Powerlink 2027-32 Revenue Proposal (Draft)

September 2025

Please direct enquiries to:

Roger Smith
Director Revenue Reset
Powerlink Queensland

Email: revenueresetteam@powerlink.com.au

Table of Contents

List of Figures

List of Tables

Foreword

I am pleased to present our draft Revenue Proposal for the 2027-32 regulatory period. Our revenue determination process is a once-in-five-year opportunity for us to build more trust with our customers, stakeholders and the Australian Energy Regulator (AER).

The draft represents an important step in our ongoing engagement. Input received will be considered as part of the development of our Revenue Proposal, to be lodged with the AER in January 2026. Your feedback will directly contribute toward our goal of lodging a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink.

There has been significant change in our operating environment since we submitted our last Revenue Proposal. Customers and community, costs, and complexity are all key themes that necessitate changes to the way we meet the needs of Queenslanders now and in the future.

While we will need new approaches to the challenges and opportunities the current external environment presents, we remain committed to providing safe, secure, reliable and cost-effective transmission services to our directly connected customers and over five million Queenslanders.

Key components of our 2027-32 Revenue Proposal include:

- a nominal increase of 22% in the transmission component of electricity prices by the end of the 2027-32 regulatory period, we estimate this will result in an increase to bills, with all other factors being equal, of approximately $33 for households and $63 for small businesses over the 5 years
- total unsmoothed revenue for the 2027-32 regulatory period of $5,743.2 million ($nominal) or $5,308.1 million ($real, 2026/27)
- operating expenditure of $1,831.3 million ($real, 2026/27), a $333.0 million increase from the 2022-27 period
- capital expenditure of $2,796.7 million ($real, 2026/27), a $1,142.8 million increase from the 2022-27 period
- a proposal for alternative output growth measures, used to calculate the operating expenditure increase in the 2027-32 period, to reflect the increasing complexity that drives operating and maintenance activities on the transmission network, and
- a proposal for an alternative method of calculating net carryovers under the Capital Expenditure Sharing Scheme (CESS) that takes into account the circumstances of Powerlink during the 2022-27 regulatory period, i.e. unprecedented increases in the costs of major plant items, materials and skilled resources.

Our draft Revenue Proposal is the fourth time we have publicly released expenditure and revenue forecasts for feedback and forms part of our open and transparent engagement approach.

On behalf of the Powerlink Board and Executive, I would like to thank members of our Customer Panel and Revenue Proposal Reference Group for their regular participation and insights on our forecasts and engagement topics so far.

I look forward to hearing your thoughts on our draft Revenue Proposal.

Regards,

Paul Simshauser

Chief Executive

Guide to the draft Revenue Proposal

Introduction

This guide has been prepared to help readers understand the purpose of the draft Revenue Proposal, how to provide feedback and some of the nuances in writing the draft.

Purpose

The purpose of the draft Revenue Proposal is to provide customers, stakeholders and the Australian Energy Regulator (AER) with an early version of what is to be our Revenue Proposal, due to be lodged with the AER in January 2026.

Providing feedback

We will consider all feedback as part of the development of our Revenue Proposal. To enable sufficient time to consider feedback, submissions must be received by **10 October 2025**.

An online form has been prepared to assist providing feedback and is available on our website[1]. Feedback may also be presented in any format and emailed to revenueresetteam@powerlink.com.au.

All customers and stakeholders will have the opportunity to provide a submission to the AER on our Revenue Proposal after it is lodged in January 2026. We would also encourage customers and other stakeholders to provide their input and feedback to us directly.

Structure and style

The structure and style of this document refers to 'our Revenue Proposal' or 'this Revenue Proposal' rather than 'draft Revenue Proposal'.

We have provided breakout boxes which state 'Note for the draft Revenue Proposal' in sections to clearly articulate information that may change, is being considered, or cannot be provided at this time. This is not intended to capture all potential changes that may occur, but rather to highlight key areas.

Conventions (e.g. figures, sources) are discussed in Chapter 1 Introduction.

Appendices

We have included instances where appendices and supporting documentation are likely to be referenced. This is intended to provide readers with an indication of supporting documentation we are likely to provide as part of the Revenue Proposal in January 2026.

In some instances, supporting documentation has been provided as part of this draft Revenue Proposal (e.g. where already published), but in most circumstances supporting documentation is still being prepared.

A list of supporting documentation is included in the Appendices. This section identifies supporting information that is included as part of this draft Revenue Proposal.

[1] https://www.powerlink.com.au/2027-2032-regulatory-period.

1 Introduction

This Revenue Proposal presents Queensland Electricity Transmission Corporation Limited's (Powerlink's) proposed revenue requirements for prescribed transmission services for our next regulatory period from 1 July 2027 to 30 June 2032.

We have developed our Revenue Proposal consistent with Chapter 6A of the National Electricity Rules (Rules), the Australian Energy Regulator's (AER) Framework and Approach Paper[2] and the Regulatory Information Notice (RIN) issued to Powerlink by the AER for the purpose of this Revenue Proposal (the Reset RIN).

This Revenue Proposal provides an overview of our business and operating environment, customer engagement process, expenditure forecasts and proposed revenue requirements for the 2027-32 regulatory period.

Our Revenue Proposal reflects the outcomes of extensive engagement with our customers and stakeholders, including our Customer Panel and a sub-group of that panel, the Revenue Proposal Reference Group (RPRG). We acknowledge the time and resources committed by our customers and stakeholders as part of this process, which has provided us with valuable insights and feedback on key aspects of our Revenue Proposal (refer Chapter 3 Customer Engagement).

About Powerlink

We are a Government Owned Corporation that owns, develops, operates and maintains the electricity transmission network in Queensland. Our transmission network runs approximately 1,700km from north of Cairns to the New South Wales (NSW) border.

Our role in the electricity supply chain is to transport high voltage electricity from large generators through the transmission grid to the distribution networks owned by Energex and Ergon Energy (part of the Energy Queensland Group) and Essential Energy (in northern NSW) to ensure a safe, secure, reliable and cost-effective power supply to over five million Queenslanders.

We also transport electricity to industrial customers such as rail companies, mines and mineral processing facilities, and to NSW via the Queensland/NSW Interconnector (QNI) transmission line.

We are registered with the Australian Energy Market Operator (AEMO) as a Transmission Network Service Provider (TNSP) and are the System Strength Service Provider and Inertia Service Provider for Queensland. We hold a Transmission Authority issued under the *Electricity Act 1994 (Qld)* and have been appointed by the Queensland Government as the entity responsible for transmission network planning in Queensland (the Jurisdictional Planning Body) for the purpose of the Rules[3].

[2] Framework and Approach Paper Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025.
[3] National Electricity Rules.

Our services

We provide prescribed transmission services consistent with the Rules, the *Electricity Act 1994 (Qld)* and our Transmission Authority. These services include:

- shared transmission services provided to directly connected customers and distribution networks (prescribed Transmission Use of System (TUOS) services)
- connection services for the Queensland Distribution Network Service Providers (DNSP) who are connected to our transmission network (prescribed exit services)
- grandfathered connection services provided to generators and customers directly connected to the transmission network that were in place on 9 February 2006 (prescribed entry and exit services), and
- services required under the Rules or to comply with jurisdictional electricity legislation that are necessary to ensure the integrity of the transmission network, including through the maintenance of power system security and quality (prescribed common transmission services).

The quality, reliability and security of supply of the prescribed transmission services we provide are established in the Rules, our Transmission Authority (and other jurisdictional legislation and instruments), and customer connection and access agreements.

Conventions

In our Revenue Proposal we have applied the following number conventions, unless otherwise specified:

- regulatory periods are expressed consistent with the AER's convention, e.g. 2022-27 refers to the period 1 July 2022 to 30 June 2027
- where our Revenue Proposal for the current 2022-27 period is referenced, it uses the published name of our 2023-27 Revenue Proposal
- years referenced in tables and figures relate to financial years (July – June) unless otherwise stated
- negative values in tables are presented in brackets
- historical and forecast capital expenditure is presented in mid-year real 2026/27 dollars
- historical and forecast operating expenditure is presented in year-end real 2026/27 dollars, and
- our revenue building-blocks from the Post-tax Revenue Model (PTRM) are presented in year-end nominal dollars.

Totals presented in tables may not add due to rounding.

The source of all figures and tables is Powerlink, unless otherwise specified.

Confidential information

We do not anticipate claiming confidentiality over any part of the Revenue Proposal document. However, some components of the Revenue Proposal, including supporting documents, are confidential, and we have clearly noted where this is the case.

Where confidential information has been identified in separate appendices and supporting information, a confidential version has been provided to the AER and registered consistent with the AER's Confidentiality Guideline[4].

[4] Better Regulation: Confidentiality Guideline, Australian Energy Regulator, August 2017.

Governance and compliance

Note for the draft Revenue Proposal: the following section will be completed for lodgement of our Revenue Proposal in January 2026.

Our Board has issued the following resolution in relation to this Revenue Proposal:

- certified that the key assumptions that underlie the capital and operating expenditure forecasts are reasonable[5] (refer Appendix 1.01).

We also provide a Statutory Declaration from our Chief Executive in relation to the historical and forecast data contained in our Reset RIN (refer Appendix 1.02).

To assist the AER in assessing our Revenue Proposal's compliance with the Rules, we have provided a compliance checklist in Appendix 1.03. Our compliance checklist to the Reset RIN is provided in Appendix 1.04.

[5] National Electricity Rules, clause S6A.1.1(5), S6A.1.2(6).

2 Business and Operating Environment

2.1 Introduction

This chapter sets out the key external drivers that impact Powerlink or are expected to impact Powerlink over the 2027-32 regulatory period and beyond.

This chapter builds on the Business Narrative developed with our Revenue Proposal Reference Group (RPRG) early in our customer engagement process for this Revenue Proposal (refer Chapter 3 Customer Engagement and Appendix 2.01).

Key highlights:

- The operating environment has changed significantly since we lodged our 2023-27 Revenue Proposal in January 2021. Unprecedented rises in transmission equipment prices and supply chain shocks from the Russia-Ukraine war has seen costs rising at multiples of the prevailing inflation rates. Compounding matters, the power system is becoming more complex to operate due to the changing nature of generation and demand.
- We have ensured that our forecast expenditure for the 2027-32 regulatory period is prudent, efficient and essential to the delivery of safe, secure and reliable electricity supply.
- We have grouped the key elements of our business and operating environment in the 2027-32 regulatory period into themes of customers and community, costs and complexity.
    - Customers: Affordability remains a key concern for customers. Customers expect services to be affordable and offer value for money, and this remains a key focus for Powerlink.
    - Community: Meeting the expectations of communities and other stakeholders is critical to efficient delivery of capital and operating works. Powerlink has proactively lifted its approach to community engagement, social impact and benefit delivery. Our approach now embeds social performance as a core management system, aligning with government policy, regulatory frameworks, and the Energy Charter's Better Practice Social Licence Guideline.
    - Costs: A combination of global and local factors is placing significant pressure on delivery costs, and we expect this to continue into the 2027-32 period. We have sought proactive solutions to these rising costs.
    - Complexity: System complexity encompasses changes in network demand and connectivity to the network, including the digital network. Deliverability encompasses those factors that can have a material impact on the timeframe of projects, such as social licence, political licence and the regulatory environment for approvals.

2.2 Our approach

Our business and operating environment continues to present challenges and opportunities for Powerlink. Our priority remains to deliver safe, secure, reliable and cost-effective electricity services to our customers. We also see an ongoing role in guiding the market in Queensland, including through the publication of our Transmission Annual Planning Report, during a period of significant change for the energy market and consumers.

We have summarised the key elements within our business and operating environment into three themes. These themes influence our day-to-day business, as well as components of our Revenue Proposal, and are discussed in further detail in the following sections.

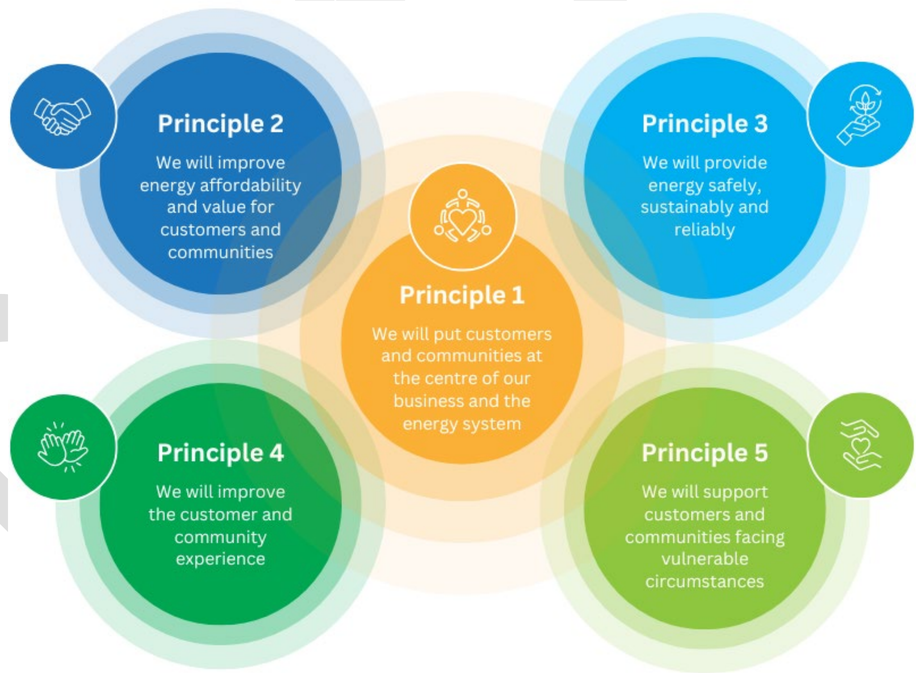
- Customers and Community
- Costs
- Complexity.

2.3 Customers and Community

Our purpose is to connect Queenslanders to a world-class energy future. We aim to achieve this by consistently prioritising Queenslanders' long-term interests throughout the energy transformation. Our purpose is supported by four strategic objectives, including to *Drive value for customers.*

We put customers at the centre of our business and aim to spend no more than necessary in delivering our services to the people of Queensland. We are proud to be a foundation signatory to The Energy Charter and remain committed to the principles that are at the core of this initiative, which are shown on Figure 2.1.[6]

Figure 2.1 – The Energy Charter Principles



We recognise that to deliver against these principles we must continue to seek customers' views and inputs to inform not only our Revenue Proposal, but our day-to-day business activities. The following sections outline the four key customer and community elements that have influenced our Revenue Proposal: affordability, price predictability, reliability and resilience, and social value.

[6] The Energy Charter Principles, The Energy Charter, retrieved from the Energy Charter website (www.theenergycharter.com.au), 3 July 2025.

We will continue to review and update our Revenue Proposal in line with the insights we learn from ongoing engagement with customers. More detail on our engagement approach and response to customer feedback on our Revenue Proposal is included in Chapter 3 Customer Engagement.

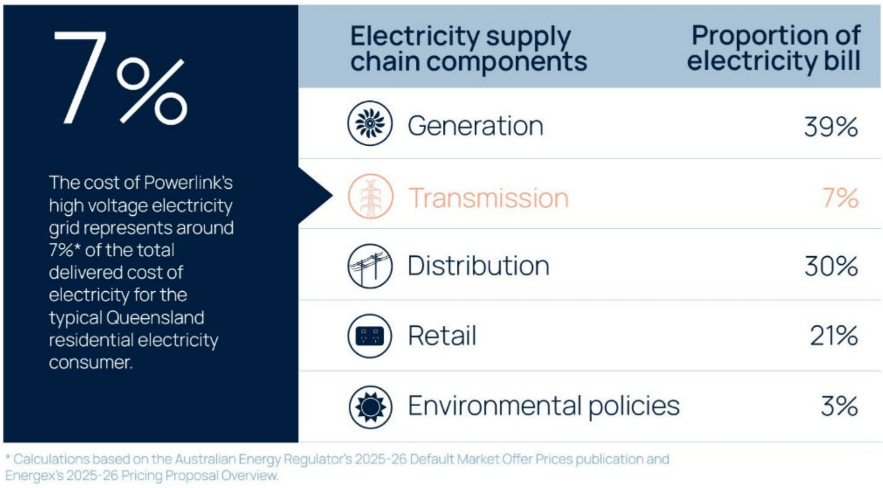
2.3.1 Affordability

The cost of electricity remains a key concern for our customers.

The 2025 Queensland Household Energy Survey[7] highlighted significant ongoing concerns about electricity affordability, particularly among renters (66%), households without rooftop solar (58%), and those with lower incomes[8] (56%). The AER found that more than 80,000 residential customers in Queensland were on either a payment plan or a hardship program to manage their electricity payments[9]. In particular, the number of customers on a hardship program has increased by more than 14,000 in the last five years to 33,200.

While our transmission network charges comprise around 7% of the average residential household bill (refer Figure 2.2), our focus does not stop here. We will continue to guide the market to minimise bulk supply costs for electricity users.

Figure 2.2 - Breakdown of typical Queensland household electricity bill



When we lodged our 2023-27 Revenue Proposal we sought to respond to customer affordability concerns through targeting a small decrease in our capital expenditure and no real growth in operating expenditure compared to the 2018-22 regulatory period. While these targets were set in the genuine belief that Powerlink could meet them, unprecedented increases in transmission equipment prices, supply chain shocks and the increasing complexity of the operating environment meant that we were unable to deliver our capital and operating expenditure programs in line with these targets.

However, we continued to target improved outcomes for our customers in our capital expenditure planning through engaging with customers and stakeholders, including the AER, in our Asset Reinvestment Review[10]. This

[7] Queensland Household Energy Survey (qhes.com.au).
[8] Less than $31,000 per annum.
[9] Annual retail markets report 2023-24 - Jurisdictional snapshot, Australian Energy Regulator, November 2024.
[10] Asset Reinvestment Review, Powerlink Queensland, June 2023.

review considered alternative strategies for transmission line refit works and resulted in the efficient deferral of capital works within the current 2022-27 regulatory period.

We also commenced a trial of in-situ replacement of secondary systems panels. The trial is expected to result in reduced costs, support shorter network outage times and enhance our capability in replacement techniques. This replacement approach comes with a trade-off of placing more pressure on scarce highly skilled resources necessary to undertake the work. This approach will be deployed where most appropriate, however we will need to continue to develop this and other innovative approaches to meet the changing environment and challenges of replacing an aging fleet of secondary systems with increased input costs.

Our capital expenditure forecasts build on these reviews and incorporate efficiencies in line with the expected benefits of these approaches. This is discussed further in Chapter 5 Forecast Capital Expenditure.

We also continue to seek innovative approaches to prioritising work and enhancing utilisation of resources to manage the cost impacts on operating expenditure. These improvements have been factored into our forecasts, which we discuss further in Chapter 6 Forecast Operating Expenditure.

We recognise our impact on customer affordability is not limited to the prices we charge for transmission services. Our role in connecting electricity generators and electricity storage facilities such as pumped hydro energy storage and battery energy storage systems across Queensland is essential in ensuring customers have access to the lowest cost electricity when they need it. Network outages, constraints and congestion on the transmission network can lead to higher wholesale prices as more expensive generation is required to operate to meet customer demand.

As part of the economic assessment for major new transmission network investments, we analyse the potential benefits of improved network operation on the wholesale market. In this way we seek the best overall outcome for everyone who produces, transports and consumes electricity.

The Queensland Government is developing an Energy Roadmap for the state which is expected to be released in October 2025. This Energy Roadmap will be an important input into our ongoing assessments of network investment needs. We also have regard to Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP), which presents an integrated approach to necessary transmission developments in the National Electricity Market (NEM) and a plan for Australia's eastern power system for the next 20 years.

The commitment we have made to The Energy Charter is to make ourselves accountable to our customers and communities across all aspects of our operations. This includes improved energy affordability. Consistent with that commitment, we have worked to ensure that our forecast expenditure for the 2027-32 regulatory period is prudent, efficient and essential to the delivery of safe, secure and reliable electricity supply.

2.3.2 Price predictability

Large commercial and industrial (C&I) customers in Queensland, including our directly connected customers, value stable prices and predictability in future charges. This was clearly identified during the survey we recently conducted with C&I customers. For this reason, we have engaged with the RPRG and major customers on the approach to price path smoothing. From this engagement, we have considered a balanced approach to the smoothing of revenues to deliver a more stable price path over the 2027-32 regulatory period. We discuss this approach further in Chapter 11 Maximum Allowed Revenue.

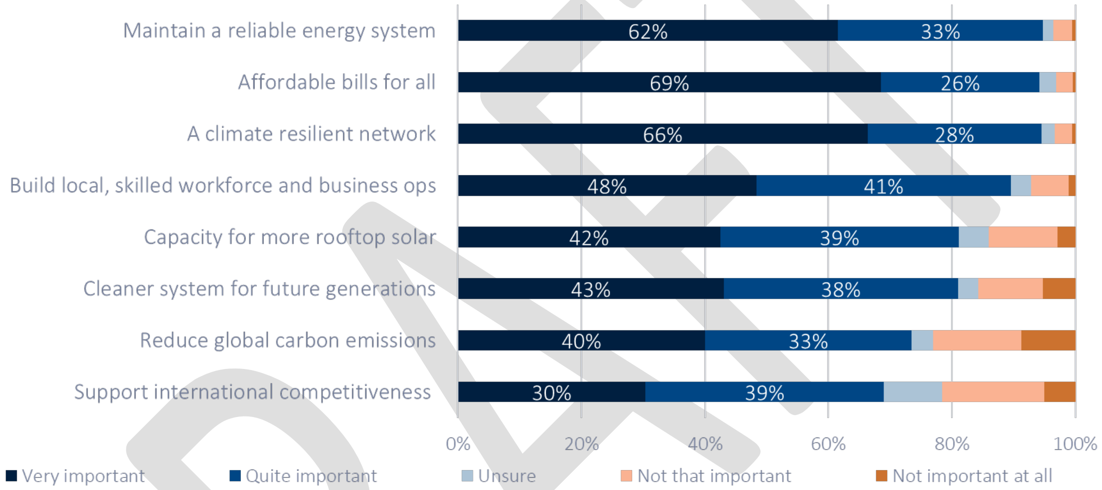
We are also working on a framework to provide more flexibility for connected customers. We will engage with our customers and other key stakeholders on any proposed amendments to our Pricing Methodology arising from this framework review, separate to this Revenue Proposal.

For the purposes of this Revenue Proposal, we have sought to implement minimal changes to our Pricing Methodology. We discuss the customer surveys and related engagement in Chapter 3 Customer Engagement, while in Chapter 15 Pricing Methodology we discuss the proposed Pricing Methodology changes in further detail.

2.3.3 Reliability and resilience

Reliability of supply, even during extreme weather events, is important to our customers. In the 2025 Queensland Household Energy Survey, households considered investment to support reliability and resilience of the network as important (very important or quite important), as illustrated in Figure 2.3. Three-quarters of households that responded considered that they had a reliable electricity supply, with only 3% unhappy with the reliability of their supply.

Figure 2.3 - Importance of investment by purpose (source: Powerlink, QHES)



Our large C&I customers also rated the need for reliability as a high priority, and it is also a concern for the agricultural sector. Extreme weather events and supply disruptions disproportionately affect rural areas, where the absence of diverse supply paths to enable supply restoration can result in longer and more frequent outages.

Electricity is an essential service, yet those most affected by higher prices often have fewer options to reduce demand. As rooftop solar and household battery adoption continues to grow, support will be necessary to address the resulting impacts on more vulnerable and lower income groups unable to access these consumer energy resources. We are dedicated to addressing these challenges by advancing a low-cost energy transition, ensuring fair cost allocation, aligned with the principles of distributional and procedural fairness, and building partnerships across the energy supply chain to achieve better outcomes for customers.

Our capital expenditure forecast presented in Chapter 5 Forecast Capital Expenditure is built upon a need to maintain reliability of electricity supply, including during extreme weather events.

2.3.4 Social value

Powerlink's operating environment is increasingly shaped by the expectations of communities and other stakeholders who are directly impacted by transmission infrastructure. In the 2022-27 regulatory period, social licence has emerged as a critical enabler of project delivery, influencing planning, engagement, and investment decisions. This shift will continue into the 2027-32 period and reflects a broader recognition that procedural fairness, transparency, and community benefit-sharing are not only ethical imperatives but also essential to securing timely approvals and maintaining trust.

Our approach now embeds social performance as a core management system, aligning with government policy, regulatory frameworks, and the Energy Charter's Better Practice Social Licence Guideline. Community expectations are driving change across the business and Powerlink is responding with co-designed engagement processes, tailored landholder support, and measurable commitments to social value.

2.4 Costs

When lodging our 2023-27 Revenue Proposal in 2021, Powerlink's operating environment was markedly different to what we face today. Our forecasts of a reduction in capital expenditure and no real growth in operating expenditure were reasonable at the time and reflective of our view of the future operating environment. It was aimed at keeping costs low for Queenslanders.

Events such as the long-tailed global supply disruption following COVID-19, Russia's invasion and war in Ukraine, and global targets for emissions reductions driving unprecedented demand for materials, equipment and specialised labour could not have been reasonably foreseen at the time of lodging our Revenue Proposal in January 2021, or our Revised Revenue Proposal in November 2021. Market data for transmission equipment available at that time did not reveal the looming cost shock or lead-order time blow-outs which are now a matter of documented history.

These cost pressures are not unique to Powerlink with similar trends being experienced by other transmission and distribution businesses across the NEM, and indeed, across the globe.

We expect the global and local competition impacting the supply chain to continue for the foreseeable future, resulting in a challenging operating environment throughout the 2027-32 regulatory period.

2.4.1 Global impacts

The ongoing increased demand for materials, equipment and specialised labour is driven primarily by global structural shocks to historic trade patterns for energy as a consequence of the Russia-Ukraine war, and commitments to net-zero greenhouse gas emissions targets by 2050. This continues to drive a significant shift in the mix of generation globally, and the need to substantially expand electricity networks. In June 2024, 107 countries had adopted net-zero pledges[11], covering approximately 82% of current global greenhouse gas emissions.

To support these targets, the global demand for new electricity transmission lines is substantial. In November 2023, the International Energy Agency (IEA) identified that to meet global targets, more than 80 million kilometres of new or refurbished transmission lines would need to be delivered by 2040 – the equivalent of the entire existing global grid.[12]

The Energy Transitions Commission, a global coalition of leaders from energy producers, energy users, financiers and environmental groups, identified a similar need, stating in September 2024 that global networks must grow from around 68 million kilometres to a range of around 110–200 million kilometres by 2050[13] The investment

[11] Emissions Gap Report 2024, United Nations Environment Programme, October 2024, page XV.
[12] Electricity Grids and Secure Energy Transitions, International Energy Agency, November 2023, Revised Version, page 7.
[13] Building grids faster: the backbone of the energy transition, Energy Transitions Commission, September 2024, page 9.

required for this necessary expansion is estimated to reach $690 billion per year by 2030[14], which is double the current global investment levels.

Infrastructure Australia published its Infrastructure Market Capacity Report in December 2024. The forecast expenditure for the five-year outlook, from 2024 to 2028, for utilities infrastructure investment is $16 billion [15]. This is made up predominantly of renewable energy and transmission line projects and represents a $6 billion increase on the previous year's outlook.

The impact of this significant global and local demand on the cost of transmission projects in Australia has been reflected in the draft 2025 Electricity Network Options Report published by AEMO. Research by GHD Advisory found that global demand, along with Australian demand, is competing for the same pool of skills, production floor capacity and other supply chain arrangements[16]. As a result of these global and local cost pressures, the draft 2025 Electricity Network Options Report identifies that the costs for transmission line projects have increased by up to 55%, while transmission substation projects have increased by up to 35%, in real terms since 2023[17].

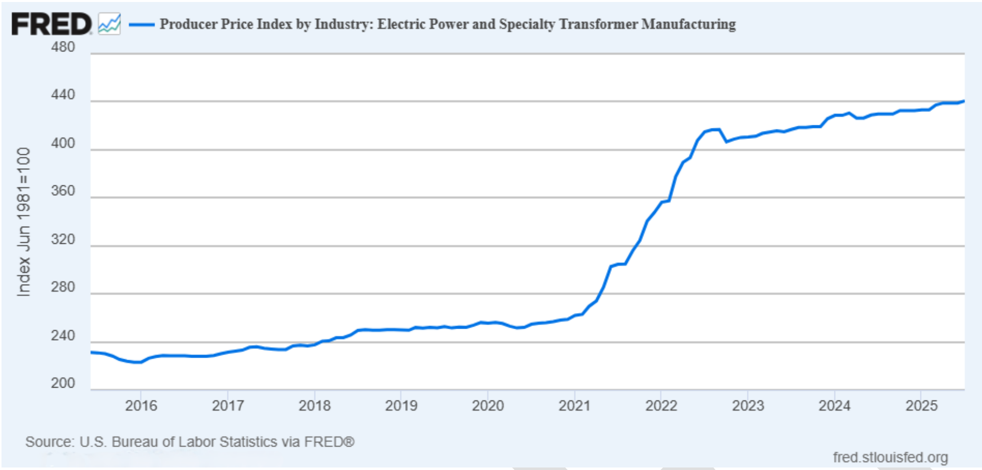
AEMO notes that the cost increases are primarily driven by:

- sustained supply chain pressures on materials, equipment and workforce
- market competition driven by a high number of concurrent projects under development in the NEM
- project complexity, including an increased number of projects planned for remote areas
- social licence and additional community and landholder engagement along proposed transmission line routes
- additional contracting costs to account for risk allocation in engineering, procurement and construction contracts in response to pressures in the current market.

The United States Bureau of Labor Statistics track the producer price indices of a range of transmission related equipment. The Electric Power and Specialty Transformer Manufacturing producer price index is shown in Figure 2.4 below[18] which illustrates that the price of transformers has increased substantially in the four years from 2021 to 2025. The scale of price increase over the last four years is unprecedented, equivalent to the cumulative price increase over the preceding 40 years.

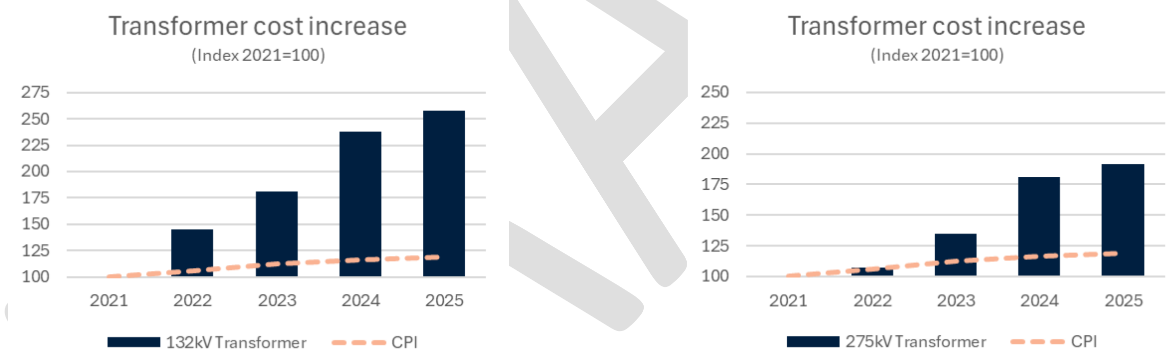
[14] World Energy Outlook 2024, International Energy Agency, October 2024, page 133.
[15] Infrastructure Market Capacity 2024 Report, Infrastructure Australia, December 2024, page 25.
[16] ISP Transmission Cost Database Tool: 2025 Update, GHD Advisory, May 2025, page 41.
[17] Draft 2025 Electricity Network Options Report, Australian Energy Market Operator, May 2025, page 5.
[18] Producer Price Index by Industry: Electric Power and Specialty Transformer Manufacturing, US Bureau of Labor Statistics, retrieved from FRED (Federal Reserve Bank of St. Louis), 24 August 2025.

Figure 2.4 - Historical transformer price index (US)



These cost impacts are borne out by Powerlink's recent experience, with the price of transformers doubling over the last four years, significantly exceeding the consumer price index as shown in Figure 2.5.

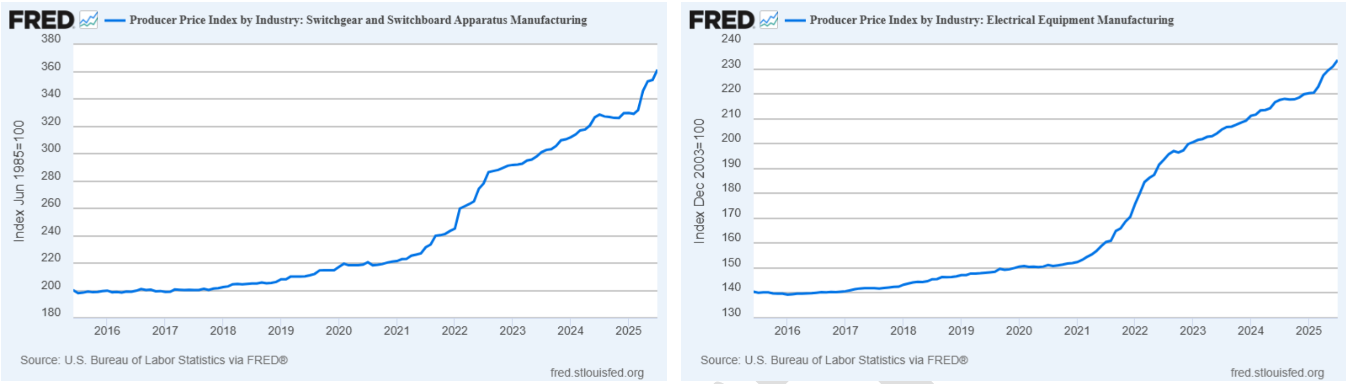
Figure 2.5 - Historical transformer cost indices (source: Powerlink)



Similar cost effects are observable for switchgear and associated equipment[19, 20] as shown in Figure 2.6.

[19] Producer Price Index by Industry: Switchgear and Switchboard Apparatus Manufacturing, US Bureau of Labor Statistics, retrieved from FRED (Federal Reserve Bank of St. Louis), 24 August 2025.
[20] Producer Price Index by Industry: Electrical Equipment Manufacturing, US Bureau of Labor Statistics, retrieved from FRED (Federal Reserve Bank of St. Louis), 24 August 2025.

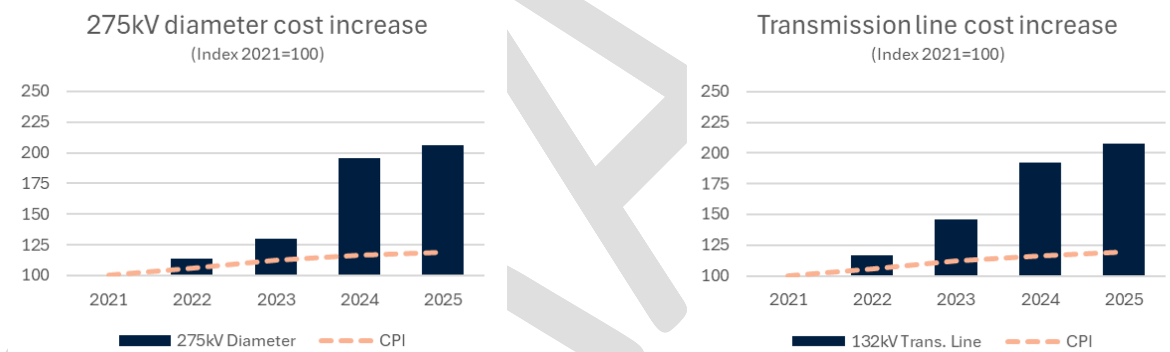
Figure 2.6 - Historical switchgear and equipment price indices (US)



Composite cost metrics, which include contractors' costs and internal labour costs in addition to plant and materials, illustrate the impacts of these increases on the delivery of transmission development. Similar to the cost of major plant items, the cost of delivering transmission assets has doubled over the last four years.

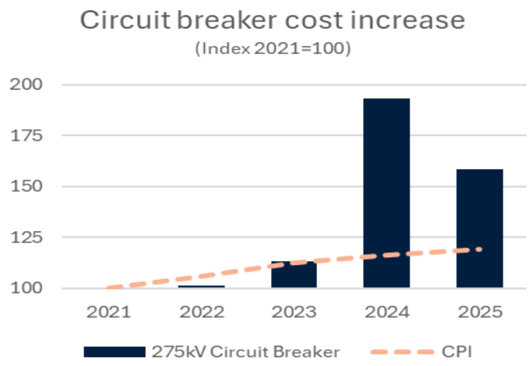
Figure 2.7 shows the delivered cost of a 275kV switchgear diameter in a substation and the delivered cost per kilometre of 132kV transmission line.

Figure 2.7 - Historical composite cost indices (source: Powerlink)



While significant global demand has driven costs upward and extended delivery timeframes for most transmission equipment types, we have sought to mitigate these impacts. For example, Powerlink has reduced the cost of 275kV circuit breakers by developing alternative supply options. Through proactive engagement, we negotiated for a key supplier to establish a new manufacturing facility in China, providing both a lower cost and reducing the reliance upon the manufacturing plant in the United States. The impact of this new supply arrangement is illustrated in Figure 2.8 below.

Figure 2.8 - Historical 275kV circuit breaker cost index (source: Powerlink)



In 2022 Powerlink undertook a review of our approach to life extension (refit) of transmission lines. We committed to the review at the time of our last Revenue Proposal. The review considered targeted investment in life extension of transmission line assets, to defer costly rebuild, which provided the opportunity to reprioritise our capital expenditure in the current 2022-27 regulatory period, discussed in Chapter 4 Historical Capital and Operating Expenditure. The outcomes of this review have also been included in our forecast for the 2027-32 regulatory period, as highlighted in Chapter 5 Forecast Capital Expenditure.

2.5 Complexity

Powerlink has grouped complexity factors into two key components impacting Powerlink's operating environment – system complexity and deliverability.

System complexity encompasses changes in network demand and connectivity to the network, including the digital network. Deliverability encompasses those factors that can have a material impact on the timeframe of projects, such as social licence, political licence and the regulatory environment for approvals.

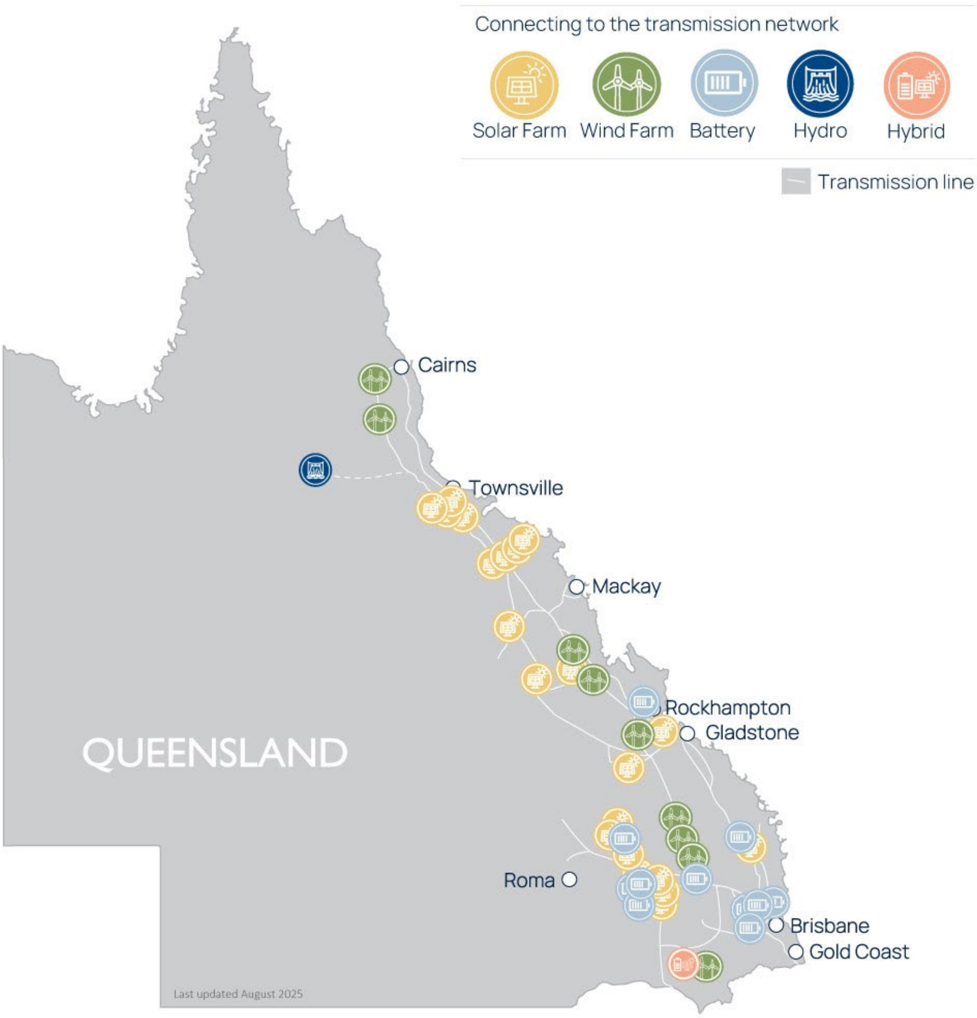
2.5.1 System complexity

The transmission system is becoming more complex to operate. More than 9,500MW of large-scale renewable generation capacity, across 44 projects, has been added (or under construction) to the transmission network since 2018. In addition, approximately 8,000MW of rooftop solar has been installed across Queensland[21].

