the northern area. It is noted that some expenditure allowance has been included for the Line 25/26 conductor replacement in the upcoming regulatory period to enable the project to be initiated and ready for delivery in the subsequent period.
  - Deliverability / resource levelling was reviewed by considering the timing of individual projects and their associated S-curve within the project estimates. The timing of larger projects such as transformer replacement and full site secondary systems replacements were reviewed and spaced such that there was a steady spread across the entire regulatory period. Where outage restrictions determined the timing of the project, these were “locked in” and other projects phased around them as appropriate. Smaller asset replacement strategy programs, which comprise of individual smaller unit replacement projects, have greater flexibility in delivery and accordingly the quantity for delivery in each year has been adjusted to level the resourcing requirements as appropriate.
  - Considered project scope interactions across both Repex and Augex projects and programs. Direct scope overlaps were identified across the needs including:
    - Replacement of an auxiliary transformer at Murray due to condition that was proposed under Repex and also under an Augex need to maintain safety and quality of supply at Khancoban.

The replacement was included under the Repex portfolio and the Augex need not included in the forecast capex.

> Low spans remediation and conductor replacement on Line 23 have been captured under the full line replacement option.

> Low spans remediation and conductor replacement on Line 11 have been captured under the full line replacement option.

> The Line 12 OPGW telecommunications upgrade need has been incorporated and included as part of the assessment for the Line 12 refurbishment works, where the option considered includes replacement of the corroded earthwire with an OPGW.

> Scope overlaps between the Repex programs and the Manage increased fault levels in Southern NSW contingent project were identified. In considering the likelihood of the contingent project proceeding during the next regulatory period we have removed the following from our Repex forecast:

  ○ Disconnector units proposed to be replaced under Repex programmes also included in the scope of the contingent project at Murray substation and Upper Tumut switching station.
  ○ CVT’s proposed to be replaced under Repex programmes also included in the scope of the contingent project at Wagga substation and Upper Tumut switching station.
  ○ Power transformer replacement at Murray substation is included in the Repex forecast, so replacement of the same transformer’s bushings have been removed from the scope from the fault levels contingent project.

> Portfolio adjustments have been made to so to not include the expenditure associated with the direct scope overlaps.

- Bundling opportunities and potential impacts on portfolio cost estimates.

  > In reviewing the options at Murray substation associated with the different Augex and Repex needs, it was identified that efficiencies could be achieved by combining the delivery of the power and auxiliary transformer replacements at Murray. This revised cost associated with the auxiliary transformer replacement has been incorporated into transformer renewal program and highlighted in the Option Evaluation Report.

  > Other bundling opportunities were considered at common sites across the portfolio, in particular on Digital Infrastructure and Substations projects and programs. Our practice in the current and previous regulatory periods is to bundle works at common sites where there is benefit to do so. As the cost estimating database already considers the average historical rates, this bundling is inherently built in to the rates in our cost estimating database. Accordingly, considered at a portfolio level, opportunities for further bundling efficiencies are limited.

- Changes in generation – Full in-situ secondary system replacement options at both Vales Point and Eraring substations were considered and reviewed in the repex program. This option was not progressed at both sites for the next period due to the expected retirement of the coal-fired power stations in 2029 and 2032 respectively. Instead only minor secondary system works have been forecasted, along with some minor HV equipment replacement works at Eraring.

Our 2023–28 forecast Repex has been independently reviewed for consistency with good industry practice. This review supports our forecast Repex as being prudent and efficient.

6.17. Addressing uncertainty in investment requirements

Uncertainty is inherent in any forecast and our Repex forecasts are no different. To avoid adding additional risk-costs to our projected expenditure requirements, our forecasting approach addresses uncertainty through several mechanisms to ensure that we do not overestimate our expenditure requirements. These include:

- using recent market costs in our cost estimation database to monitor and minimise cost variation over the life of projects,
- evaluating asset replacement requirements through the risk and investment process that establishes the probabilities of failure, value of the consequences, and likelihood of experiencing the consequence in the event of a failure. We recognise that uncertainty in this process arises from its reliance on the underlying assumptions – which we have based on reputable third-party sources wherever possible.
- conducting sensitivity analysis on the key risk and cost expenditure inputs for asset replacement investments, to test the sensitivity of the evaluated benefits associated with the proposed investment options to reasonable changes in input parameters. In most cases, the value of consequences and probabilities will change but not enough to change the preferred option,
- recognising the flexibility available to manage risks within the period to respond to unforeseen needs by re-evaluating priorities in response to more up-to-date asset condition and network loading information. This results in reallocating investment allowances from planned projects that have not proceeded to other projects as priorities change, followed by a review of whether any asset condition risks can be managed in the short term to accommodate more critical investment needs, and
- the uncertainty provisions in the regulatory framework provide broader measures for managing uncertainty.

This process ensures that we manage forecasting uncertainty for the direct benefit of customers and stakeholders.

Attachment 1 – Supporting documentation

The following documents support our Repex submission for the 2023-28 regulatory period.

Asset Management System and Governance

- Asset Management Policy
- Asset Management System Description
- ISO55001 Asset Management Accreditation
- Network Asset Strategy
- Prescribed Network Capital Investment Process
- Network Asset Risk Assessment Methodology
- Network Asset Criticality Framework
- Network Asset Health Framework
- Electricity Network Safety Management System (ENSMS) Description

Asset Management Lifecycle Strategies & Plans

- Substations Renewal and Maintenance Strategy
- Transmission Line Renewal and Maintenance Strategy
- Underground Cables Renewal and Maintenance Strategy
- Automation Renewal and Maintenance Strategy
- Market Metering Renewal and Maintenance Strategy
- Network Property Renewal and Maintenance Strategy
- Telecommunication Systems Renewal and Maintenance Strategy
- Infrastructure Systems Renewal and Maintenance Strategy

Business cases (OER justifications supporting forecast Repex)

- OER-1164 Rev 3 Rev 0 Asbestos Paint on Towers in Various Locations
- OER-1194 FY24-28 Rev 0 Tenterfield Secondary Systems Renewal
- OER-1271 Rev 1 Line 12 Livrpool Sydney Sth Refurb
- OER-1272 Rev 1 Line 13 Kemps Ck Sydney Sth Refurb
- OER-1353 Rev 1 Line 16 Marulan Avon Tower Refurb
- OER-1408 Rev 1 Line 23 Vales Pt Munmorah Refurb
- OER-1600 Rev 1 Line 11 Sydney Sth Dapto Twr Repl
- OER-2062 FY24-28 Rev 0 BKH SVC Server Upgrade
- OER-N2020 Rev 0 FY24-28 Operation Comms Renewal

- OER-N2212 Rev 0 FY24-28 SE1 Secondary Systems Renewal
- OER-N2213 Rev 0 FY24-28 BER Secondary Systems Renewal
- OER-N2214 Rev 0 FY24-28 ER0 Secondary Systems Renewal
- OER-N2242 Rev 0 FY24-28 Prot Line Renewal
- OER-N2243 Rev 0 FY24-28 Prot Transformer Renewal
- OER-N2244 Rev 0 FY24-28 Prot Reactor Renewal
- OER-N2245 Rev 0 FY24-28 Prot Capacitor Renewal
- OER-N2246 Rev 0 FY24-28 Prot Busbar Renewal
- OER-N2290 v3 Rev 2 Fit OLCM to OIP Bushings
- OER-N2345 Rev 3 FY24-28 Circuit Breaker Renewal Program
- OER-N2347 Rev 1 FY24-28 CT Renewal Program
- OER-N2348 Rev 4 FY24-28 VT Renewal Program
- OER-N2349 Rev 3 FY24-28 Disconnector Renewal Program
- OER-N2404-INV Rev 0 FY24-28 Transformer Refurb Program
- OER-N2404-MUR Rev 1 FY24-28 Transformer Refurb Program
- OER-N2404-PMA Rev 2 FY24-28 Transformer Refurb Program
- OER-N2404-RGV Rev 2 FY24-28 Transformer Refurb Program
- OER-N2405 Rev 0 FY24-28 LT1 Secondary Systems Renewal
- OER-N2409 Rev 0 FY24-28 KS2 Secondary Systems Renewal
- OER-N2410 Rev 0 FY24-28 FNY Secondary Systems Renewal
- OER-N2411 Rev 0 FY24-28 WL1 Secondary Systems Renewal
- OER-N2412 Rev 0 FY24-28 Prot UFLS Renewal
- OER-N2419 Rev 0 FY24-28 PMA Secondary Systems Renewal
- OER-N2421 Rev 1 Molong No1 Transformer Renewal
- OER-N2422 Rev 1 Tamworth Transformer Renewals
- OER-N2423 Rev 2 Yass No3 Transformer Renewal
- OER-N2424 Rev 0 Tenterfield Transformer Renewals
- OER-N2425 Rev 0 TL Public Safety Compliance
- OER-N2426 Rev 0 FY24-28 WW1 Secondary Systems Renewal
- OER-N2427 Rev 0 FY24-28 RGV Secondary Systems Renewal
- OER-N2428 Rev 0 FY24-28 CW2 Secondary Systems Renewal
- OER-N2429 Rev 0 FY24-28 VP1 Secondary Systems Renewal
- OER-N2430 Rev 0 FY24-28 FB2 Secondary Systems Renewal