Figure 2.9 shows the number of current and completed connection projects (up to July 2025) and illustrates the increasing number of geographically dispersed generators, battery energy storage systems and pumped hydro energy storage connected to Powerlink's transmission network. This trend is expected to continue throughout the 2027-32 regulatory period. It is important to note these connection projects are non-regulated projects and their connection costs are not included in our Revenue Proposal expenditure forecasts, they may however drive additional investments in the provision of prescribed transmission services, depending on the nature, number and location of connections and the timing of thermal generation retirements.

[21] Rooftop solar and storage report: July–December 2024, Clean Energy Council, March 2025, page 4.

Figure 2.9 – Transmission connections since 2018



The increasing number of geographically distributed, inverter-based generators connected to the transmission network presents technical challenges in keeping electricity supply and demand balanced in real time, creating complexity in how we operate and plan the network. This is further complicated by generator connections within the distribution network that may impact transmission network performance or constraints. We work closely with Distribution Network Service Providers (DNSP) Energex and Ergon Energy (part of the Energy Queensland group) through joint planning processes to identify and understand the impact of such generation within the distribution network.

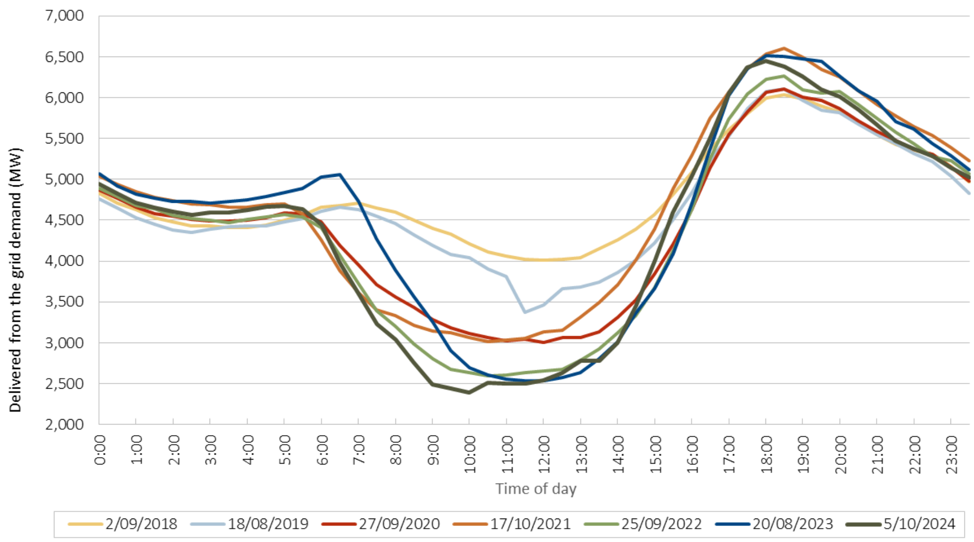
As the complexity of the system increases, the risk of unanticipated events in response to system disturbances increases. While the root cause of the blackout that affected Spain and Portugal in April 2025 is not yet known, it is suspected that the increasing complexity of the system may have been a contributing factor to the outcome.

Operating envelope

A key driver of system complexity of the transmission network is the increasing operating envelope - the gap between maximum and minimum demand. This is especially challenging while planning and managing network outages to deliver work.

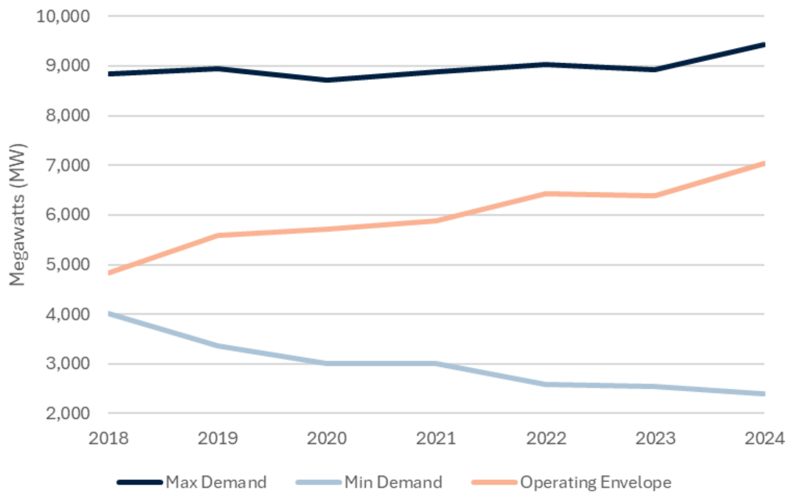
The increased operating envelope is predominantly due to the fall in minimum demand on the transmission network. Figure 2.10, reproduced from Powerlink's 2024 Transmission Annual Planning Report (TAPR), shows how minimum demand during the day has continued to decrease since 2018, shown in megawatts (MW). This is driven by the significant uptake of rooftop solar, which contributes to meeting demand during daylight hours and results in a lower minimum demand on the transmission network.

Figure 2.10 - Changing minimum demand conditions (source: Powerlink)



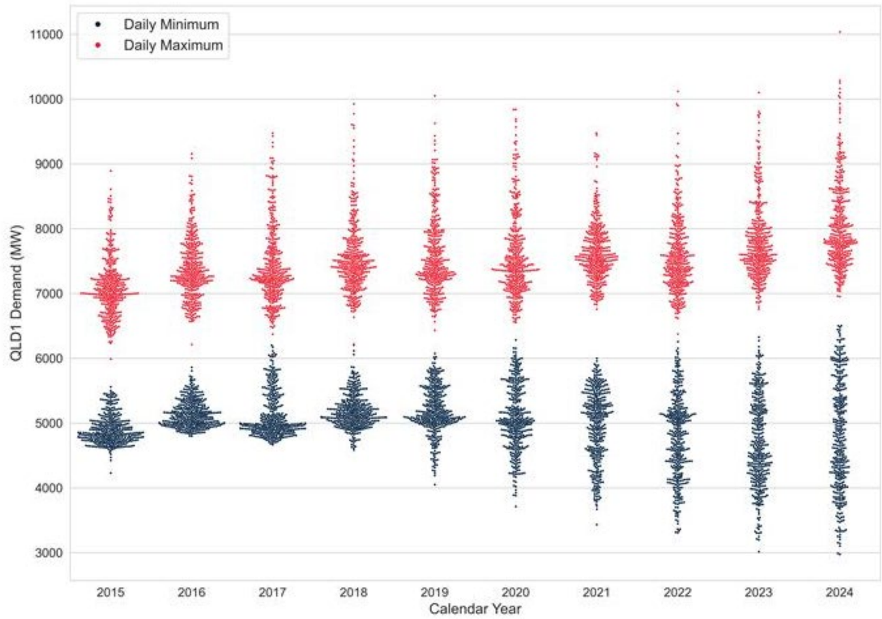
While minimum demand has fallen significantly, maximum demand has continued to increase. This means that the Queensland energy system's operating envelope has increased by almost 50% from 4,834MW in 2018 to 7,032MW in 2024, based on transmission delivered demand, as shown in Figure 2.11.

Figure 2.11 - Operating envelope – transmission delivered demand (Source: Powerlink)



In addition to the increasing operating envelope, the daily maximum and minimum demand is becoming more variable and less predictable, with an increasingly broad spread of values. This results in further complexity in operating and planning the power system, as a range of potential demand scenarios must be provided for. The increasing spread of maximum and minimum demand each year is shown in Figure 2.12, where the maximum and minimum operational demand for every day of the year is represented by a dot.

Figure 2.12 - Operating envelope – transmission operational demand (Source: Powerlink)



The operating envelope and its daily variability are contributing to increasingly dynamic operating conditions for the network, particularly for reactive plant such as Static Var Compensators, capacitors, reactors, and transformer tap-changers. Many of these assets were not originally foreseen to operate under such variable conditions, having been installed based on historical network assumptions.

The rapid increase in dynamic technologies such as batteries and inverter-based resources connected to the network add further complexity. These assets offer new opportunities to support system security services, including voltage control and inertia, but they are inherently variable in nature. Synchronous condensers, which provide protection-grade fault current, are also expected to play a critical role in delivering an underlying level of stable system strength services. While these technologies expand our toolkit, they also introduce a multi-faceted operational challenge.

We are committed to implementing the most efficient mix of tools, balancing capital investment with market-based solutions to manage complexity and deliver safe, secure, reliable and cost-effective outcomes for customers and the market. Long duration storage, advanced energy management tools and operational forecasting capabilities will be key to managing the complexity and security of supply challenges during all variable conditions including minimum load scenarios. Operational forecasting tools will also support improved visibility of network conditions during planned outages.

This is a significant operational challenge, and managing the security of the transmission network within the increasing operating envelope remains a key focus for Powerlink in the 2027-32 regulatory period.

Cyber security

As information technology and operational technology become increasingly integral to energy system operations, the risk of cyber-attacks grows. Implementing robust cyber security measures, including threat detection, incident response, and regular assessments, is essential for safeguarding critical infrastructure.

As a Transmission Network Service Provider, Powerlink is required to comply with *Security of Critical Infrastructure Act 2018*, which includes mandatory reporting requirements and the development risk management programs. The Act ensures that entities like Powerlink enhance security and resilience against various threats by implementing measures to mitigate risks associated with cyber threats, espionage, and other security concerns to safeguard essential services. We are advancing the cyber security of our network to protect against the rising level of emerging threats by aligning with the Australian Energy Sector Cyber security Framework (AESCF). We are required to continue this focus in the 2027-32 regulatory period.

2.5.2 Deliverability

Powerlink, together with other network service providers, faces significant challenges in delivering safe, secure, reliable and cost-effective prescribed transmission services.

Community engagement and social licence

Communities and landholders are key stakeholders in Powerlink's activities. Social licence to operate, the informal acceptance by stakeholders of our operations within their community, is critical for Powerlink to successfully construct and maintain our network assets. Stakeholder support to maintain and enhance social licence depends on early, transparent, coordinated and consistent engagement.

This is why we have progressed initiatives to improve our approach to early engagement, corridor selection processes, landholder and neighbour payments, social impact assessments, and community benefit and social value investment. These considerations are incorporated within our forecast for both capital expenditure and operating expenditure (refer Chapter 5 Forecast Capital Expenditure and Chapter 6 Forecast Operating Expenditure, respectively).

Powerlink also recognises the importance of building long-term relationships with Traditional Owner groups where our infrastructure is situated. By fostering stable partnerships and supporting capacity development through relationship agreements, we have a unique opportunity to assist groups to ensure benefit sharing, while continuing to deliver safe, reliable and cost-effective transmission services.

Environment

Climate resilience has been identified as a key concern by our customers. We will continue to adopt proactive approaches to managing the network as conditions change and to also address wider environmental protections. We will continue to comply with relevant legislation, including related reporting requirements, which may lead to additional initiatives and obligations.

We will also seek collaborative approaches in complying with legislation, such as the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act). This federal legislation protects areas of national environmental and cultural significance. We have been working closely with the Commonwealth Department of Climate Change, Energy, the Environment and Water (DCCEEW) to support collaboration, culminating in a Memorandum of Understanding between Powerlink and DCCEEW in October 2024.

Beyond the complexities of environmental compliance requirements, extreme weather events in Australia and across the world have placed upward pressure on insurance premiums. We have continued to engage directly with insurance underwriters, our customers and the AER to propose appropriate insurance policies, excess levels and premiums. Further information on our proposed approach to insurance is provided in Chapter 6 Forecast Operating Expenditure.

Energy market regulation

The NEM regulatory environment is continuing to change. Key consultations relevant to electricity transmission recently concluded, underway, or expected to soon commence include system security reforms, such as the AEMC's Improving Security Frameworks for the Energy Transition Rule change, the Ring-fencing Guideline (Electricity Transmission) Update - Negotiated Transmission Services, and incentive schemes, including the Service Target Performance Incentive Scheme (STPIS) Review and the Capital Expenditure Incentive Guideline Review.

The outcomes of these regulatory reforms could have material impacts on our operations, such as changes to funding models for future network investment and the way revenue is collected. We proactively provide input into these processes from a transmission perspective, while the outcome is determined by the various bodies involved. We will implement the necessary changes as required.

Until we know the scope and scale of any changes to the existing arrangements, it will be difficult to estimate the cost impacts on the business. As a result, we have not allowed for changes in our operating expenditure forecast that may result from in-progress regulatory processes (refer Chapter 6 Forecast Operating Expenditure). If material costs are likely to be incurred, we may seek a cost pass through (refer Chapter 12 Pass Through Events).

Federal and Queensland Government policies

As a Government Owned Corporation, Powerlink must be responsive to requirements and policy settings of its shareholder, the Queensland Government.

We are working closely with Queensland Treasury, and across the Queensland Government more broadly, to engage on future policy settings. The Queensland Government's Energy Roadmap is expected to be released in October 2025, with Powerlink providing modelling and data to help shape future planning.

While we acknowledge the potential for policy changes, we consider the core focus of our business will remain unchanged, particularly in the provision of prescribed transmission services that are subject to the revenue determination process.

While no specific current policies of the Queensland Government or the Federal Government directly impact our Revenue Proposal, we will continue to monitor emerging policy and legislative outcomes over the course of the revenue determination process.

3 Customer Engagement

Note for the draft Revenue Proposal: This chapter reflects activities and input undertaken up to September 2025. We will update this section for the Revenue Proposal in January 2026 with feedback received on our draft Revenue Proposal, and for any activities undertaken between October 2025 and January 2026.

3.1 Introduction

This chapter outlines Powerlink Queensland's customer engagement activities and how they influenced and improved decision-making in our 2027-32 Revenue Proposal.

Key highlights:

- Engagement is fundamental to the way we do business to drive better outcomes for our customers and stakeholders. Powerlink's purpose is firmly focused on serving Queenslanders, supported by four strategic objectives including to *Drive value for customers*.
- Our engagement also aligns with our commitment to the Energy Charter principles, in particular Principle One – we will put customers at the centre of our business.
- We established a Revenue Proposal Reference Group (RPRG), a subset of our wider business as usual Customer Panel, to engage more intensively on key aspects of the Revenue Proposal and report back to the Customer Panel.
- We co-designed our engagement scope, schedule and participation levels with the Customer Panel, Australian Energy Regulator (AER), government and other stakeholders, including members of the AER's Consumer Challenge Panel.
- Engagement directly influenced many aspects of our draft Revenue Proposal, including:
    - **Engagement scope** – to ensure discussions focused on aspects that had a material impact and could be influenced through engagement
    - **Engagement breadth** – following RPRG feedback, Powerlink widened its engagement approach to seek the views of Queensland households and commercial and industrial loads, in addition to its directly connected customers
    - **Engagement schedule** – additional RPRG meetings were organised on aspects such as the capital expenditure forecasting methodology
    - **Capable of acceptance criteria** – the RPRG had direct input on the criteria to be used to determine if Powerlink's Revenue Proposal is capable of acceptance
    - **Operating Expenditure forecasting methodology** – including selection of base year and alternative output growth measures to better reflect growing network complexity
    - **Capital Expenditure forecasting methodology** – including additional deep dive session into Powerlink's project identification and estimating processes
    - **Price path smoothing** – to investigate a more balanced approach that reduces the initial price impact and predictability of increases over the remainder of the regulatory period.

3.2 Our engagement goal and principles

3.2.1 Overview

Powerlink has a long history of strong engagement with its customers and other stakeholders. At the time of our 2023-27 Revenue Proposal, we were the first network business to co-design our engagement approach with customers and stakeholders.

We are committed to genuine and timely engagement to inform our decision-making as part of our normal business operations. It is fundamental to the way we do business and has improved outcomes for our customers and stakeholders. Our purpose is firmly focused on serving Queenslanders and is supported by four strategic objectives, including to *Drive value for customers*. This also aligns with our commitment to the Energy Charter principles, in particular Principle One – we will put customers at the centre of our business.

As our operations stretch across Queensland, we engage with a diverse range of stakeholders in the normal course of business. This includes our customers, landholders, environmental and community groups, government agencies and industry bodies. Our engagement is designed to create a shared understanding of future business decisions and the trade-offs involved (e.g. cost, reliability). This engagement occurs as part of business as usual (BAU)[22] through:

- our Customer Panel, which meets at least three times a year and provides input on our activities to inform our decision-making across a broad range of areas (e.g. the business environment, growing network complexity and Regulatory Investment Test for Transmission (RIT-T) assessments).
- our annual Transmission Network Forum, which is our flagship engagement activity, typically involving more than 600 stakeholders and customers.
- targeted webinars and workshops on RIT-Ts, regional developments, demand and energy forecasts, and
- regular briefings to government, industry and community representatives across Queensland about our operations in their areas.

At the start of the current 2022-27 regulatory period, Powerlink reviewed its asset reinvestment approach and criteria to optimise capital project delivery and minimise costs for customers. The outcomes of the Asset Reinvestment Review underpin our capital expenditure forecast for this Revenue Proposal.

3.2.2 Engagement goal

Powerlink's engagement goal remains to deliver a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink.

During engagement with our customers and stakeholders, we identified the need to clearly define what we mean by 'capable of acceptance', and the expectations of the parties in relation to the assessment criteria. We provide more information on capable of acceptance criteria in Section 3.4.

3.2.3 Engagement principles

The engagement principles for the revenue determination process are:

- **Active Engagement** – actively involve customers and stakeholders in developing and refining our engagement approach.

[22] https://www.powerlink.com.au/stakeholder-engagement.

- **Appropriate Influence** – engage at the appropriate level of the International Association for Public Participation (IAP2) Spectrum so that customer and stakeholder feedback appropriately influences our decisions.
- **Plan Ahead** – communicate the timing of key engagement forums well in advance to maximise participation.
- **Clear Scope** – provide a clear scope of engagement to ensure stakeholders can focus on and influence areas that have a material impact.
- **Resource Effectively** – provide training and access to funding, if necessary, to allow customer representatives to engage effectively with the material and process.
- **Demonstrate Impact** – demonstrate how engagement has impacted Powerlink's positions by regularly communicating how input and feedback has been considered.
- **Information to be Accessible** – present information in a clear, concise and accessible manner to assist stakeholders to participate meaningfully and provide informed feedback.

We consider that all these principles are consistent with those set out by the AER in its Better Resets Handbook[23].

3.3 Our engagement approach

3.3.1 Powerlink's Customer Panel and Revenue Proposal Reference Group

Powerlink's Customer Panel was established in May 2015 to make a positive step-change in our engagement activities. Our Customer Panel has and will continue to play a primary role in informing our BAU decisions, while influencing Powerlink's Revenue Proposal.

In late 2024, Powerlink established a Revenue Proposal Reference Group (RPRG) in addition to its existing Customer Panel. The Group includes:

- members of our Customer Panel representing the diversity of Powerlink's customers
- key Powerlink staff associated with the revenue determination process (such as the Director Revenue Reset, General Manager Network Regulation and General Manager Communications, Customer and Engagement)
- the AER's Consumer Challenge Panel members, and
- AER's coordinator for Powerlink's 2027-32 revenue determination process.

The RPRG is intended to be an advisory body that meets more frequently (every 4-6 weeks) throughout the revenue determination process. This allows for more regular and detailed discussion on matters identified for engagement over the course of the revenue determination process, particularly in preparing our Revenue Proposal.

This group reports back to the broader Customer Panel and assists in ensuring that our Revenue Proposal is aligned with customer and stakeholder expectations. Powerlink prepared a Terms of Reference[24] for this group and sought initial interest from Customer Panel members in mid-2024. The group met formally for the first time in February 2025.

The format for the RPRG and a broad outline of the operations of both the Customer Panel and RPRG over the course of our revenue determination process is provided in Table 3.1.

[23] Better Resets Handbook - Towards Consumer Centric Network Proposals, Australian Energy Regulator, July 2024.
[24] 2027-32 Revenue Proposal Reference Group - Terms of Reference, Powerlink Queensland, February 2025 (updated).

Table 3.1 - Customer Panel and RPRG

	Customer Panel	RPRG
Standing membership	• Aurizon • Canegrowers Queensland • Council on the Ageing (COTA) QLD • CS Energy • CSIRO • Edify Energy • Energy Queensland • Energy Users Association of Australia (EUAA) • Neoen • Queensland Farmers Federation (QFF) • Queensland Renewable Energy Council (QREC) • Queensland Treasury • Shell • St Vincent de Paul • Townsville Enterprise Limited • 6 Powerlink representatives (incl. chair)	• Aurizon • COTA • EUAA • QFF • QREC • St Vincent de Paul • Director Revenue Reset (chair) • GM Network Regulation • GM Communications, Customer & Engagement
Invited stakeholders & observers	• AER Consumer Challenge Panel (CCP34) • AER staff • Powerlink staff as required	• AER Consumer Challenge Panel (CCP34) • AER staff • Other Customer Panel members and Powerlink staff as required
Meeting frequency & duration	Three-hour meeting, three to four times a year	Meetings every four to six weeks of two to three-hour duration
Focus areas	Provide input on BAU Powerlink activities. Provide input and guidance on key aspects of the Revenue Proposal, including areas for discussion at RPRG meetings.	Detailed involvement on key aspects of the Revenue Proposal. Report back to Customer Panel on discussions.
Budget to support engagement on revenue determination process	Powerlink will financially support reasonable expenditure by the Customer Panel, for instance, to enable in person attendance where appropriate and possible.	

3.3.2 Senior Powerlink management engagement

Powerlink recognises the importance of hearing customer and stakeholder concerns directly. Powerlink executives regularly attend Customer Panel meetings, either as presenters of strategic insights or as observers to understand the issues discussed from a customer perspective, while Powerlink Board members attend on a frequent basis also.

This approach extends to the RPRG meetings, where all meetings are attended by at least one of Powerlink's executives, with the Executive General Manager Network Investment having attended all meetings to date.

3.3.3 Engagement approach key elements

We consider that our approach to engagement on the revenue determination process is an extension of BAU engagement.

We commenced discussions regarding our 2027-32 Revenue Proposal with our Customer Panel in early 2024 and held a co-design workshop to shape our engagement approach in November 2024 (described in Section 3.5.1). This engagement approach was captured in our Engagement Plan, published in December 2024, and updated in June and September 2025. We have included our updated Engagement Plan as Appendix 3.01.

Our engagement approach is built on four foundational elements, shown in Figure 3.1. These reflect feedback received from customers and stakeholders about what comprises successful engagement for a Revenue Proposal. We explain our approach to each element in the following sections.

Figure 3.1 - Engagement foundational elements

Targeted and fit-for-purpose

Powerlink is a Queensland-based electricity transmission business that is here to serve Queenslanders. As a result, we adopt an engagement approach that aligns with our business, customer and stakeholder needs to the extent practicable.

We intend to leverage the engagement activities we undertake as part of BAU, which includes working closely with our Customer Panel.

Support a clear business narrative

We developed a Business Narrative document with input from our Customer Panel and other stakeholders in late 2024. This describes, at a high level, Powerlink's longer-term view about our operations, challenges and opportunities and how we plan to deliver value for our customers. It is informed by a range of internal and external strategies and plans. Key among these is Powerlink's purpose – to connect Queenslanders to a world class energy future.

We have expanded on our Business Narrative in Chapter 2 Business and Operating Environment, to provide broader context to our Revenue Proposal to enable customers and stakeholders to participate more effectively in our engagement activities.

Seek early involvement from the AER

Powerlink engages with the AER on various matters related to aspects of its operations in the normal course of business. These matters include regulatory reporting items such as Annual Information Order (AIO) returns, cost pass through applications, as well as changes to the National Electricity Rules (Rules) and reviews of AER Guidelines.

Powerlink has also maintained regular contact with AER staff during this regulatory period to discuss some of the key developments and challenges faced by our business, the Queensland operating environment and the broader national environment.

Powerlink engaged with senior AER management in August 2024 to discuss early preparations and expectations for its 2027-32 revenue determination process. Powerlink and AER staff have also met regularly since then to continue the engagement, including commencement of the Framework and Approach process under the Rules.

Powerlink invited an AER representative to attend our Customer Panel meeting in September 2024. We continue to invite the AER and the AER's two Consumer Challenge Panel representatives for our revenue determination process (CCP34) to all our Customer Panel and RPRG meetings as well as other key engagement forums over the course of the revenue determination process.

Powerlink has committed to a 'no surprises' approach with the AER and will seek to ensure that we continue to develop our constructive relationship throughout the process. We consider there to be significant value to Powerlink, our customers and the AER in having AER representatives attend our engagement sessions. However, we recognise that the AER must also manage its resources efficiently and that, while in attendance, AER staff cannot commit the AER Board to any positions in the development of our Revenue Proposal.

Apply a transparent and rigorous approach

All presentation slides and minutes for Customer Panel and RPRG meetings are circulated to members for comment before finalising. They are then published on Powerlink's website to allow for a wider audience to view progress on key topics.

Powerlink has also prioritised having clear actions identified, with regular update on how action items have been completed or progressed.

We have established protocols regarding confidentiality, conflicts of interest and behaviour at our Customer Panel and RPRG forums to ensure we maintain a transparent and rigorous approach. The RPRG Terms of Reference is kept up to date to ensure its purpose, composition, responsibilities and reporting requirements are clear.

We continue to provide transparency to our customer representatives on activities and expenditure that fall outside of the revenue determination process, so that they may consider our Revenue Proposal in the context of Powerlink's broader investment portfolio.

3.4 Engagement criteria for capable of acceptance

The AER's Better Resets Handbook[25] identifies three specific criteria to assess the engagement undertaken – *the nature of engagement, breadth and depth of engagement, and clearly evidenced impact of the engagement*.

[25] Better Resets Handbook - Towards Consumer Centric Network Proposals, Australian Energy Regulator, July 2024.

These are consistent with the engagement criteria that were used for assessing the capability of acceptance of Powerlink's 2023-27 Revenue Proposal.

While the operating environment has changed significantly since our last Revenue Proposal, we consider that for our 2027-32 Revenue Proposal the three engagement criteria remain fit for purpose and should be retained.

3.4.1 Proof point criterion

In addition to the engagement criteria, the AER typically also refers to a proof point criterion, which assesses the reasonableness of the operating and capital expenditure forecasts proposed.

Powerlink recognises the need for a proof point criterion to provide for an assessment of the reasonableness of forecast expenditure within its Revenue Proposal but considers that this criterion should be amended to reflect the context of the current and forecast operating environment for the 2027-32 Revenue Proposal.

We engaged with the RPRG and our Customer Panel on this criterion and our proposed amendment. We were strongly encouraged to reference the AER's expectations for expenditure forecasts in its Better Resets Handbook as part of the criterion. Consequently, we propose the following criterion as the proof point:

> *Reasonable opex and capex expenditure forecasts are proposed that reflect prevailing conditions, and are:*
>
> - *underpinned by appropriate and transparent forecasting methodologies*
> - *supported by clear explanations as to why forecasts are different from historical expenditure*
> - *have regard to the AER's top-down analysis of expenditure*
> - *align with the AER's expectations for capex, opex and regulatory depreciation stated in the AER's Better Resets Handbook.*

3.4.2 Framework for application of the criteria

Criteria to be applied to the 2027-32 Revenue Proposal and the expected assessment by our Customer Panel, the AER and Powerlink are summarised in Table 3.2.

Table 3.2 - Capable of acceptance criteria

Capable of Acceptance Criteria ✓ – expected assessment o – optional assessment	Customer Panel	AER	Powerlink
Nature of engagement	✓	✓	✓
Breadth and depth	✓	✓	✓
Clearly evidenced impact	✓	✓	✓
Proof point	o	✓	✓

3.5 Engagement scope

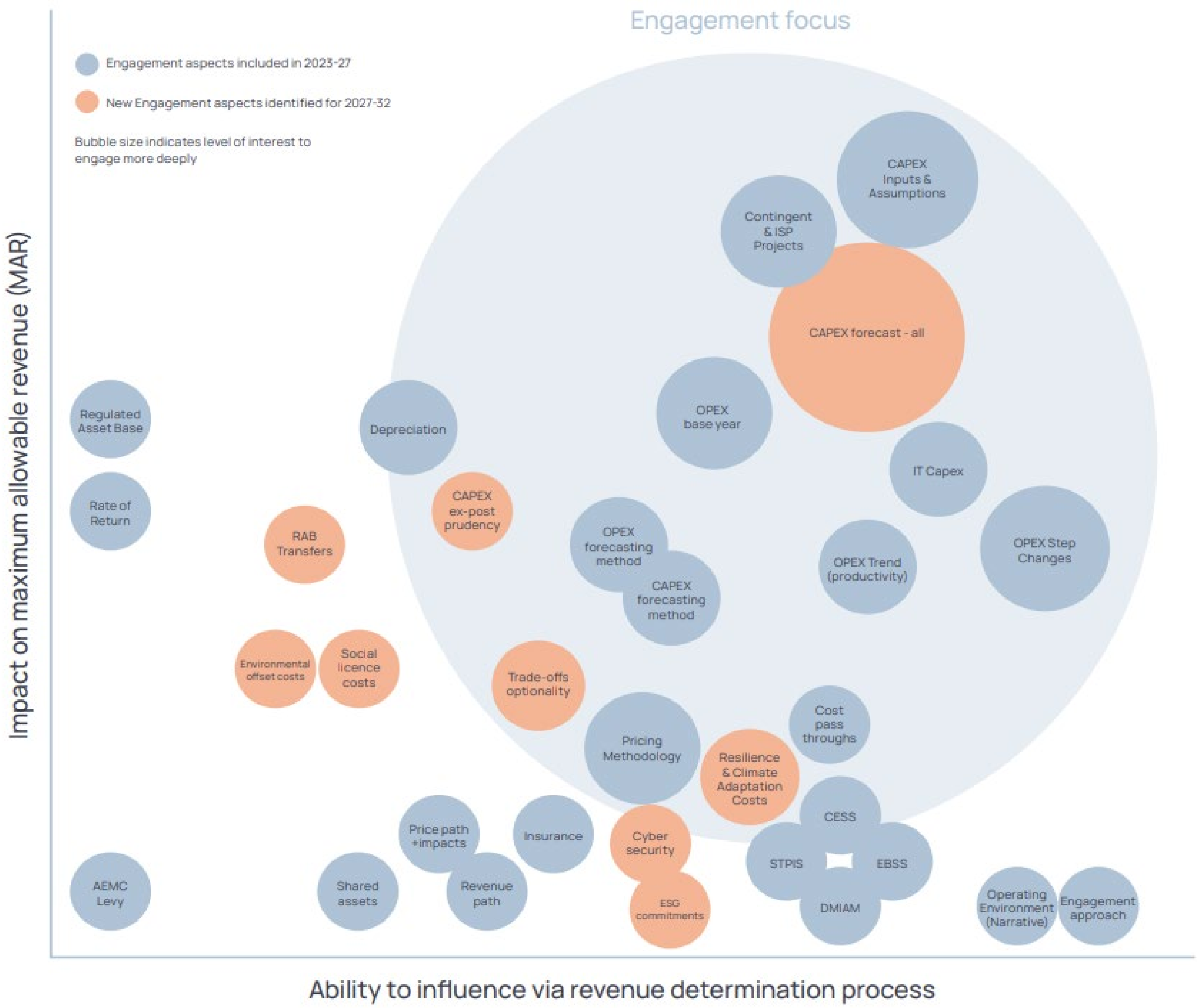
We recognise that our customers' and stakeholder representatives' time is valuable. A clear scope helps these representatives, as well as Powerlink and the AER, better allocate their time, energy and resources to the areas of the Revenue Proposal that have material customer impacts and can be influenced through engagement.

3.5.1 Co-design process

Powerlink held a co-design process at an engagement scoping workshop on 26 November 2024 to help establish the scope of engagement for our 2027-32 Revenue Proposal. The workshop comprised representatives from Powerlink's Customer Panel, the AER, including a member of its Board, the AER's Consumer Challenge Panel, Queensland Government as well as senior Powerlink representatives, including members of the executive and Board.

During the session, participants mapped elements they felt had the greatest impact on Powerlink's Maximum Allowed Revenue (MAR) against their potential to be influenced through engagement. As engagement on the revenue determination process has progressed and actual impact on MAR has been quantified, some scope elements have been repositioned. The resulting scoping diagram is shown in Figure 3.2.

Figure 3.2 - Engagement scope



3.5.2 IAP2 Spectrum Participation Level

Consistent with our approach to the previous 2023-27 Revenue Proposal, we have taken the output of the engagement co-design workshop and plotted these against what we consider to be the appropriate level of the International Association for Public Participation (or IAP2) Spectrum in Table 3.3.

Table 3.3 - IAP2 Spectrum Participation Level

IAP2 Spectrum Level of Engagement	Aspect of Revenue Proposal
Empower – to place final decision-making in the hands of customers and stakeholders.	
Collaborate – to work together with our customers and stakeholders to formulate alternatives and incorporate their advice into final decisions to the maximum possible extent.	• Engagement approach (Engagement Plan) • Operating environment (Business Narrative)
Involve – to work directly with customers and stakeholders to ensure their concerns and aspirations are directly reflected in the alternatives developed.	• Capable of acceptance criteria • Capex – inputs and assumptions • Capex – contingent and ISP projects • Capex – business IT • Capex – trade-offs and optionality* • Opex – step changes • Opex – trend
Consult – to obtain feedback on alternatives and draft proposals.	• Capex forecasting methodology • Capex – forecast, incl. reinvestment and augmentation* • Capex – ex-post prudency* • Capital Expenditure Sharing Scheme (CESS) • Cost pass throughs • Cyber security* • Demand Management Innovation Allowance Mechanism (DMIAM) • Depreciation • Efficiency Benefit Sharing Scheme (EBSS) • Insurance • Opex forecasting methodology • Opex – base year • Price path impacts • Service Target Performance Incentive Scheme (STPIS)

Increasing level of influence on decision

IAP2 Spectrum Level of Engagement	Aspect of Revenue Proposal
Inform – to provide balanced information to keep customers and stakeholders informed.	• Environmental offset costs* • Social licence costs* • AEMC Levy • Regulatory Asset Base (RAB) • RAB transfers* • Rate of return • Revenue path • Shared assets • Pricing methodology • ESG commitments* • Resilience and climate adaptation*

* New engagement aspects identified for our 2027-32 revenue determination process.

3.6 Engagement techniques

Note for the draft Revenue Proposal: This section only reflects feedback up to September 2025 and will be updated after engagement activities from October 2025 to January 2026.

Powerlink is utilising the following range of engagement techniques as appropriate:

- **Leverage 'business-as-usual' forums** – Powerlink's Customer Panel plays a key role in Revenue Proposal engagement activities. In addition to this, Powerlink proposes to use its annual Transmission Network Forum to engage on the key highlights of its Revenue Proposal.
- **One-on-one briefings** – these will be held with Powerlink's directly connected customers as well as key stakeholder and industry organisations, where appropriate. Such an approach allows engagement to be more tailored to the customer or stakeholder, particularly on confidential matters.
- **Workshops (or deep dives)** – several workshops have been undertaken with the Customer Panel and RPRG to focus on more complex matters and to enable more detailed exploration of the topic at hand.
- **Regional engagement forums** – the Central Queensland Transmission Network Forum in Gladstone on 19 August 2025 allowed local customers and stakeholders the opportunity to provide input in a face-to-face environment in their community.
- **Webinars** – we will gauge interest in webinars to enable broader input regardless of physical location.
- **Research/surveys** – customer and stakeholder insights will also be drawn from formal research mechanisms such as the Queensland Household Energy Survey and Powerlink Stakeholder Perception Survey.
- **Site tours** – can be useful to inform discussions on capital and operating and maintenance expenditure. This allows customers and stakeholders to see our assets, their location, condition and factors which contribute to our asset management practices firsthand. We have provided opportunity for tours of South Pine Substation and our Control Room.
- **Other information** – we will prepare information sheets, infographics, slide-packs and other relevant material to explain key aspects of our Revenue Proposal in a simplified and concise way. These are developed proactively by Powerlink and at the request of our customers.

3.7 End-user and directly connected customer engagement

3.7.1 Directly connected loads and Commercial and Industrial (C&I) customer engagement

Early in the engagement process, the RPRG recommended Powerlink engage a broader representation of our customers, including directly connected and other large loads.

In response, we initiated dedicated engagement with this customer segment, including:

- Hosting an interactive engagement session on the Revenue Proposal at the Central Queensland Transmission Network Forum in Gladstone in August 2025.
- Undertaking an EOI process with over 600 direct-connect and C&I customers to participate in a short survey.
- Distributing a short survey to understand the strategies and other factors that will shape these customers' use of the electricity grid, so that we may calibrate our own strategies, plans and forecasts to respond to their evolving needs.
- One-on-one meetings with Powerlink's directly connected customers as part of BAU practices as requested.

Key insights from this engagement with direct-connect customers included:

- **Cost and price predictability** – Predictable and transparent pricing is as critical as affordability for industrial and commercial customers, who seek to avoid sudden cost increases.
- **Investment preferences** – There is support for targeted, timely investment to meet future needs to avoid disproportionate cost impacts on existing customers. Predictability in pricing and network upgrades are fundamental to long-term planning.
- **Electrification and emissions reduction** – Most respondents are advancing electrification and energy efficiency to meet emissions targets, though approaches differ across sectors and customers acknowledge diminishing returns in some areas.
- **Demand expectations** – Industrial customers foresee greater reliance on the transmission network as they electrify core processes and introduce new loads. Commercial customers expect grid demand to remain steady or increase gradually alongside on-site renewables, batteries, and small-scale electrification.
- **Load profiles and flexibility** – Distinct energy profiles influence strategies: commercial loads are smaller, more flexible, and better suited to demand management and shaping technologies.
- **Future use of the grid**– Both customer groups intend to maintain grid connections, though with varying degrees of dependence and integration with on-site solutions.
- **Customer priorities** – Commercial customers value peak and nighttime reliability, with stronger emphasis on resilience through self-supply options (e.g. batteries, backup generation). Industrial users consider the grid a critical backbone, requiring additional capacity, reliability, and a cleaner energy supply.

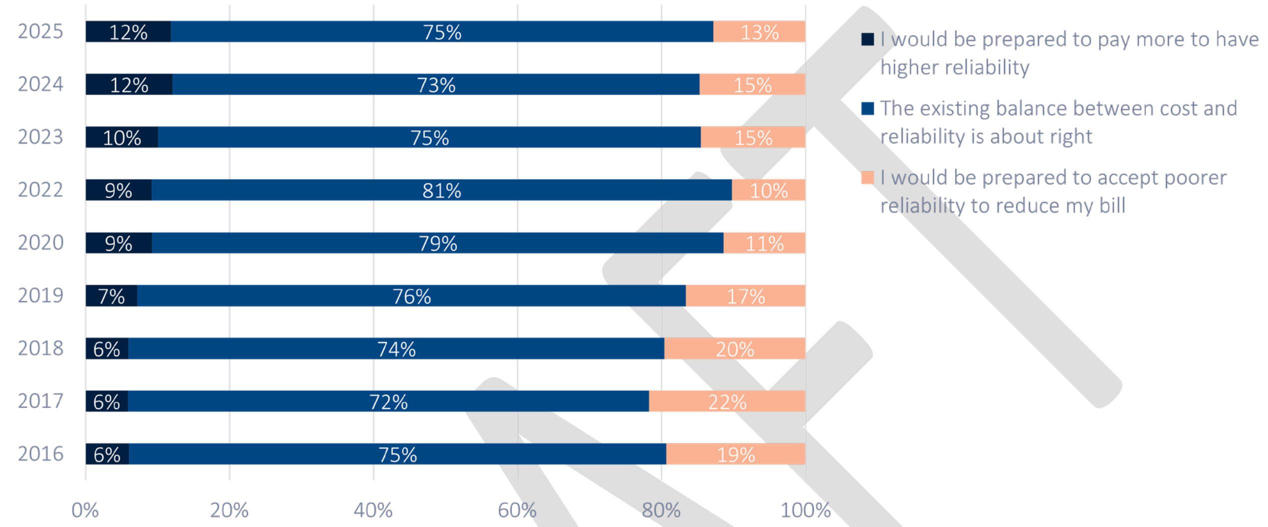
3.7.2 Queensland Household Energy Survey

Each year, Powerlink and Energy Queensland undertake the Queensland Household Energy Survey (QHES), to gain insights from more than 4,000 households across the state.

Powerlink leveraged input from the RPRG to design two new questions which were added to the QHES in 2025 to help inform the Revenue Proposal. The questions aimed to gauge support for upfront investment in the power system and identify which long-term benefits of upfront investment are most important to residential customers. More than 57% of surveyed households support upfront investment in the power system for long term benefits. Less than 7% are opposed and the remainder are neutral or require further information before they can have an opinion. The most important benefits identified by households are affordability, reliability and resilience, as discussed in Chapter 2.