- OER-N2431 Rev 0 FY24-28 NAM Secondary Systems Renewal
- OER-N2432 Rev 0 FY24-28 GN2 Secondary Systems Renewal
- OER-N2433 Rev 0 FY24-28 TOM Secondary Systems Renewal
- OER-N2434 Rev 0 FY24-28 LSM Secondary Systems Renewal
- OER-N2435 Rev 0 FY24-28 NB2 Secondary Systems Renewal
- OER-N2436 Rev 0 FY24-28 INV Secondary Systems Renewal
- OER-N2441 Rev 0 FY24-28 Multiplexer Renewal Program
- OER-N2442 Rev 0 FY24-28 Microwave Renewal Program
- OER-N2443 Rev 0 FY24-28 NEW Secondary Systems Renewal
- OER-N2444 Rev 0 FY24-28 KCR Secondary Systems Renewal
- OER-N2446 Rev 0 FY24-28 BRG Secondary Systems Renewal
- OER-N2447 Rev 0 FY24-28 MPP Secondary Systems Renewal
- OER-N2449 Rev 0 FY24-28 Prot Temporary Recall Renewal
- OER-N2453 Rev 0 FY24-28 Comms Alarm System Renewals
- OER-N2473 Rev 3 FY24-28 Replace capacitors end of life
- OER-N2474 Rev 1 Line 13-78 Refurb
- OER-N2476 Rev 1 Line 12-76 Refurb
- OER-N2477 Rev 2 Line 76-78 Refurb
- OER-N2479 Rev 1 Line 977-1 Refurb
- OER-N2482 Rev 0 FY24-28 Fire Systems (Electronic) Renewal
- OER-N2485 Rev 1 FY24-28 Steelwork Remediation Program
- OER-N2488 Rev 0 Underground Cable Capital Spares
- OER-N2490 Rev 0 Cable Monitoring Systems Renewal
- OER-N2496 Rev 1 Line 8C-8J Refurb
- OER-N2497 Rev 1 Line 8C-8E Refurb
- OER-N2498 Rev 1 Line 8L-8M Refurb
- OER-N2499 Rev 1 Line 9W-96 Refurb
- OER-N2501 Rev 1 Line 94-96 Refurb
- OER-N2502 Rev 1 Line 25-92 Refurb
- OER-N2504 Rev 1 Line 95 Refurb
- OER-N2505 Rev 1 Line 82-95 Refurb
- OER-N2520 Rev 1 Line 24-90 Refurb
- OER-N2525 Rev 1 Line 29-26 Refurb

- OER-N2526 Rev 1 Line 90-92 Refurb
- OER-N2527 Rev 1 Line 92-93 Refurb
- OER-N2536 Rev 0 FY24-28 Physical Security Renewals
- OER-N2546 Rev 0 FY24-28 Fire Extinguisher Renewal
- OER-N2551 Rev 0 FY24-28 Critical Infrastructure Uplift OT Environment
- OER-N2553 Rev 0 FY24-28 Building Refurbishment
- OER-N2555 Rev 0 FY24-28 DI Capital Spares
- OER-N2562 Rev 0 FY24-28 Palisade Renewal
- OER-N2579 Rev 1 Line 9ML Refurb
- OER-N2580 Rev 1 Line 94M Refurb
- OER-N2582 Rev 1 Line 94U Refurb
- OER-N2595 Rev 0 Various Lines Conductor Condition
- OER-N2599 Rev 1 Line 966 Refurb
- OER-N2601 Rev 3 Transformer Compound Wall Renewal
- OER-N2603 Rev 1 Line 99B Refurb
- OER-N2604 Rev 1 Line 992 Refurb
- OER-N2605 Rev 1 Line 99Z Refurb
- OER-N2606 Rev 1 Line 963 Refurb
- OER-N2607 Rev 1 Line 964 Refurb
- OER-N2609 Rev 0 Main Grid Low Spans
- OER-N2616 Rev 0 132kV TLs Low Spans
- OER-N2617 Rev 5 Substation Capital Spares
- OER-N2621 Rev 1 Line 947 Refurb

Attachment 2 – Summary of Key Changes in the Option Evaluation Reports and the Proposed Portfolio

Due to the influence of the portfolio optimisation and prioritisation process (described in section 6.16) on the individual needs, adjustments were required to be made to their associated individual capital expenditure. Accordingly, there are some differences between the values presented in the Option Evaluation Report (OER), which includes all assets identified to be included as part of the portfolio mix based on their economic evaluation, and the final capital expenditure forecast after undertaking portfolio optimisation.

The adjustment has been achieved through a combination of methods described below:

- changing the project preferred option to include the lower cost option in the Repex forecast
- phasing of the project forecast expenditure across regulatory periods, including extending the delivery timeframe on projects. This in particular has been applied to projects where outage restrictions have impacted the timing of the project, and
- high level review of historical trend expenditure across individual asset equipment and component types, and prioritisation within an individual asset replacement program using a similar prioritisation approach to that adopted for the portfolio.

Secondary System Renewals

During the optimisation process, the primary approach taken on secondary system renewal projects to adjusting the expenditure at an individual need level has been to change the preferred option to address the need. Whilst the entire site secondary systems replacement option might have been preferred due to the increased economic benefits associated with improving and aligning the technologies with the latest standards, their expenditure requirements did not enable them to be included within the portfolio.

Accordingly, the number of full site replacements were limited and selected in line with our prioritisation approach, and other sites had their option changed in order to address the minimum required scope in order to maintain reliability and manage our compliance requirements at these locations.

The relevant projects where the option change approach have been applied are listed below:

- Beryl Secondary Systems Renewal
- Cowra Secondary Systems Renewal
- Finley Secondary Systems Renewal
- Forbes Secondary Systems Renewal
- Gunnedah Secondary Systems Renewal
- Inverell Secondary Systems Renewal
- Nambucca Secondary Systems Renewal
- Newcastle Secondary Systems Renewal
- Panorama Secondary Systems Renewal
- Tenterfield Secondary Systems Renewal
- Vales Point Secondary Systems Renewal
- Wellington Secondary Systems Renewal

Asset Replacement Programmes

The primary approach taken on asset replacement program expenditure adjustments has been to undertake a high level review of trend expenditure across individual asset equipment and component types. This includes both assessment of historical expenditure of the items, movements in relation to population asset health and condition, and review of need drivers. Once the top down challenge had been applied to the programs, the individual assets within the program were prioritised using a similar prioritisation approach to that adopted for the portfolio, in particular, ranked by highest economic benefit or NPV. These assets were included in the revised replacement scope and the final expenditure forecast adjusted accordingly to reflect this.

The relevant impacted programs include:

- Disconnector Programme
- Busbar Protection Relay Replacements
- Multiplexer Renewal Program
- Microwave Renewal Program
- Comms Alarm System Renewals
- Operational Building Refurbishments
- Physical Security Upgrade
- Conductor Replacement Programme
- Low Spans 132kV Programme
- Transmission Line Public Safety Enhancement Programme

Transmission Line Projects

The timing of transmission line projects, typically refurbishment projects have been largely determined by the availability of outages required to facilitate the work. Accordingly, project expenditure has been phased to align with the relevant scheduled outage window. This has involved bringing forward expenditure such that the development of the project has been brought into the current regulatory period to meet an outage window scheduled at the beginning of the next period, and also to delay expenditure where outage window, or part thereof, is scheduled in the subsequent period. In particular where the project has been scheduled to be initiated in the current period, the first year project cost within the expenditure profile has been adjusted to also include the design component.