Survey results also showed reliability has continued to grow in importance over time and household trust in energy suppliers to provide a reliable system hit an all-time high of 76% in 2025, up from 71% in 2024. Households that perceive energy suppliers are working to make energy more affordable decreased slightly from 38% in 2024 to 36% in 2025. Figure 3.3 charts the QHES data on the balance between cost and reliability from 2016 to 2025.

Figure 3.3 - Balance of cost and reliability 2016-2025



3.7.3 Key insights for our Revenue Proposal

The insights from end-user and directly connected customers reinforce Powerlink's view that the balance between cost and reliability remains vitally important. There is broad support for network investment to ensure reliability and longer-term benefits. There was also a view that price predictability is highly valued among customers. In response, Powerlink has investigated an alternative approach to smoothing the price path for customers, to avoid sudden increases and provide greater predictability. Further information on Powerlink's price path is included in Chapter 11 Maximum Allowed Revenue.

3.8 Engagement timeline

Note for the draft Revenue Proposal: this section will be updated when we lodge our Revenue Proposal in January 2026 to reflect engagement activities undertaken between October 2025 and January 2026.

The RPRG have met monthly since February 2025. A timeline of engagement activities is shown in Figure 3.4.

Figure 3.4 - Engagement timeline

2024	JUNE	**Customer Panel meeting** Regulatory timeframes and initial engagement proposal
	SEPTEMBER	**Revenue Determinations 101** Powerlink provided an introductory training session to new members of its Customer Panel
	NOVEMBER	**Revenue Determination Scoping Workshop** Co-design of our engagement scope with Customer Panel and critical stakeholders
2025	FEBRUARY	**RPRG meeting 1** Initial expenditure forecasts
	MARCH	**RPRG meeting 2** Capital and operating expenditure forecasting methodologies
	APRIL	**Customer Panel meeting** RPRG member report back and criteria for capable of acceptance **RPRG meeting 3** Capital expenditure forecasting methodology (additional meeting scheduled in response to RPRG feedback)
	MAY	**RPRG meeting 4** Updated expenditure forecasts **Queensland Household Energy Survey** Two additional questions to inform the 2027-32 revenue Proposal
	JUNE	**RPRG meeting 5** Cyber security and business IT expenditure forecast and contingent projects **Customer Engagement Survey** Powerlink reached out to directly connected and C&I customers
	JULY	**Customer Panel meeting** RPRG member report back and updated expenditure forecasts **RPRG meeting 6** Operating expenditure base year, step changes and trend
	AUGUST	**RPRG meeting 7** **Central Queensland Transmission Network Forum** **Powerlink Substation and Control Room Site Tour**

3.9 How feedback influenced our decision-making

We have committed to genuinely considering input and feedback received from customers and stakeholders consistent with the areas of focus identified in the engagement scope.

3.9.1 Engagement outcomes

The key topics discussed with the RPRG, Customer Panel and at engagement forums, feedback received and how that feedback influenced our decision-making is summarised in Table 3.4.

The date provided reflects when topics were discussed with the relevant customer representatives.

Table 3.4 - Engagement outcomes

Topic	Feedback received	What we've done
RPRG and Customer Panel		
Business Narrative (November 2024)	• First draft did not adequately represent customer drivers in the business and operating environment • Encouraged Powerlink to represent needs of different customer groups including households, commercial and industrial and agricultural sectors	• Restructured our Business Narrative to commence with overview of customer drivers from the perspective of each customer group
Engagement scope (November 2024)	• Customer and stakeholder representatives volunteered to participate in the co-design workshop • Nine new engagement topics were identified for 2027-32, in addition to 24 topics carried over from 2023-27 (refer Figure 3.2) • Topics were prioritised for engagement focus, based on their relative impact on MAR and ability to be influenced by the revenue determination process	• Developed and executed our engagement schedule according to the topics identified in co-design process and subsequent engagement with the RPRG • Engaged on each topic at the appropriate IAP2 Spectrum Participation Level according to the prioritisation of topics during the co-design workshop and subsequent engagement with the RPRG
QHES (February 2025)	• Support for inclusion of additional questions in the 2025 QHES to inform the 2027-32 Revenue Proposal • Encouraged Powerlink to frame the questions to determine customers understanding and appetite for investment to deliver public benefits such as reliability and climate resilience	• Two additional questions included in the 2025 QHES, testing customer support for upfront investment in the power system and relative importance of investment benefits including climate resilience, reliability, affordability and sustainability
RPRG Independent Chair (March 2025)	• Proposed nomination of an Independent Chair to coordinate RPRG formal responses and convene additional meetings outside of Powerlink schedule	• Facilitated nomination of an Independent Chair and updated the RPRG Terms of Reference to reflect the role

Topic	Feedback received	What we've done
Direct-connect and C&I customer engagement (April 2025)	• Encouraged Powerlink to broaden the reach of our engagement by involving large load customers and providing in-person engagement forums for regional customers	• Undertook dedicated engagement approach for direct-connect and C&I customers, including launch of an EOI and online survey • Hosted an interactive session at the Central Queensland Transmission Network Forum on the 2027-32 Revenue Proposal in Gladstone in August
Capable of acceptance criteria (April 2025)	• Support for retention of three engagement criteria from the 2023-27 Revenue Proposal (refer Section 3.4) • Support for updating the proof point criterion to reflect current operating environment whilst retaining focus on cost impacts for customers • Support for application framework (refer Table 3.2), setting the expectation for the Customer Panel to provide assessment of the engagement criteria with the option to also assess the proof point • Encouraged Powerlink to reference the AER Better Resets Handbook directly in the proof point criterion	• Engagement criteria retained and proof point criterion updated • Application framework included in our Engagement Plan and 2027-32 Revenue Proposal • Direct reference to AER Better Resets Handbook included in our proof point criterion
Expenditure Forecasting Methodology (March-June 2025)	• Requested an additional meeting to cover the capital expenditure forecasting methodology and Powerlink's project identification and estimating processes in more detail • Encouraged Powerlink to improve coverage of operating expenditure step changes in its Expenditure Forecasting Methodology	• Held an additional meeting on capital expenditure forecasting in April 2025 with presentations from relevant subject matter experts • Added an additional section on step changes to our Expenditure Forecasting Methodology

Topic	Feedback received	What we've done
Expenditure forecasts (May 2025)	• Challenged increases in Powerlink's operating expenditure forecasts compared to the 2023-27 Revenue Proposal, seeking to understand how increasing labour and insurance costs are carried forward and how productivity factors are calculated • Challenged increases in Powerlink's capital expenditure forecasts compared to the 2023-27 Revenue Proposal, seeking to understand costs associated with system strength, replacement, augmentation and non-network projects • Requested further information on our method for forecasting revenue adjustments arising from the Efficiency Benefit Sharing Scheme (EBSS)	• Increased engagement focus on opex base year, step changes and trend at the RPRG meeting in July 2025 • Detailed coverage of insurance as a category specific operating expense scheduled for the upcoming RPRG meeting in November 2025 • Increased engagement focus on non-network projects and published a system strength customer overview. • Informed our review and challenge of expenditure needs and timing • Presented a detailed breakdown of drivers for MAR increases from 2023-27 to 2027-32 regulatory periods • Published customer overviews explaining the EBSS, and the Capital Expenditure Sharing Scheme
Contingent projects (June 2025)	• Requested visibility of expenditure currently outside the scope of the Revenue Proposal, including the Gladstone Priority Transmission Investment (PTI) • Challenged the identified triggers and estimated cost of proposed contingent projects, seeking to understand their importance for performance of the shared network and Powerlink's provision of prescribed transmission services • Questioned deliverability of the capital expenditure forecast in the case of multiple contingent projects being triggered in the 2027-32 regulatory period	• Modelled and presented the hypothetical impact on MAR if <u>all</u> contingent projects proceeded and the Gladstone PTI • Informed our review and challenge of contingent project triggers, cost and timing • Informed our review and challenge of deliverability of portfolio of capital and operating works, and consideration of project priorities • Presented on deliverability risks and opportunities at the Customer Panel meeting in July 2025
Opex base year and step changes (July 2025)	• Expressed concerns regarding potential late changes due to realised differences between the initial base year forecasts and the final revealed costs • Advised that another TNSP had previously applied for a network complexity step change, but the AER had not allowed it in its determination	• Committed to update base year costs progressively throughout the Revenue Proposal development to ensure draft figures reasonably represent actual costs and to engage with the RPRG on any material changes • Informed our review and challenge of proposed step changes

Topic	Feedback received	What we've done
Opex trend (July 2025)	• Supported Powerlink's proposal to engage with the AER on alternative output growth measures • Challenged whether Powerlink can achieve the target productivity improvement given declines in recent years	• Informed our development and review of alternative output growth factors to enable further engagement with AER, customers and stakeholders • Alternative output growth measures are presented alongside AER standard measures in Chapter 6 • Committed to further engagement with the RPRG on productivity targets prior to lodgement of the Revenue Proposal
Price path smoothing (July 2025)	• RPRG requested further engagement on price path smoothing and raised the importance of price predictability for customers	• Commenced investigation into a more balanced alternative that reduces the initial price impact and smooths price changes over the remainder of the regulatory period
Depreciation (August 2025)	• Supported Powerlink's intent to continue using the year-by-year tracking method with no change to asset classes and no proposed accelerated depreciation	• Progressed draft Revenue Proposal with no change to depreciation calculations
Alternative CESS approach (August 2025)	• Considered Powerlink's alternative approach to re-state the regulatory allowance for 2027-32 to reflect actual cost escalations outside Powerlink's control • Requested further engagement on this topic and clarification on the level of influence the RPRG would have over its representation in the Revenue Proposal	• Confirmed RPRG feedback will directly inform Powerlink's decision on whether to progress this issue from the draft to the final Revenue Proposal • Committed to further engagement with the RPRG following publication of the draft Revenue Proposal
Research/surveys		
QHES (April 2025)	• >57% of surveyed households support upfront investment in the power system for long term benefits, <7% are opposed with the remainder neutral or unsure • >90% of households rated long term benefits of "maintaining a reliable energy system", "affordable bills for all" and "ensuring a resilient network after disasters" as high or very high importance	• Given the equal levels of importance given to affordability, reliability and resilience, extended the upcoming March 2026 Customer Panel meeting session to accommodate information provision across changing climate adaptation and ESG requirements, resilience planning and response and recovery activities

Topic	Feedback received	What we've done
Survey of direct-connect and C&I customers (June 2025)	• Customers indicated continued prioritisation of electrification and renewable energy sourcing, with renewable energy or decarbonisation ambitions being key drivers for seven out of nine survey respondents • Customers identified reliability of supply, resilience to network interruptions and predictability of pricing and network development as being critical to support their long-term planning • Customers advocated for targeted and timely investment to ensure costs will not disproportionately impact existing customers	• Commenced investigation into price path smoothing to reduce the initial price impact and spread increases over the remainder of the regulatory period • Forums in Gladstone and Brisbane will provide customers with the latest update on our plans for network development • Offered one on one briefings for directly connected customers to discuss concerns and bill impacts • Directly connected customers and C&I customers will be invited to comment on our Draft Revenue Proposal along with other interested stakeholders
Engagement forums		
Central Queensland Transmission Network Forum (August 2025)	• Attendees identified reliability and affordability as the most important benefits of investing in the power system and as critical focus areas for Powerlink's long-term investment plans • In the ranking of benefits, reliability and affordability were followed by investment certainty and economic growth, local skills and job opportunities • Other key focus areas for Powerlink's investment plans included resilience, community and clean energy	• Attendees will be invited to comment on our Draft Revenue Proposal • Increased focus on in-person rather than digital engagement activities, given significantly higher participation at the live forum compared to the online survey of direct-connect and C&I customers (69 versus 9)

3.10 Engagement evaluation

Note for the draft Revenue Proposal: Prior to the publication of the Revenue Proposal in January 2026, we will undertake an evaluation on our engagement approach. This has not yet occurred, therefore this section outlines our intended approach to evaluating engagement.

3.10.1 Informal feedback

The RPRG have been asked to provide informal feedback on the engagement undertaken throughout the process. We sought feedback in May and August 2025, to understand the effectiveness of the engagement undertaken, suitability of the supporting documents provided and additional engagement topics to be scheduled in the plan.

Feedback provided to date indicates the meeting frequency and group composition is appropriate and the additional engagement activities including the Central Queensland Transmission Forum have been beneficial. Members feel comfortable to raise any questions or issues that arise during RPRG meetings and have been able to leverage learnings from Powerlink's engagement approach in their own organisations. Feedback did not identify any gaps in our engagement scope and approach to date and acknowledged the information provided has been clear, well understood and accessible to both RPRG members and their stakeholders.

Expectations for ongoing engagement include more detailed exploration of expenditure forecast deliverability with consideration of Powerlink's broader portfolio and competitive operating environment. The RPRG will seek to understand how Powerlink is applying lessons learned in the current period and contingency planning to account for uncertainty in the forecasts.

More formal feedback on the engagement approach will be sought in late 2025.

3.10.2 Engagement evaluation KPIs

Our Engagement Plan, included in Appendix 3.01, includes a set of Key Performance Indicators (KPI). Powerlink's intention is to work further with the Customer Panel and RPRG to finalise these KPIs and seek input from other key stakeholders. The KPIs, our method of evaluation and the evaluation outcomes are outlined in Table 3.5.

Table 3.5 - Engagement evaluation KPIs

KPI	Target	Measurement
Effectiveness and quality of information provided to stakeholders	Overall satisfaction rating of 7/10 for quality of information provided	Pulse check surveys Informal debriefs
Stakeholders were engaged at appropriate level on the IAP2 spectrum	Identified that majority of stakeholders had appropriate level of influence on Powerlink decision-making	Survey/solicit feedback from external stakeholders Internal review
Satisfaction level of stakeholders with engagement activities	Overall satisfaction rating of 7/10 for engagement activities	Post-activity satisfaction surveys Informal debriefs and feedback
Impact of engagement on Powerlink decision-making and quality of feedback provided	Ability to demonstrate what changed as a result of engagement	Survey/solicit feedback from external stakeholders Internal review Peer review/audit
Timely delivery of engagement program	Engagement program delivered on-schedule	Internal monitoring

4 Historical Capital and Operating Expenditure

4.1 Introduction

This chapter provides an overview of Powerlink's performance against the Australian Energy Regulator's (AER's) allowances for capital and operating expenditure during the current and preceding regulatory period and provides context for forecast expenditure in the 2027-32 regulatory period.

Our cost performance under the AER's Annual Benchmarking Report on Transmission Network Service Providers (TNSP) is also discussed.

Key highlights:

- Our forecast outcome for the current 2022-27 regulatory period is as follows:
  - total capital expenditure (adjusted for system strength contingent project application) of $1,465.4 million. This is $390.6 million (36%) higher than the AER's allowance of $1,074.7 million, and
  - total operating expenditure (adjusted for agreed pass throughs) of $1,495.0 million. This is $241.7 million (19%) higher than the AER's allowance of $1,253.3 million. These figures are exclusive of debt raising costs.
- Our performance under the AER's economic benchmark approach has increased slightly (0.2%) over the course of the current regulatory period (to 2023 only). This is primarily attributable to a 1.2% improvement in reliability, offset by increases in operating expenditure and transformer inputs.
- The AER's 2025 Annual Benchmarking Report on TNSPs will be released in November 2025. We will provide additional analysis and insight on the outcomes of the most recent benchmarking results as part of our 2027-32 Revenue Proposal in January 2026.

4.2 Regulatory requirements

The National Electricity Rules (Rules)[26] require that our Revenue Proposal provide information related to our actual/forecast operating and capital expenditure over the current and preceding regulatory periods. The Rules[27] also require that, when considering our proposed forecast expenditure, the AER also has regard to such expenditure.

[26] National Electricity Rules, Schedule 6A.1, clauses S6A.1.1(6) and S6A.1.2(7).
[27] National Electricity Rules, clauses 6A.6.7(e)(5) and 6A.6.6(e)(5).

4.3 Factors impacting Powerlink's capital and operating expenditure

The operating environment has changed significantly since our previous Revenue Proposal was lodged in 2021. This change has impacted our cost performance in both capital and operating expenditure.

Factors that have contributed to this include:

- customers and community expectations are driving change in our engagement and delivery practices, while the need to maintain the reliability and affordability of our services has never been more important
- global demand for major plant items, materials and skilled resources driving industry-specific inflation
- long lead times for critical equipment, necessitating a change in inventory management (i.e. moving away from just-in-time inventories to larger holdings and associated warehousing), and
- increasing complexity of the system and operating environment.

4.3.1 Customers and community

Reliability and affordability were consistently the highest priorities across all customer sectors we surveyed, making them fundamental concerns for Powerlink as a business.

Our operating environment is increasingly shaped by the expectations of communities and other stakeholders, particularly those directly impacted by transmission infrastructure. Our approach now embeds social performance as a core management system, aligning with government policy, regulatory frameworks, and the Energy Charter's Better Practice Social Licence Guideline. Community expectations are driving change and Powerlink is responding with co-designed engagement processes, tailored landholder support, and measurable commitments to social value.

4.3.2 Costs

As discussed in Chapter 2 Business and Operating Environment, global conditions have resulted in unprecedented cost increases for key equipment and major plant items, such as power transformers. We have experienced cost increases well in excess of inflation over the current 2022-27 regulatory period driven by global events such as the long-tail disruption to supply from the COVID-19 pandemic, Russia's invasion of Ukraine and net-zero emissions targets. Consequently, the total cost to deliver transmission assets has increased significantly since 2021.

The increasing demand for skilled labour resources is one of many factors driving increased capital and operating expenditure in the 2022-2027 regulatory period, with the recent report on AEMO's 2024 Integrated System Plan noting that electricity sector jobs are expected to increase steeply for all scenarios in the run up to 2030[28]. The 2024 Working at Powerlink Agreement (WAPA) came into effect from March 2024 and includes increases to base salary, superannuation and allowances, as well as changes to conditions. The WAPA reflects the increased demand for skilled resources within the energy sector and is critical to enable Powerlink to secure and retain the resources to deliver the capital and operating objectives for the current 2022-27 and upcoming 2027-32 regulatory periods and beyond.

[28] The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050, UTS Institute for Sustainable Futures, September 2024.

4.3.3 Complexity

The transition of the energy system within Queensland is well underway. To accommodate the increasing integration of large-scale inverter-based resources (IBR), energy storage and rooftop solar, there are new regulatory obligations for services such as system strength, and the operating envelope – the difference between maximum demand and minimum demand – continues to increase. Powerlink is learning and adapting to new ways in which the grid is being used.

4.4 Historical capital expenditure

This section summarises our historical capital expenditure, consistent with the requirements of the Rules[29].

4.4.1 Historical capital expenditure summary

Table 4.1 shows our actual/forecast capital expenditure for the previous 2017-22 and current 2022-27 regulatory periods by expenditure category. Expenditure for the 2017/18 to 2024/25 financial years is based on actual expenditure, while the 2025/26 and 2026/27 financial years are based on our current expenditure forecasts.

[29] National Electricity Rules, Schedule 6A.1, clause S6A1.1(6).

Table 4.1 - Capital expenditure - actual/forecast ($million real, 2026/27)

	2017-22 regulatory period						2022-27 regulatory period					
	2018	2019	2020	2021	2022	Total	2023	2024	2025(1)	2026 forecast	2027 forecast	Total
Network capital expenditure												
Augmentations	1.7	7.0	4.8	5.7	26.5	**45.7**	8.9	6.9	8.8	11.4	8.8	**44.8**
Connections	-	0.1	-	-	-	**0.1**	-	-	-	-	-	**-**
Easements	(0.2)	1.0	2.5	0.4	2.6	**6.3**	0.7	1.9	0.6	8.6	19.5	**31.4**
Total load-driven	**1.4**	**8.1**	**7.4**	**6.1**	**29.0**	**52.1**	**9.7**	8.8	**9.5**	**20.0**	**28.3**	**76.2**
Reinvestments	150.8	180.7	170.0	171.2	171.7	**844.4**	184.8	205.2	131.2	278.5	288.7	**1,088.3**
System Services	-	-	-	-	-	**-**	10.9	15.1	7.7	82.4	101.4	**217.6**
Security/compliance	25.7	2.7	1.6	13.5	2.6	**46.1**	8.1	4.7	5.8	18.1	16.4	**53.3**
Other	(0.3)	1.2	4.1	7.5	14.4	**26.8**	21.8	6.9	13.5	16.2	2.7	**61.1**
Total non-load driven	**176.1**	**184.6**	**175.8**	**192.1**	**188.7**	**917.3**	**225.7**	**231.9**	**158.2**	**395.2**	**409.2**	**1,420.2**
Total Network	**177.5**	**192.7**	**183.2**	**198.2**	**217.8**	**969.3**	**235.3**	**240.7**	**167.7**	**415.2**	**437.5**	**1,496.4**
Non-network capital expenditure												
Business IT	14.8	15.8	25.2	21.7	19.3	**96.9**	24.4	24.1	14.6	16.8	15.4	**95.3**
Support the Business (2)	5.8	10.1	7.1	8.9	16.7	**48.5**	16.3	41.7	(17.2)	13.9	7.6	**62.2**
Total Non-network	**20.6**	**25.8**	**32.4**	**30.6**	**36.0**	**145.4**	**40.7**	**65.7**	**(2.6)**	**30.7**	**23.0**	**157.5**
TOTAL	**198.1**	**218.5**	**215.5**	**228.8**	**253.8**	**1,114.7**	**276.0**	**306.5**	**165.1**	**445.8**	**460.5**	**1653.9**
Less proposed contingent project (3)	-	-	-	-	-	**-**	-	-	4.8	82.3	101.4	**188.6**
TOTAL less contingent project	**198.1**	**218.5**	**215.5**	**228.8**	**253.8**	**1,114.7**	**276.0**	**306.5**	**160.3**	**363.5**	**359.1**	**1,465.4**

(1) 2024/25 actuals are preliminary and subject to finalisation and audit. Actual/forecast expenditure reported above does not include any margins paid or expected to be paid to related parties.
(2) All figures are net of disposals.
(3) Powerlink intends making a contingent project application (CPA) for the preferred network solution in relation to provision of system strength services. The AER will update the capex allowance if they deem the CPA prudent and efficient, per clause 6A.8.2(h) of the Rules.

4.4.2 Performance against allowance

In determining the Maximum Allowed Revenue (MAR) that Powerlink may recover during a regulatory period, the AER provides an allowance for the prudent and efficient capital expenditure needed to achieve the capital expenditure objectives. For our current 2022-27 regulatory period, this was based on Powerlink's forecast of capital expenditure in 2021. No cost estimation risk factor was applied to this forecast by Powerlink and the forecast did not anticipate the significant global factors that have subsequently impacted the cost of transmission works. The AER's allowance for the 2022-27 regulatory period was $1,074.7 million, restated in real 2026/27 prices.

At this time, we forecast our total capital expenditure for the 2022-27 regulatory period to be $390.6 million (36%) more than the AER's total capital expenditure allowance, when adjusted for a potential contingent project application. This is discussed further in Section 4.4.3.

Table 4.2 summarises our total actual capital expenditure compared to the AER's allowance in its Final Decision for the current 2022-27 regulatory period[30]. Expenditure for the 2025/26 to 2026/27 years is based on our current forecast.

Table 4.2 - Capital expenditure - allowance vs actual/forecast ($million real, 2026/27)

	2023	2024	2025(1)	2026 forecast	2027 forecast	Total
AER Allowance	236.4	260.4	196.0	189.9	191.9	**1,074.7**
Actual/forecast	276.0	306.5	165.1	445.8	460.5	**1,653.9**
Less proposed contingent project (2)	-	-	4.8	82.3	101.4	**188.6**
Adjusted actual/forecast	276.0	306.5	160.3	363.5	359.1	**1,465.4**
Difference	39.5	46.0	(35.7)	173.6	167.2	**390.6**
Difference (%)	17%	18%	(18%)	91%	87%	**36%**

(1) All figures are net of disposals. 2024/25 actuals are preliminary and subject to finalisation and audit. Actual/forecast expenditure reported above does not include any margins paid or expected to be paid to related parties.
(2) Powerlink intends to make a contingent project application (CPA) for the preferred network solution in relation to provision of system strength services. The AER will update the capex allowance if they deem the CPA prudent and efficient, per clause 6A.8.2(h) of the Rules.

Powerlink considers the additional capital expenditure within the 2022-27 regulatory period was necessary to continue to provide safe, secure and reliable prescribed transmission services. As described in Section 4.3, and more fully in Chapter 2 Business and Operating Environment, the current 2022-27 regulatory period has been challenging for all network businesses in Australia and abroad due primarily to global events, outside of individual businesses' control.

We understand the long-term impact on customer bills arising from additional capital expenditure, as well as the short-term financial penalties borne by Powerlink. We have proactively sought to address the inflationary pressures where possible, and actively deferred work where it has been safe and efficient to do so. This has involved application of the outcomes of our Asset Reinvestment Review to transmission line refit works and accepting slightly higher risks to reduce secondary systems replacement needs.

[30] Final Decision Powerlink Queensland Transmission Determination 2022 to 2027, Australian Energy Regulator, April 2022, page 45.

We are continuing to challenge the need, timing and deliverability of our capital works program within the 2022-27 regulatory period, with more than 50% of the expected capital expenditure within the period forecast in the last two years.

Table 4.3 - Capital expenditure - allowance vs actual/forecast ($million real, 2026/27)

	AER Allowance	Actual/forecast	Variance
Network capital expenditure			
Augmentations	8.1	44.8	36.7
Connections	2.9	-	(2.9)
Easements	26.3	31.4	5.1
Total load driven	**37.3**	**76.2**	**38.9**
Reinvestments	838.7	1,088.3	249.6
System Services	28.0	217.6	189.5
Security/compliance	18.0	53.3	35.2
Other	17.9	61.1	43.2
Total non-load driven	**902.7**	**1,420.2**	**517.5**
Total Network	**940.0**	**1,496.4**	**556.4**
Non-network capital expenditure			
Business IT	74.0	95.3	21.3
Support the Business (1)	60.8	62.2	1.4
Total Non-network	**134.8**	**157.5**	**22.7**
TOTAL	**1,074.7**	**1,653.9**	**579.2**
Less proposed contingent project (2)	-	**188.6**	**188.6**
TOTAL excluding contingent project	**1,074.7**	**1,465.4**	**390.6**

(1) All figures are net of disposals. 2024/25 actuals are preliminary and subject to finalisation and audit. Actual/forecast expenditure reported above does not include any margins paid or expected to be paid to related parties.
(2) Powerlink intends to make a contingent project application (CPA) for the preferred network solution in relation to provision of system strength services. The AER will update the capex allowance if they deem the CPA prudent and efficient, per clause 6A.8.2(h) of the Rules. For the purposes of this table these costs have been excluded.

4.4.3 Network capital expenditure

The main drivers for network capital expenditure exceeding the regulated allowance are described in this section.

Load-driven capital expenditure

We forecast our load-driven capital expenditure for the 2022-27 regulatory period will be $38.9 million higher than the AER's allowance.

The main driver of the additional expenditure is ground clearance rectification projects within the augmentation category. These works increase the capability of the transmission network by increasing the rating of existing overhead transmission lines without the need to rebuild or establish additional lines. Ground clearance rectification addresses a range of clearances to ground level, vegetation or buildings within a defined geographic program to address specific area-based reliability requirements. An increased volume of these works was undertaken to address emerging power transfer limitations in the period. The cost of the works also significantly increased due to inflationary pressures and additional project scope, as the specific activity to address the limitation was only developed following detailed design.

Expenditure on easements is forecast to be $5.1 million higher than the AER's allowance for the period. This is primarily due to easement investments required to secure a new transmission line route between Woree and Kamerunga substations to support the ongoing reliability of supply in the area, as discussed in Chapter 5 Forecast Capital Expenditure.

Non load-driven capital expenditure

We currently forecast that we will invest $517.5 million more than the AER's allowance for network non-load driven capital expenditure.

Reinvestment

We expect a total reinvestment expenditure of $1,088.3 million in the 2022-27 regulatory period, which is $249.6 million over the AER's allowance. The additional reinvestment expenditure is primarily due to the increased cost of our Next Generation Network Operations (NGNO) program to replace our obsolete Energy Management System (EMS) and associated infrastructure and systems. The additional capital expenditure on the NGNO program has been partly offset by a reduction in other network reinvestment programs.

Our network operations are central to navigating the challenges of the energy transition, and the core of our network operations is the EMS. The EMS provides visibility and situational awareness of an increasingly complex power system and is crucial to maintain a safe, secure and reliable electricity supply. Our current EMS has reached end-of-life, exceeding its original design life and extended vendor support life, and is being replaced. When we submitted our previous Revenue Proposal in January 2021, we expected this replacement to be largely completed within the last regulatory period with final testing and commissioning to occur early in the current regulatory period. As the AER accepted all key elements of the revenue proposal, no further amendments were put forward in our revised revenue proposal submitted in November 2021.

However, delivery of the project has been constrained significantly by the long-tail impacts of COVID-19, which was not apparent at the time, while subsequent detailed design identified much greater complexity in the architecture and interoperability with other systems. Powerlink has implemented unique customisations to the existing EMS to extend its life and ability to support the energy transition for the benefit of customers, however this has created additional complexity in moving to a new, contemporary system. The increased complexity of replacing this system, combined with the industry-specific inflationary pressures discussed in Chapter 2 Business and Operating Environment, has resulted in an additional $180 million network reinvestment capex on NGNO related projects within the current 2022-27 regulatory period.

We increased reinvestment capital expenditure on substation primary plant. Key drivers of this increased expenditure is the need to replace 430 oil-filled current transformers (CTs) at 23 substation sites due to significant safety concerns. This was unforeseen, as the age of these CTs is approximately half of their original expected design life. The CT replacement program has further impacted the delivery of the portfolio of works due to the need to restrict access to substations with these specific CTs.

Prioritisation of the unforeseen primary plant reinvestment, and the consequential resource and safe-access impacts, resulted in lower than planned expenditure on secondary systems replacements. Substation primary and secondary reinvestment have also been impacted by the significant cost increases arising from industry-specific inflationary pressures and the challenges in obtaining outages due to system strength.

We reduced expenditure on transmission line reinvestment as we implemented the findings of our 'Asset Reinvestment Review'[31]. This meant we were able to efficiently defer expenditure by targeting works, balancing reduced expenditure against incremental network risk. As part of this review, we committed to return any windfall gains made under the Capital Expenditure Sharing Scheme (CESS). However, increased costs and complexity in the delivery of transmission works mean that there is no windfall gain. The approach has however allowed us to prioritise capital expenditure within the period to mitigate overall capital expenditure.

System Services

We currently forecast we will invest $189.5 million more than the AER's allowance for system services.

System services capital expenditure includes $188.6 million of investment in synchronous condensers to address system strength shortfalls arising from the increased penetration of IBR and the displacement of traditional synchronous generation resources. No allowance for investment in system strength services was included in the 2023-27 Revenue Proposal or subsequent revenue determination as the obligations and costs related to system strength services were not known at the time the Revenue Proposal was prepared.

In October 2021, the Australian Energy Market Commission (AEMC) introduced the efficient management of system strength on the power system Rule change. From December 2025, Powerlink as the System Strength Service Provider in Queensland is required to plan, procure and make available system strength services. Consequently, Powerlink completed a Regulatory Investment Test for Transmission for System Strength in July 2025, recommending investment in several synchronous condensers by June 2030.

The 2021 rule change contains a transitional provision, allowing Powerlink to make a contingent project application (CPA) to the AER requesting an amended revenue determination for the current period, incorporating the capital and operating expenditure arising from the preferred option identified in the Regulatory Investment Test for Transmission (RIT-T).

We expect that once the CPA process has concluded, and our revenue determination is amended to include the investment in synchronous condensers, we will forecast a minor overspend of $1 million against the AER's allowance for system services.

Security and compliance

Security and compliance investments arising from increasing system complexity and a step change in cyber security requirements have resulted in capital expenditure $35.2 million over the AER allowance for this category.

The rapid shift towards IBR, such as wind and solar photovoltaic (PV) technologies, and the displacement of traditional synchronous generation sources, has altered the performance characteristics of the transmission network. These changes have required Powerlink to develop and implement new control and protection schemes to maintain system stability in accordance with the Rules[32]. Wide Area Monitoring Protection and Control (WAMPAC) is a new secondary system platform that Powerlink has implemented, which rapidly detects specified conditions on the grid and coordinates appropriate responses across the state-wide network. This approach avoids the need for more expensive network augmentation. In the current period we forecast capital expenditure of $12.1 million on several WAMPAC schemes across the state.

[31] Asset Reinvestment Review Working Group Report, Powerlink Queensland, June 2023.
[32] National Electricity Rules, Schedule 5.1, clause S5.1.8.

The Australian Energy Market Operator (AEMO) identified critical locations in the Queensland network where high-speed streaming of power system data is required. AEMO issued a notice to Powerlink in June 2022 under the Rules, which requires Powerlink to install and configure phasor measurement units (PMUs) at twenty-three locations[33]. In the current period we forecast $17.4 million will be invested on installation of PMUs.

Security threats for the energy sector have escalated rapidly and significantly in recent years. These threats required substantial additional investment to improve operational technology (OT) cyber security and physical security of operational sites, resulting in a total of $13.6 million investment on both physical and cyber security in the current period.

Other

We currently forecast that we will overspend the AER allowance in this category by $43.2 million. This is mainly due to a major investment in OT to support the EMS replacement at an updated Business Continuity Site (BCS). There have also been investments in enhancing field delivery technologies and upgrading our data centre equipment in the current period.

4.4.4 Non-network capital expenditure

Our current forecast is that we will invest $22.7 million more than the AER's allowance for non-network capital expenditure in the 2022-27 regulatory period.

Within business information technology (IT), additional investment in cyber security was necessary to meet Australian Energy Sector Cyber security Framework (AESCSF) standards as well as expenditure on specific cyber-risk mitigation. These additional requirements, in addition to cost escalation for IT services, equipment and software, means that we currently forecast capital expenditure $21.3 million over the AER allowance.

In the Support the Business category, overspend on motor vehicles and tools and equipment was offset by an underspend on buildings due to deferral of our proposed office building refit project, resulting in a small overspend of $1.4 million overall.

4.4.5 Ex post review period

The Rules provide for the AER to undertake a review of past capital expenditure where the capital expenditure within a defined review period exceeds the respective capital expenditure allowance by the AER[34]. The purpose of the review is to assess any capital expenditure over the allowance and exclude any additional capital expenditure that is not deemed prudent and efficient from being included in the Regulatory Asset Base (RAB). The AER describes the ex post review process in its Capital Expenditure Incentive Guideline[35].

[33] Notice issued by AEMO to Powerlink on 27 June 2022 under clauses 4.11.1(d) and (e) of the National Electricity Rules.
[34] National Electricity Rules, Schedule 6A.2, clause S6A.2.2A.
[35] Capital Expenditure Incentive Guideline for Electricity Network Service Providers, Australian Energy Regulator, August 2025, pages 18-21.

For Powerlink's 2027-32 revenue determination, the review period is from 1 July 2020 to 30 June 2025. Our capital expenditure within the review period compared to AER allowance is shown in Table 4.4.

Table 4.4 - Capital expenditure – ex post review period ($million nominal)

	2021	2022	2023	2024	2025(1)	Total
AER Allowance	185.5	179.7	209.3	239.9	184.9	**999.4**
Actual	180.5	207.2	242.9	280.7	154.9	**1,066.1**
Difference	(5.1)	27.5	33.6	40.8	(30.1)	**66.7**
Difference (%)	(3%)	15%	16%	17%	(16%)	**6.7%**

(1) 2024/25 actuals are preliminary and subject to finalisation and audit.

We have actively managed our capital expenditure over the entire period and proactively sought to address the inflationary pressures (refer Chapter 2 Business and Operating Environment) where possible, and actively deferred work where it has been safe and efficient to do so. This has included application of the outcomes of our Asset Reinvestment Review to transmission line refit works and accepting slightly higher risks to reduce secondary systems replacement needs.

These actions resulted in an overspend in the review period of 6.7%. Powerlink does not consider this a significant overspend within the context of the operating environment.

During the 2022-27 regulatory period, like all other network businesses in Australia, Powerlink experienced unprecedented increases in the costs of major plant items, materials and skilled resources (refer Chapter 2 Business and Operating Environment). This led to increases in capital expenditure that were outside the control of Powerlink. Consequently, we have considered an alternative approach to the calculation of the net carryover amount under the CESS that appropriately recognises the operating environment during the current period (refer Chapter 14 Incentive Schemes). If this approach was applied to the AER allowance for the review period, then actual capital expenditure would be below the corresponding adjusted allowance in the review period.

4.5 Historical operating expenditure

This section summarises our historical operating expenditure, consistent with the requirements of the Rules[36].

4.5.1 Historical operating expenditure summary

Table 4.5 shows our actual/forecast operating expenditure for the current regulatory period by expenditure category. Expenditure for the 2022/23 to 2024/25 financial years are actuals while the 2025/26 and 2026/27 financial years are based on our current expenditure forecasts.

Table 4.5 - Operating expenditure - actual/forecast ($million real, 2026/27)

	2023	2024	2025(1)	2026 forecast	2027 forecast	Total
Controllable operating expenditure						
Field Maintenance	84.0	93.1	101.9	115.6	128.6	**523.2**
Operational Refurbishment	35.7	36.7	48.1	42.2	45.4	**208.2**
Maintenance Support	18.8	22.1	27.4	30.2	31.2	**129.6**
Network Operations	22.3	26.5	36.6	36.5	41.1	**163.0**
Asset Management Support	30.6	35.3	40.6	41.0	38.6	**186.1**
Corporate Support	41.0	54.5	23.5	41.4	36.5	**196.9**
Total controllable operating expenditure	**232.5**	**268.1**	**278.1**	**306.9**	**321.4**	**1,407.0**
Other operating expenditure						
Insurance Premiums	9.1	9.5	8.5	9.1	9.9	**46.1**
Self-Insurance	0.9	0.9	1.0	2.0	2.3	**7.0**
AEMC Levy	8.1	6.1	6.7	5.9	6.2	**33.1**
Network Support – Alternative Support	0.6	1.2	2.1	-	-	**3.8**
Network Support – System Security(2)	-	-	-	-	-	**-**
Debt raising costs	0.2	0.1	0.1	0.4	0.6	**1.4**
Total other operating expenditure	**18.8**	**17.9**	**18.4**	**17.4**	**18.9**	**91.4**
Total operating expenditure	**251.3**	**286.0**	**296.5**	**324.3**	**340.3**	**1,498.3**
Total operating expenditure (excluding debt raising costs)	**251.1**	**285.9**	**296.4**	**323.9**	**339.7**	**1,496.9**

(1) 2024/25 actuals are preliminary and subject to finalisation and audit.
(2) From 1 December 2024, System Security payments are recovered as a direct pass through to customers. We have not included a forecast for 2025/26 and 2026/27.

[36] National Electricity Rules, Schedule 6A.1, clause S6A1.2(7).

4.5.2 Performance against allowance

In determining the Maximum Allowed Revenue (MAR) that Powerlink may recover during a regulatory period, the AER provides an allowance for the prudent and efficient operating expenditure needed to achieve the operating expenditure objectives. The AER's allowance for the 2022-27 regulatory period was $1,253.3 million (exclusive of debt raising costs), restated in real 2026/27 prices.

We expect total operating expenditure to be $1,495.0 million (adjusted for agreed pass throughs) which is $241.7 million (19%) higher than the AER's total allowance for the 2022-27 regulatory period. These figures are exclusive of debt raising costs. Table 4.6 outlines the annual trend in allowed and actual operating expenditure over the 2022-27 regulatory period.

Table 4.6 - Operating expenditure - allowance vs actual/forecast ($million real, 2026/27)

	2023	2024	2025[1]	2026 forecast	2027 forecast	Total
AER Allowance[2]	248.7	251.8	250.8	251.0	251.0	**1,253.3**
Actual/forecast[2]	251.1	285.9	296.4	323.9	339.7	**1,496.9**
Less agreed pass through[3]	0.9	1.0	-	-	-	**1.9**
Adjusted actual/forecast	250.2	284.9	296.4	323.9	339.7	**1,495.0**
Difference	1.5	33.1	45.6	72.8	88.7	**241.7**
Difference (%)	1%	13%	18%	29%	35%	**19%**

(1) 2024/25 actuals are preliminary and subject to finalisation and audit.
(2) Figures are exclusive of debt raising costs. There was no allowance for network support costs.
(3) The AER has approved positive pass through amounts in relation to Powerlink's network support costs in 2022/23 and 2023/24. These pass throughs are recovered through the Maximum Allowed Revenue in the following year. Costs incurred relating to these pass throughs are included in the total actual/forecast operating expenditure. We have subtracted the agreed pass throughs values from the total operating expenditure for the comparison to the allowance.

Operating expenditure has increased progressively over the 2022-27 regulatory period. We have experienced cost increases in several controllable and non-controllable operating expenditure categories.

Controllable operating expenditure

Controllable operating expenditure is expected to be $236.3 million higher in the 2022-27 regulatory period than compared to the AER's allowance. Several key drivers of expenditure have been identified in the current regulatory period.