The impacted projects include:

- Line 11 Replacement: Phasing includes works proposed to be delivered in the 2028-2033 regulatory period.
- Line 12/76 Refurbishment: Phasing includes development works being to be conducted in the 2018-23 regulatory period.
- Line 13 Refurbishment: Phasing includes development works being to be conducted in the 2018-23 regulatory period.
- Line 16 Refurbishment: Phasing includes development works being to be conducted in the 2018-23 regulatory period.

- Line 13/78 Refurbishment: Phasing includes development works being to be conducted in the 2018-23 regulatory period.
- Line 24/90 Refurbishment: Phasing includes development works being to be conducted in the 2018-23 regulatory period.
- Line 76/78 Refurbishment: Phasing includes development works being to be conducted in the 2018-23 regulatory period.
- Line 23 Replacement: Phasing includes development works being to be conducted in the 2018-23 regulatory period.

Substation Steelwork

The substation sites with end of life steelwork were initially identified in our 2018-2023 revenue proposal. During the 2018-2023 regulatory period the sites have undergone additional modelling to enable scope refinement and to confirm the optimal renewal strategy and feasibility. We also completed initial renewal work and site trials.

This has led to lower expenditure in the 2018-2023 regulatory period and has also enabled some scope reduction. The renewal works at the identified sites are now proposed over the current, next and subsequent regulatory periods.

The phasing of the steelwork renewal program provides the following advantages:

- puts immediate focus on the highest priority gantries
- reduce the step change in expenditure on this asset type, and
- enable efficient resource utilisation through sequential completion of projects, rather than a large concurrent program. Enabling the transfer of lessons learnt and experience from one to project to another.

Detailed Listing of Final 2023-28 Repex Portfolio Expenditure Against OER Values (where a variance exists)

Table A-1: Listing of Final 2023-28 Repex Portfolio Expenditure Against OER Values – Direct Capital Cost (excluding overheads) ($Million, Real 2020-21)

Need ID	Need Description	Forecast Expenditure	OER Preferred Option Capital Value	Comment
N2428	Cowra substation Secondary Systems Renewal	2.18	7.36	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2410	Finley Secondary Systems Renewal	2.74	6.00	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2430	Forbes Secondary Systems Renewal	1.51	7.35	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2432	Gunnedah Secondary Systems Renewal	2.19	6.86	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2431	Nambucca Secondary Systems Renewal	2.17	7.12	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2443	Newcastle Secondary Systems Renewal	6.67	22.07	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2419	Panorama Secondary Systems Renewal	2.08	6.31	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.

Need ID	Need Description	Forecast Expenditure	OER Preferred Option Capital Value	Comment
N2536	Physical Security Upgrade	31.40	42.39	Project cost restricted in the portfolio to align with top down portfolio challenge.
N2212	Sydney east Secondary Systems Renewal	17.57	20.01	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2242	Transmission Line Protection Relay Replacements	11.42	11.87	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2429	Vales point Secondary Systems Renewal	3.20	12.43	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2405	Lower Tumut Secondary Systems Renewal	16.66	21.72	Initially preferred option B has since been deemed technically infeasible. Option C now the preferred option.
1194	Tenterfield Secondary Systems Renewal	1.82	5.89	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2214	ER0 Secondary Systems Renewal	2.17	2.24	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2213	BER Secondary Systems Renewal	1.90	8.17	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.

Need ID	Need Description	Forecast Expenditure	OER Preferred Option Capital Value	Comment
N2446	BRG Secondary Systems Renewal	0.69	0.71	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2434	LSM Secondary Systems Renewal	2.54	2.61	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2447	MPP Secondary Systems Renewal	1.87	1.93	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2436	INV Secondary Systems Renewal	2.11	6.68	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2411	WL1 Secondary Systems Renewal	2.37	9.07	Option B as preferred in the OER as it has the greatest NPV. However, Option A selected in the portfolio to align with top down portfolio challenge.
N2246	Busbar Protection Relay Replacements	2.68	8.30	Scope increase due to NPV re-evaluation of individual assets based on varying useful life. Project cost restricted in the portfolio to align with top down portfolio challenge.
N2245	Capacitor Protection Relay Replacements	1.63	1.86	Minor scope change. Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2244	Reactor Protection Relay Replacements	0.84	0.87	Expenditure associated with development works brought into 2018-23 Regulatory Period.