Skilled labour

The labour cost increases described in Section 4.3.2 result in a significant portion of additional operating expenditure, as labour comprises almost 70% of our controllable operating expenditure. This drives $176.1 million (75%) of additional expenditure in this category.

Complexity

The rapidly increasing technical complexity of operating the transmission network introduces several key operational challenges which results in additional costs. These include the need for more frequent operator intervention, an increasing number of alarms, a rise in the labour effort required for scheduling, planning and management of outages, and an increase in complex switching activities and network support activations to ensure the network operates securely and reliably. We require the development of more specific operating and contingency plans, schemes and complex operating strategies to maintain power system security and optimise utilisation of installed network assets. These factors have had an impact on expenditure within the current regulatory period and have also been closely considered in the development of operating expenditure forecasts for the 2027-32 regulatory period (refer Chapter 6 Forecast Operating Expenditure).

New regulatory and compliance obligations

As a Transmission Network Service Provider, Powerlink is required to comply with the *Security of Critical Infrastructure Act 2018*. The Act requires that owners of critical infrastructure assets implement a risk management plan to mitigate material risks associated with cyber and information hazards, personnel hazards, supply chain hazards, and physical and natural hazards. At the time of the 2023-27 Revenue Proposal, the impacts of this and associated legislation were not fully understood and as a result Powerlink did not seek an allowance for this.

Powerlink has incurred new costs of compliance related to SOCI physical security obligations with phased implementation throughout the current 2022-27 regulatory period, and into the 2027-32 regulatory period, which has contributed over $12 million to the operating expenditure overspend.

The cyber security threat to Powerlink is high and a successful attack on its critical infrastructure could have severe consequences. During the 2022-27 regulatory period we have evolved our cyber security focus and capability and have now achieved Security Profile 2 (SP-2) level of maturity under the AESCSF as flagged in our 2023-27 Revenue Proposal. The release of version 2 of the AESCSF in 2023 included a 37% increase in the number of practices and anti-patterns (currently at 354) required to be implemented to maintain the SP-2 maturity level. This heightened focus and escalating risk in the cyber threat environment has had a significant effect on cyber security related operating expenditure, with the operating costs of maintaining this cyber security maturity level continuing to increase and contribute over $20 million to the operating expenditure overspend.

To date, Powerlink has not claimed a pass through in relation to these costs, but we will investigate the appropriate recognition of such costs within the current 2022-27 regulatory period.

Non-controllable operating expenditure

We forecast to exceed the AER's 2022-27 regulatory period allowance for non-controllable operating expenditure by $7.3 million. This excludes debt raising costs.

Network Support

We forecast to incur alternative network support costs during the 2022-27 regulatory period of $3.8 million.

There was considerable uncertainty around potential costs with no contracts in place at the time of our 2023-27 Revenue Proposal, and the possibility for emerging energy market dynamics to alter the requirements for network support. For this reason, we did not seek an allowance for network support costs.

To date, the AER has agreed to pass through $1.9 million in relation to these costs. The remaining $1.9 million relates to non-network costs in lieu of a network solution, displacing capital expenditure that had been provided for in the allowance. Hence, no pass-through has been sought for these costs.

Insurance

Insurance costs (premiums and self-insurance) for the 2022-27 regulatory period are forecast to be $5.1 million (10.6%) higher than the AER's allowance. At the time of preparing our previous Revenue Proposal the insurance industry was in a hard phase of the cycle, creating uncertainty around future costs. Increases are anticipated to continue into the 2027-32 regulatory period, but at a rate aligned with a 'softening' global insurance market. This is discussed further in Chapter 6 Forecast Operating Expenditure.

4.5.3 Productivity initiatives

In our 2023-27 Revenue Proposal, we proposed an annual productivity target higher than the industry average and identified several productivity initiatives to support this target. We have achieved some productivity savings, partially offsetting the impacts of the cost increases highlighted in section 4.5.2.

Material supply chain and direct purchasing

We have focused on delivering productivity improvements through digitisation, process optimisation and commercial innovation in our material supply chain and direct purchasing functions. We have increased the number of procurement panels and period agreements which has enabled more structured and competitive sourcing, consolidated spend, reduced sourcing cycle times and improved process efficiency. We are implementing a Source-to-Contract platform which will automate workflow, improve transparency, enhance compliance and enable better data-driven decision making across the procurement lifecycle.

Vegetation management

We have improved how we plan, prioritise, coordinate and verify vegetation works across our network with satellite data capture technology. This technology has provided information that allows us to tailor inspection cycles and maintenance works across our network. Combined with the shift to a statewide vegetation contract, this has seen a reduction in our vegetation management costs, with the cost per span decreasing since 2023.

Improving the efficiency of central processes and activities

We have progressed the implementation of the Field Delivery Optimisation program which comprises enhanced technology and tools to support frontline teams. Through this program, we have realised benefits in the utilisation of our field-based teams with improvements in work scheduling and packaging. We hope to derive further benefits in future upgrades by embedding the processes across the business.

Office refit

In the 2022-27 regulatory period we have shifted to shared working arrangements, maximising the utilisation of office space at our Virginia site, and deferring the need to establish additional office space.

Business information technology (IT)

We continue to deliver on business IT replacements, software upgrades and rationalisation of our systems planned for the 2022-27 regulatory period. We delivered upgrades to core business systems which has improved functionality and modernised our tools, allowing for improvements in business processes and some savings in licensing costs. We are consolidating platforms and data warehouses to reduce support requirements and deliver greater efficiency.

In-Vehicle Asset Management Systems

We have progressed the installation of In-Vehicle Asset Management Systems (IVAMS) across our vehicle fleet as part of a project to improve our operational vehicle resource utilisation, improve safety and refine maintenance schedules. These systems are not yet operational while we continue consultation with our employees, hence we have not yet realised the benefits associated with this system.

Value driven maintenance

Powerlink takes a value driven maintenance approach to deliver the most cost-effective outcomes, while meeting our obligations to provide safe, secure and reliable transmission services to our customers. We have found opportunities to improve and deliver greater value by changing the frequency of selected maintenance activities and removing some annual activities in favour of a risk-based program.

Other productivity initiatives

In addition to the productivity initiatives we identified in our 2023-27 Revenue Proposal, we have realised benefits from other initiatives implemented in the current 2022-27 regulatory period. The implementation of Microsoft Copilot has boosted productivity through the automation of repetitive tasks, the ability to quickly research, analyse and interpret large datasets and streamline communication. Other initiatives included the commencement of a Christmas closure period and the option to cash out leave.

4.6 Benchmarking performance

Note for the draft Revenue Proposal: the information in the following sections is based on the AER's 2024 TNSP Annual Benchmarking Report dataset. The AER's 2025 Annual Benchmarking Report will be publicly released in November 2025. We will update this section and provide further information prior to publishing our Revenue Proposal in January 2026.

4.6.1 Regulatory requirements

The Rules[37] require the AER to prepare and publish an annual benchmarking report that describes the relative efficiency of each TNSP. The AER must have regard to the most recent annual benchmarking report when assessing whether operating and capital expenditure forecasts provided by a TNSP within its Revenue Proposal represent efficient expenditure[38].

4.6.2 Our approach

We consider benchmarking as part of the calculation of the trend parameter of our operating expenditure 'base-trend-step' model. This includes consideration of our benchmarking results and industry-wide productivity trends.

The AER focuses on multilateral productivity measures in its annual benchmarking report for TNSPs. This measures how efficiently a business transforms a 'basket' of physical and financial inputs into a 'basket' of outputs. Inputs to the AER's benchmarking model for transmission include both physical inputs, such as the capacity of the network, as well as financial inputs, such as operating expenditure. It is not solely related to the cost to customers. The AER's annual benchmarking report also considers partial productivity indicators (e.g. ratios of total costs to specific outputs such as cost per customer).

Economic benchmarking of electricity transmission businesses is impacted by the small number of TNSPs in Australia. The AER acknowledges this limitation in applying its benchmarks to TNSPs. In particular, it acknowledges that not all external factors arising from a TNSP's operating environment can be captured in the benchmark models[39].

[37] National Electricity Rules, clause 6A.31.
[38] National Electricity Rules, clause 6A.6.6(e) and 6A.6.7(e).
[39] Annual Benchmarking Report - Electricity transmission network service providers, Australian Energy Regulator, November 2024, section 2.2.

There are also potential Operating Environment Factors (OEFs) that may be specific to one or a subset of TNSPs, which can influence outcomes. For example:

- application of different capitalisation policies, i.e. instances where a TNSP incorporates expenditure into operating expenditure where another would capitalise it
- differences in network terrain, that may influence expenditure necessary to maintain the network and
- differences in the geographic nature of networks, which may mean some TNSPs need to invest in infrastructure that another TNSP would not.

Our performance under the AER's economic benchmark approach in its most recent 2024 TNSP Annual Benchmarking Report has increased slightly (0.2%) over the course of the current regulatory period (to 2023 only). This is primarily attributable to a 1.2% improvement in reliability, offset by increases in opex and transformer inputs.

The AER's 2025 TNSP Annual Benchmarking Report will be released in November 2025. We will provide additional analysis and insight on the outcomes of the most recent benchmarking results as part of our 2027-32 Revenue Proposal in January 2026.

4.6.3 Independent assessment of performance

We engaged HoustonKemp to provide an independent review of our relative performance based on available and forecast information, and to advise on the potential efficiency of our proposed base year (2025/26) to forecast operating expenditure in the 2027-32 regulatory period. The key elements of that review are focused on:

- Multilateral Total Factor Productivity (MTFP)
- Capital Multilateral Partial Factor Productivity (capital expenditure MPFP) and
- Operating expenditure Multilateral Partial Factor Productivity (operating expenditure MPFP).

Based on actual results for 2023/24 and 2024/25 and the current forecast for 2025/26, Powerlink's operating expenditure performance is expected to decline due to an increase in cost, with no corresponding increase in output. The outcome for 2023/24 is aligned with the trend for all TNSPs, with no TNSP displaying an improvement in operating expenditure MPFP for that year. Comparative data for 2024/25 and 2025/26 is not yet available.

HoustonKemp's key findings on our operating expenditure performance, particularly as they relate to our proposed operating expenditure base year (2025/26), is summarised in Chapter 6 Forecast Operating Expenditure.

5 Forecast Capital Expenditure

5.1 Introduction

This chapter presents Powerlink's forecast capital expenditure for each year of the 2027-32 regulatory period.

Key highlights:

- We have developed our forecast capital expenditure for the 2027-32 regulatory period consistent with the requirements of the National Electricity Rules (Rules) and our Expenditure Forecasting Methodology.
- Our hybrid forecasting approach integrates top-down and bottom-up forecast methods, with project-specific justification provided for at least 80% of our forecast capital expenditure.
- Our forecast capital expenditure for the 2027-32 regulatory period is $2,796.7 million ($ real, 2026/27). This is:
    - $1,142.8 million higher than actual/forecast capital expenditure for the 2022-27 regulatory period, and
    - the majority of this forecast is non load-driven network expenditure of $2,274.2 million.
- The key drivers that underpin our forecast for the 2027-32 regulatory period are:
    - reinvestment in the transmission network to maintain safety, security, reliability and quality of supply as our assets continue to age
    - our response to the changing use of electricity and our transmission network, and new obligations to provide system strength services, and
    - critical investment in the redevelopment of our Virginia complex and the development of a facility in Gladstone as we grow our regional workforce.

5.2 Regulatory requirements

We must submit our forecast capital expenditure for the 2027-32 regulatory period based on the requirements set out in the Rules[40].

The Rules[41] require that our Revenue Proposal provides information on our capital expenditure for each year of the previous and current regulatory periods. The Rules[42] also require that the Australian Energy Regulator (AER) has regard to this expenditure when it considers our forecast capital expenditure.

Prior to the submission of our Revenue Proposal, we are required to propose a methodology for the development of our capital and operating expenditure forecasts[43] (refer Appendix 5.03 Expenditure Forecasting Methodology). This methodology, and our forecasts, must also have regard to the AER's Expenditure Forecast Assessment Guideline for Electricity Transmission[44].

[40] National Electricity Rules, clause 6A.6.7.
[41] National Electricity Rules, Schedule 6A.1, clause S6A.1.1.
[42] National Electricity Rules, clause 6A.6.7(e)(5).
[43] National Electricity Rules, clause 6A.10.1B.
[44] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.

5.2.1 Capital expenditure objectives

We consider that our forecast capital expenditure achieves the capital expenditure objectives set out in clause 6A.6.7(a) of the Rules. This is summarised in Table 5.1 and discussed in detail in Appendix 5.01 Operating and Capital Expenditure Criteria and Factors.

Table 5.1 - How we meet the capital objectives

Capital expenditure objective	How our proposal meets this objective
Meet or manage the expected demand for prescribed transmission services over the period	Demand from our 2024 Transmission Annual Planning Report (TAPR) forecast shows steady average annual growth over the forecast horizon. The main driver for this is the magnitude and pace of electrification. In addition to meeting customer demand, Powerlink must also meet forecast increase in the demand for prescribed system services such as inertia and system strength, as set out in the Australian Energy Market Operator's (AEMO) 2024 system security planning reports[45].
Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services	We are subject to regulatory obligations as the holder of a Transmission Authority under the *Electricity Act 1994 (Qld)* and as a registered Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM). As a corporation, we are also subject to various environmental, cultural heritage, planning, industrial, Workplace Health & Safety, critical infrastructure, financial and other regulations. Our compliance with these regulatory obligations and requirements is encompassed in our Asset Management Framework, policies and procedures, which provide the foundation for our capital expenditure activities.
Maintain the quality, reliability and security of supply of prescribed transmission services and maintain the safety, reliability and security of the transmission system through the supply of prescribed transmission services	Our capital expenditure forecasts include prudent provision for maintaining the safety of the transmission system while maintaining and meeting the mandated level of quality, reliability and security of supply to customers. Where there are no mandated service levels we will maintain the existing levels of service.
Contribute to achieving emissions reduction targets through the supply of prescribed transmission services	Powerlink plays a pivotal role in Queensland's energy transition through its transmission infrastructure. As Queensland's System Strength Service Provider, Powerlink is investing in synchronous condensers to address system strength shortfalls due to the change in the mix of generation from predominantly synchronous generation (coal-fired) to a blend of synchronous generation and inverter-based resources (IBR).

5.3 Capital expenditure categories

We have retained the same categories of capital expenditure drivers as applied in our 2023-27 Revenue Proposal. Capital expenditure categories, and the prescribed transmission services they relate to, are shown in Table 5.2.

[45] AEMO System Security Planning (https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning).

Table 5.2 - Powerlink's capital expenditure categories

Capital expenditure category	Definition	Prescribed transmission service
Network – Load driven		
Augmentations	Relates to augmentations defined under the Rules. Typically, these include projects such as the construction of new lines, substation establishments and reinforcements or extensions of the existing network.	Transmission Use of System (TUOS) services and exit services
Connections	Works to facilitate additional connection point capability between Powerlink and Distribution Network Service Providers (DNSPs) or other TNSPs. Associated works are identified through joint planning with the relevant Network Service Provider.	Exit services
Easements	The acquisition of transmission line easements to facilitate the projected expansion and reinforcement of the transmission network. This includes land acquisitions associated with the construction of substations or communication sites.	Common services, TUOS services and exit services
Network – Non-load driven		
Reinvestments	Relates to reinvestment to meet the expected demand for prescribed transmission services. Expenditure is primarily undertaken due to end of asset life, asset obsolescence, asset reliability or safety requirements. A range of options is considered for asset reinvestments, including removing assets without replacement, non-network alternatives, life extension to extend technical life or replacing assets with assets of a different type, configuration or capacity. Each option is considered in the context of future capacity needs accounting for forecast demand.	Common services, TUOS services and entry/exit services
System Services	Investments to meet overall power system performance standards and support the secure operation of the power system. This includes the provision of system strength services and inertia services.	Common services
Security / Compliance	Expenditure undertaken to ensure compliance with amendments to various technical, safety or environmental legislation. In addition, expenditure is required to ensure the physical security (as opposed to network security) of Powerlink's assets.	Common services, TUOS services and entry/exit services
Other	All other expenditure associated with the network which provides prescribed transmission services, such as communications system enhancements, improvements to network switching functionality and insurance spares.	Common services
Non-network		
Business Information Technology (IT)	Expenditure to maintain IT capability, replace or improve business system functionality, assist in meeting regulatory requirements, enhance productivity, and improve cyber security of business systems.	Common services
Support the Business	Expenditure to replace or improve business requirements including the areas of commercial property, vehicles and moveable plant, for instance to address safety.	Common services

5.4 Forecast capital expenditure

This section presents our forecast capital expenditure for the 2027-32 regulatory period.

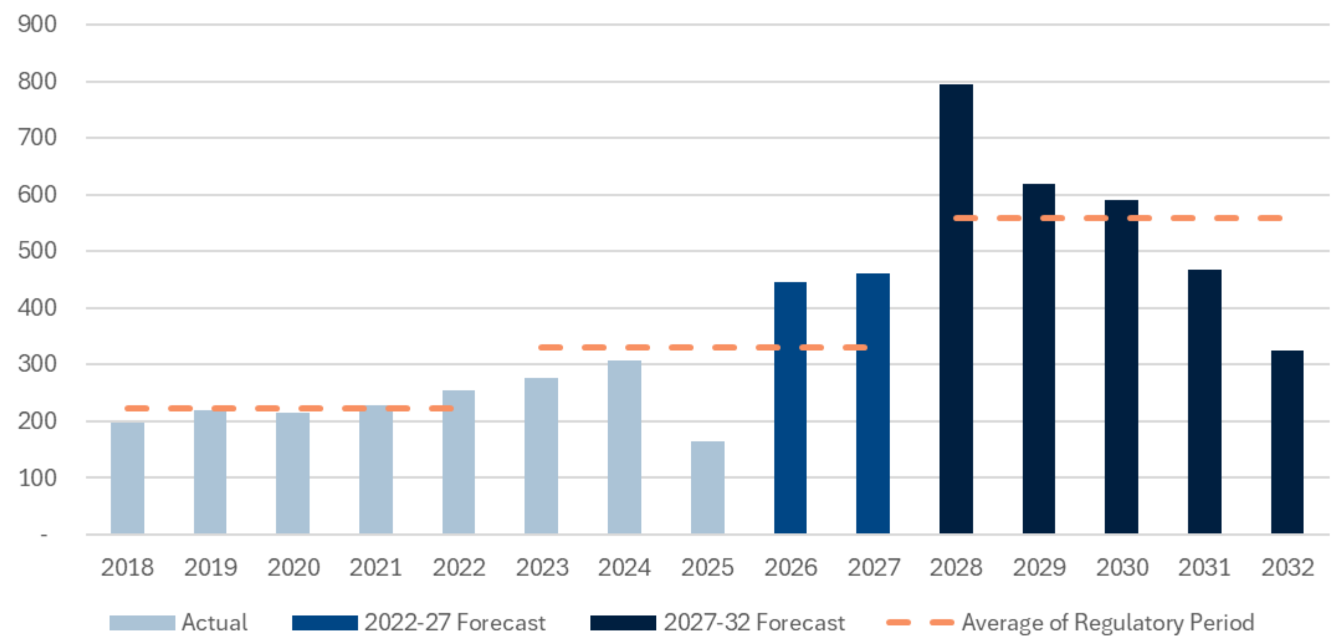
5.4.1 Forecast capital expenditure

Our forecast capital expenditure reflects the key drivers for investment described in our Business Narrative (Appendix 2.01) and in Chapter 2 Business and Operating Environment.

- Forecast load-driven capital expenditure reflects a return to moderate growth in peak demand as household consumption increases and industry sectors start to electrify to reduce their greenhouse gas emissions.
- Reinvestment in existing network assets accounts for more than 60% of the total forecast capital expenditure. The most significant driver for this reinvestment is the risk-based replacement of substation secondary systems, which protect and control our high voltage assets, as they become obsolete.
- Installation of synchronous condensers is necessary to ensure essential system services such as minimum levels of inertia and system strength are available for the secure operation of the power system.
- Investment in operational tools to enhance real-time situational awareness and decision-making capabilities in response to the increasing complexity of operating the transmission network.
- The need to invest in non-network building infrastructure to redevelop our Virginia complex and to accommodate our employees based in Central Queensland, as we develop a more cost-effective approach to maintaining and developing our network outside of South-East Queensland.

Our total forecast capital expenditure for the 2027-32 regulatory period, along with our actual/forecast expenditure for the previous and current regulatory periods, is shown in Figure 5.1.

Figure 5.1 - Capital expenditure by driver ($million real, 2026/27)



Our forecast expenditure by category is shown in Table 5.3.

Table 5.3 - Forecast capital expenditure by category ($million real, 2026/27)

Category	2028	2029	2030	2031	2032	Total
Network – load-driven						
Augmentations	13.7	5.3	11.7	4.6	0.4	**35.8**
Connections	-	-	-	-	-	**-**
Easements	36.4	20.0	22.0	26.1	42.4	**147.0**
Total Network – load-driven	**50.1**	**25.3**	**33.8**	**30.7**	**42.9**	**182.7**
Network – non load-driven						
Reinvestments	388.1	349.0	381.2	328.0	239.2	**1,685.6**
System Services	113.6	153.8	135.9	73.3	-	**476.6**
Security/compliance	8.4	2.2	3.9	2.5	6.4	**23.4**
Other	17.2	16.3	15.9	17.8	21.5	**88.6**
Total Network – non load-driven	**527.2**	**521.4**	**537.0**	**421.5**	**267.1**	**2,274.2**
Total Network	**577.3**	**546.7**	**570.7**	**452.2**	**310.0**	**2,456.9**
Non-network capital expenditure						
Business IT	6.1	6.7	8.2	6.7	5.4	**33.2**
Support the Business	211.9	65.7	10.7	9.4	9.0	**306.7**
Total Non-network	**218.0**	**72.4**	**18.9**	**16.1**	**14.4**	**339.8**
TOTAL	**795.3**	**619.1**	**589.6**	**468.3**	**324.4**	**2,796.7**

(1) This table is net of disposals.

Our total forecast capital expenditure is $2,796.7 million, which is $1,142.8 million higher than the actual/ forecast expenditure for the 2022-27 regulatory period. The majority of this is non load-driven network expenditure of $2,274.2 million.

5.5 Forecasts by category

Table 5.4 - Capital expenditure - comparison of 2027-32 forecast to 2022-27 actual/forecast ($million real, 2026/27)

	Actual/Forecast 2022-27	Forecast 2027-32	Variance
Network – load driven			
Augmentations	44.8	35.8	(9.0)
Connections	-	-	-
Easements	31.4	147.0	115.6
Total load driven	**76.2**	**182.7**	**106.6**
Network – non-load driven			
Reinvestments	1,088.3	1,685.6	597.3
System Services	217.6	476.6	259.0
Security/compliance	53.3	23.4	29.9
Other	61.1	88.6	27.5
Total non-load driven	**1,420.2**	**2,274.2**	**853.9**
Total Network	**1,496.4**	**2,456.9**	**960.5**
Non-network			
Business IT	95.3	33.2	(62.1)
Support the Business	62.2	306.7	244.5
Total Non-network	**157.5**	**339.8**	**182.4**
TOTAL	**1,653.9**	**2,796.7**	**1,142.8**

5.5.1 Network load-driven expenditure

Our total forecast load-driven expenditure of $182.7 million is $106.6 million higher than the actual/forecast expenditure in the current regulatory period. This includes augmentations, relating to our ongoing program of ground clearance rectification for selected transmission lines to provide increased network capacity at modest cost.

This category also includes forecast expenditure on easements, primarily to progress acquisition to support new load driven connections to Energy Queensland, forecast to occur in the 2032-37 period. We anticipate that the timing for some of these projects will require construction to commence by the early 2030s. This requires that works on easement acquisition will need to commence during the 2027-32 regulatory period. A key driver of this timing is to ensure we can undertake meaningful engagement with landholders who may be impacted by these investments.

5.5.2 Network non-load driven expenditure

Non-load driven expenditure is the most significant contributor to our forecast capital expenditure for the 2027-32 regulatory period. Our forecast expenditure of $2,274.2 million is $853.9 million higher than the actual/forecast expenditure in the current regulatory period. The majority of expenditure is in the reinvestment category.

While substantial, a large amount of this investment (approx. $815 million) relates to several large projects/ programs of work, namely the substation and transmission line reinvestment around Kamerunga, the installation of synchronous condensers to deliver system strength services, and the physical security uplift program. Other non-load driven expenditure continues to follow the historical trend, once adjusted for the industry-specific inflation highlighted in Chapter 2 Business and Operating Environment.

Transmission towers reinvestment

During the revenue determination process for our 2022-27 regulatory period, we committed to undertake a review of our approach to network asset reinvestment, particularly for overhead transmission lines. This review included representatives of customers, the AER and Powerlink subject matter experts, and concluded in June 2023 with the publication of the Asset Reinvestment Review Working Group Report[46].

In preparing our 2027-32 Revenue Proposal we have implemented the key recommendations of the Asset Reinvestment Review. In addition, we have identified further improvements to deliver a more cost-effective approach, which has substantially reduced the number of towers requiring intervention in the 2027-32 period.

Secondary systems and telecommunications reinvestment

A significant driver of asset reinvestment expenditure is the need to renew our fleet of digital secondary systems and telecommunications assets. Our total forecast secondary systems capital expenditure of $543.9 million is $296.3 million more than the actual/forecast expenditure for the current regulatory period.

The nature of these digital technologies is such that obsolescence and lack of vendor support for discontinued devices are the primary drivers for reinvestment. Once a device is no longer available, its replacement is operationally and technically more complex due to issues such as:

- interoperability and protocol difference between other devices on site, and at adjacent substations
- the need to develop and test new configurations and settings
- physical differences with the mounting and installation, including cabling and connectivity and
- legislative requirements for professional engineering certification[47].

In the event of failure of an unsupported device, the return to service times extend considerably. In addition to the impacts of obsolescence at any one site, it is also important to note the compounding impact of equipment obsolescence that may occur across the fleet of secondary systems assets installed in the network. When a particular equipment type or model is no longer supported by the manufacturer, and limited spares are available to service the fleet of assets, an attempt to run multiple secondary systems to failure across the network would increase the likelihood of concurrent systemic faults. This could overwhelm our capacity to undertake corrective maintenance or replacement projects and potentially leave us in breach of the Rules[48], AEMO standards[49] and our jurisdictional obligations[50].

In addition, the growing cyber threat landscape affecting the electricity sector means the timely deployment of software updates has become a critical component of maintaining appropriate cyber security standards. Sustained vendor support to ensure the availability and integrity of these updates is essential to safeguarding operational systems and meeting regulatory expectations for cyber resilience. For these reasons, we consider it is

[46] Asset Reinvestment Review - Working Group Report, Powerlink, June 2023.
[47] *Professional Engineers Act 2002 (Qld),* s115.
[48] National Electricity Rules, Schedule 5.1, clause S5.1.2.1(d), clause S5.1.9(c).
[49] Power System Operating Procedure (SO_OP_3715), AEMO and Power System Security Guidelines, AEMO.
[50] *Electricity Act 1994 (Qld),* s34(1)(a) and Powerlink's Transmission Authority T01/98.

critical to address the fleet of assets, such that the number of obsolete and unsupported devices in service on the network is managed effectively.

The typical product lifespan for our secondary systems assets is around 20 years. The expansion of our network during the 2000s and early 2010s in response to growth in customer demand means there will be an increasing volume of secondary systems assets requiring reinvestment in the 2027-32 regulatory period.

To address the challenges of managing an ageing fleet of assets, we have commenced a trial of in-situ replacement of secondary systems panels. This approach is enabled by the generation of digital secondary systems coming up for replacement. We expect this trial to result in reduced costs, support shorter network outage times and enhance our capability in replacement techniques. This replacement approach comes with a trade-off of placing more pressure on scarce highly skilled resources necessary to undertake the work. The outcome of the trial will inform our ongoing approach to secondary systems reinvestment projects.

There have been rapid changes in the technology of telecommunications equipment, which enables the control and operation of the high voltage network. As telecommunications service providers look to remain competitive through adoption of new technologies to provide more features, the investment in legacy technology is reduced, resulting in shorter product support periods. This rapidly advancing environment is a key driver behind increased investment in telecommunications in the 2027-32 regulatory period.

Physical security uplift

As part of our security strategy to protect business-critical assets, we have included an allowance for future physical security uplift of our operational sites. This is currently based on standardised approach to each site, based on its comparative size and criticality. A targeted risk assessment will be conducted to confirm the criticality and vulnerability of each site and works tailored to specific site requirements. This process will ensure that implemented security controls are proportionate, effective, and aligned with our obligations under the *Security of Critical Infrastructure (SOCI) Act 2018*. This requirement will drive significant reinvestment capital expenditure where existing security systems are replaced and enhanced in the 2027-32 regulatory period as the physical security of existing operational sites is enhanced.

Meeting power system performance standards

The System Services capital expenditure category was introduced in the 2022-27 regulatory period. This was driven by the emerging need to meet power system performance standards beyond the traditional network augmentation driver of growth in demand. System Services includes voltage control as well as the unbundling of services such as inertia and system strength. Since December 2022, Powerlink is the System Strength Services Provider (SSSP) for Queensland and has obligations to plan, procure and make available system strength services.

Continuing the trend in the current period (refer Chapter 4 Historical Capital and Operating Expenditure) for increased investment in system services, our current forecast is for a substantial increase in investment in this category to address system strength requirements arising from the increased penetration of Inverter-Based Resources (IBR) and the displacement of traditional synchronous generation resources.

Powerlink completed a Regulatory Investment Test for Transmission (RIT-T) in July 2025 to address the system strength requirements in Queensland, recommending the installation of up to nine synchronous condensers across Central and Southern Queensland by June 2034. The RIT-T recognised the potential for alternative technologies and system service providers to establish in the market, offering a lower long-run cost than installing additional synchronous condensers. For this reason, we have commenced early project development activities to establish four synchronous condensers within the 2027-32 regulatory period.

Given the early stage of project development for a new major plant item for Powerlink, there is some uncertainty in the forecast cost and cash flow associated with these synchronous condensers. The cost and timing of these works will be refined as we engage with potential suppliers and develop estimates to support a contingent project application for the capital expenditure within the 2022-27 regulatory period.

Additional synchronous condensers are included as contingent projects (refer Section 5.6) should project development activities need to commence within the 2027-32 regulatory period.

Improving network utilisation and customer outcomes through enhanced situational awareness and decision support

Our total forecast Other capital expenditure of $88.6 million is $27.5 million more than the actual/forecast expenditure for the current regulatory period.

The increasing number of inverter-based generation and storage resources being integrated into the Queensland network is changing the dynamic behaviour of the power system. Combined with the challenging transmission network investment conditions and unbundling of system services (system strength, inertia etc), this results in greater variability and complexity for power system operators. In this evolving environment, there is a clear and urgent need to strengthen real-time situational awareness and decision-making capabilities to ensure operators can effectively monitor the network and respond swiftly to contingency events.

Additionally, the changing system dynamics are making network outage planning increasingly complex. To address these challenges, Powerlink is initiating a series of targeted work packages aimed at enhancing control room operations. These include improvements in forecasting and data analytics to support operational decisions, advanced tools for situational awareness, and operational capability to support the deployment of Wide Area Monitoring, Protection and Control (WAMPAC) systems.

Collectively, these initiatives are designed not only to support more informed and agile operational responses but also to enable Powerlink to operate the network at higher risk tolerances. This will lead to improved network utilisation and reduced curtailment of inverter-based resources, achieving system security and reliability outcomes at a lower cost to consumers.

5.5.3 Non-network expenditure

Our total forecast non-network capital expenditure of $339.8 million is $182.4 million more than the actual/ forecast expenditure for the current regulatory period.

The largest component of this additional expenditure relates to the need to substantially redevelop our Virginia complex to be able to continue to efficiently provide transmission services. As highlighted in our 2023-27 Revenue Proposal it remains important that we provide facilities for contemporary work practices. Our further analysis of options during the current regulatory period has identified that it is not efficient to continue to reinvest in our existing facilities where the underlying infrastructure is over 60 years old. We now propose a major investment in our Virginia complex as the most efficient solution to meet our long-term needs.

Our Business IT capital expenditure forecast for the 2027-32 period is $33.2 million. This is $62 million less than the actual/forecast expenditure for the current regulatory period. This decrease is due to the increased adoption of Software-as-a-Service (SaaS) systems. The increased utilisation of SaaS services means that solutions will more frequently rely on outsourced hosting of services (e.g. cloud services) rather than Powerlink-owned infrastructure and hardware (e.g. servers), while solutions are also offered on a subscription basis. This change in the nature of the IT solutions means that the costs will need to be treated as operating expenditure rather than capital expenditure, in line with accounting standards.

5.6 Contingent projects

Contingent projects are investments that may be needed during the regulatory period should certain trigger events occur. As the need for investment during the regulatory period is not certain, or the costs associated with addressing the need for investment are not sufficiently certain, contingent projects do not form part of the ex-ante capital expenditure allowance[51]. If a contingent project trigger event occurs during the regulatory period, we can apply to the AER to amend the Revenue Determination to include the revenue required to undertake the contingent project. Before it amends the Revenue Determination the AER will assess the prudency and efficiency of the proposed additional expenditure[52].

Generally, contingent projects are significant network augmentation projects that are reasonably required to achieve the capital expenditure objectives set out in the Rules. Such projects are often linked to unique investment drivers, such as commitment of new large loads or retirement of generation, rather than general investment drivers such as expectations of load growth in a region.

We have considered potential contingent projects under two categories of drivers.

5.6.1 Local demand increase and/or generation reduction

Our TAPR identifies potential load developments and generation retirements that could trigger significant expenditure to augment the network to continue to meet our mandated reliability of supply standard. For these projects we propose contingent project triggers that identify the level of additional demand or reduction in generating capacity that will lead to failure to meet our mandated reliability of supply standards.

5.6.2 Integrated System Plan

AEMO's 2024 Integrated System Plan (ISP) identified significant network augmentations that could deliver net market benefits and are part of the optimal development path across the NEM. AEMO declared one of these projects, QNI Connect (Queensland – New South Wales Interconnector), to be actionable and requires that Powerlink and TransGrid commence the RIT-T assessment and publish a Project Assessment Draft Report (PADR) by 25 June 2026. Two other Queensland projects in the 2024 ISP that would ordinarily have been declared as 'actionable' under the Rules were instead flagged to be progressed under Queensland's new Priority Transmission Investment (PTI) framework[53]. Beyond these actionable projects several future ISP projects were identified with optimal timing in Powerlink's future 2032-37 regulatory period. Given the rapid changes occurring in the electricity sector with the retirement of ageing coal-fired generation and rapid uptake of inverter-based resources it is possible that one or more of these projects could be identified in a future ISP as required during the 2027-32 regulatory period.

The Rules provide that where an ISP identified project is declared 'actionable' it is automatically treated as a contingent project, even if it was not identified as such in the relevant TNSPs' Revenue Proposal[54]. While we have not formally proposed any future ISP projects as contingent projects, we have listed those identified by AEMO in the 2024 ISP or in the 2025 Electricity Network Options Report that we consider could be triggered during the 2027-32 regulatory period. This is to aid transparency around the process and ensure customers are fully informed.

[51] National Electricity Rules, clause 6A.8.1.
[52] National Electricity Rules, clause 6A.8.2.
[53] *Energy (Renewable Transformation and Jobs) Act 2024 (Qld),* Part 5.
[54] National Electricity Rules, clause 6A.8.2(a)(2).

Our proposed contingent projects and their indicative costs are summarised in Table 5.5. Appendix 5.07 provides further detail on Powerlink's proposed contingent projects and their triggers.

Table 5.5 - Contingent projects ($million real, 2026/27)

Project name	Type of trigger	Indicative total capital cost
Reliability of supply in the Northern Bowen Basin	Additional customer demand	1,200
Additional synchronous condenser installation	Generation closure/minimum demand	500
Southpine to Nudgee network augmentation	Additional customer demand	200

Potential future ISP projects and their indicative costs are summarised in Table 5.5.

Table 5.6 - Future ISP projects ($million real, 2026/27)

Project name	Type of trigger	Indicative total capital cost
QNI Connect	ISP/Market benefit	1,500 (1)
Augmentation within the Gladstone Zone	ISP/Market benefit	410
Central Queensland and North Queensland augmentation	ISP/Market benefit	1,900
Central Queensland and South Queensland augmentation	ISP/Market benefit	1,500
South-West Queensland network augmentation	ISP/Market benefit	100
Bungaban to Auburn River network augmentation	ISP/Market benefit	400

(1) Cost shown is for Queensland component of project only.

Should any of these triggers occur, or should a project be declared an actionable ISP project, we will undertake the required regulatory processes, including engagement with the AER. Further, should a contingent project application (CPA) be made which offsets capital expenditure already identified in the ex-ante forecast (for example, a line rebuild which results in line refit works no longer being required), we will reduce the CPA by the appropriate amount.

5.7 Deliverability of future expenditure

When developing this capital expenditure forecast, we have predominantly used a bottom-up approach. The resultant forecast was subsequently tested and adjusted using top-down methods that considered our historical capital expenditure trends over the last 10 years. We then undertook a further review of deliverability of the proposed program of work in the 2027-32 regulatory period through application of business as usual program management practices, which considered the volume of work required and future resource capacity.

We have a proven ability to deliver capital projects to meet the needs of Queensland customers for a safe, secure and reliable supply of electricity. Our forecast capital expenditure is more than 50% higher than the actual/ forecast expenditure for the current regulatory period and as a result we have taken several significant steps in the current period to ensure we have the capability to deliver this quantum of work going forward:

- **Major Projects Division** – We have established a dedicated division to oversee the delivery of key portfolios within our capital expenditure program. This initiative is designed to ensure robust project development, governance, and delivery frameworks are applied to major greenfield projects. As part of our ex-ante capital expenditure forecast, the installation of four synchronous condensers in Central Queensland will be managed by this division. The focus will be on ensuring cost-effective delivery and maintaining robust governance throughout the project lifecycle.

- **Portfolio risk management –** We have enhanced our portfolio risk management approach with the deployment of PRS2, an advanced Portfolio Risk System that performs asset data analytics. This supports structured reinvestment planning across asset classes and helps optimise project timing to manage overall network risk.
- **Field delivery resource models –** We have expanded our regional workforce capacity in response to forecast increases in workload across central and northern Queensland. In parallel, we have secured a new Service Level Agreement with our maintenance service provider to ensure that field delivery resources are aligned with projected demand, supporting efficient and reliable network service delivery over the regulatory period.
- **Panel arrangements** – We are consolidating our transmission lines and substations outsourcing arrangements under a newly established panel agreement with contractors to support the efficient delivery of construction works. This enhanced framework will introduce additional delivery partners and incorporate scalable capacity provisions to accommodate future workload increases. The expanded panel structure is expected to foster competitive tension, improve cost efficiency, and support timely execution of capital works across the regulatory period.
- **Supply chain enhancements** – We have leveraged our positive relationships with suppliers to secure new manufacturing capability to minimise lead times and reduce procurement costs. We will continue to develop our procurement practices to reduce supply side risk, securing a supply chain that supports cost-effective delivery of projects.

5.8 Capital expenditure forecasting methodology

We have developed our capital expenditure forecast consistent with the requirements of the Rules[55] and our Expenditure Forecasting Methodology, which was provided to the AER in June 2025 (refer Appendix 5.03). We have also had regard to the AER's 2024 Industry Practice Application Note for Asset Replacement Planning[56].

Information on proposed transmission investments within a 10-year outlook is published in our TAPR and related material[57]. We also refer to AEMO's 2024 ISP. These longer-term plans are particularly relevant to identify contingent projects, which are discussed in Section 5.6.

As we developed our methodology and forecasts for the 2027-32 regulatory period, we engaged with our customers and stakeholders (refer Chapter 3 Customer Engagement). We also regularly engage with our customers and stakeholders on planning and other business-related matters in the normal course of business, including at our annual Transmission Network Forum[58].

5.8.1 Our hybrid forecasting approach

We continue to evolve a hybrid approach to develop our capital expenditure forecasts, which integrates top-down and bottom-up methods.

[55] National Electricity Rules, clause 6A.6.7.
[56] Industry practice application note - Asset replacement planning, Australian Energy Regulator, July 2024.
[57] Refer: https://www.powerlink.com.au/planning-report/transmission-annual-planning-report-2024.
[58] Refer: https://www.powerlink.com.au/engagement-forums.

We have built on the experience, input and feedback gained during our previous revenue determination process and have further refined and improved this approach for the 2027-32 regulatory period. As part of this improvement, we have targeted development of project-specific supporting justification for at least 80% of our total forecast capital expenditure. Depending on the type and stage of development of the project, this may include asset condition assessment reports, applicable asset strategies, project scopes, project estimates, network planning assessments and risk-cost quantification. For lower dollar value replacement capital expenditure projects our forecasting approach will be based on a bottom-up view of project needs developed using forecast asset-specific health indices and informed assumptions in respect of the option presented.

This approach provides several advantages in that it:

- reduces the resources needed to prepare our Revenue Proposal compared to an entirely bottom-up approach
- balances the desire of stakeholders to understand the technical and economic justification for significant forecast investments, while recognising the uncertainty of forecasting capital expenditure needs many years in advance when the technical demands on the transmission network are rapidly changing.
- assists the AER and stakeholders in terms of the time, effort and cost to review and assess our Revenue Proposal.
- addresses concerns expressed by the AER over the use of its Repex Model in our 2023-27 Revenue Proposal.

Some categories of non-network capital expenditure will be forecast using a top-down methodology, whereby the future requirements are based upon a trend of historical expenditure. This will include adjustments to historical capital expenditure where appropriate to remove specific expenditure that does not represent an ongoing trend. Details of the hybrid approach can be found in our Expenditure Forecasting Methodology and a summary is presented in Table 5.7.

Table 5.7 - Summary of Powerlink's hybrid approach

Approach	Capital Expenditure Category	Supporting Information
Bottom-up	Approved projects Load-driven capital expenditure Network reinvestment System services such as system strength and inertia Other major one-off expenditure needs Contingent projects[1]	Description of need, preparation of project specific scope, estimate, planning statement and risk-cost assessment. Note: the level of documentation provided will vary depending on the maturity of the project.
Top-down (trend analysis)	Security / compliance Other network capital expenditure Non-network capital expenditure	Use of a forecasting methodology similar to the base-step-trend approach for forecasting operating expenditure.

(1) Contingent projects are not included in the ex-ante capital expenditure forecast.

Regardless of the methodologies used to forecast our capital expenditure for the purpose of this Revenue Proposal, detailed bottom-up analysis continues to be required and prepared to support final investment approval in our normal course of business. Much of our network capital expenditure is also subject to consultation through the RIT-T process.

5.8.2 Cost estimating methodology

We develop project cost estimates based on a defined scope of work to address an identified investment need.

Depending on the category of project, identified investment needs may be triggered by growth in customer demand exceeding existing network capacity, the condition or obsolescence of existing network assets, the need to enhance building facilities, or the need to upgrade cyber security protection.

We produce our project estimates using a first principles approach, where the estimate is calculated based upon the specific resources and quantities required to complete the defined scope of works (e.g. labour, equipment, materials and subcontracts). We also identify and cost items particular to the project site to account for project-specific site conditions.

Project estimates provide the basis for economic analysis, management decisions, budgets and cost control. Estimates of increasing accuracy may be produced to support these activities as a project progresses, and engagement occurs with external providers.

Network project estimate types

We adopt two formal estimating methodologies for network projects. This reflects a fit-for-purpose approach to estimating based on project complexity, risk and expected cost as detailed below.

- Concept Estimates: produced in response to a high-level project scope requiring the consideration of multiple options, with a wider cost accuracy range these are typically developed for future investment needs or to support the detailed investigation of a confirmed investment need.
- Project Proposals: developed in response to a detailed project scope for a single option, which enables a narrower cost accuracy range, to support the full financial approval of a project consistent with Powerlink's corporate governance framework.

For the purpose of establishing the capital expenditure forecast in our Revenue Proposal, we have scoped and estimated a single option using the Concept Estimate approach. All projects will undergo full option analysis as part of business as usual processes, which also includes application of the RIT-T where appropriate and related public consultation. This will require a new Concept Estimate to compare option costs on a like basis before the preferred option is selected and a Project Proposal completed to provide a more detailed scope and estimate.

Network project estimate classes and accuracy

We produce estimates in line with international recommended practice[59] that are informed by the level of specific project information available at the time the estimate is prepared. The most common class of estimate for Concept Estimates and Project Proposals are class 5 and class 3 respectively. Table 5.8 provides the typical level of detail required and accuracy of each class of estimate produced.

Table 5.8 - Estimate classes and accuracy (source: AACE International, Powerlink)

Estimate Class	Maturity of Project Definition	Typical Accuracy Range	Typical Estimate Type
Class 5	0% to 2%	-50% to +100%	Concept Estimate
Class 4	1% to 15%	-30% to +50%	
Class 3	10% to 40%	-20% to +30%	Project Proposal
Class 2	30% to 75%	-15% to +20%	
Class 1	65% to 100%	-10% to +15%	

[59] Association for the Advancement of Cost Estimating (AACE International), Recommended Practice No. 18R-97.

The estimate classification is derived from the maturity of the data that makes up the project definition, such as the specific items of equipment required, quantities of construction materials, and construction staging. Each project estimate is based upon known quantities where available but will also include assumed quantities based upon recent project examples where necessary.

5.8.3 Capex Model

Our Capex Model compiles all the project cost estimates that make up our capital expenditure forecast and transforms them to produce the key data necessary to support our draft Revenue Proposal. This includes:

- forecast capital expenditure inputs to the Post Tax Revenue Model (PTRM) and
- forecast capital expenditure data to be included in the Reset Regulatory Information Notice (RIN).

Depending on where a project is in its lifecycle, its forecast expenditure will be expressed as either:

- $nominal – where the project is already approved; or
- $real, 2025/26 – where the project is not approved and an estimate has been prepared for the purposes of the draft Revenue Proposal.

Where forecast expenditure is expressed in $nominal the expenditure is de-escalated to $real, 2026/27 using the forecast of inflation from the PTRM. Where forecast expenditure is expressed in $real, 2025/26 the expenditure is first escalated to a $nominal basis using the appropriate real price escalators set out in Chapter 7 Escalation Rates. The resulting $nominal expenditure is then de-escalated to $real, 2026/27 using the forecast inflation from the PTRM.

Each project is assigned a project type, such as Power Transformer, Secondary Systems, IT – Non-recurrent, etc. The project type specifies the percentage breakdown of expenditure into the categories of direct materials, direct labour, contract costs and other costs. This breakdown allows the appropriate real cost escalation to be applied to each project in the forecast. Each project also includes a percentage breakdown of the forecast expenditure into asset classes.

This process ensures all forecast capital expenditure is expressed on a consistent basis that meets the requirements of the PTRM and supports the reporting for the Reset RIN.

5.8.4 Key inputs and assumptions

Table 5.9 summarises the key inputs and assumptions we applied to develop our forecast capital expenditure for the 2027-32 regulatory period.

Table 5.9 - Inputs and assumptions for our capital expenditure forecast

Variable/assumption	Description
Forecast demand and generation	• The electricity demand forecast to be adopted for our Revenue Proposal will be the Central Scenario outlook in Powerlink's 2025 Transmission Annual Planning Report, expected to be published in October 2025. • The location and capacity of existing and committed generation in Queensland is sourced from AEMO, unless modified following specific advice from relevant participants. • Information about existing and committed embedded generation and demand management within distribution networks is provided by Distribution Network Service Providers (DNSP).

Variable/assumption	Description
Transmission reliability of supply standard	• Clause 6.2 of our Transmission Authority[60] obligates us to plan and develop the transmission network such that mandated power quality and reliability of supply standards will be met. • This includes a requirement to plan and develop the transmission network to be able to supply the forecast maximum demand, with no more than 50MW or 600MWh of customer supply curtailed, even with the most critical network element out of service.
Integrated System Plan	• AEMO's 2024 ISP sets out a whole-of-system, least-cost development path for the NEM over a 20 year outlook. • Where the ISP identifies future augmentation of a part of Powerlink's transmission network in the optimal development path we will consider reinvestment in existing assets, and future easement requirements in that context.
System Security Reports	• AEMO's 2024 system security reports includes forecasts of system security services requirements for system strength, inertia and network support and control ancillary services (NSCAS). Powerlink is required to procure prescribed transmission services (network and/or non-network) to meet these forecast needs in its capacity as System Strength Service Provider (SSSP), Inertia Service Provider, and TNSP respectively.
Cost escalators and risk	• The main input cost components of our capital expenditure forecasts are labour costs (internal and external), various metals commodities (aluminium, copper and steel) and general plant and equipment. • The cost escalators we have applied are outlined in Chapter 7 Escalation Rates.

Demand and energy forecast

Powerlink's 2024 TAPR central scenario load forecasts are the basis for our planning analysis. The central scenario forecast published in the 2024 TAPR included a new block load for a hydrogen project. However, recent developments have lowered the likelihood of this project proceeding and we have removed it from the central scenario forecast for the 2027-32 Revenue Proposal analysis.

The load forecast is developed through a methodology that projects future electricity demand. Historical actual demand and energy data forms the foundation, identifying trends and patterns in consumption. These data points establish a baseline for understanding usage over time.

A further seven additional input datasets are included to form the final forecast projections. These inputs are sourced from AEMO, Energy Queensland and external consultants for market or industry trends. Powerlink also uses internal data, including confidential customer information. The annual forecast process requires all TNSP connected customers to provide a 10-year load forecast and through this process a number of existing connections have signalled increases in demand and energy due to decarbonisation ambitions.

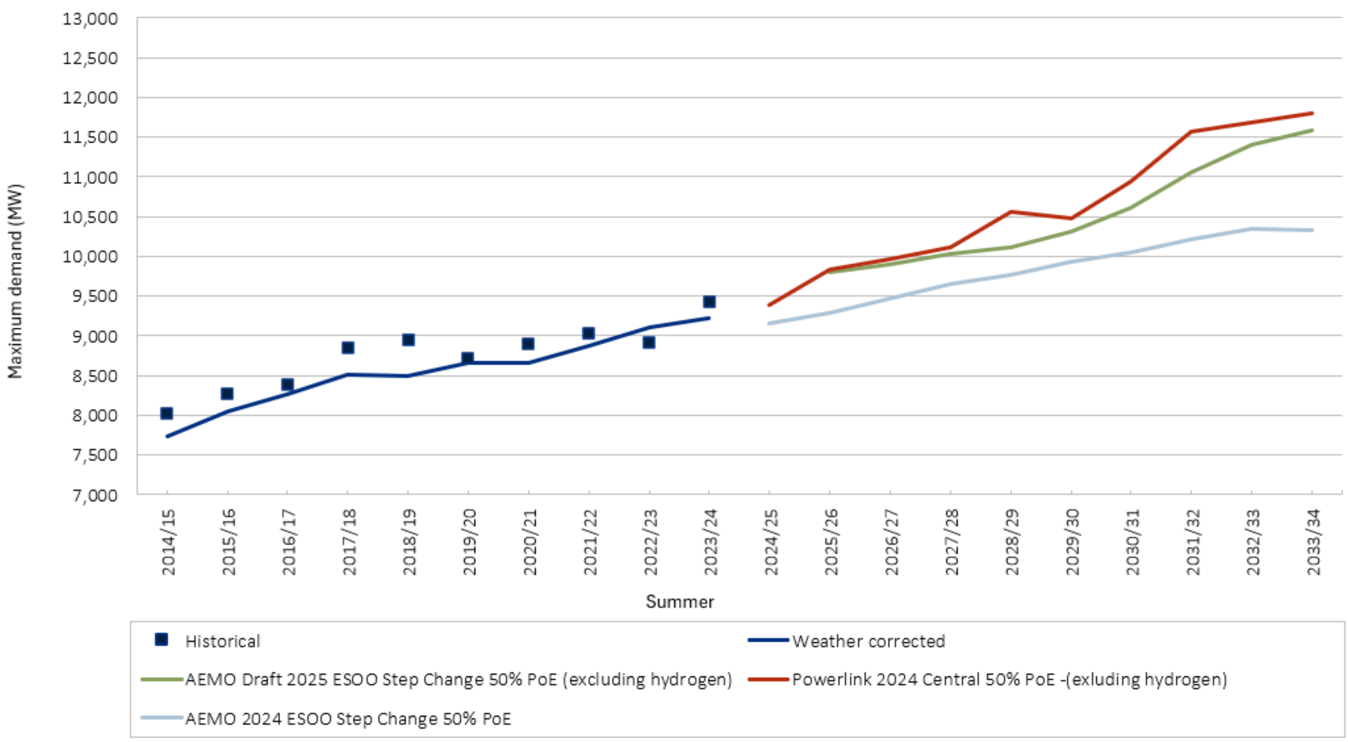
The resultant central scenario demand forecast (adjusted to exclude hydrogen load) is shown in Figure 5.2 compared with AEMO's 2024 and 2025 Electricity Statement of Opportunities (ESOO) forecasts. The alignment with AEMO's 2025 Step Change scenario forecast is significantly closer compared to their forecast in 2024. Powerlink's forecast remains higher than AEMO's due to the difference in the input assumptions used. The main

[60] Transmission Authority Number T01/98 issued by the Queensland Energy Regulator under the Electricity Act 1994 (Qld).

contributing factor is the magnitude and pace of electrification of industry located within the Gladstone region. Network limitations due to this load growth are being addressed through the current Gladstone Project PTI process.

Other forecasted demand growth can generally be accommodated within the existing network capacity. However, in certain areas where the planning standard is nearing its limit, schemes are being implemented to effectively manage the network limitations.

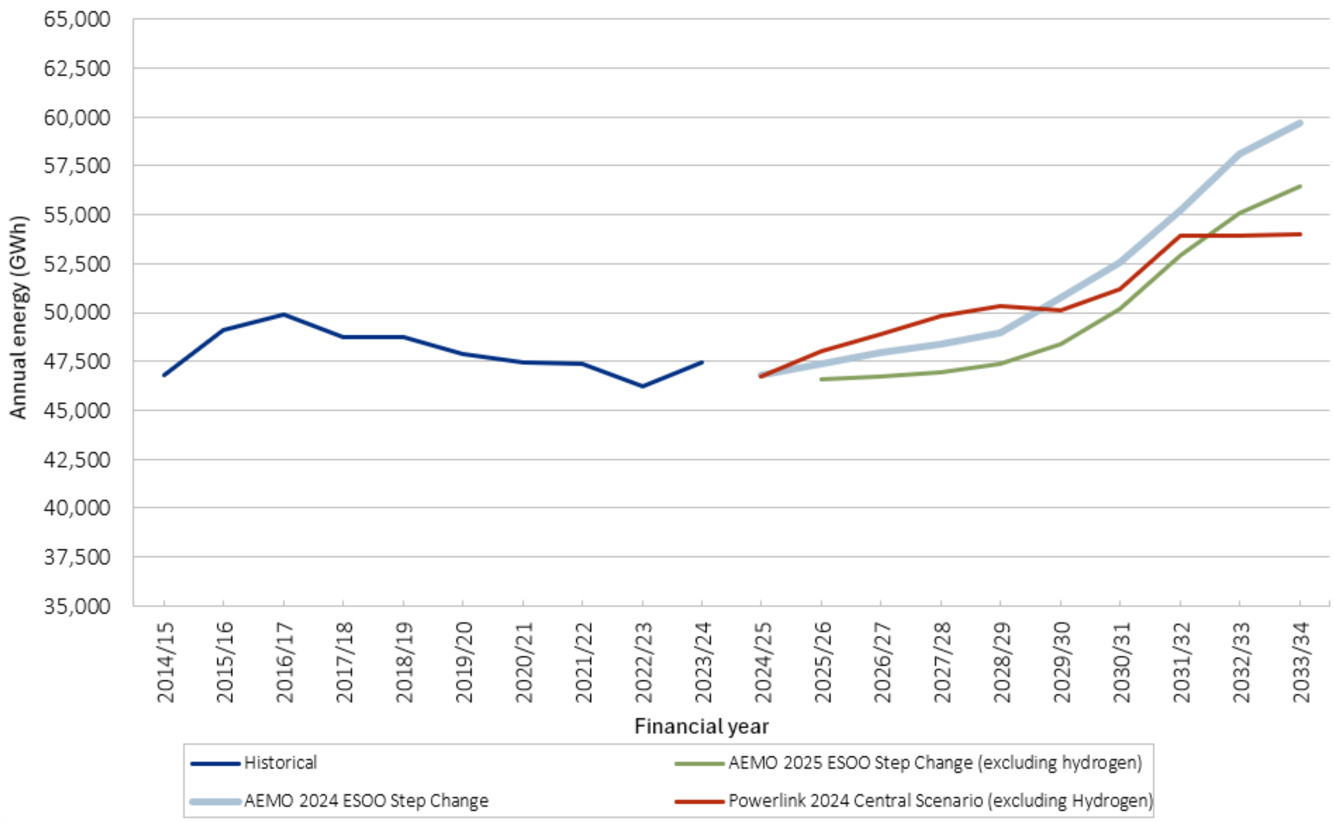
Figure 5.2 - Comparison of the 2024 TAPR demand forecast with AEMO's 2024 and 2025 ESOO demand forecast



Note: AEMO's 2024 and (draft) 2025 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison.

The forecast annual energy consumption (Figure 5.3) shows steady average annual growth over the forecast horizon.

Figure 5.3 - Comparison of the 2024 TAPR energy forecast with AEMO's 2024 and 2025 ESOO consumption forecast



Note: AEMO's 2024 & (draft) 2025 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison.

Powerlink's forecasting process also provides sub regional forecasts at more granular levels than previously available. This enables Powerlink to assess demand drivers relevant to the geographical area being assessed.

Asset planning criteria

Powerlink has been issued a Transmission Authority by the Queensland Government. The Transmission Authority requires Powerlink to plan and develop the network so that only a limited amount of customer demand and energy is at risk of not being supplied during the most critical single contingency event. These demand and energy limits are set in the Transmission Authority at 50MW and 600MWh.

The Transmission Authority also includes a requirement to apply good electricity industry practice which, in turn, necessitates the use of a range of supporting technical standards.

The reliability of supply standard, along with the supporting technical standards, comprises our Asset Planning Criteria Framework. Our Asset Planning Criteria Framework is provided as a supporting document to our Revenue Proposal.

Asset reinvestment criteria

Powerlink's Asset Management System ensures assets are managed in a manner consistent with the Asset Management Policy and overall corporate objectives to deliver safe, secure, reliable and cost-effective services. We demonstrate this by adopting a proactive approach to asset management that optimises whole of life-cycle costs, benefits and risks, while ensuring compliance with applicable legislation, regulations, standards, statutory requirements, and other relevant instruments.

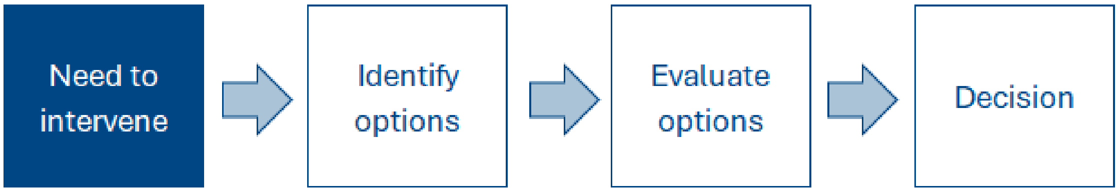
Our Asset Reinvestment Criteria Framework defines the methodology that we use to assess the need and timing for intervention on network assets to ensure that industry compliance obligations are met. The methodology aims to improve transparency and consistency within the asset reinvestment process, enabling our customers and stakeholders to better understand the criteria to determine the need and timing for asset intervention.

This framework is relevant where the asset condition changes so it no longer meets its level of service or complies with a regulatory requirement. This category of reinvestment is triggered when the existing asset has degraded over time and no longer provides the required standard of service as prescribed within applicable legislation, regulations and standards.

The trigger to intervene needs to be identified early enough to provide an appropriate lead time for the asset reinvestment planning and assessment process. The need and timing for intervention is defined when business as usual activities (including routine inspections, minor condition based and corrective maintenance and operational refurbishment) no longer enable the network asset to meet prescribed standards of service due to deteriorated asset condition.

Our Asset Reinvestment Process (refer Figure 5.4) enables timely, informed and prudent investment decisions to be made that consider all economic and technically feasible options, including non-network alternatives or opportunities to remove assets where they are no longer required. An assessment of the need and timing for intervention is the first stage of this process.

Figure 5.4 - Asset reinvestment process



Our Asset Reinvestment Criteria Framework has been developed progressively, and we have engaged with our Customer Panel during the course of its development. The principles set out in the Asset Reinvestment Criteria Framework underpin the timing of specific reinvestment projects in this Revenue Proposal. The Asset Reinvestment Criteria Framework is provided as a supporting document to our Revenue Proposal.

6 Forecast Operating Expenditure

6.1 Introduction

This chapter outlines Powerlink's operating expenditure forecasts for the 2027-32 regulatory period.

Our operating expenditure enables the operation and maintenance of our network, as well as the business activities that support the delivery of prescribed transmission services.

Note that references in this chapter to total operating expenditure reflect underlying operating expenditure, unless otherwise stated. For clarification, our underlying operating expenditure excludes movements in provisions, debt raising and network support costs. This is explained further in section 6.4.1.

Key highlights:

- Our total operating expenditure forecast for the 2027-32 regulatory period is $1,805.5 million (excluding debt raising costs) and $1,831.3 million (including debt raising costs).
    - This represents a $333.0 million, or 22%, increase from actual/forecast operating expenditure for the 2022-27 regulatory period (including debt raising costs).
- Our forecasts are based on the Australian Energy Regulator's (AER's) base-trend-step methodology.
- We have selected the 2025/26 year as our base year as this will provide the most recent actual costs at the time the revised Revenue Proposal is submitted in December 2026. We have engaged HoustonKemp to perform an independent assessment of the efficiency of our proposed base year expenditure.
    - Powerlink's operating expenditure efficiency is forecast to decline in 2024/25 and 2025/26 due to increases in operating expenditure, and
    - comparative data is not available at this time to determine whether the decline in operating expenditure efficiency reflects the broader industry trend.
- Powerlink considers that the benchmarking approach, which provides historical context, does not reflect the rapid change in the operating environment and will engage with customers, stakeholders and the AER further prior to lodging our Revenue Proposal in January 2026.
- We have included four step changes at a total of $101.6 million in our total operating expenditure forecasts. The step changes reflect material costs not included in our base year to:
    - uplift physical security
    - transition to cloud-based computing solutions
    - address sole overnight control room operator risk, and
    - maintain synchronous condensers.
- We have proposed an alternative option for the rate of change of output growth to better reflect the services provided by transmission service providers. If included, this results in an overall increase of $54.4 million to the total operating expenditure forecast.
- We have included category-specific forecasts for insurance costs, Australian Energy Market Operator (AEMO) participant and cyber security fees and debt raising costs.

6.2 Regulatory requirements

The National Electricity Rules (Rules)[61] require that we must submit our forecast operating expenditure for the 2027-32 regulatory period in our Revenue Proposal.

Our Expenditure Forecasting Methodology (refer Appendix 5.03) discusses our approach to forecasting operating expenditure. Our operating expenditure forecasting methodology is designed to produce operating expenditure forecasts that satisfy the requirements of the Rules[62]. It will allow us to maintain and operate the network safely, meet the expected demand for prescribed transmission services and comply with all applicable regulatory obligations and requirements. We have also had regard to the AER's 2024 Expenditure Forecast Assessment Guideline for Electricity Transmission[63].

6.2.1 Operating expenditure objectives

We consider that our forecast operating expenditure achieves the operating expenditure objectives set out in the Rules. This is summarised in Table 6.1 and discussed in detail in Appendix 5.02.

Table 6.1 - How we meet the operating expenditure objectives

Operating expenditure objective	How our proposal meets this objective
Meet or manage the expected demand for prescribed transmission services over the period	Maximum demand is forecast to gradually increase over the 2027-32 regulatory period, while minimum demand is forecast to decline. We have included costs associated with maintaining synchronous condensers which we will commission during the regulatory period to provide essential system strength services. Our operating expenditure reflects a prudent and reasonable cost forecast to operate and maintain our transmission network and deliver safe, secure and reliable outcomes in an increasingly complex operating environment.
Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services	We are subject to regulatory obligations as the holder of a Transmission Authority under the *Electricity Act 1994 (Qld)* and as a registered Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM). As a corporation, we are also subject to various other environmental, cultural heritage, planning approval, Workplace Health & Safety, financial and other regulations. Our compliance with these regulatory obligations and requirements is encompassed in our Asset Management Framework and associated policies and procedures, which provide the foundation for our operating and maintenance activities. New regulatory obligations or requirements have also been assessed to determine the potential effect on forecast operating expenditure in the 2027-32 regulatory period.

[61] National Electricity Rules, clause 6A.6.6 and Schedule 6A.1, clause S6A.1.2.
[62] National Electricity Rules, clause 6A.6.6.
[63] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.

Operating expenditure objective	How our proposal meets this objective
Maintain the quality, reliability and security of supply of prescribed transmission services and maintain the safety, reliability and security of the transmission system through the supply of prescribed transmission services	Our operating expenditure forecasts include prudent provision to maintain the safety of the transmission system and deliver reliable services to our customers. An appropriate balance of operating and capital expenditure has been proposed within our 2027-32 Revenue Proposal to ensure network assets deliver the required safety, reliability, availability and quality of supply in the most prudent and efficient manner.
Contribute to achieving emissions reduction targets through the supply of prescribed transmission services	Powerlink plays a pivotal role in Queensland's energy transition through its transmission infrastructure. As Queensland's System Strength Service Provider, Powerlink is investing in synchronous condensers to address system strength requirements to maintain fault levels for legacy equipment and support voltage stability for new inverter-based resources (IBR). We have included costs associated with maintaining these synchronous condensers to reliably deliver the necessary system strength services in our forecast.

6.3 Operating expenditure categories

We have retained the same broad categories of operating expenditure from the current 2022-27 regulatory period, with the addition of one new non-controllable expenditure category, AEMO participant and cyber security fees, as outlined in Table 6.2.

Table 6.2 - Operating expenditure categories

Operating expenditure category	Definition	Prescribed transmission service
Controllable operating expenditure		
Direct operating and maintenance		
Field maintenance	Includes all field activities to ensure plant can perform its required functions. There are four types of field maintenance: routine, condition-based, emergency and deferred corrective maintenance. Field maintenance costs include all labour and materials needed to perform the required maintenance tasks. Each field maintenance type is further separated into five major asset type categories: substations, transmission lines, secondary systems, communications and vegetation.	Exit, entry, Transmission Use of System (TUOS) and common services
Operational refurbishment	Involves activities that return an asset to its pre-existing condition or function, or activities undertaken on specific parts of an asset to return these parts to their pre-existing condition or function. These refurbishment activities do not involve increasing the capacity or capability of the plant or extending its life beyond its original design.	Exit, entry, TUOS and common services

Operating expenditure category	Definition	Prescribed transmission service
Maintenance support	Includes activities where maintenance service providers undertake asset support functions in the field as well as non-field functions supporting maintenance functions for the operate/maintain phase of the asset life cycle. Examples of activities include maintenance procedure development, performance management and maintenance auditing. This category also includes local government rates charges, water charges, electricity charges and charges for permits and licencing for Powerlink.	Exit, entry, TUOS and common services
Network operations	Includes control centre functions as well as those additional activities required to ensure the safe, secure, reliable and efficient operational management of the Queensland transmission network.	Exit, entry, TUOS and common services
Other controllable expenditure		
Asset management support	Activities required to support the strategic analysis, development and ongoing asset management of the network. There are four major sub elements: network planning, business development, regulatory management and operations.	Exit, entry, TUOS and common services
Corporate support	Corporate support encompasses the support activities required by Powerlink to ensure adequate and effective corporate governance. This includes corporate and direct corporate support charges and also revenue reset costs.	Common services
Non-controllable operating expenditure		
Insurances	This covers both insurance premiums for Powerlink's network and non-network assets and a self-insurance allowance to provide cover for losses that cannot be insured.	Common services
Network support	Network support refers to costs associated with non-network solutions used by Powerlink as a cost-effective alternative to network investment. These costs can be for various services including inertia provision and system strength. From 2025/26, Powerlink will incorporate forecast system strength network support payments in its prescribed transmission services prices for the relevant year, subject to the AER's approval via an annual network support pass through application.	TUOS services
AEMC levy	Since 2014/15, the *Electricity Act 1994 (Qld)* has required electricity transmission networks in Queensland to pay a share of the State's cost to fund the Australian Energy Market Commission (AEMC).	Common services

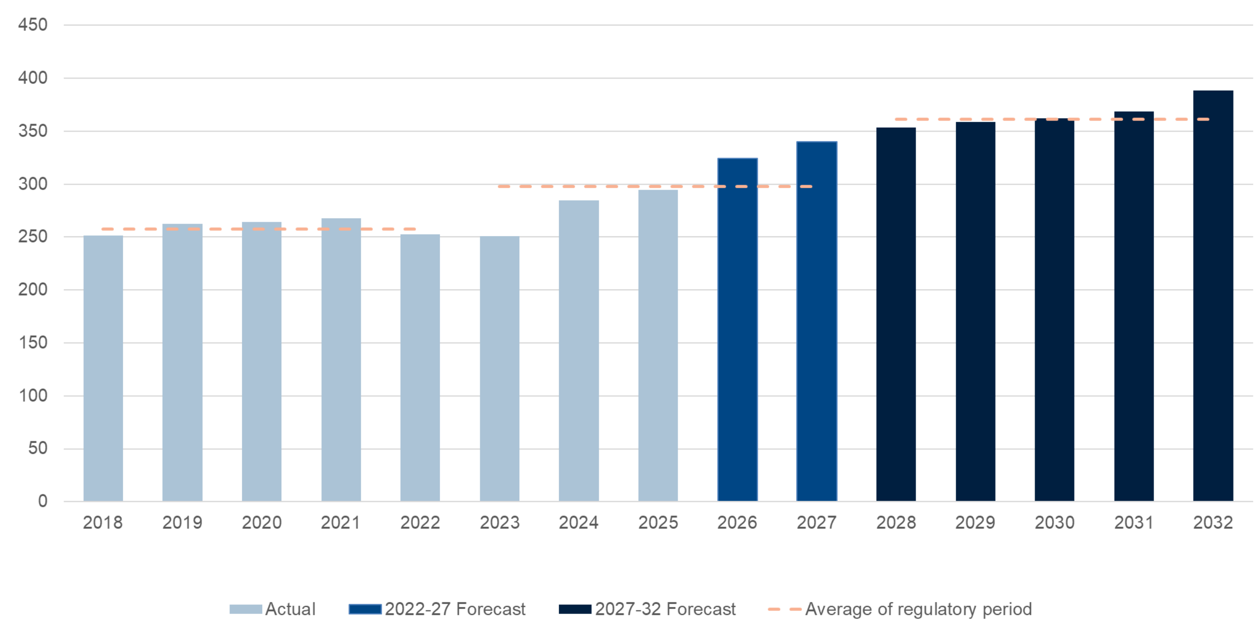
Operating expenditure category	Definition	Prescribed transmission service
AEMO participant and cyber security fees	Since July 2023, TNSPs have been levied a portion of National Electricity Market (NEM) participant fees from AEMO. A transitional rule[64] has been in place that supported the recovery of these fees by passing them directly through to customers for a transitional period. For Powerlink, this transitional period will end on 30 June 2027. Following the transitional period these costs are to be recovered through existing mechanisms under the incentive-based revenue determination framework. AEMO is also introducing a new cyber security fee to recover costs associated with its expanded cyber security roles and responsibilities. The recovery of these costs will commence from 1 July 2025.	Common services
Debt raising costs	Debt raising costs relate to costs incurred by an entity over and above the debt margin.	Common services

6.4 Total forecast operating expenditure

6.4.1 Total forecast operating expenditure

Our total forecast operating expenditure for the 2027-32 regulatory period, along with our actual/forecast expenditure for the previous and current regulatory periods, is shown in Figure 6.1.

Figure 6.1 - Total actual historical and forecast operating expenditure ($million real, 2026/27)



[64] National Electricity Rules, rule 11.153.

Our total forecast operating expenditure is $1,805.5 million (excluding debt raising costs). This represents $308.6 million (21%) increase from actual/forecast operating expenditure for the 2022-27 regulatory period. With debt raising costs included, our total forecast operating expenditure is $1,831.3 million, a $333.0 million (22%) increase from actual/forecast operating expenditure in the 2022-27 regulatory period.

To derive this forecast, we have applied the AER's base-trend-step approach.

We have proposed 2025/26 as our efficient base year. We have reviewed our expenditure in this year on a category basis and have had the efficiency of this base year independently assessed (refer Section 6.6.1).

We applied a rate of change to our base year and have developed an alternative option for this rate of change that we are considering. Our application of the rate of change elements is discussed further in Section 6.6.2 and broadly reflects the change in output growth, price growth and productivity growth.

We have included step changes for material new costs that we will incur that are not in our base year operating expenditure. These are discussed further in section 6.6.3, in summary:

- uplift physical security, associated with meeting our obligations as a critical infrastructure provider under the *Security of Critical Infrastructure (SOCI) Act (2018)*
- transition to cloud-based computing solutions, in line with industry trends, and the appropriate accounting treatment for those costs, with an associated reduction in capital expenditure
- address sole overnight control room operator risk, as supported by AEMO, and
- maintain synchronous condensers, which are required to meet our system security requirements.

We have provided category-specific forecasts for the AEMO participant and cyber security fees, insurances and debt raising costs (refer Section 6.7).

Our forecast expenditure by category is shown in Table 6.3.

Table 6.3 - Forecast operating expenditure by category ($million real, 2026/27)

Operating expenditure category	2028	2029	2030	2031	2032	Total
Field maintenance	116.5	117.6	119.0	121.0	133.6	**607.7**
Operational refurbishment	42.5	43.0	43.5	44.2	45.1	**218.3**
Maintenance support	32.3	32.6	32.9	33.3	33.9	**164.9**
Network operations	39.7	39.9	40.2	40.7	41.3	**202.0**
Asset management support	41.3	41.7	42.2	42.9	43.8	**211.9**
Corporate support	48.4	50.1	48.7	48.8	51.2	**247.3**
Total controllable operating expenditure	**320.7**	**324.9**	**326.5**	**330.9**	**349.0**	**1,652.0**

Operating expenditure category	2028	2029	2030	2031	2032	Total
Insurance premiums	8.0	8.7	9.6	10.9	11.9	**49.1**
Self-insurance	2.6	2.8	3.0	3.2	3.4	**14.9**
Network support (alternative support) [(1)]	-	-	-	-	-	**-**
AEMC levy	6.0	6.0	6.1	6.2	6.3	**30.7**
AEMO participant and cyber security fees	11.1	11.4	11.7	12.1	12.4	**58.8**
Debt raising costs	4.8	5.1	5.2	5.3	5.4	**25.8**
Total other operating expenditure	**32.6**	**34.0**	**35.7**	**37.7**	**39.4**	**179.3**
Total operating expenditure	**353.3**	**358.9**	**362.2**	**368.6**	**388.4**	**1,831.3**
Total operating expenditure (excluding debt raising costs)	348.4	353.8	357.0	363.2	383.0	1,805.5

(1) This refers to payments made for network support services that are not system security network support payments (NSCAS, inertia service, system strength service), as an alternative to network augmentation. We forecast no alternative support costs in the 2027-32 regulatory period at this time. System security network support costs are not included in our operating expenditure forecast and will be recovered through transmission pricing.

6.5 Operating expenditure forecasting methodology

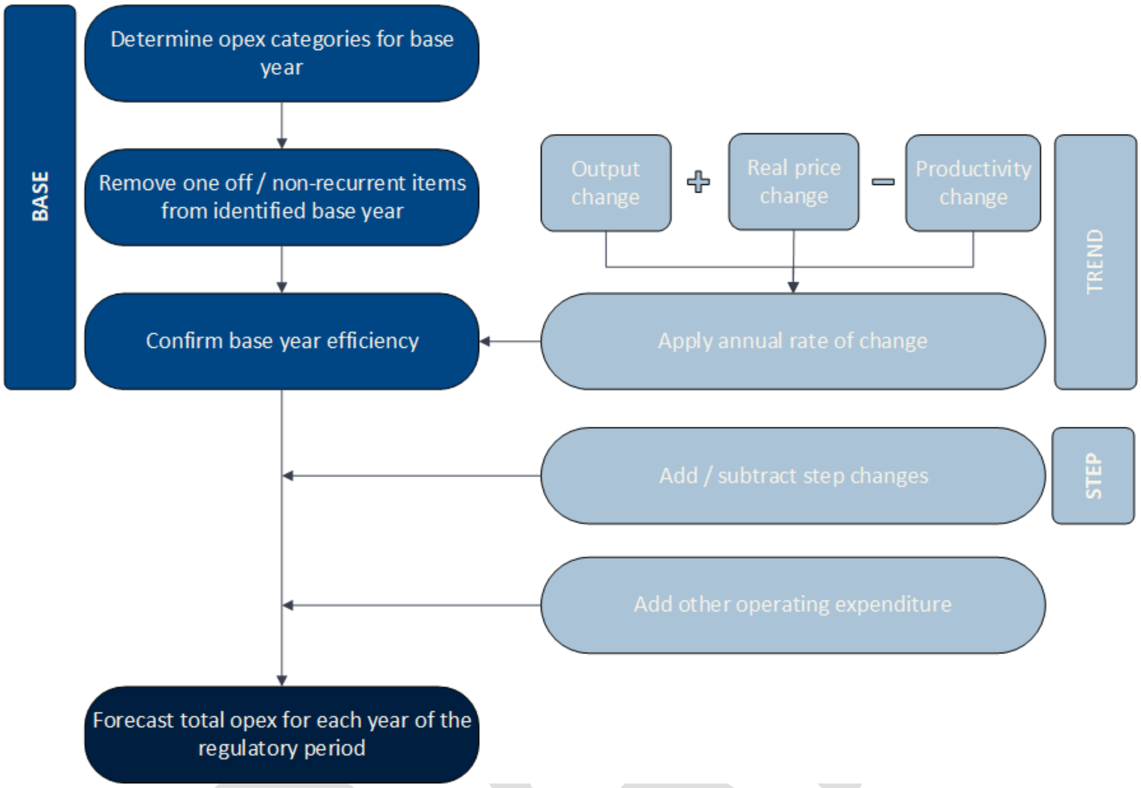
We have based our approach on the AER's 2024 Expenditure Forecast Assessment Guideline for Electricity Transmission[65]. The AER's base-trend-step methodology was used for most operating expenditure categories, with category-specific (or bottom-up) forecasts developed for the AEMO participant and cyber security fees, insurances, network support costs (alternative support) and debt raising costs.

Our forecasting approach is consistent with our Expenditure Forecasting Methodology submitted to the AER in June 2025. The methodology used to prepare our operating expenditure forecast is summarised in Figure 6.2 and explained in the following sections. Further information on our approach is provided as Appendix 5.01.

We noted in our Expenditure Forecasting Methodology that we intended to review the appropriateness of the output measures. We engaged with the Revenue Proposal Reference Group (RPRG) on this in July 2025 and have developed an alternative forecast based on a change to the output growth measures. We have provided more detail on this in section 6.6.2.

[65] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.

Figure 6.2 - Powerlink's operating expenditure forecasting methodology



6.6 Application of the base-trend-step methodology

Note for the draft Revenue Proposal: For the purposes of this draft Revenue Proposal, information from the Economic Benchmarking Results for the AER's 2024 TNSP Annual Benchmarking Report has been used. We will confirm and publish further information as part of our Revenue Proposal in January 2026.

This section outlines how we have applied the AER's base-trend-step methodology to forecast our operating expenditure, and the inputs and assumptions used for each element of the base-trend step. The base-trend-step approach consists of the following:

- determine an efficient base year from which to forecast operating expenditure (Section 6.6.1)
- establish an annual rate of change to trend forecast operating expenditure (Section 6.6.2)
- assess step changes in operating expenditure (Section 6.6.3) and
- add other category specific operating expenditure (Section 6.7)

6.6.1 Efficient base year

Base year selection

We have selected 2025/26 as the base year for use in our base-trend-step model. This base year has been selected as it is reflective of a typical year of operations. For this draft Revenue Proposal, and the Revenue Proposal we will submit in January 2026, we will apply a forecast for our 2025/26 base year. For our Revised Revenue Proposal in December 2026, we will apply the 'revealed cost' in line with the AER's preference[66].

We considered the use of 2024/25 as a potential base year from which to forecast operating expenditure for the next regulatory period as it represents the latest year of audited accounts prior to lodging our Revenue Proposal. However, this is not a typical year of operation for the following reasons:

- there are new regulatory and compliance costs that we will incur to meet our SOCI Act obligations, maintain a Security Profile (SP-2) maturity level for cyber security and address arc flash electrical safety risks that are not revealed in 2024/25; and
- the volume of maintenance work undertaken was lower than required ongoing levels with both routine and non-routine maintenance activities impacted by restricted access to numerous sites across the network.

As a result, we determined that 2025/26 is the most appropriate choice for our base year operating expenditure. We have engaged HoustonKemp to undertake an independent review of the efficiency of our 2025/26 operating expenditure and our performance against other TNSPs. This is discussed further in this section and HosutonKemp's report is provided in Appendix 4.01.

Base year adjustments

We have reviewed forecast expenditure in the base year for non-recurrent items or items that are not considered to reflect an efficient level of recurrent operating expenditure. We have adjusted for a portion of Operational Technology licences that will not continue after 2025/26, a reduction in lease costs and an adjustment for the costs associated with the preparation of the Revenue Proposal.

Our approach to remove this expenditure is consistent with the AER's 2024 Expenditure Forecast Assessment Guideline. We will refine our base year adjustments to align with the revealed cost in our Revised Revenue Proposal. We outline these adjustments and the resultant base year expenditure in Table 6.4.