Need ID	Need Description	Forecast Expenditure	OER Preferred Option Capital Value	Comment
N2243	Transformer Protection Relay Replacements	4.97	5.48	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2412	UFLS Protection Relay Replacements	0.40	0.87	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2449	Temporary protection renewal for recall periods	0.62	0.64	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2441	Multiplexer Renewal program	6.64	7.32	Project cost restricted in the portfolio to align with top down portfolio challenge.
N2442	Microwave Renewal Program	6.53	8.72	Minor scope change. Project cost restricted in the portfolio to align with top down portfolio challenge.
N2453	Comms Alarm System Renewals	4.28	4.55	Minor scope change.
N2553	Operational Building Refurbs	9.83	16.51	Project cost restricted in the portfolio to align with top down portfolio challenge.
N2345	Circuit Breaker Program	35.02	36.11	Expenditure associated with development works brought into 2018-23 Regulatory Period.

Need ID	Need Description	Forecast Expenditure	OER Preferred Option Capital Value	Comment
N2290	Fit OLCM to OIP bushings	4.45	4.74	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2424	Tenterfield Transformer Renewals	6.55	9.96	Phasing of project to have first transformer within RP3 and second transformer replacement to be RP4.
N2601	Transformer Compound Wall Renewal	2.35	2.43	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2347	CT Program	5.92	6.10	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2348	VT Program	11.54	11.97	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2349	Disconnector	12.75	23.44	Project cost restricted through reduction of quantities in the portfolio to align with top down portfolio challenge.
N2485	Steelwork Program	32.61	69.82	Project cost restricted through reduction of quantities in the portfolio to align with top down portfolio challenge.
N2404	Transformer refurbishment program	33.74	34.45	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2473	Capacitor Banks	10.14	10.42	Expenditure associated with development works brought into 2018-23 Regulatory Period.

Need ID	Need Description	Forecast Expenditure	OER Preferred Option Capital Value	Comment
1600	Line 11 - Sydney Sth - Dapto - Twr Repl	53.62	79.87	Outage constraint prioritisation. Phasing to prioritise the structure and conductor that identified as having priority condition issues in 2023-2028 Regulatory Period.
N2476	Line 12/76 Refurbishment	4.75	5.19	Outage constraint prioritisation. Expenditure associated with development works brought into 2018-23 Regulatory Period.
1272	Line 13 Kemps Creek Sydney South Refurb	2.57	2.81	Outage constraint prioritisation. Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2474	Line 13/78 Refurbishment	3.82	4.17	Outage constraint prioritisation. Expenditure associated with development works brought into 2018-23 Regulatory Period.
1353	Line 16 Marulan Avon refurb	7.48	8.17	Outage constraint prioritisation. Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2520	Line 24/90 Refurbishment	0.88	0.99	Outage constraint prioritisation. Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2477	Line 76/78 Refurbishment	3.11	3.38	Outage constraint prioritisation. Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2498	Line 8L/8M Refurbishment	0.08	6.00	Prioritised into 2029-2033 Regulatory Period. Expenditure associated with development works brought into 2023-2028 Regulatory Period.

Need ID	Need Description	Forecast Expenditure	OER Preferred Option Capital Value	Comment
N2605	Line 99Z Refurbishment	2.42	2.58	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2579	Line 9ML Refurbishment	4.43	4.74	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2595	Conductor Replacement	29.14	102.56	Programme prioritisation. Project cost restricted through reduction of quantities in the portfolio to align with top down portfolio challenge. Some lines could not be included due to outage constraints, including Lines 17, 25/26, 2M, 90, 93 and 81.
N2616	Low Spans -132kV TL	12.09	20.20	Programme prioritisation. Project cost restricted through reduction of quantities in the portfolio to align with top down portfolio challenge.
N2425	Public Safety Enhancements - Climbing deterrents, signage, aerial marker balls, earthing	16.25	21.80	Portfolio optimisation to address higher risk structures.
1408	Line 23 - Vales Point Munmorah Refurb	10.52	11.38	Expenditure associated with development works brought into 2018-23 Regulatory Period.
N2604	Line 992 Refurbishment	5.52	22.34	Phasing and addressing wood pole that exhibiting known deterioration as per Option A which has optimal timing in 2023-2028 Regulatory Period