Table 6.4 - Adjusted expenditure items in the 2025/26 base year

Operating expenditure category	$million (real 2026/27)
2025/26 unadjusted base year controllable operating expenditure	312.8
Adjustment for Operational Technology Licences not continuing	(0.4)
Adjustment for Lease Rentals	(0.5)
Adjustment for Revenue Reset preparation	(6.0)
2025/26 base year controllable operating expenditure – efficient base year	**305.9**

Operating expenditure associated with the AEMO participant and cyber security fees, insurances, network support and debt raising is not included in the base year, as we have taken a category specific approach to forecast these items (refer Section 6.7).

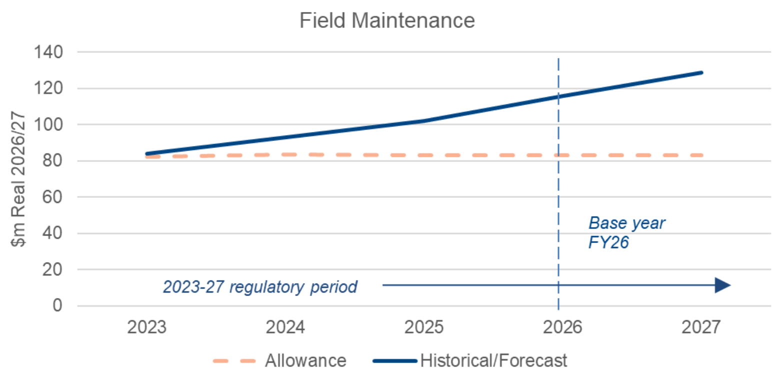
[66] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.

Category analysis of controllable operating expenditure

To confirm the reasonableness of our selected base year, we assessed the relative performance of each major category of controllable operating expenditure for the current 2022-27 regulatory period. These categories are trended under the base-trend-step methodology. Other non-controllable expenses have been forecast as category specific items using a zero-based approach and therefore were not assessed.

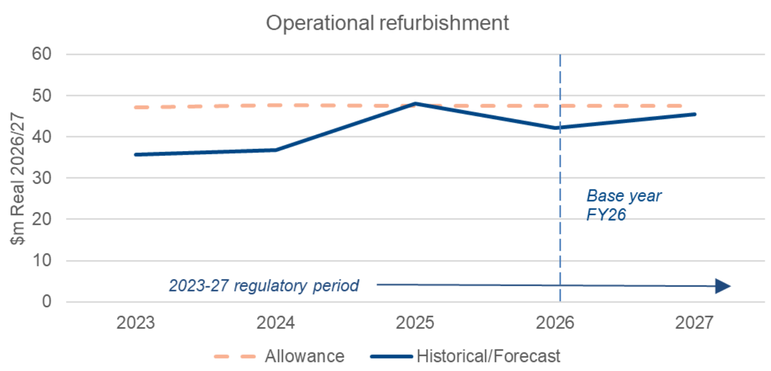
The result of this analysis, shown in Figure 6.3, highlights that at a category level, the proposed 2025/26 base year is more reflective of the ongoing costs required to maintain and operate the network.

Figure 6.3 - Category analysis of controllable operating expenditure ($million real, 2026/27)

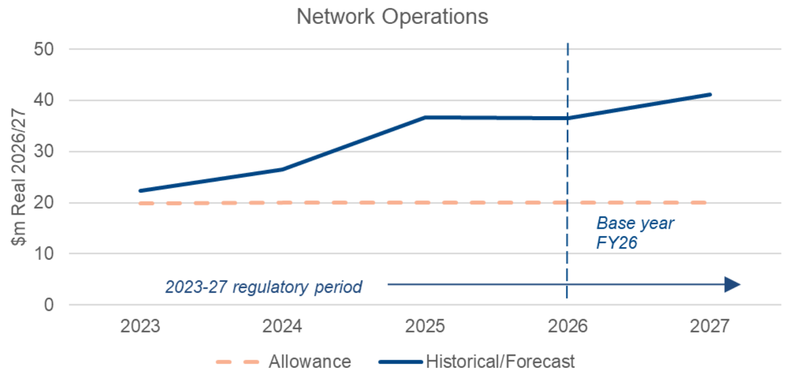


Maintenance in 2024/25 was disrupted by limited access to 24 substations due to a safety concern related to current transformers, and the response to Tropical Cyclone Alfred. This led to the cancellation and rescheduling of some maintenance work, such that the volume was below ongoing required volumes. The 2025/26 forecast reflects maintenance volumes aligned with expected needs during the upcoming regulatory period.

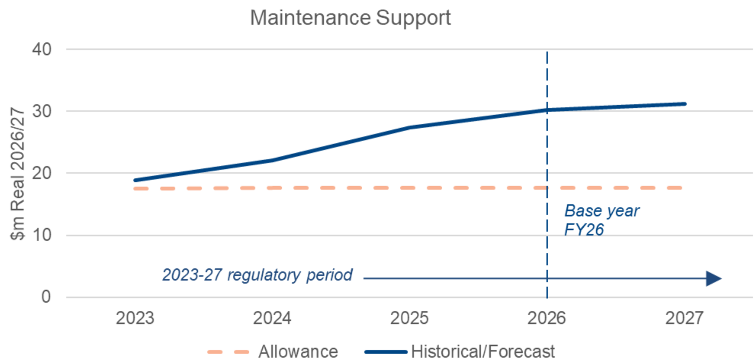
From 2025/26 we have forecast the full cost of compliance with new electrical safety obligations addressing arc flash risk near energised equipment, effective from January 2025.



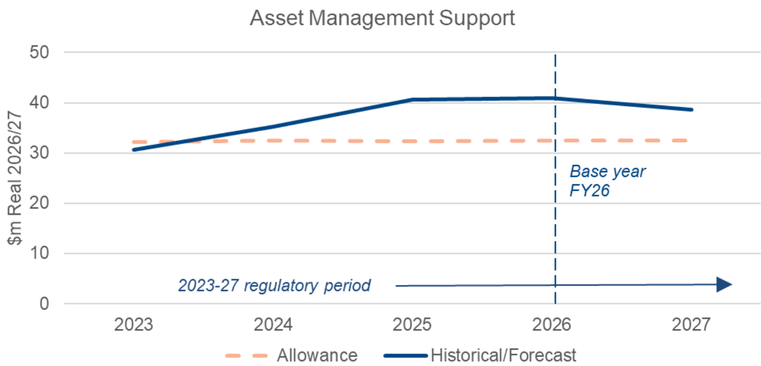
The ongoing insulator replacement program forms the core of the refurbishment expenditure. This is forecast to continue at a consistent level for the next regulatory period.



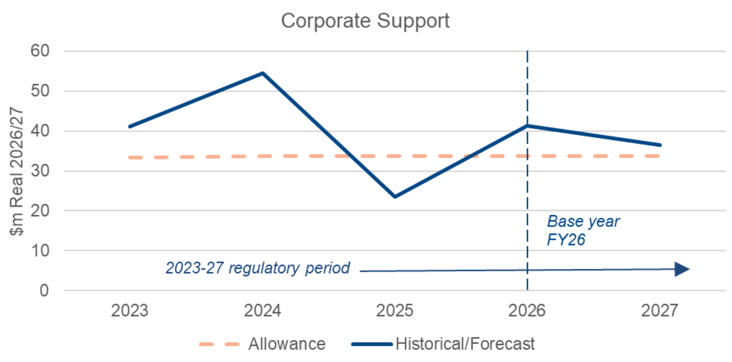
As the transmission system evolves and complexity increases, so does the effort required to maintain safe, secure and efficient transmission operations. There are increasing requirements for more engineering studies, alarm responses, simulations, contingency planning and network support. Additional increases are anticipated to mitigate risks of sole overnight operator network monitoring.



Expenditure in 2025/26 reflects ongoing recurrent costs, with additional spend driven by changes to management of electrical authorisations and investigations into plant condition and failures. A base year adjustment is proposed to account for reductions in leases and changes in OT licensing.



Expenditure increases in 2025/26 reflect strategic planning for the future network, including network simulation tools, operating schemes, system restart and contingency plans and network support activations. We consider these costs are representative of ongoing requirements in this category.



Expenditure in 2025/26 reflects ongoing IT support and licensing costs and expenditure related to maintaining our cyber security maturity level of SP-2 under AESCSF[67]. We have commenced uplifting our management of physical security to meet obligations under the SOCI Act in 2025/26, but further improvements are required in the 2027-32 regulatory period. The base year will be adjusted to exclude non-recurrent costs of preparing our Revenue Proposal.

Benchmarking of base year

This section provides detail about our benchmarking outcomes relative to our proposed 2025/26 base year. Further information about our historical benchmarking performance is included in Chapter 4 Historical Capital and Operating Expenditure.

Benchmarking plays a role in the AER's assessment of TNSP performance and expenditure forecasts, particularly with respect to base year operating expenditure efficiency and trends. The AER has acknowledged that with only a small number of TNSPs in Australia, benchmarking and efficiency comparisons are difficult[68].

We engaged HoustonKemp to undertake an independent review of our base year operating expenditure. As part of its review, HoustonKemp benchmarked our expenditure against other TNSPs and examined productivity trends. Comparative data for other TNSPs is available to the 2023/24 financial year.

Key findings were:

- Powerlink's operating expenditure efficiency has declined in 2023/24 and is forecast to continue to decline in 2024/25 and 2025/26 due to increases in operating expenditure
- The decline in 2023/24 reflects the broader industry trend, and
- comparative data from other TNSPs is not available at this time to determine whether Powerlink's decline in operating expenditure efficiency in 2024/25 and forecast decline in 2025/26 continues to reflect the broader industry trend.

Powerlink recognises that the AER undertakes ongoing development of its benchmarking approach over time but considers that the approach, which provides historical context, has not been able to reflect the rapid change in the operating environment experienced by Powerlink and other network businesses, particularly over the last four years. In its most recent report in November 2024, the AER acknowledged that the changing operating environment for transmission network businesses may be reflected in input costs but may not be recognised in outputs considered[69].

We discuss a potential alternative measure of output growth in Section 6.6.2, which may be a suitable substitute output measure for benchmarking. We will investigate this and engage with our stakeholders and the AER prior to lodging our Revenue Proposal in January 2026.

---

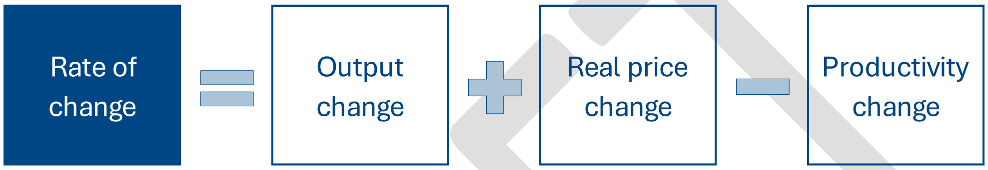
[67] The Australian Energy Sector Cyber security Framework (AESCSF) is a cyber security framework developed for the Australian energy sector that leverages recognised industry frameworks and references global best-practice control standards.
[68] 2024 Annual Benchmarking Report – Electricity Transmission Network Service Providers, Australian Energy Regulator, November 2024.
[69] Ibid., page 8.

6.6.2 Rate of change

Total rate of change

The overall real rate of change in the base-trend-step model is a function of the forecast change in network output, real input costs (labour and non-labour) and productivity. The calculation method for total rate of change is shown in Figure 6.4 and is consistent with the AER's 2024 Expenditure Forecast Assessment Guideline for Electricity Transmission[70] and our Expenditure Forecasting Methodology in Appendix 5.03.

Figure 6.4 - Forecast rate of change method



The AER expects a trend to adopt its approach to output, price and productivity change[71]. Each of these components are discussed in the following sections.

Output change

Output change is the expected growth in network output, measured by the four parameters outlined in Table 6.5. These are weighted by their assessed share of gross revenue based on weighting factors defined by the AER as part of its economic benchmarking of TNSPs.

Table 6.5 - Output measures

Output measure	Weighting[72]	Description
Energy throughput	14.9%	A measure of the amount of electricity that TNSPs deliver to their customers.
Ratcheted maximum demand (RMD)	24.7%	TNSPs endeavour to meet the demand for energy from their customers when that demand is greatest. RMD recognises the higher maximum demand that the TNSP has had to meet in the time period examined.
Number of customers	7.6%	The number of end users is a proxy for the complexity of the TNSPs network.
Circuit length	52.8%	Reflects the distances over which TNSPs transport electricity and is a significant driver of the services a TNSP must provide.

The standard approach assumes the number of customers connected to transmission and distribution networks represents an appropriate proxy for the complexity of operating and maintaining a safe, secure and reliable transmission system. Powerlink considers that an alternative output measure may better represent the increasing complexity experienced by TNSPs in the current environment, which is not driven by number of customers (refer Chapter 2 Business and Operating Environment).

[70] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.
[71] Better Resets Handbook – Towards Consumer Centric Network Proposals, Australian Energy Regulator, July 2024, p.25.
[72] AER, Annual Benchmarking Report 2020 – Electricity transmission network service providers, November 2020, pp. 3–5; Quantonomics, Economic Benchmarking Results for the Australian Energy Regulator's 2024 TNSP Benchmarking Report, July 2024.

In addition to reliability and affordability of transmission services, our customers highlighted[73] that they support investment in the energy system to move to a cleaner system for future generations. Additionally, we surveyed major commercial and industrial customers, some directly connected to our network while others connected to distribution networks, who told us that they continue to prioritise electrification and renewable energy.

The energy transition is already underway and with the increasing integration of new inverter connected generation and energy storage, Powerlink is learning and adapting to the new ways in which the grid is being used. The energy system of the future will be characterised by a mix of technologies and infrastructure along the entire energy supply chain, which increases complexity of the transmission network.

Consequently, we engaged with the RPRG on the potential to establish an alternative output measure to the number of customers. The RPRG supported further analysis to understand the potential impact of an alternative output measure. The alternative output measure we have identified is transmission connected renewable energy supplied (gigawatt-hours, GWh), which we consider better reflects the increasing complexity of operating the transmission network to provide safe, secure, reliable and cost-effective services to customers.

The measures and their respective growth rates and data sources are detailed in Table 6.6.

Table 6.6 - Output growth rates (% per annum)

Output measure	2028	2029	2030	2031	2032	Source [1]
Energy throughput (GWh)	0.29	0.75	1.96	3.58	4.9	AEMO Electricity Statement of Opportunities (ESOO) 2025
Ratcheted maximum demand (RMD)	1.04	1.51	1.64	2.42	3.56	AEMO Electricity Statement of Opportunities (ESOO) 2025
Circuit length	0.00	0.00	(0.32)	(0.13)	0.00	Powerlink's Enterprise Resource Planning database (SAP) Plant Maintenance Module. Powerlink has forecast no increase in circuit length over the 2027-32 regulatory period and has adjusted the forecast down to reflect forecast transmission line decommissioning over the 2022-27 regulatory period.
Number of customers	1.05	1.03	1.01	1.04	1.01	Number of customers from Ergon Energy and Energex 2025-30 Revenue Proposals, trended forward for the 2030/31 and 2031/32 years, plus Powerlink direct connect customers.
Renewable energy supplied (GWh)	10.41	3.68	35.92	7.34	15.50	Powerlink's forecast of renewable energy supplied by the transmission network based on committed and emerging connections. This is used instead of the number of customers in the alternative forecast only.

[73] Queensland Household Energy Survey, April 2025.

(1) Output measures will be updated with the most current data available at the time of submission of our Revenue Proposal.

We developed an alternative output change forecast based on substituting renewable energy supplied (GWh) for the total number of customers, retaining the weighting applied to the original measure. Table 6.7 presents the forecast total output change for the 2027-32 regulatory period, for both the standard approach and the alternative approach.

Table 6.7 - Output change (% and $million real, 2026/27)

Output change	2028 (%)	2029 (%)	2030 (%)	2031 (%)	2032 (%)	Average (%)	Total output growth ($)
Total output change – standard	0.38	0.56	0.60	1.14	1.69	0.88	**30.90**
Total output change – alternative	1.05	0.76	2.86	1.60	2.70	1.79	**72.01**

The operating expenditure forecast in this draft Revenue Proposal is based upon the standard approach.

We consider that the alternative output measure better reflects the increasing complexity of operating the transmission network to provide safe, secure, reliable and cost-effective services to customers. We also consider that the alternative approach may offer a potential trade-off with some proposed step changes, thereby limiting the impact on the operating expenditure within the 2027-32 regulatory period.

Powerlink will engage further with our customers, the AER and other stakeholders to finalise a position prior to lodging our 2027-32 Revenue Proposal.

Real price change

Real price change is the forecast real change in input costs, measured for labour and non-labour costs. We consider the forecast labour and non-labour price changes represent a realistic forecast of input increases over the 2027-32 regulatory period.

Our forecast of labour input price changes is based on an average of two state-level utility industry Wage Price Index (WPI) forecasts: an independent forecast developed by BIS Oxford Economics (BISOE)[74], and an alternative Queensland WPI forecast[75]. Our approach is detailed in Chapter 7 Escalation Rates.

Table 6.8 presents these forecasts along with the simple average of the two forecasts that has been used in the rate of change calculations. The average annual labour price change over the 2027-32 regulatory period is 1.1%.

Table 6.8 - Real labour price growth (% per annum)

Labour Price Growth	2028	2029	2030	2031	2032	Average
BISOE EGWWS WPI - Qld	1.2	1.4	1.6	1.5	1.3	**1.4**
Alternative Utilities WPI - Qld	0.7	0.6	0.9	0.8	0.8	**0.8**
Average	**1.0**	**1.0**	**1.3**	**1.2**	**1.1**	**1.1**

We propose a real materials price growth of zero in our expenditure forecasts for the 2027-32 regulatory period.

[74] Labour Cost Escalation Forecasts to 2031/32 Preliminary report for Powerlink, BIS Oxford Economics, July 2025.
[75] Labour price growth forecasts, Deloitte Access Economics, March 2025. This was prepared for the Australian Energy Regulator and referenced in the Final Decision for Energex 2025-30 Revenue Proposal.

As discussed earlier in our Revenue Proposal, there have been significant materials price increases over the 2022-27 regulatory period, far beyond the level of CPI (refer Chapter 2 Business and Operating Environment). Although there are still many unknowns in the global economic environment, along with the broader rate of global and local inflation, the rate of price growth appears to be moderating back towards long term trend in line with CPI. To be clear, there is no indication that materials prices will decline in real terms.

While noting there are substantial on-going risks as global demand for major plant items and materials remains high, we propose a real price growth of zero for materials in our expenditure forecasts for the 2027-32 regulatory period. This reflects the expectation that materials costs will revert to increases that broadly align with CPI, which is consistent with the AER's preferred approach[76].

To develop our real price growth escalation forecasts for the 2027-32 regulatory period, we have applied weightings of labour to non-labour of 70.4 to 29.6. These weightings are consistent with the AER's 2017 TNSP Annual Benchmarking Report. We have investigated the appropriateness of this weighting and found it is consistent with the split of labour and materials costs in our historical operating expenditure.

Table 6.9 - Price growth rate (% and $million real, 2026/27)

Price Growth Rate	2028 (%)	2029 (%)	2030 (%)	2031 (%)	2032 (%)	Average (%)	Total price growth ($)
Total price growth	0.67	0.70	0.88	0.81	0.75	0.76	**34.70**

Productivity change

Note for the draft Revenue Proposal: We have adopted the industry average productivity change from the AER's 2024 Annual Benchmarking Report for Transmission. The AER's 2025 Annual Benchmarking Report is not publicly released until November 2025. The January 2026 Revenue Proposal will be updated with the results from the 2025 report.

Productivity change measures the forecast expected productivity improvements for a business. The AER currently applies an industry average to calculate productivity, based on operating expenditure productivity across all TNSPs, as published annually in the AER's Economic Benchmarking Report for Transmission.

Table 6.10 presents the forecast total productivity growth for the 2027-32 regulatory period in accordance with the AER specification.

Table 6.10 - Productivity growth rate (% and $million real, 2026/27)

Productivity growth	2028 (%)	2029 (%)	2030 (%)	2031 (%)	2032 (%)	Average (%)	Total productivity growth ($)
Average productivity growth	0.3	0.3	0.3	0.3	0.3	0.3	**(13.9)**

We have adopted the AER's preferred productivity growth forecast of the industry average productivity change for electricity transmission in our current forecasts[77]. Powerlink is currently trending in line with industry average productivity trend. We forecast a decline in productivity based on the AER's benchmarking approach which we expect will be in line with prevailing industry outcomes. We recognise the need to identify ways to deliver further

[76] Better Resets Handbook, Australian Energy Regulator, July 2024, p.25.
[77] Based on latest publicly available TNSP operating expenditure partial factor productivity 2006-2023, published within the AER's 2024 Annual Benchmarking Report – Electricity Transmission Network Service Providers.

efficiency and productivity improvements during the 2027-32 regulatory period and commit to doing this as part of BAU operations.

Total rate of change

Table 6.11 reflects the total rate of change applied under the standard and alternative approach. The alternative approach results in an additional $54.4 million operating expenditure for the 2027-32 regulatory period. As noted above, this additional expenditure may be partially offset by step changes which can be accommodated within the alternative rate of change. This is detailed further in section 6.6.3.

Table 6.11 - Total rate of change ($million real, 2026/27)

Rate of change	2028	2029	2030	2031	2032	**Total**
Standard approach	2.3	5.3	9.0	14.2	21.0	**51.7**
Alternative approach	5.5	10.2	21.5	28.8	40.2	**106.1**

6.6.3 Step changes

We have included four operating expenditure step changes for the 2027-32 regulatory period. This followed detailed investigation of potentially material changes in our regulatory obligations, the external market and trade-offs between capital expenditure and operating expenditure.

As part of the preparation of our Revenue Proposal, we initially identified 21 potential step changes and reviewed them against a set of criteria. The criteria included whether costs were material, had not already been realised in the base year, had a high likelihood of being realised, and/or were associated with a new legislative / regulatory obligation, a change in the external market beyond our control, or a trade-off between capital expenditure and operating expenditure.

We had initial discussions about several of these potential step changes with the RPRG in February and March 2025[78] and have since narrowed these down to four step changes presented at our July 2025 RPRG meeting[79].

Table 6.12 outlines those potential step changes that will result in an increase in costs in the 2027-32 regulatory period, for which we have chosen to pursue a regulatory expenditure allowance. In determining our step changes, we have considered costs incurred during the 2025/26 base year. Accordingly, the step change requested represents the amount exceeding any recurrent costs already included in base year operating expenditure.

Table 6.12 - Step changes ($million real, 2026/27)

Name [(1)]	Estimated cost uplift	Driver and description
Physical security uplift [(2)]	13.7	Regulatory obligation. Costs associated with complying with our obligations for physical security under the SOCI Act and subsequent amendments.

[78] Presentation to Revenue Proposal Reference Group (RPRG), Powerlink, February and March 2025.
[79] Presentation to Revenue Proposal Reference Group (RPRG), Powerlink July 2025.

Name [1]	Estimated cost uplift	Driver and description
Transition to cloud-based solutions	64.4	External market impact. There is an ongoing market shift to cloud-based information technology (IT) solutions. The costs associated with the implementation, configuration and customisation of these solutions are generally required to be treated as operating expenditure under Australian Accounting Standards. It is expected that there would be a commensurate reduction in future IT capital expenditure.
Addressing sole overnight control room operator risk [2]	13.4	Regulatory obligation. Costs incurred in addressing sole overnight control room operator risk, as supported by AEMO.
Synchronous condenser maintenance	10.1	Regulatory obligation. Costs incurred in maintaining synchronous condensers commissioned within the regulatory period. As the System Strength Service Provider for Queensland, Powerlink is required to plan, procure and make available system strength services as set out in the AEMO annual System Strength Report. Powerlink will commission several synchronous condensers to meet our system strength obligations during the 2027-32 regulatory period.

(1) We are currently investigating potential site modification works to address arc flash risks under the *Electrical Safety Act*. If material, this could be added as a step change.
(2) If the alternative trend approach is adopted, we propose to exclude addressing sole overnight control room operator risk and security uplift as step changes as these would be appropriately recognised within the revised rate of change.

Security Uplift

As a Transmission Network Service Provider, Powerlink is required to comply with *Security of Critical Infrastructure Act 2018.* The SOCI Act requires that owners of critical infrastructure assets implement a risk management plan to mitigate material risks associated with cyber and information hazards, personnel hazards, supply chain hazards, and physical and natural hazards.

Powerlink has identified several initiatives to uplift physical (protective) security controls to meet our needs under these regulations. Those initiatives which are related to this step change are detailed below:

- **Uplift of site security and monitoring –** the initiative aims to increase specialist security capability and implement security upgrades to deliver the fundamentals of visitor sign in, intruder detection and real time CCTV to key corporate sites as well as deployable CCTV trailers to provide prompt and local temporary security services for a range of maintenance and construction activities at at-risk sites and known 'hot spot' locations. This, along with the implementation of a single video monitoring platform and monitoring through the security control room will ensure that CCTV becomes a key security control by providing real time monitoring of physical security risks.
- **Establishing a 24-hour security control room –** the 24-hour security control room will centralise monitoring and response to security incidents, enhancing our ability to protect critical infrastructure. As the operator of Queensland's high-voltage electricity network, Powerlink needs an effective framework for detecting and managing threats. This control room will help meet compliance obligations under the SOCI Act by providing real-time monitoring of physical security risks, improving situational awareness and incident management, and safeguarding personnel.

Transition to cloud-based services

Powerlink's investment in its information technology (IT) infrastructure and software solutions includes a mix of on-premises and cloud-based services. Powerlink has identified a full IT investment program for the 2027-32 period, which will be allocated to either capital expenditure or operating expenditure, depending on the nature of the investment.

In April 2021, the International Accounting Standards Board clarified its definition of intangible assets which led to most cloud-based services (or Software-as-a-Service (SaaS)) costs no longer meeting that definition. The International Financial Reporting Standards guidance suggested that these costs should be expensed (operating expenditure) rather than capitalised (capital expenditure), shifting the approach taken in the past in relation to cloud-based solutions.

Given the continuing maturity of SaaS offerings by leading technology companies, and the move by those companies to only offer SaaS solutions in the future, Powerlink has determined, in line with the Australian Accounting Standards, that most of the future IT investment will need to be treated as an operating expense rather than a capital asset.

An overview of the IT investment program for the 2027-32 period is attached in Appendix 5.05 and includes the classification for each proposed investment.

Addressing sole overnight control room operator risk

The key component to address our sole control room operator risk is to transition to two system controllers on overnight shifts. This shift is driven by a combination of regulatory direction, good industry practice, incident learnings, and broader workforce and safety considerations. It is increasingly recognised as a necessary evolution in transmission network operations given the increasing complexity.

AEMO has recommended increased staffing in control rooms to ensure real-time system stability and rapid response to contingencies as well as for the timely coordination of increasing customer connections. These require operational coordination in real-time, often within short timeframes, to align to power system security guidelines for re-securing post contingent.

Additionally, past incidents in the NEM and internationally have highlighted the significant risks of single-controller operations, especially during complex or cascading events. Increasing resources enables cross-checking of decisions, reduces the risk of human error and supports continuous situational awareness as well as mitigates workplace health and safety risks. Powerlink will also actively use any additional capacity to assist with managing the increasing preparatory tasks for the following day shift, providing more effective distribution of work and reducing pressure on both overnight and day shift teams.

Synchronous condenser maintenance

System strength is a measure of the ability of the network to control the voltage both during steady state operation and in response to a network disturbance, such as a sudden change in generation or load, or a fault on the network. The Queensland energy system has historically comprised of synchronous generation such as coal-fired generators, gas turbines and hydro-electric plants. These large synchronous generators have provided various services as a by-product of their dispatch for energy, including system strength, to enable the power system to operate stably.

As the energy system moves to a greater reliance on inverter-based resources such as solar and wind generation, certain system services are less freely available and must be planned for and delivered by other means.

AEMO and Powerlink are responsible for the planning and delivery of power system security services in Queensland. These arrangements were fundamentally revised following the Efficient Management of System Strength on the Power System Rule (System Strength Rule), made by the AEMC[80] in October 2021.

As the System Strength Service Provider for Queensland, Powerlink is required to plan, procure and make available system strength services as set out in AEMO's annual System Strength Report. In planning for these services, Powerlink has undertaken a Regulatory Investment Test for Transmission (RIT-T) to address system strength requirements. Following completion of this RIT-T, the preferred option includes installing up to nine synchronous condensers across Queensland or contracting for services from non-network service providers.

Powerlink plans to commission four synchronous condensers in the 2027-32 regulatory period. These are new assets to Powerlink, as such the inspection and maintenance activities are not represented in the base operating expenditure or trend calculations.

6.7 Forecast other operating expenditure

We have developed category-specific forecasts for insurance costs (premiums and self-insurance), AEMO participant and cyber security fees and debt raising costs. Whilst network support costs are also included in other operating expenditure, we do not currently forecast any expenditure in this category in the 2027-32 regulatory period.

Our category-specific (zero-based) forecasts use an external or bottom-up cost build to estimate the total cost of a particular activity. For these expenditure items, we do not consider that a trend of base year expenditure will reasonably reflect future operating expenditure requirements. In the normal course of business, we classify our AEMC levy costs as non-controllable, other operating expenditure. However, we have included AEMC levy costs in our base year and have applied the rate of change rather than a category-specific forecast, consistent with the AER's preferred approach.

6.7.1 Insurance

Note for the draft Revenue Proposal*:* Our insurance renewal is scheduled for November 2025 and we expect to have more accurate forecasts available at that time.

As a business, we take a holistic approach to risk management. We propose to adopt a combination of insurance policies, self-insurance and pass through arrangements in the 2027-32 regulatory period to efficiently manage the risks associated with operating our network and deliver the most cost-effective outcome for customers and Powerlink.

We engaged our insurance brokers, Marsh Pty Ltd (Marsh), to advise us on our insurance and risk management approach for the 2027-32 regulatory period. We will also take the opportunity to arrange for Marsh to discuss the insurance market with the RPRG, scheduled for November 2025. Draft forecasts from Marsh[81] indicate that total insurance costs may increase by $10.9 million (21%) in the 2027-32 regulatory period compared to our total actual/forecast insurance costs for the 2022-27 regulatory period.

The adoption of a category-specific forecast for both categories of insurance for the 2027-32 regulatory period results in a $6.9 million increase overall in the insurance costs compared to a base-trend-step approach.

[80] Efficient management of system strength on the power system | AEMC (www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system).
[81] Draft forecasts from Marsh have been adjusted to reflect the costs attributable to prescribed transmission services only.

The elements of our insurance requirements are defined in more detail in the following sections.

External insurance

A key component of our risk management strategy is the establishment and maintenance of a prudent and efficient insurance program that provides financial coverage for most of our major risk exposures. We seek advice from our insurance brokers for domestic insurance and international cover, to ensure that our insurance coverage is effective and is delivered at a competitive cost.

We have decided that, due to the limited availability of insurance coverage for towers and transmission lines, it is neither prudent nor efficient for Powerlink to maintain this level of cover. As a result, our forecast insurance premiums do not include this cover. This has been partially offset by an increase to our self-insurance forecast to mitigate this risk.

Table 6.13 outlines our insurance premium cost forecast, trended from the 2025/26 base year expenditure, and the forecast from Marsh. We have included the Marsh forecast in our operating expenditure forecast.

Table 6.13 - Insurance premiums ($million real, 2026/27)

Insurance premiums	2028	2029	2030	2031	2032	Total
Base-trend-step forecast	9.2	9.2	9.4	9.5	9.7	**47.0**
Marsh forecast	8.0	8.7	9.6	10.9	11.9	**49.1**
Variance	**1.2**	**0.5**	**(0.2)**	**(1.4)**	**(2.2)**	**(2.1)**

Self-insurance

Self-insurance costs relate to losses that are below the insurance deductible amounts contained in our insurance portfolio. We engaged Marsh to review historical levels of these losses and develop a forecast of prudent self-insurance amounts for the 2027-32 regulatory period.

Table 6.14 outlines the self-insurance cost forecast, trended from the 2025/26 base year, and the forecast from Marsh. In this case, the Marsh forecast is considerably higher than the base-trend-step forecast largely due to the inclusion of an additional self-insurance allowance to provide for the anticipated increase in Towers and Lines in this category (previously included as part of the external insurance premium). We have included the Marsh forecast in our operating expenditure forecast.

Table 6.14 - Self-insurance ($million real, 2026/27)

Self-insurance	2028	2029	2030	2031	2032	Total
Base-trend-step forecast	2.0	2.0	2.0	2.0	2.1	**10.1**
Marsh forecasts	2.6	2.8	3.0	3.2	3.4	**14.9**
Variance	**(0.6)**	**(0.8)**	**(1.0)**	**(1.2)**	**(1.3)**	**(4.8)**

Pass through events

Residual risk events outside our control, that cannot be commercially insured or self-insured, can be addressed through the cost pass through mechanism in the Rules. Our nominated pass through events are discussed in Chapter 12 Pass Through Events.

6.7.2 AEMC levy

In 2014, the Queensland Government enacted changes to the *Electricity Act 1994 (Qld)*[82]. Under these changes, Powerlink, as holder of a Transmission Authority in Queensland, must pay an annual fee that is a portion of the Queensland Government's funding commitments to the AEMC.

The AEMC levy is applied to all jurisdictions across the NEM to cover the operations of the AEMC. In Queensland, the majority of the AEMC levy is passed through to Powerlink and we incur this cost as operating expenditure. Forecast expenditure for the AEMC levy over the 2027-32 regulatory period, shown in Table 6.15, is higher than the corresponding rate of change derived base-trend-step forecast. Notwithstanding, we have chosen to include the base-trend-step forecast in our operating expenditure forecast, in line with the AER's preferred approach to such costs.

Table 6.15 - AEMC levy ($million real, 2026/27)

AEMC Levy	2028	2029	2030	2031	2032	Total
Base-trend-step forecast	6.0	6.0	6.1	6.2	6.3	**30.7**
AEMC forecast	6.6	6.7	6.7	6.7	6.6	**33.2**
Variance	**(0.6)**	**(0.7)**	**(0.6)**	**(0.5)**	**(0.3)**	**(2.7)**

6.7.3 AEMO participant and cyber security fees

This is a new category of other operating expenditure for the 2027-32 regulatory period.

In 2020, AEMO conducted a review of its current Electricity Market Participant Fee Structure. An outcome of this review was a change to the fee structure of the NEM, with a portion of the NEM fees to be levied on the TNSPs starting from 1 July 2023. A transitional rule[83] that supported the recovery of the AEMO participant fees by passing them directly through to customers through the annual transmission price setting process will end on 30 June 2027 for Powerlink. Following the transitional period these costs are to be recovered through existing mechanisms under the incentive-based revenue determination framework.

In December 2024, the AEMC published a final determination and final rule to confirm and clarify AEMO's cyber security role in the Rules. Consequently, in June 2025, AEMO established an additional cyber security fee structure to recover the costs of the new cyber security roles and responsibilities declared NEM project. The recovery of these costs will commence from July 2025.

The fee structure that will apply in the 2027-32 regulatory period in relation to the AEMO participant and cyber security fees is currently under review, with the final determination expected to be published in February 2026. For this reason, we have applied the rate of change to AEMO's current published 2025/26 fees[84] to determine our forecasts, noting that the fee structure may change. The AEMO participant and cyber security fees are shown in Table 6.16.

[82] Electricity and Other Legislation Amendment Bill 2014, Queensland Government, Part 2, Amendment of Electricity Act 1994.
[83] National Electricity Amendment (Recovering the Cost of AEMO's Participant Fees) Rule 2022, Australian Energy Market Commission, October 2022.
[84] Budget and Fees FY26, Australian Energy Market Operator, June 2025.

Table 6.16 - AEMO participant and cyber security fees ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
AEMO participant fee	10.1	10.4	10.7	11.0	11.3	**53.5**
AEMO cyber security fee	1.0	1.0	1.1	1.1	1.1	**5.3**
Total AEMO fees	**11.1**	**11.4**	**11.8**	**12.1**	**12.4**	**58.8**

6.7.4 Network support

Note for the draft Revenue Proposal: We are still considering potential network support expenditure for the 2027-32 regulatory period, and this is reflected in our forecasts and the section below. At this stage, we may propose a network support forecast requirement in the 2027-32 regulatory period in our 2027-32 Revenue Proposal.

The Rules[85] allow for TNSPs to seek a determination from the AER to pass through any differences in costs between the amount included in the annual revenue requirement and actual efficient costs associated with network support events directly to customers.

While Powerlink will incur system security network support costs, these have not been included in our operating expenditure forecast in line with the AEMC's final rule for the Improving Security Frameworks for the Energy Transition rule change. This resulted in non-network system security costs no longer needing to be forecast within five-year revenue determinations. They are instead recovered by an annual forecasting and true up process, part of the annual transmission price setting process, as a direct pass through to customers. These changes to cost recovery commenced in December 2024.

6.7.5 Debt raising costs

Debt raising costs relate to transaction costs incurred when new debt is raised, or current lines of credit are renegotiated or extended. These costs include arrangement fees, legal fees, company credit rating fees and other transaction costs. Debt raising costs would be incurred by a prudent service provider and are an unavoidable aspect of raising debt.

The AER's standard approach is to provide an annual allowance for debt raising costs as part of operating expenditure. This is based on an efficient benchmark rather than a business's actual costs. This is consistent with the approach used to set the forecast cost of debt in the rate of return (refer Chapter 9 Rate of Return, Taxation and Inflation).

We have forecast debt raising costs of 9.62 basis points per annum based on the preliminary independent advice provided by Incenta[86] in June 2025. Applying this basis point assumption results in forecast debt raising costs for the 2027-32 regulatory period as shown in Table 6.17.

[85] National Electricity Rules, clause 6A.7.2.
[86] Incenta, Draft Benchmark debt and equity raising costs, June 2025.

Table 6.17 - Debt raising costs ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
Debt raising costs	4.8	5.1	5.2	5.3	5.4	**25.8**

6.8 Interaction between forecast capital and operating expenditure

The Rules[87] require that a Revenue Proposal identify and explain any significant interactions between forecast capital and operating expenditure.

We have a legislative responsibility to provide safe and reliable transmission services to customers and other NEM participants. To meet this obligation, we ensure network assets deliver the required reliability, availability and quality of supply through an appropriate balance of operating expenditure and capital expenditure. Consistent with our asset management framework, we use life-cycle cost analysis to deliver prudent and efficient outcomes for our customers.

There are several key network and market trends that may impact our combined capital and operating expenditure approach over the 2027-32 regulatory period. As referenced in Chapter 5 Forecast Capital Expenditure, reinvestment in the transmission network is required as our assets reach end of life, with reinvestment decisions also needing to respond to the changing energy environment. These capital investments are not only essential for maintaining the safety, reliability and security of the transmission network, but they also have direct and ongoing impacts on operating expenditure. Delays to reinvestment may result in increased operating expenditure to manage deterioration of asset condition. Conversely, additional operating expenditure to undertake enhanced maintenance of assets may enable the efficient deferral of reinvestment decisions.

Chapter 5 also references capital expenditure proposed to enhance situational awareness and decision support to improve network utilisation and customer outcomes. Delays to investment in these enabling supportive capex initiatives may result in increased operating expenditure for network operations and asset management support.

Several additional non-network initiatives within the 2027-32 regulatory period are also expected to involve interaction between capital and operating expenditure activities:

- We continue to investigate opportunities to extend the capability of transmission network assets through non-network solutions. Contracts with generators, batteries and large loads may mitigate the power system impact from contingency events and improve power system security and allow us to deliver additional market benefits without network augmentation or reinvestment.
- Powerlink's investment in IT infrastructure and software solutions includes a mix of on-premises and cloud-based services. This expenditure is expected to deliver operating efficiencies, address cyber security risks, focus IT delivery for better customer outcomes, rationalise systems, and facilitate upgrades to specific programs. The IT investment program for the 2027-32 period will be allocated to either capital expenditure or operating expenditure, depending on the nature of the specific solution implemented.

[87] National Electricity Rules, Schedule 6A.1, clause S6A.1.3(1).

7 Escalation Rates

7.1 Introduction

This chapter explains how Powerlink has determined escalation rates for internal labour, external labour and materials. We have used these escalation rates as an input to forecast our operating and capital expenditure.

Key highlights:

- As inputs to forecast our capital and operating expenditure, we have used:
    - an average annual growth rate of 1.1% for internal labour costs and 1.1% for external labour costs over the 2027-32 regulatory period, and
    - an annual increase in the costs of materials based on the Consumer Price Index. This results in a zero real (or inflation-adjusted) increase.
- We sought independent advice from Oxford Economics Australia (OEA) on wage growth forecasts.
- Real labour price growth has been calculated using a simple average of the OEA forecasts and alternative forecasts sourced from Deloitte Access Economics (DAE) advice on other revenue determination processes.

7.2 Regulatory requirements

The National Electricity Rules (Rules)[88] require our operating and capital expenditure forecasts to reasonably reflect prudent and efficient costs with a realistic expectation of demand and cost inputs required to achieve the operating and capital expenditure objectives.

7.3 Cost escalation

We have adopted real input cost changes, which excludes inflation, for internal labour, external labour and materials as presented in Table 7.1.

Table 7.1 - Real input price growth (% per annum) (Source: OEA, DAE)

	2028	2029	2030	2031	2032
Internal Labour	1.0	1.0	1.3	1.2	1.1
External Labour	0.9	1.1	1.3	1.1	1.0
Materials	-	-	-	-	-

[88] National Electricity Rules, clauses 6A.6.6 and 6A.6.7.

7.4 Cost escalation approach

A summary of the approach used to determine our cost escalation forecasts is provided in Table 7.2.

Table 7.2 - Approach used to forecast cost escalation

Escalation factor	Basis of forecast
Internal Labour	Simple average of two forecasts over the 2027-32 regulatory period: • OEA - Electricity, Gas, Water and Wastewater (EGWWS) Wage Price Index (WPI) forecast for Queensland; and • DAE Alternative Utilities WPI forecast for Queensland
External Labour	Simple average of two forecasts over the 2027-32 regulatory period: • OEA Construction WPI forecast for Australia; and • DAE Alternative All Industries WPI forecast for Australia
Materials	Consumer Price Index (CPI)

Further detail on each approach is provided below.

7.4.1 Real labour price growth

Real labour price growth has been based on a simple average of two independent forecasts: the forecast prepared for us by OEA and an alternative forecast. This approach is consistent with the Australian Energy Regulator's (AER) standard approach[89] in recent regulatory determinations.

We anticipate that the AER will again engage DAE to provide alternative WPI forecasts for our Draft Decision. In the interim, we have used the most recent available and relevant DAE forecasts publicly available for the purpose of our alternative forecast. Our real labour price growth forecast is shown in Table 7.3.

Table 7.3 - Real labour cost escalators (% per annum) (Source: OEA, DAE)

	2028	2029	2030	2031	2032
Internal labour					
OEA EGWWS WPI - Qld	1.2	1.4	1.6	1.5	1.3
DAE Alternative Utilities WPI - Qld	0.7	0.6	0.9	0.8	0.8
Average	**1.0**	**1.0**	**1.3**	**1.2**	**1.1**
External labour					
OEA Construction WPI – Aus	1.0	1.3	1.5	1.1	0.9
DAE Alternative All Industries – Aus	0.7	0.9	1.0	1.0	1.0
Average	**0.9**	**1.1**	**1.3**	**1.1**	**1.0**

[89] Final Decision, Energex Distribution Determination 2025-2030: Attachment 6 Operating Expenditure, Australian Energy Regulator, April 2025, p.25.
Note: this approach was also applied to Final Decisions published in 2025 for Ergon Energy and Jemena Gas Networks and to previous Powerlink determinations.

Oxford Economics Australia forecast

We engaged OEA to provide an independent expert opinion on WPI forecasts specific to Queensland's business environment and economic outlook. OEA is a leading provider of industry research, analysis and forecasting services. OEA's wage growth forecasts for Queensland and nationally leverage their comprehensive knowledge of the Australian economy and industrial sectors, to link labour market conditions to overarching macroeconomic and regional drivers.

OEA provided WPI forecasts over the seven-year period from 2025/26 to 2031/32. This captures the last two years of the current 2022-27 regulatory period and the five years of the 2027-32 regulatory period. Separate forecasts were prepared for internal and external labour. This reflects the use of our own workforce and external contractors to deliver our operational and capital works:

- internal labour price growth - EGWWS sector specific to Queensland has been used
- external labour price growth - Construction sector for Australia has been used, recognising that the labour market accessed by contractors is not constrained to Queensland.

The advice from OEA is that over the forecast period, the Queensland EGWWS WPI average growth of 3.9% per annum (applied to internal labour) is expected to remain higher than the Australian EGWWS WPI average of 3.7% per annum. Utilities wages are forecast to increase by more than the national (All Industries) average over the forecast period due to the following factors:

- The electricity, gas and water sector is a largely capital-intensive industry whose employees have higher skill, productivity and commensurately higher wage levels than most other sectors.
- Strong wage pressure across the sector due to collective bargaining.
- Demand for skilled labour will remain high and strengthen with the sustained increases in overall construction activity and high levels of utilities investment from 2024/25 to 2031/32 (and beyond).
- The overall national trend tends to be dragged lower by some of its constituent groups (retail, trade, hospitality, etc.).

OEA's report is provided in Appendix 7.01.

Alternative forecast

Consistent with the approach it has applied historically, we anticipate that the AER will engage DAE to provide an alternative WPI forecast for our Draft Decision. In the interim, we have used the DAE Labour Price Growth Forecasts report used by the AER in Ergon's final decision for their 2025-30 determination and trended the final years.

We recognise this alternative forecast will be replaced by the latest DAE forecast published in the AER's Draft Decision.

7.4.2 Real materials price growth

As discussed earlier in our Revenue Proposal, there have been significant materials price increases over the 2022-27 regulatory period, far beyond the level of CPI (refer Chapter 2 Business and Operating Environment). Although there are still many unknowns in the global economic environment, along with the broader rate of global and local inflation, the rate of price growth appears to be moderating back towards long term trend in line with CPI. To be clear, there is no indication that materials prices will decline in real terms.

While noting there are substantial on-going risks as global demand for major plant items and materials remains high, we propose a real price growth of zero for materials in our expenditure forecasts for the 2027-32 regulatory period. This reflects the expectation that materials costs will revert to increases that broadly align with CPI.

7.4.3 Interaction with expenditure incentive schemes

Powerlink may be subject to substantial penalties under both the Capital Expenditure Sharing Scheme (CESS) and the Efficiency Benefit Sharing Scheme (EBSS) during the current regulatory period, largely due to significant increases in the real prices of labour and materials above inflation that were outside of Powerlink's control. This outcome is a feature of the incentive based economic regulatory framework in Australia that is designed to have regulated businesses reveal their efficient costs to provide prescribed transmission services.

Consistent with this incentive-based framework, our Revenue Proposal adopts the current revealed prices for labour and materials as the starting point for forecasts and applies the AER's standard approach to forecast these prices during the 2027-32 regulatory period. We consider this approach provides the appropriate incentives for Powerlink to seek to achieve real reductions in costs going forward.

8 Regulatory Asset Base

8.1 Introduction

This chapter outlines Powerlink's approach to calculating the opening Regulatory Asset Base (RAB) as at 1 July 2027 and our forecast RAB for each year of the 2027-32 regulatory period.

Key highlights:

- Our opening RAB as at 1 July 2027 is forecast to be $8,402.4 million ($ nominal).
- The RAB is forecast to increase by $1,975.9 million ($ nominal) over the 2027-32 regulatory period[90]. The increase is primarily driven by forecast capital expenditure within the period due to reinvestment in ageing network assets.
- The closing RAB as at 30 June 2032 is forecast to be $10,378.3 million ($ nominal).

8.2 Regulatory requirements

The National Electricity Rules (Rules)[91] sets out the requirements for establishing the opening value of our RAB. We are also required to provide the annual RAB calculations for each year of the current 2022-27 regulatory period[92]. This is done using the Australian Energy Regulator's (AER) Roll Forward Model (RFM)[93].

The Rules[94] allow for the value of assets that previously provided non-prescribed transmission services to be transferred into the RAB as part of a revenue determination. The transfer amount is limited to the extent that such capital expenditure relates to an asset that is used for the provision of prescribed transmission services.

The Rules[95] also provide that the RAB is the value of assets used to provide prescribed transmission services, but only to the extent that they are used to provide such services. The Rules[96] require that the RAB for each year of the regulatory period be reduced by the disposal value of any asset disposed of in the period.

8.3 Our approach

We established the opening value of our RAB and rolled it forward for each year of the regulatory period in accordance with the Rules[97].

We used the AER's RFM to establish the opening RAB as at 1 July 2027 and the AER's Post-Tax Revenue Model (PTRM)[98] to calculate the forecast RAB for the 2027-32 regulatory period. We continued to apply year-by-year depreciation tracking (refer Chapter 10 Depreciation) and used the AER's Depreciation Tracking Module (DTM)[99].

[90] Based on a comparison of 1 July 2027 opening RAB to 30 June 2032 closing RAB.
[91] National Electricity Rules, Schedule 6A.2, clause S6A.2.1(f).
[92] Ibid., clause 6A.6.1 and Schedule 6A.1, clause S6A.1.3(5).
[93] Electricity Transmission Network Service Provider Roll Forward Model (Version 4.1), Australian Energy Regulator, May 2022.
[94] National Electricity Rules, Schedule 6A.2, clause S6A.2.1(f)(8).
[95] Ibid., clause 6A.6.1(a).
[96] Ibid., Schedule 6A.2, clause S6A.2.1(f)(6).
[97] Ibid., Schedule 6A.2, clause S6A.2.1(f).
[98] Electricity Transmission Network Service Provider Post-Tax Revenue Model (Version 6), Australian Energy Regulator, March 2025.
[99] Electricity Transmission Network Service Provider RFM - Depreciation Tracking Module (Version 1), April 2020.

Prior to the Final Decision, we will update our forecast opening RAB as at 1 July 2027 to reflect the actual capital expenditure in 2025/26 and update the forecast RAB roll forward for the 2027-32 regulatory period accordingly.

8.4 Opening RAB as at 1 July 2027

To establish the forecast opening RAB as at 1 July 2027, we have adjusted the opening RAB as at 1 July 2022, $7,157.9 million, for capital expenditure and regulatory depreciation as shown on Table 8.1.

Table 8.1 - Establishment of opening RAB as at 1 July 2027 ($million nominal)

	2023	2024	2025	2026 (forecast)	2027 (forecast)
Opening RAB	7,157.9	7,636.4	7,857.8	7,818.9	8,095.5
Capital expenditure as incurred (1)	253.2	278.6	154.9	435.7	460.6
Regulatory depreciation (2)	225.2	(57.2)	(193.8)	(159.1)	(167.6)
Closing RAB	7,636.4	7,857.8	7,818.9	8,095.5	8,388.4
Difference between forecast and actual capital expenditure in 2021/22					10.1
Return on capital for the difference between forecast and actual expenditure in 2021/22					3.9
Opening RAB as at 1 July 2027					**8,402.4**

(1) Net of disposals, adjusted for inflation and one-half Weighted Average Cost of Capital (WACC) allowance[100]. The roll forward also reflects forecast capitalised movements in provisions.
(2) Depreciation is based on forecast depreciation as approved by the AER for the 2022-27 regulatory period and is net of indexation applied to the RAB.

8.5 Forecast RAB for the 2027-32 regulatory period

The forecast RAB for each year of the 2027-32 regulatory period is shown in Table 8.2.

Table 8.2 - Forecast RAB roll forward 2027-32 regulatory period ($million nominal)

	2028	2029	2030	2031	2032
Opening RAB	8,402.4	9,011.8	9,490.8	9,949.4	10,264.7
Capital expenditure, as incurred (1)	826.7	659.5	644.1	524.3	371.7
Regulatory depreciation	(217.4)	(180.4)	(185.5)	(209.0)	(258.1)
Closing RAB	9,011.8	9,490.8	9,949.4	10,264.7	10,378.3

(1) Net of disposals, adjusted for inflation and one-half WACC allowance. The roll forward also reflects forecast capitalised movements in provisions

[100] PTRM calculates the return on capital based on the opening RAB and capital expenditure is assumed to occur half-way through the year. To address this timing difference, a half WACC is added to compensate for the six-month period before capital expenditure is included in the RAB.

8.6 RAB additions and removals

8.6.1 Additions

The Rules[101] allow for the value of assets that previously provided non-prescribed transmission services to be transferred into the RAB as part of a revenue determination. The transfer amount is limited to capital expenditure relating to assets used to provide prescribed transmission services.

We are currently assessing the potential transfer of assets to our RAB in accordance with the Rules. No asset transfer has been included in our draft Revenue Proposal. If we identify any potential additions, we will engage with our customers and the AER prior to lodging our Revenue Proposal.

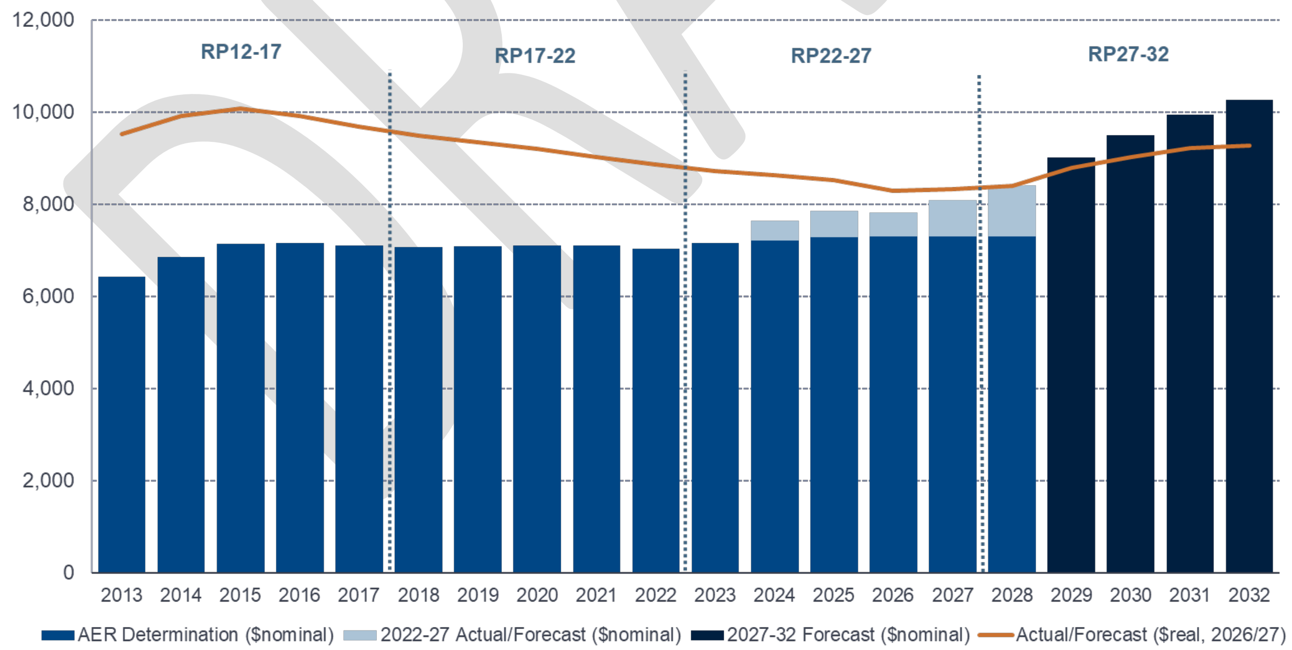
8.6.2 Removals

We have removed $2.8 million in assets from our RAB which have been repurposed to provide non-prescribed transmission services. This approach ensures that assets with no enduring need for the provision of prescribed transmission services and can be repurposed, are removed from the RAB. It also means that customers who will derive benefit from the use of the assets going forward will pay for them. This adjustment has been effected by means of an asset disposal.

Given the commercial-in-confidence nature of additions and removals, further information to support our proposal is provided to the AER on a confidential basis in Appendix 8.01 Regulatory Asset Base Transfers.

8.7 Historical and forecast RAB

Figure 8.1 – Opening RAB 2012/13 to 2031/32



[101] National Electricity Rules, Schedule 6A.2, clause S6A.2.1(f)(8).

The RAB is forecast to increase by $1,975.9 million ($ nominal) and by $748.1 million ($ real, 2026/27) over the 2027-32 regulatory period[102]. The increase is primarily driven by forecast capital expenditure within the period, due to reinvestment in ageing network assets and the need to enhance both physical and cyber security in response to the *Security of Critical Infrastructure (SOCI) Act 2018* (refer Chapter 5 Forecast Capital Expenditure).

The higher forecast capital expenditure also reflects the increased cost of delivering prescribed transmission services due to global demand for major plant items and competition for scarce skilled resources (refer Chapter 2 Business and Operating Environment).

[102] Based on a comparison of 1 July 2027 opening RAB to 30 June 2032 closing RAB.

9 Rate of Return, Taxation and Inflation

9.1 Introduction

This chapter outlines Powerlink's approach to estimating the rate of return, also referred to as the Weighted Average Cost of Capital (WACC), taxation and inflation for the 2027-32 regulatory period.

Key highlights:

- We estimate a rate of return (RoR) of 6.17% for the first year of the 2027-32 regulatory period (2027/28), calculated using the Australian Energy Regulator's (AER) binding 2022 Rate of Return Instrument (RoRI).
    - The final RoR will be updated by the AER in its Final Decision using updated market data and the updated 2026 RoRI, expected to be finalised in December 2026.
- The RoR reflects a significant shift in the interest rate environment since our last revenue determination, with increases in both the risk-free rate and the cost of debt.
- Our taxation allowance is estimated using the AER's Post-Tax Revenue Model (PTRM)[103], applying a corporate tax rate of 30% and a gamma value of 0.57, consistent with the 2022 RoRI.
- Our forecast inflation is 2.55%, calculated using the methodology set out in the PTRM. The AER will update the inflation forecast in its Final Decision to reflect the latest available forecasts published by the Reserve Bank of Australia (RBA).

9.2 Regulatory requirements

Under the National Electricity Rules (Rules)[104], the return on capital allowance is calculated by multiplying the allowed RoR by the opening value of our Regulatory Asset Base (RAB) for each year of the regulatory period.

The RoR[105] must be determined in accordance with the current RoRI published by the AER[106]. These calculations are included in the RoR Model submitted as part of the Revenue Proposal[107].

With regards to inflation, the Rules[108] require the AER to specify in the PTRM a methodology that is likely to result in the best estimate of expected inflation.

The Rules[109] require that our corporate tax allowance be calculated by applying the expected statutory income tax rate to the estimated taxable income for each year of the regulatory period, less the value of imputation credits (gamma).

[103] Electricity Transmission Network Service Provider Post-Tax Revenue Model (version 6), Australian Energy Regulator, March 2025.
[104] National Electricity Rules, clause 6A.6.2.
[105] National Electricity Rules, Chapter 10, definition of "allowed rate of return".
[106] Rate of Return Instrument (Version 1.2), Australian Energy Regulator, March 2024.
[107] National Electricity Rules, Schedule 6A.1, clause S6A.1.3(4A)
[108] National Electricity Rules, clause 6A.5.3(b)(1).
[109] National Electricity Rules, clause 6A.6.4.

9.3 Rate of return

9.3.1 Overview

Our estimated RoR for the 2027-32 regulatory period is shown in Table 9.1.

Table 9.1 - Rate of Return 2027-32

	2028	2029	2030	2031	2032
Return on equity	8.04%	8.04%	8.04%	8.04%	8.04%
Nominal pre-tax return on debt	4.93%	5.07%	5.19%	5.47%	5.84%
Gearing	60.00%	60.00%	60.00%	60.00%	60.00%
Nominal vanilla WACC	6.17%	6.26%	6.33%	6.50%	6.72%

9.3.2 Our approach

The RoR has been calculated in accordance with the 2022 RoRI. The final RoR will be updated in the AER's Final Decision in line with the nominated averaging periods and the 2026 RoRI, which it anticipates finalising in December 2026. Nominated averaging periods have been provided to the AER on a confidential basis in Appendix 9.01 Nominated Averaging Periods.

Return on equity

Applying the 2022 RoRI, we estimate a return on equity of 8.04% for the 2027-32 regulatory period. The risk-free rate is based on a 20-business-day averaging period ending 27 August 2025. This is a placeholder estimate, with the final return to be determined in accordance with the 2026 RoRI and our nominated averaging period. The parameter values are presented in Table 9.2

Table 9.2 - Return on equity

Parameter	Estimate
Risk free rate	4.32%
Equity beta	0.60
Market risk premium	6.20%
Return on equity	8.04%

Return on debt

Applying the 2022 RoRI, our indicative return on debt for the first year of the 2027-32 regulatory period (2027/28) is 4.93%. Under the trailing average approach, the AER will update our return on debt annually throughout the regulatory period to reflect prevailing rates at that time. For the Revenue Proposal, we have assumed the prevailing return on debt is the same as the AER's most recent annual update[110].

This results in the following estimates in Table 9.3.

[110] Powerlink – Determination 2022-27 Update Return on Debt 2025-26, Australian Energy Regulator, January 2025.

Table 9.3 - Return on debt 2027-32

	2028	2029	2030	2031	2032
Nominal pre-tax return on debt	4.93%	5.07%	5.19%	5.47%	5.84%

9.4 Taxation

Our taxation forecast for the 2027-32 regulatory period is presented in Chapter 11 Maximum Allowed Revenue. We have estimated our taxation allowance using the PTRM and the 2022 RoRI, applying:

- a statutory tax rate of 30% per year, and
- a gamma value of 0.57 to estimate the value of imputation credits.

Immediate expensing of capital expenditure

Our forecast of immediately deductible capital expenditure is based on the average of actual immediate deductions of capitalised overheads in previous years. We confirm that our current tax policy will remain unchanged for the 2027-32 regulatory period.

Diminishing value depreciation

We continue to apply the diminishing value (DV) method for tax depreciation for all new capital expenditure, except for buildings and in-house software, which continue to be depreciated using the straight-line method, consistent with the *Income Tax Assessment Act 1997* (ITAA).

9.5 Forecast inflation

We estimated expected inflation using AER's methodology set out in the PTRM. Expected inflation is calculated as the geometric average of inflation rates over the 2027-32 regulatory period based on the Reserve Bank of Australia (RBA) forecasts and a glide path to the midpoint of the RBA's target inflation band (2.5%) in the fifth year.

We have used the RBA's *Statement of Monetary Policy* in August 2025[111] to derive a placeholder estimate of 2.55% for this draft Revenue Proposal.

[111] Statement on Monetary Policy – August 2025, Reserve Bank of Australia, May 2025.

10 Depreciation

10.1 Introduction

This chapter outlines Powerlink's proposed return of capital allowance (also referred to as regulatory depreciation) for the 2027-32 regulatory period. Depreciation enables investors to recover the cost of their capital investment over the economic life of the asset.

Key highlights:

- We forecast a regulatory depreciation of $1,050.4 million ($ nominal) or $972.0 million ($ real, 2026/27), which is $75.4 million (8%) higher than the current 2022-27 regulatory period in real terms.
- We do not propose to apply any depreciation adjustments relating to financeability or accelerated depreciation in the 2027-32 regulatory period.
- We continue to apply the year-by-year depreciation tracking approach in forecasting depreciation.
- We propose to maintain the same asset classes and standard asset lives as approved in the current determination.
- We propose to roll forward our Regulatory Asset Base (RAB) using forecast depreciation to calculate the opening RAB for the subsequent 2032-37 regulatory period.

10.2 Regulatory requirements

The National Electricity Rules (Rules)[112] requires that depreciation schedules use a profile that reflects the nature of each asset class over its economic life.

10.3 Depreciation forecast

Under the regulatory framework, regulatory depreciation is calculated as straight-line depreciation less the inflation adjustment on the opening RAB. Straight-line depreciation reduces an asset's value evenly over its useful life. To calculate the value of the opening RAB, the previous year's RAB must be adjusted for inflation to maintain its real value at the start of the subsequent year[113].

Our depreciation forecast for the 2027-32 regulatory period is set out in Table 10.1.

Table 10.1 - Forecast regulatory depreciation 2027-32 regulatory period ($million nominal)

	2028	2029	2030	2031	2032	Total
Straight-line depreciation	431.6	410.2	427.5	462.7	519.8	2,251.9
Less inflation adjustment on opening RAB	(214.3)	(229.8)	(242.0)	(253.7)	(261.7)	(1,201.5)
Regulatory depreciation	217.4	180.4	185.5	209.0	258.1	1,050.4

[112] National Electricity Rules, clause 6A.6.3.
[113] National Electricity Rules, Schedule S6A.2, clause 6A.2.4(c)(4).

Our forecast regulatory depreciation of $1,050.4 million ($ nominal) or $972.0 million ($ real, 2026/27) is $75.4 million (8%) higher than the current 2022-27 regulatory period in real terms. The increase is primarily driven by growth in our RAB resulting from capital works completed during the current regulatory period.

This forecast reflects the inputs in our Revenue Proposal and will be updated by the AER in its Final Decision to reflect the approved capital expenditures and updated inflation forecast.

10.4 Our approach

We have calculated regulatory depreciation as a forecast depreciation less the inflation adjustment to the opening RAB, consistent with the Rules and the Australian Accounting Standards[114]. We use the AER's Post-Tax Revenue Model (PTRM)[115] to calculate the depreciation forecast for new assets from 1 July 2027 and the AER's Roll Forward Model (RFM)[116] and Depreciation Tracking Module (DTM)[117] for existing assets at 30 June 2027.

The PTRM introduces key changes to align with the Australian Energy Market Commission's (AEMC) 2024 rule change on accommodating financeability in the regulatory framework[118] and AER's Financeability Guideline[119]. It allows for accelerated depreciation to address demonstrated financeability issues resulting from the delivery of actionable Integrated System Plan (ISP) projects. We do not consider that Powerlink requires financeability-related depreciation adjustments for the 2027-32 regulatory period.

We also assessed the treatment of assets where the expected life has been shortened due to technical or operational reasons that may be eligible for application of accelerated depreciation. However, Powerlink has opted not to apply accelerated depreciation to these assets in the 2027-32 regulatory period to avoid short-term price impacts on customers.

In summary, we do not propose to apply any depreciation adjustments relating to financeability or accelerated depreciation for the 2027-32 regulatory period.

10.4.1 Year-by-year depreciation tracking

We continue to use a year-by-year depreciation tracking approach to calculate depreciation. Under this method, new capital expenditure is grouped by asset class, and each asset class is depreciated separately over its approved standard life, ensuring that the recovery profile of our costs reflects the economic lives of our assets.

We have provided our year-by-year depreciation tracking model with this Revenue Proposal. Further information is included in Appendix 10.01 Depreciation Tracking Approach.

[114] Australian Accounting Standard AASB 116 Property, Plant and Equipment.
[115] Electricity Transmission Network Service Provider Post-Tax Revenue Model (Version 6), Australian Energy Regulator, March 2025.
[116] Electricity Transmission Network Service Provider Roll Forward Model (Version 4.1), Australian Energy Regulator, May 2022.
[117] Electricity Transmission Network Service Provider RFM - Depreciation Tracking Module (Version 1), April 2020.
[118] National Electricity Amendment (Accommodating financeability in the regulatory framework) Rule 2024, Australian Energy Market Commission, March 2024.
[119] Financeability guideline - Final, Australian Energy Regulator, November 2024.

10.4.2 Use of forecast depreciation

The AER determined that it will use forecast depreciation to:

- roll forward the RAB for the 2022-27 regulatory period to establish our opening RAB as at 1 July 2027[120] and
- establish our opening RAB as at 1 July 2032 for commencement of the subsequent 2032-37 regulatory period[121].

10.5 Asset classes and asset lives

The standard lives we propose to apply to each asset class are shown in Table 10.2. We propose to apply the same standard asset lives for the 2027-32 regulatory period as applied in the current 2022-27 regulatory period.

Table 10.2 - Standard asset lives – as at 30 June 2027 (years)

Asset class	Standard life (1)
Overhead lines	50
Underground lines	45
Lines (refit)	30
Substations primary plant	40
Substations secondary systems	15
Communications (civil works)	15
Communications – other assets	40
Network switching centres	12
Land	n/a(1)
Easements	n/a
Commercial buildings	40
Computer equipment	5
Office furniture and miscellaneous	7
Office machines	7
Vehicles	7
Moveable plant	7
Insurance spares	n/a
In-house software	5

(1) Asset classes marked 'n/a' do not depreciate.

[120] Powerlink 2022-27 Final Decision, Australian Energy Regulator, April 2022, p.37.
[121] Powerlink Final Framework and Approach Paper 2027-32, Australian Energy Regulator, July 2025.

11 Maximum Allowed Revenue and Price Impact

11.1 Introduction

This chapter outlines Powerlink's Maximum Allowed Revenue (MAR) and forecast price impacts for the 2027-32 regulatory period.

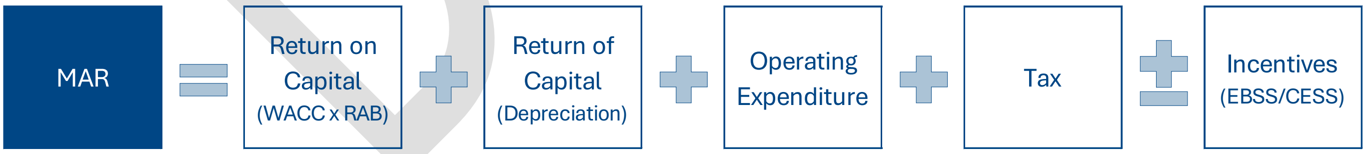
Key highlights:

- Forecast unsmoothed MAR for the 2027-32 regulatory period is $5,743.2 million ($nominal) or $5,308.1 million ($real, 2026/27). This is $1,130.2 million (27%) higher than our allowed MAR in real terms for the 2022-27 regulatory period. The increase in MAR is mainly driven by:
    - significantly higher rates of return, reflecting a sharp increase in the interest rate environment relative to the historically low rates in the current regulatory period
    - growth in the Regulatory Asset Base (RAB) due to increased capital expenditures, impacting both return on capital and depreciation, and
    - higher operating expenditure, reflecting changes in the operating environment.
- The increases are partly offset by estimated negative revenue adjustments under the AER's capital expenditure sharing scheme (CESS) and efficiency benefit sharing scheme (EBSS).
- The increase in MAR results in a forecast increase in the indicative transmission price in the first year of the next regulatory period of 8%. For average residential and small business customers, this represents an estimated increase in the first year of $11 and $22, respectively, based on the assumed tariff and consumption[122].

11.2 Regulatory requirements

We determine the MAR using the building-block approach outlined in the National Electricity Rules (Rules)[123]. This approach calculates the unsmoothed annual revenue requirement, as shown in Figure 11.1.

Figure 11.1 - MAR building-block approach



WACC: Weighted Average Cost of Capital (rate of return)
RAB: Regulatory Asset Base
EBSS: Efficiency Benefit Sharing Scheme
CESS: Capital Expenditure Sharing Scheme

---

[122] The transmission component of electricity bills is based on Australian Energy Regulator's (AER) Default Market Offer 2025-26 Final Determination (DMO 7), May 2025 and Energex's 2025-26 Pricing proposal Overview, May 2025. The assumed residential and small business consumption is based on AER's DMO 7 with median energy usage of 4,600 kWh pa and 10,000 kWh pa, respectively.

[123] National Electricity Rules, clause 6A.5.4.

The Rules[124] require that this annual revenue requirement be smoothed using an X-factor, ensuring the net present value (NPV) of the smoothed revenue equals that of the unsmoothed revenue over the regulatory period. Additionally, the smoothed MAR in the final regulatory year should closely align with the unsmoothed revenue. The smoothed MAR forms the basis for setting our final MAR and prices.

The Rules[125] also provide for adjustments to MAR through pass through applications. These apply when actual transmission network support costs or other approved transmission related costs differ from the forecast during the regulatory control period (refer Chapter 12 Pass Through Events).

Finally, the Rules[126] allows the AER to amend our revenue allowance for contingent projects triggered during the regulatory control period (refer Chapter 5 Forecast Capital Expenditure).

11.3 Forecast total revenue

Our total MAR for each year of the 2027-32 regulatory period is shown in Table 11.1. These figures are calculated using AER's Post-Tax Revenue Model (PTRM)[127], which applies the building-block approach to calculate the unsmoothed annual revenue requirement. Section 11.5 outlines the approach used to calculate each building-block component.

Table 11.1 - Unsmoothed revenue requirement ($million nominal)

	2028	2029	2030	2031	2032	Total
Return on capital	518.5	563.9	600.8	646.5	689.9	3,019.4
Return of capital	217.4	180.4	185.5	209.0	258.1	1,050.4
Operating expenditure	362.3	377.4	390.6	407.6	440.5	1,978.4
Revenue adjustments	(103.7)	(100.5)	(77.4)	(61.5)	(28.5)	(371.5)
Taxation (1)	20.4	15.7	14.3	-	16.2	66.6
Unsmoothed revenue requirement	**1,014.9**	**1,036.9**	**1,113.7**	**1,201.6**	**1,376.1**	**5,743.2**

(1) The zero tax impact in 2031 is due to a significant forecast of immediately deductible capital expenditure in that year.

11.4 Change in MAR from the 2022-27 regulatory period

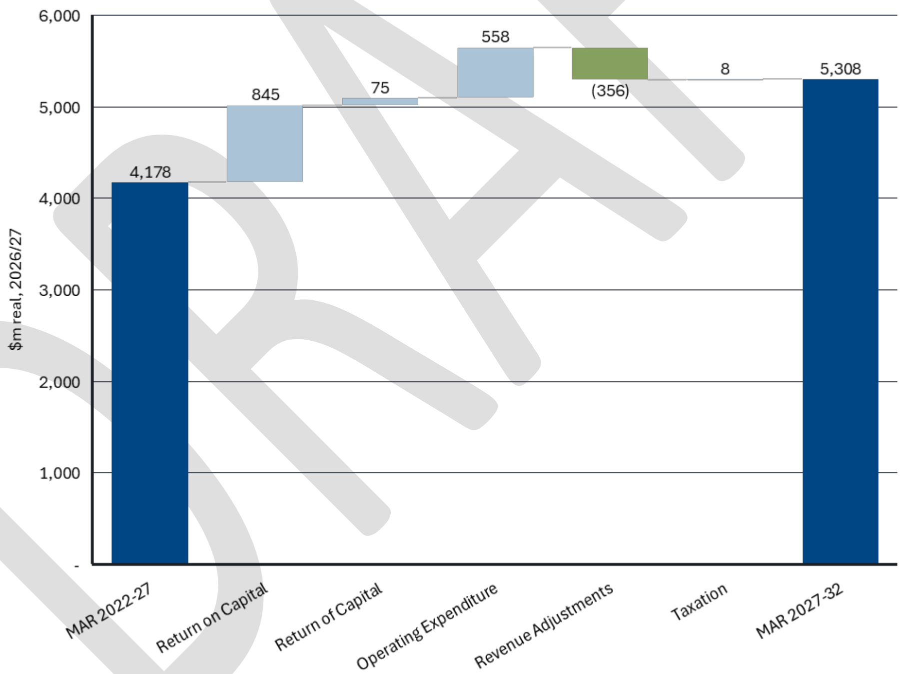
Our unsmoothed MAR is forecast to increase by $1,130.2 million (27%) in real terms compared to our allowed MAR for the 2022-27 regulatory period. Figure 11.2 shows the drivers of revenue change between the 2022-27 and 2027-32 regulatory periods. The key drivers are:

- **Return on capital:** increase of $844.7 million, driven by a higher rate of return (refer Chapter 9 Rate of Return, Taxation and Inflation) and growth in the RAB (refer Chapter 8 Regulatory Asset Base). The RAB growth reflects:
    - higher capital expenditure in the current 2022-27 regulatory period, driven by a significantly different operating environment, including expanded investment needs, new regulatory obligations, and

[124] National Electricity Rules, clause 6A.6.8.
[125] National Electricity Rules, clause 6A.7.2 and 6A.7.3.
[126] National Electricity Rules, clause 6A.8.
[127] Electricity Transmission Network Service Provider Post-Tax Revenue Model (Version 6), Australian Energy Regulator, March 2025.

  substantial cost pressure from global supply chain disruptions, inflation and the energy system transition (refer Chapter 4 Historical Capital and Operating Expenditure), and
  - higher forecast capital expenditure in the 2027-32 regulatory period, driven by reinvestment in ageing network assets, system security needs, and the replacement of our Virginia complex along with expanded facilities in Central Queensland to support a more cost-effective network development approach beyond South-East Queensland (refer Chapter 5 Forecast Capital Expenditure).
- **Return of capital:** increase of $75.4 million, reflecting growth in the RAB.
- **Operating expenditure:** increase of $557.8 million increase, driven by changes in the operating environment including increased demand for skilled labour, greater operating complexity and new regulatory requirements (refer Chapter 6 Forecast Operating Expenditure).
- **Taxation:** increase of $8.4 million, primarily due to the higher MAR (refer Chapter 9 Rate of Return, Taxation and Inflation).
- **Revenue adjustments:** reduction of $356.1 million, driven by estimated net carryovers under CESS and EBSS due to additional capital and operating expenditure compared to allowances in the current 2022-27 period (refer Chapter 14 Incentive Schemes).

Figure 11.2 - Drivers of unsmoothed MAR change ($million real, 2026/27)



11.5 Our approach

We used the AER's PTRM to calculate the MAR. We have engaged with our customers on key changes to our approach that impact our MAR (refer Chapter 3 Customer Engagement).

The AER will update its revenue building blocks for the relevant inputs and forecasts that underpin the MAR in its Final Decision.

11.5.1 Regulatory Asset Base

The value of our RAB determines our return on and return of capital allowances. Our estimated opening RAB as at 1 July 2027 is $8,402.4 million ($ nominal). Our approach to calculating this is outlined in Chapter 8 Regulatory Asset Base.

We have forecast a roll-forward of our RAB for each year of the 2027-32 regulatory period based on our forecasts for inflation (refer Chapter 9 Rate of Return, Taxation and Inflation), capital expenditure (refer Chapter 5 Forecast Capital Expenditure) and regulatory depreciation (refer Chapter 10 Depreciation).

This is summarised in Table 11.2.

Table 11.2 - Forecast RAB roll-forward 2027-32 regulatory period ($million nominal)

	2028	2029	2030	2031	2032
Opening RAB	8,402.4	9,011.8	9,490.8	9,949.4	10,264.7
Capital expenditure, as incurred (1)	826.7	659.5	644.1	524.3	371.7
Regulatory depreciation	(217.4)	(180.4)	(185.5)	(209.0)	(258.1)
Closing RAB	**9,011.8**	**9,490.8**	**9,949.4**	**10,264.7**	**10,378.3**

(1) Net of disposals, adjusted for inflation and one-half Weighted Average Cost of Capital (WACC) allowance[128]. The roll-forward also reflects capitalised movements in provisions.

11.5.2 Return on capital

The return on capital is calculated by applying our rate of return (also referred to as the Weighted Average Cost of Capital, WACC) to the opening RAB in each year of the regulatory period, as detailed in Chapter 9 Rate of Return, Taxation and Inflation.

Our return on capital forecast is presented in Table 11.3.

Table 11.3 - Return on capital ($million nominal)

	2028	2029	2030	2031	2032	Total
Opening RAB	8,402.4	9,011.8	9,490.8	9,949.4	10,264.7	n/a
Rate of return	6.17%	6.26%	6.33%	6.50%	6.72%	n/a
Return on capital	**518.5**	**563.9**	**600.8**	**646.5**	**689.9**	**3,019.4**

[128] The PTRM calculates the return on capital based on the opening RAB and capital expenditure is assumed to occur half-way through the year. To address this timing difference, a half WACC is added to compensate for the six-month period before capital expenditure is included in the RAB.

11.5.3 Return of capital

Our return of capital (also referred to as regulatory depreciation) is calculated by deducting the inflation adjustment made to the RAB from forecast depreciation, as shown in Table 11.4.

More information on our approach to calculating depreciation is included in Chapter 10 Depreciation.

Table 11.4 - Return of capital ($million nominal)

	2028	2029	2030	2031	2032	Total
Straight-line depreciation(1)	431.6	410.2	427.5	462.7	519.8	**2,251.9**
Less inflation adjustment opening RAB	(214.3)	(229.8)	(242.0)	(253.7)	(261.7)	**(1,201.5)**
Return of capital	**217.4**	**180.4**	**185.5**	**209.0**	**258.1**	**1,050.4**

(1) Straight-line depreciation is a method of calculating depreciation whereby an asset is expensed consistently throughout its useful life.

11.5.4 Operating expenditure

Our operating expenditure forecast (refer Chapter 6 Forecast Operating Expenditure) is shown in Table 11.5.

Table 11.5 - Operating expenditure ($million nominal)

	2028	2029	2030	2031	2032	Total
Controllable operating expenditure and insurances	345.9	360.1	372.3	388.4	420.4	**1,887.0**
Australian Energy Market Commission (AEMC) levy	11.4	12.0	12.7	13.3	14.1	**63.5**
Debt raising costs	5.0	5.3	5.6	5.9	6.1	**27.9**
Total operating expenditure	**362.3**	**377.4**	**390.6**	**407.6**	**440.5**	**1,978.4**

11.5.5 Taxation

Our forecast for taxation, applying a value for imputation credits of 0.57 consistent with the AER's 2022 Rate of Return Instrument (refer Chapter 9 Rate of Return, Taxation and Inflation), is presented in Table 11.6.

Table 11.6 - Taxation ($million nominal)

	2028	2029	2030	2031 (1)	2032	Total
Corporate tax	47.5	36.4	33.2	-	37.7	154.9
Value of imputation credits	(27.1)	(20.8)	(18.9)	-	(21.5)	(88.3)
Taxation	**20.4**	**15.7**	**14.3**	**-**	**16.2**	**66.6**

(1) The zero tax impact in 2031 is due to a significant forecast of immediately deductible capital expenditure in the 2031 year.

11.5.6 Revenue adjustments

Any efficiency gains or losses arising from the EBSS and CESS in the 2022-27 regulatory period are carried over as an adjustment to the MAR in the 2027-32 regulatory period (referred to as a carryover amount).

Our estimated EBSS and CESS carryover amounts and CESS true-up carryover (refer Chapter 14 Expenditure Incentive Schemes) from the 2022-27 regulatory period are summarised in Table 11.7.

Table 11.7 - EBSS and CESS carryover amounts ($million nominal)

	2028	2029	2030	2031	2032	Total
EBSS carryover	(77.9)	(74.1)	(50.4)	(33.7)	-	(236.1)
CESS carryovers	(24.9)	(25.6)	(26.2)	(26.9)	(27.6)	(131.2)
CESS true-up for 2021/22	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(4.3)
Total revenue adjustments	**(103.7)**	**(100.5)**	**(77.4)**	**(61.5)**	**(28.5)**	**(371.5)**

11.6 X-factors and smoothed revenue

To minimise revenue fluctuations and pricing impacts on customers, we apply an X-factor to the unsmoothed revenue requirement, in accordance with the Rules[129]. This smoothed revenue profile is the MAR that is used to set our prices each year.

Within the regulatory period, our MAR will be updated each year to reflect actual inflation, changes to the annual return on debt, and any approved cost pass-through (refer Chapter 12 Pass Through Events) or contingent projects triggered during the regulatory control period (refer Chapter 5 Forecast Capital Expenditure).

11.6.1 Default revenue smoothing

We derived X-factors by applying the default smoothing approach in the PTRM. Our X-factors and smoothed MAR for the 2027-32 regulatory period are summarised in Table 11.8.

Table 11.8 - X-factors and smoothed MAR ($million nominal)

	2028	2029	2030	2031	2032	Total
Unsmoothed revenue requirement	1,014.9	1,036.9	1,113.7	1,201.6	1,376.1	5,743.2
X-factors	(5.40%)	(3.44%)	(3.44%)	(3.44%)	(3.44%)	
Smoothed MAR (default)	**1,014.9**	**1,076.6**	**1,142.1**	**1,211.6**	**1,285.3**	**5,730.4**

In the final year of the 2027-32 regulatory period, the smoothed revenue is 6.6% lower than the unsmoothed revenue based on the default smoothing approach. This exceeds the AER's 3% threshold[130] that it considers reasonable for such a variance, hence suggests that an alternative revenue smoothing approach should be used.

[129] National Electricity Rules, clause 6A.6.8(c).
[130] Final decision – Electricity transmission network service providers PTRM handbook, Australian Energy Regulator, March 2025, page29.

11.6.2 Alternative revenue smoothing

We engaged with the Revenue Proposal Reference Group (RPRG) on the approach to revenue smoothing, and specifically on the resulting impacts on customers' prices.

The impact of MAR on customers' prices can be partly offset by increased energy delivered. The RPRG supported further consideration of an alternative approach to revenue smoothing that deferred revenue in line with forecast increases in demand, hence providing a smoother price path.

The alternative X-factors and smoothed revenue profile are shown in Table 11.9.

Table 11.9 - X-factors and alternative smoothed MAR ($million nominal)

	2028	2029	2030	2031	2032	Total
Unsmoothed revenue requirement	1,014.9	1,036.9	1,113.7	1,201.6	1,376.1	5,743.2
X-factors	(3.00%)	(3.50%)	(4.50%)	(5.80%)	(7.27%)	
Smoothed MAR (alternative)	**991.8**	**1,052.7**	**1,128.1**	**1,224.0**	**1,346.4**	**5,743.0**

In the final year of the 2027-32 regulatory period, based on the alternative smoothing approach, the smoothed revenue is 2.2% lower than the unsmoothed revenue, which is within the AER's 3% threshold.

11.7 Average price path

11.7.1 Default revenue smoothing

We calculate our annual prescribed transmission service charges consistent with our approved Pricing Methodology (refer Chapter 15 Pricing Methodology), which must comply with the requirements of the Rules and the AER 2025 Transmission Pricing Methodology Guidelines[131].

To illustrate the indicative impact of our Revenue Proposal on average transmission prices, we divide our forecast MAR by forecast energy delivered in Queensland in each year of the 2027-32 regulatory period. This is shown in Figure 11.3.

Powerlink's contribution to the average Queensland electricity bill is currently 6.7% for households and 6.5% for small businesses[132]. This equates to approximately $148 per annum for residential customers[133] and approximately $287 per annum for small businesses[134].

Based on our default smoothed revenue, the indicative impact on the transmission component of electricity prices in the first year of the next regulatory period (2027/28) would be:

- **Residential –** a nominal increase of $11 (8%), real increase of approximately $8 (5%).
- **Business –** a nominal increase of $22 (8%), real increase of approximately $15 (5%).

[131] Electricity Transmission Network Service Providers: Pricing Methodology Guidelines, Australian Energy Regulator, July 2025.
[132] Default Market Offer 7, 2025-26, Australian Energy Regulator (AER), May 2025; and 2025-26 Pricing Proposal Overview document, Energex, May 2025.
[133] Based on the AER's residential median energy usage of 4,600kWh per annum, May 2025.
[134] Based on the AER's small business median energy usage of 10,000kWh per annum, May 2025.

The annual price increases for average residential customers and small businesses will be 3% in nominal terms for the remainder of the 2027-32 regulatory period[135].

The estimated impact of our forecast revenue on the transmission component of average annual electricity bills in each year of the 2027-32 regulatory period is shown in Table 11.10.

Table 11.10 - Estimated impact on transmission component of average annual electricity bills ($ nominal)

	2027	2028	2029	2030	2031	2032
Residential annual bill	148	159	168	174	178	180
Annual change		**11**	**8**	**7**	**4**	**2**
Small business	287	309	326	339	347	350
Annual change		**22**	**16**	**13**	**8**	**3**

11.7.2 Alternative revenue smoothing

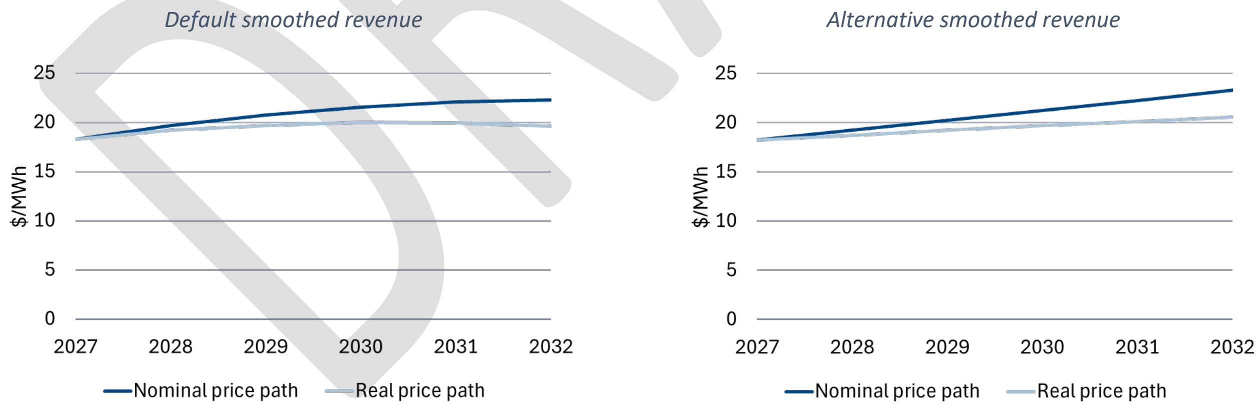
Based on the alternative approach to revenue smoothing, the indicative impact on the transmission component of electricity prices in the first year of the next regulatory period (2027/28) would be:

- **Residential –** a nominal increase of $8 (5%), real increase of approximately $4 (3%).
- **Business –** a nominal increase of $15 (5%), real increase of approximately $8 (3%).

The annual price increases for average residential customers and small businesses will be 5% in nominal terms for the remainder of the 2027-32 regulatory period.

The alternative approach to smoothing revenue results in a more balanced price path relative to the default method, as shown in Figure 11.3.

Figure 11.3 - Indicative price path from 2026/27 to 2031/32



135 Based on forecast energy delivered per AEMO's Electricity Statement of Opportunities (ESOO) 2025.

The estimated impact of our forecast revenue on the transmission component of average annual electricity bills in each year of the 2027-32 regulatory period for this approach is shown in Table 11.11.

Table 11.11 - Estimated impact on transmission component of average annual electricity bills - alternative revenue smoothing ($ nominal)

	2027	2028	2029	2030	2031	2032
Residential annual bill	148	156	164	172	180	189
Annual change		**8**	**8**	**8**	**8**	**9**
Small business	287	302	319	335	351	367
Annual change		**15**	**16**	**16**	**16**	**17**

11.8 Revenue and price impact with alternative CESS carryover amount from the 2022-27 regulatory period

During the 2022-27 regulatory period, like all other network businesses in Australia, Powerlink experienced unprecedented increases in the costs of major plant items, materials and skilled resources. These cost pressures were outside Powerlink's control and resulted in higher capital expenditure than initially forecast. To provide an alternative view, we have recalculated the regulatory allowance to reflect the actual increases to the cost inputs included in the AER's original capital expenditure allowances (refer Chapter 14 Incentive Schemes). The alternative regulatory allowance was then used to calculate the overspend against allowance, which is lower, and assess an alternative CESS carryover amount, which is also lower.

Using the lower alternative CESS carryover amount, we have estimated the corresponding alternative unsmoothed MAR and price impacts. For the 2027-32 regulatory period, the alternative unsmoothed MAR would be $5,833.6 million, or $90.3 million higher than the forecast MAR in nominal terms, as shown in Table 11.12.

Table 11.12 - Unsmoothed revenue requirement under alternative CESS carryover amount ($million nominal)

	2028	2029	2030	2031	2032	Total
Alternative Unsmoothed MAR	1,032.1	1,054.5	1,131.8	1,220.1	1,395.1	**5,833.6**
Unsmoothed MAR	1,014.9	1,036.9	1,113.7	1,201.6	1,376.1	**5,743.2**
Difference	**17.2**	**17.6**	**18.1**	**18.5**	**19.0**	**90.3**

The indicative price path for the transmission component of electricity prices in the 2027-32 regulatory period has been calculated using the default revenue smoothing approach included in the PTRM. This provides a direct comparison to the price path presented in Section 11.7.1.

Using this approach, the transmission component of electricity prices in the first year of the next regulatory period (2027/28) would be:

- **Residential –** a nominal increase of $14 (10%), which is $3 higher than our forecast increase of $11 (23%).
- **Business –** a nominal increase of $28 (10%), which is $5 higher than our forecast increase of $22 (23%).

For the remainder of the 2027-32 regulatory period, the average annual transmission price increases for residential customers and small businesses would be 3% in nominal terms.

The estimated impact of our alternative MAR on the transmission component of average annual electricity bills in each year of the 2027-32 regulatory period is shown in Table 11.13.

Table 11.13 - Estimated impact on transmission component of average annual electricity bills - alternative CESS approach ($ nominal)

	2027	2028	2029	2030	2031	2032
Residential annual bill	148	162	170	177	181	183
Annual change		**14**	**8**	**7**	**4**	**2**
Small business	287	315	331	344	352	356
Annual change		**28**	**16**	**13**	**8**	**3**

12 Pass Through Events

12.1 Introduction

This chapter sets out the nominated and other pass through events proposed by Powerlink for the 2027-32 regulatory period.

The pass through event mechanism in the National Electricity Rules (Rules) is intended to provide an efficient means for a network service provider to recover the efficient costs of uncontrollable material events that either cannot be insured or where the establishment of self-insurance is not economically viable.

Key highlights:

- We take a holistic approach to identify and manage our risks in the most cost-effective way for customers and Powerlink. We assess if and how risks can be efficiently mitigated through a balance of commercial insurance, self-insurance and pass through events.
- Having regard to the current insurance market, we nominate the following pass through events for the 2027-32 regulatory period:
    - Insurance coverage event
    - Insurer credit risk event
    - Natural disaster event and
    - Terrorism event.

12.2 Regulatory requirements

The Rules[136] allow for following pass through events:

1. A regulatory change event
2. A service standard event
3. A tax change event
4. An insurance event and
5. Any other event specified in a transmission determination as a pass through for the determination.

Pass through events can lead to an increase or decrease in costs (a positive or negative change event). The change in costs must exceed 1% of Maximum Allowed Revenue (MAR) in the relevant year before a Transmission Network Service Provider (TNSP) can seek a determination from the Australian Energy Regulator (AER) for pass through of those costs[137].

The pass through event mechanism allows a TNSP to nominate additional pass through events as part of a Revenue Proposal, referred to as a nominated pass through event.

[136] National Electricity Rules, clause 6A.7.3(a1).
[137] National Electricity Rules, Chapter 10, definition of *materially*.

12.3 Nominated pass through events

Note for the draft Revenue Proposal: The nominated cost pass throughs proposed in this section are in early draft form. We are still considering a prudent and efficient balance between commercial insurance, self-insurance and pass through events. This will be the subject of a customer and stakeholder deep dive session in November 2025 to inform our decision-making.

We take a holistic approach to the identification and management of our risks. We manage our risk profile with a suite of preventative, detective and mitigating controls. A key component of this strategy is the development and maintenance of an insurance program. To ensure an optimal balance of cover in the most cost-effective way for customers and Powerlink, we consider the complementary nature of commercial insurance coverage, self-insurance and pass through events. This holistic approach has guided the development of this Revenue Proposal.

Among the considerations that we must have regard to under the Rules for our nominated pass through events is the extent to which the event can be insured or self-insured[138].

We engaged our insurance broker, Marsh Pty Ltd (Marsh), to advise us on our insurance and risk management approach for the 2027-32 regulatory period, including any risks that may need to be addressed as a pass through event (refer Appendix 12.01). Our proposed approach to insurance and self-insurance is addressed as part of our operating expenditure forecast (refer Chapter 6 Forecast Operating Expenditure).

Based on Marsh's advice, we propose the following nominated pass through events for the 2027-32 regulatory period:

- Insurance coverage event
- Insurer credit risk event
- Natural disaster event and
- Terrorism event.

The first three events were proposed in the 2022-27 regulatory period. Marsh recommended an additional event, Terrorism, given the increasing risk of act of terrorism events (refer Chapter 6 Forecast Operating Expenditure). This type of nominated pass through is common among other TNSPs and Distribution Network Service Providers (DNSP) and has been accepted by the AER in other recent determinations[139].

The following sections set out our proposed definition and justification for each of these events. We consider that our nominated pass through events are consistent with the Rules[140].

[138] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[139] Final Decisions for Energex (2025), Ergon Energy (2025), TasNetworks (2024), TransGrid (2023) and ElectraNet (2023), AusNet Services transmission (2022).
[140] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.

12.3.1 Insurance coverage event

We propose an insurance coverage event to mitigate the risk of liability losses that exceed, and/or are not covered due to gaps in, insurance coverage where there is a lack of insurers capacity or reasonable commercial terms. We consider the nominated pass through event complies with the considerations set out in Chapter 10 of the Rules[141]:

- The proposed insurance coverage event is not a pass through event specified in the Rules[142].
- We consider that the nature and type of event can be clearly identified at the time the AER makes its determination.
- Liability events such as bushfire could result in losses that exceed the limit of cover on existing liability insurance policies. The occurrence of an insurance coverage event is not foreseeable, has a low probability of occurrence but a high cost impact. We cannot fully prevent these types of events from occurring, noting that while we invest, operate and maintain our network to withstand such events, we cannot substantially mitigate their cost impact.
- We have insurance coverage based on reasonable commercial terms and consider it would not be efficient to obtain additional insurances beyond a prudent, risk-based limit of cover.
- We cannot control movements and insurer appetite in the insurance liability market, where those movements mean that it is no longer possible to take out an insurance policy (or set of insurance policies) at all or in part, or on reasonable commercial terms.

Our proposed definition for this event is shown in Table 12.1.

Table 12.1 - Proposed definition of insurance coverage event

An Insurance Coverage Event occurs if:

1. Powerlink:
   a. makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies, or
   b. would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances, and
2. Powerlink incurs costs:
   a. beyond a relevant policy limit for that policy or set of insurance policies, or
   b. that are unrecoverable under that policy or set of insurance policies due to changed circumstances; and
3. The costs referred to in paragraph 2 above materially increase the costs to Powerlink in providing prescribed transmission services.

For the purposes of this insurance coverage event:

- 'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of Powerlink, where those movements mean that it is no longer possible for Powerlink to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies.
- 'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had:
  i. the limit not been exhausted, or
  ii. those costs not been unrecoverable due to changed circumstances.

[141] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[142] National Electricity Rules, Clause 6A.7.3(a1).

- A relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which Powerlink was regulated; and
- Powerlink will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of Powerlink in relation to any aspect of Powerlink's network or business; and
- Powerlink will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of Powerlink in relation to any aspect of Powerlink's network or business.

Note for the avoidance of doubt, in assessing an insurance coverage event through application under Clause 6A.7.3 of the Rules, the AER will have regard to:

- The relevant insurance policy or set of insurance policies for the event,
- The level of insurance that an efficient and prudent Network Service Provider (NSP) would obtain, or would have sought to obtain, in respect of the event, and
- Any information provided by Powerlink to the AER about Powerlink's actions and processes, and
- Any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event that occurs.

12.3.2 Insurer credit risk event

We propose an insurer credit risk event would be triggered where an insurer becomes insolvent and Powerlink is consequently subject to additional costs than allowed under the insurance policy with that insurer. We consider the nominated pass through event complies with the considerations set out in the Rules[143]:

- The proposed insurer credit risk event is not a pass through event specified in the Rules[144].
- We consider that the nature and type of event can be clearly identified at the time the AER makes its determination.
- We set minimum requirements for the credit rating of participating underwriters and apportion our policies across both domestic and international providers. This combination provides a level of risk mitigation against a potential Insurer Credit Risk event. However, we are not able to control whether one or more of our insurers become insolvent.
- We cannot obtain insurance on reasonable commercial terms to cover the occurrence of this type of event. In addition, we are not able to calculate a reasonable self-insurance premium for this event as it would be relative to the claim for a risk that was insured by the insolvent insurer.

Our proposed definition for this event is shown in Table 12.2.

Table 12.2 - Proposed definition of insurer credit risk event

An Insurer Credit Risk event occurs if:

- An insurer of Powerlink becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, Powerlink:
    - is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy, or
    - incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

143 National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
144 National Electricity Rules, Clause 6A.7.3(a1).

Note: In assessing an Insurer Credit Risk event pass through application, the AER will have regard to, amongst other things:

- Powerlink's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation, and
- in the event that a claim would have been covered by the insolvent insurer's policy, whether Powerlink had reasonable opportunity to insure the risk with a different insurer.

12.3.3 Natural disaster event

We propose a natural disaster risk event would be triggered where we could not obtain insurance coverage on reasonable commercial terms and the disaster caused a material increase in costs to Powerlink. We consider the nominated pass through event complies with the considerations set out in the Rules[145]:

- The proposed natural disaster risk event is not a pass through event specified in the Rules[146].
- We consider that the nature and type of event can be clearly identified at the time the AER makes its determination.
- Natural disaster events, by definition, cannot be prevented or avoided. We employ a range of strategies to minimise and mitigate the exposure of the transmission network to natural disasters. These include a broad range of technical preventative measures, asset siting and design, continuous asset monitoring and maintenance activities along with existing insurance cover. Given the potential increase in natural catastrophe event frequency and intensity, and subsequent premium changes, we consider it prudent to continue to review the level of insurance coverage, deductibles and limits over the 2027-32 regulatory period.
- Movements in the insurance market may result in situations where it is no longer possible to take out an insurance policy, (or a set of insurance policies) at all, or to do so on reasonable commercial terms. This is particularly relevant for Towers and Lines insurance, which is a bespoke product with little capacity in the insurance market.
- To manage this risk, we consider it prudent and efficient to optimise our level of insurance coverage supported by both self-insurance and a natural disaster pass through.

Our proposed definition for this event is shown in Table 12.3.

Table 12.3 - Proposed definition of natural disaster risk event

Natural Disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2027-32 regulatory control period that changes the costs to Powerlink in providing prescribed transmission services, provided the fire, flood or other event was:

- a consequence of an act or omission that was necessary for Powerlink to comply with a regulatory obligation or requirement or with an applicable regulatory instrument, or
- not a consequence of any other act or omission of Powerlink.

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

- whether Powerlink has insurance against the event, and
- the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

[145] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[146] National Electricity Rules, Clause 6A.7.3(a1).

12.3.4 Terrorism event

We propose a terrorism risk event would be triggered where an unforeseen act of terrorism for which Powerlink did not have insurance against caused a material increase in costs to Powerlink. We consider the nominated pass through event complies with the considerations set out in Chapter 10 of the Rules[147]:

- The proposed terrorism risk event is not a pass through event specified in the Rules[148].
- We consider that the nature and type of event can be clearly identified at the time the AER makes its determination.
- Terrorism events are unpredictable and cannot be prevented or avoided. We employ a range of strategies to minimise and mitigate the exposure of the transmission network to Terrorism, including actions we take to ensure the physical and electronic security of our transmission network. While these actions assist to withstand such events, an act of terrorism could significantly impact on the cost of maintaining or restoring reliable supply of our prescribed transmission services.
- The low frequency and potentially very high costs of a terrorism event make it challenging to insure such events, with many insurers excluding or limiting cover. We cannot obtain insurance on reasonable commercial terms to cover the occurrence of this type of event. In addition, we are not able to calculate a reasonable self-insurance premium for this event.

Our proposed definition for this event is shown in Table 12.4.

Table 12.4 - Proposed definition of terrorism event

Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which:

- from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear), and
- changes the costs to Powerlink in providing prescribed transmission services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

- whether Powerlink has insurance against the event,
- the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and
- whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

12.4 Network support pass through

We may be required to make a payment to a generator or other entity for the provision of network support services during the 2027-32 regulatory period.

Under the Rules[149], we can seek a determination from the AER for a pass through of any differences in costs between the amount included in the annual revenue requirement and actual efficient costs associated with network support events.

[147] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[148] National Electricity Rules, Clause 6A.7.3(a1).
[149] National Electricity Rules, Clause 6A.7.2.

13 Shared Assets

13.1 Introduction

Shared assets are used to provide both prescribed transmission services and either non-regulated transmission services or services that are not transmission services[150]. The assets may be fixed (e.g. poles), mobile (e.g. vehicles) or non-physical (e.g. radio frequency spectrum).

This chapter sets out Powerlink's assessment of our forecast unregulated revenues from shared assets for the 2027-32 regulatory period. The purpose of this assessment is to determine whether any adjustment is required to our proposed annual revenue requirement.

Key highlights:

- Shared Asset Unregulated Revenues for the 2027-32 regulatory period have been assessed as not material, based on the approach in the Australian Energy Regulator's Shared Asset Guideline[151].
- We have not adjusted our proposed annual revenues in our Revenue Proposal.

13.2 Regulatory requirements

The National Electricity Rules (Rules)[152] allows the Australian Energy Regulator (AER) to reduce a Transmission Network Service Provider's (TNSP) annual revenue requirement to reflect the costs attributable to services which generate unregulated revenues. The AER's approach to making an adjustment to revenue is set out in its Shared Asset Guideline (SA Guideline).

The SA Guideline sets out the following process to establish the shared asset cost reduction for each year of the regulatory period:

- determine the Shared Asset Unregulated Revenues (SAUR)
- determine whether the SAUR is material (i.e. exceeds 1% of the proposed annual revenue requirement)
- where the SAUR is material, calculate the shared asset cost reduction (equal to 10% of the SAUR), subject to:
    - application of the control step (i.e. a cap) and/or
    - adjustments for contributed assets, if any.

Where the SAUR is not material, no further action is required.

Materiality and the unregulated revenue relevant to cost reductions are determined by averaging the forecast SAUR over the 2027-32 regulatory period. Where the SAUR is material, the SA Guideline allows for TNSPs to propose an alternative method to calculate a cost reduction. The TNSP must demonstrate that customers would be no worse off compared to the SA Guideline approach.

Where assets provide prescribed transmission services and unregulated services consistent with a TNSP's Cost Allocation Methodology, the shared asset mechanism does not apply.

[150] National Electricity Rules, clause 6A.5.5(a).
[151] Shared Asset Guideline (Version 2), Australian Energy Regulator, June 2025.
[152] National Electricity Rules, clause 6A.5.5.

13.3 Shared assets assessment

Our assessment shows the unregulated use of shared assets is not forecast to be material (i.e. remains under the 1% materiality threshold) in any year of the 2027-32 regulatory period. As a result, we propose no adjustment to our annual revenues in our Revenue Proposal (see Table 13.1).

Table 13.1 - Materiality assessment ($million nominal)

	2028	2029	2030	2031	2032	Total
Proposed smoothed Maximum Allowed Revenue (MAR)	1,014.9	1,076.6	1,142.1	1,211.6	1,285.3	**5,730.4**
1% of smoothed MAR	10.1	10.8	11.4	12.1	12.9	**57.3**
Average annual SAUR	1.7	1.7	1.7	1.7	1.7	**8.5**
SAUR as % MAR	0.2%	0.2%	0.1%	0.1%	0.1%	
Exceed 1% Materiality Test	**No**	**No**	**No**	**No**	**No**	

13.4 Our approach

We have applied the AER's approach outlined in Section 13.2 to determine whether a revenue adjustment should be applied. We have adopted the same methodology to estimate our SAUR as applied in our previous 2023-27 Revenue Proposal.

13.4.1 Shared asset unregulated revenues

We have identified non-regulated services below that use shared assets and are applicable to the shared assets mechanism in the 2027-32 regulatory period. These are:

- **Property rentals –** rental income from our land or buildings, either acquired for or incidental to the development of our prescribed transmission network.
- **Tower access –** provision of space for the co-location of mobile phone carriers' equipment on our transmission and communications towers.
- **QDATA –** commercial data service offering network-related information for the Queensland region.
- **Property searches –** provision of information to help applicants determine whether Powerlink holds any assets or interests in relation to specified land parcels.
- **Easement compensation –** compensation received from non-regulated customers for the right to access, construct and maintain transmission lines on Powerlink's regulated substation land during the term of their Connection and Access Agreement.

Table 13.2 - Forecast SAUR ($million nominal)

	2028	2029	2030	2031	2032	Total
Property rentals	0.5	0.5	0.5	0.5	0.5	**2.6**
Tower access	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	**(0.8)**
QDATA	0.1	0.1	0.1	0.1	0.1	**0.3**
Property searches	0.3	0.3	0.3	0.3	0.3	**1.4**
Easement compensation	1.0	1.0	1.0	1.0	1.0	**5.0**
Total	**1.7**	**1.7**	**1.7**	**1.7**	**1.7**	**8.5**

13.4.2 Materiality

The SA Guideline states that SAUR will be considered material when the average for the period is greater than 1% of the total smoothed revenue requirement for that regulatory year.

Our unregulated use of shared assets applicable to the shared assets mechanism in the 2027-32 regulatory period is not forecast to exceed the 1% materiality threshold in any year. As a result, no revenue adjustment has been applied.

14 Incentive Schemes

14.1 Introduction

This chapter outlines net carryover amounts for the current 2022-27 regulatory period and Powerlink's targets for the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS) for the 2027-32 regulatory period. The EBSS relates to operating expenditure and the CESS relates to capital expenditure.

This chapter also outlines Powerlink's performance under the Service Target Performance Incentive Scheme (STPIS) in the current 2022-27 regulatory period, as well as our proposed STPIS values and targets for the 2027-32 regulatory period.

Key highlights:

- Under the EBSS, we estimate a net negative carryover amount from the 2022-27 regulatory period of $223.6 million, which will reduce the Maximum Allowed Revenue (MAR) for the 2027-32 regulatory period.
- We propose that $1,746.7 million ($ real, 2026/27) of our forecast operating expenditure for the 2027-32 regulatory period be subject to the EBSS.
- Under the CESS, we estimate a net negative carryover amount from the 2022-27 regulatory period of $121.6 million and a CESS true-up for FY22 of negative $4 million ($ real, 2026/27), which will reduce the MAR for the 2027-32 regulatory period.
- We have proposed an alternative approach to the calculation of the net carryover amount under the CESS that appropriately recognises the operating environment during the current period, which would result in a net negative carryover amount of $37.9 million ($ real, 2026/27).
- We propose that $2,781.7 million ($ real, 2026/27) of our forecast capital expenditure for the 2027-32 regulatory period be subject to the CESS.
- Under the STPIS, overall, we have maintained or improved our STPIS network performance for the current 2022-27 regulatory period and we continue to manage market impacts by applying prudent measures and behaviours.
    - Our Market Impact Component (MIC) performance has been impacted by the reasons outlined in the Australian Energy Regulator's (AER) Final Decision on its 2025 STPIS (Version 6)[153].
    - We propose Service Component (SC) targets consistent with the AER's historical data ranges.

14.2 Regulatory requirements

In its Final Decision for our 2022-27 revenue determination, the AER applied version 2 (November 2013) of the EBSS, and the CESS as set out in version 1 (November 2013) of the Capital Expenditure Incentive Guideline[154].

The AER intends to continue to apply version 2 of the EBSS for our 2027-32 regulatory period, but will confirm this approach in its Final Decision, and has confirmed it will apply the CESS as set out in the updated Capital Expenditure Incentive Guideline, to be published in September 2025[155].

[153] AER Final – Electricity transmission network service provider Service target performance incentive scheme Version 6, Australian Energy Regulator, April 2025.
[154] Final decision Powerlink Queensland transmission determination 2022 to 2027, Australian Energy Regulator, April 2022, pp63-64.
[155] Framework and approach Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025, pp3-5.

We have calculated net carryover amounts from the 2022-27 regulatory period and set our EBSS and CESS targets based on our forecast operating and capital expenditure for the 2027-32 regulatory period, consistent with these incentive schemes.

The Rules[156] require the AER to develop and publish a STPIS that complies with specified principles. We are required to include proposed values for the STPIS parameters as part of our Revenue Proposal[157]. We are currently subject to the AER's 2015 STPIS (Version 5). In its Framework and Approach paper for Powerlink[158], the AER confirmed that it will apply the AER's 2025 STPIS (Version 6) for the 2027-32 regulatory period.

14.3 Efficiency Benefit Sharing Scheme

14.3.1 Carryover amount from the 2022-27 regulatory period

Under the EBSS, our MAR for the 2027-32 regulatory period is adjusted for approximately 30% of any operating expenditure efficiency gain or loss accrued during the 2022-27 regulatory period[159] (the carryover amount).

Our total EBSS carryover amount from the 2022-27 regulatory period is estimated as $223.6 million (negative), as shown in Table 14.1.

Table 14.1 - EBSS carryover amount ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
EBSS carryover	(76.0)	(70.4)	(46.7)	(30.5)	-	**(223.6)**

Our calculated EBSS carryover is based on the difference between our actual operating expenditure and the AER allowance (target for the purpose of the EBSS) for the first three years of the 2022-27 regulatory period and an estimate of that difference for the last two forecast years (2025/26 and 2026/27). We have also adjusted our forecast and actual operating expenditure in each year of the 2022-27 regulatory period for inflation and excludable costs.

14.3.2 EBSS target for the 2027-32 regulatory period

We have used 2025/26 as our base year to forecast our operating expenditure for the 2027-32 regulatory period (refer Chapter 6 Forecast Operating Expenditure).

Consistent with Version 2 of the EBSS, we have excluded categories of operating expenditure not forecast using a single year revealed cost approach for the proposed EBSS target for the 2027-32 regulatory period. This better achieves the requirements of the Rules[160] and includes debt raising costs, network support costs, and Australian Energy Market Operator (AEMO) participant and cyber security fees.

We have not adjusted for insurance premiums and self-insurance consistent with the AER's approach for Powerlink's 2022-27 draft decision[161]. Our EBSS target for the 2027-32 regulatory period is our forecast operating expenditure (less category specific expenditure) of $1,746.7 million, as shown in Table 14.2.

[156] National Electricity Rules, clause 6A.7.4.
[157] Ibid., Schedule 6A.1, clause S6A.1.3(2).
[158] Framework and approach Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025, p.5.
[159] Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, Australian Energy Regulator, November 2013, Section 1.3.
[160] Ibid., Clause 6A.6.5.
[161] Australian Energy Regulator, Attachment 8: Efficiency benefit sharing scheme | Draft decision – Powerlink Queensland transmission determination 2022–27.

Table 14.2 - EBSS target ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
Operating expenditure forecast	353.3	358.9	362.2	368.6	388.4	**1,831.3**
Adjustments						
Debt raising costs	4.8	5.1	5.2	5.3	5.4	**25.8**
Network support costs	-	-	-	-	-	**-**
AEMO participant and cyber security fees	11.1	11.4	11.7	12.1	12.4	**58.8**
EBSS target	**337.3**	**342.4**	**345.2**	**351.2**	**370.6**	**1,746.7**

14.4 Capital Expenditure Sharing Scheme

14.4.1 Carryover amount from the 2022-27 regulatory period

As with the EBSS, the CESS requires that we adjust our MAR for the 2027-32 regulatory period for our share (30%) of any capital expenditure efficiency gain or loss from the 2022-27 regulatory period (the carryover amount). Our total CESS carryover amount from the 2022-27 regulatory period is estimated as $121.6 million (negative), shown in Table 14.3.

Table 14.3 - CESS carryover amount ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
CESS carryover	(24.3)	(24.3)	(24.3)	(24.3)	(24.3)	(121.6)

This calculation is based on the difference between our actual capital expenditure and the AER allowance (target for the purpose of the CESS) for the first three years of the 2022-27 regulatory period and an estimate of that difference for the last two forecast years (2025/26 and 2026/27). We have also adjusted our forecast and actual capital expenditure in each year of the 2022-27 regulatory period for inflation.

14.4.2 CESS FY22 true-up for the 2027-32 regulatory period

The CESS true-up requires that we adjust our MAR for the last year of the 2017-22 regulatory period to account for the difference between the forecast and actual capital expenditure. Our total CESS true-up amount from the 2017-22 regulatory period is $4.0 million (negative), shown in Table 14.4.

Table 14.4 - CESS true-up ($million real, 2026/27)

	2028	**2029**	**2030**	**2031**	**2032**	**Total**
CESS true-up	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(4.0)

14.4.3 Alternative approach for calculating carryover amount from the 2022-27 regulatory period

During the 2022-27 regulatory period, like all other network businesses in Australia, Powerlink experienced unprecedented increases in the costs of major plant items, materials and skilled resources (refer Chapter 2 Business and Operating Environment). This led to increases to capital expenditure that were outside the control of Powerlink.

Consequently, we have applied actual increases to the cost inputs included in the AER's original capital expenditure allowance. This alternative approach restates the allowance for the 2022-27 regulatory period to include the cost increases outside of Powerlink's control, allowing for a more reasonable assessment of those cost increases that were within Powerlink's control. The difference between the restated allowance and actual expenditure in the period represents a capital expenditure position that has regard for the circumstances of Powerlink during the 2022-27 regulatory period and should reasonably be subject to CESS penalty.

Powerlink recognises that this is a different approach to calculating net carryovers under CESS, and customers and the AER will be engaged further to test the likelihood of the approach being considered capable of acceptance.

Our total CESS carryover amount from the 2022-27 regulatory period based on this alternative approach would be $37.9 million (negative) as shown in Table 14.5.

Table 14.5 - Alternative CESS carryover amount ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
CESS carryover	(7.6)	(7.6)	(7.6)	(7.6)	(7.6)	(37.9)

14.4.4 CESS target for the 2027-32 regulatory period

Our CESS target for the 2027-32 regulatory period is our capital expenditure forecast (net of disposals) of $2,781.7 million as shown in Table 14.6.

Table 14.6 - CESS target ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
Capital expenditure forecast, net of disposal	795.3	619.1	589.6	468.3	324.4	**2,796.7**
Adjustments						
Movement in provisions	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	**(15.0)**
CESS target	**792.3**	**616.1**	**586.6**	**465.3**	**321.4**	**2,781.7**

Adjustments may be made during the 2027-32 regulatory period for any capital expenditure approved by the AER for contingent projects that are triggered during the period. Our proposed contingent projects are outlined in our capital expenditure forecast (refer Chapter 5 Forecast Capital Expenditure).

14.5 Service Target Performance Incentive Scheme

14.5.1 Outcomes for the 2022-27 regulatory period

The three components to the STPIS are the Service Component (SC), Market Impact Component (MIC) and Network Capability Component (NCC).

Overall, our STPIS performance demonstrates continued improvement, except for MIC performance due to the reasons outlined throughout the transmission STPIS review and in the AER's Final Decision on its 2025 STPIS

(Version 6)[162]. Our STPIS outcomes for the SC, MIC and NCC for the current 2022-27 regulatory period are summarised in Table 14.7.

STPIS operates and data is reported to the AER on a calendar year basis. As our current regulatory period commenced on 1 July 2022, the information below reflects performance for the second half of that year. The AER's 2015 STPIS requires that a two-year rolling average is used to report the SC performance of the unplanned outage circuit event rate and average outage duration.

Table 14.7 - Historical STPIS annual compliance performance 2022 2H to 2024

Parameter	Unit of Measure	2022-27 Annual Target	Calendar Year 2022 2H	2023	2024
Service Component					
Lines Event Rate – Fault (1)	Rate	17.03	7.39	7.59	9.15
Transformer Event Rate – Fault (1)	Rate	16.81	9.06	12.31	12.44
Reactive Plant Event Rate – Fault (1)	Rate	25.65	15.04	19.55	20.61
Lines Event Rate – Forced (1)	Rate	17.02	8.56	11.38	11.11
Transformer Event Rate – Forced (1)	Rate	14.82	9.36	12.03	10.64
Reactive Plant Event Rate – Forced (1)	Rate	21.21	17.67	24.44	23.24
Loss of supply events > 0.05 (x) system minutes	Count	1	1	2	0
Loss of supply events > 0.40 (y) system minutes	Count	0	0	1	0
Average outage duration (1)	Minutes	33.23	69	323	46
Failure of protection system (2)	Number	26	9	20	21
Material failure of Supervisory Control and Data Acquisition (SCADA) system (2)	Number	1	0	0	0
Incorrect operational isolation of primary or secondary equipment (2)	Number	4	1	2	5
Market Impact Component					
MIC	No. of Dispatch Intervals (DI)	1,001	3619	2239	667
Network Capability Component					
Network Capability Incentive Parameter Action Plan (NCIPAP)	No NCIPAP projects were proposed by Powerlink for the 2022-27 regulatory period.				

(1) Two year rolling average performance is reported as required by the AER's 2015 STPIS.
(2) Report only parameter with no weighting.

[162] AER Final – Electricity transmission network service provider Service target performance incentive scheme Version 6, Australian Energy Regulator, April 2025.

14.5.2 STPIS Service Component target setting for 2027-32 and historical values

Approach to set our targets and values

This section sets out our proposed STPIS Service Component (SC) values and the approach we used to set our targets for the 2027-32 regulatory period. This is based on the AER's 2025 STPIS and the AER's Framework and Approach for Powerlink's 2027-32 revenue determination[163].

The approach we used to set our STPIS targets is as follows:

- We have proposed targets, caps and floors for relevant parameters and sub-parameters related to the SC based on Section 3.2 of the AER's 2025 STPIS.
- The caps and floors were calculated based on a best fit statistical distribution to the previous five years performance data for each of the parameters and sub-parameters. The caps and floors reflect the 5th and 95th percentiles of each of the chosen statistical distributions.

The proper operation of equipment parameter is 'report only' and therefore no values are required. We have provided our STPIS SC values for the 2027-32 regulatory period based on the historical date ranges required by the AER in Table 14.8.

Table 14.8 - STPIS values

SC Parameter (±1.25% MAR)	Floor	Target	Cap	Distribution
Unplanned Outage Circuit Event Rate (±0.75% MAR)				
Lines Event Rate – Fault	11.74	9.35	6.52	Weibull
Transformer Event Rate – Fault	15.03	12.45	10.25	Pearson5
Reactive Plant Event Rate – Fault	24.27	20.72	16.45	Weibull
Lines Event Rate – Forced	17.61	12.96	9.34	Pearson5
Transformer Event Rate – Forced	19.31	13.12	7.98	Gamma
Reactive Plant Event Rate – Forced	27.91	22.83	18.18	Gamma
Loss of Supply Event Frequency (±0.30% MAR)				
Greater than 0.05 System Minutes (x)	4	1.40	0	Poisson
Greater than 0.40 System Minutes (y)	2	0.60	0	Poisson
Average Outage Duration (±0.20% MAR)				
Average Outage Duration	297.24	161.16	13.20	LogLogistic

14.5.3 STPIS Service Component historical performance

The following sections outline our historical performance for the SC, which informs our caps, floors and targets for each relevant parameter and sub-parameter.

The targets outlined in Table 14.7 have been calculated using the year ranges indicated in Figure 14.1 to Figure 14.9. The 2025 calendar year data will be incorporated when we lodge our Revised Revenue Proposal in December 2026.

[163] Framework and approach Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025, p.5.

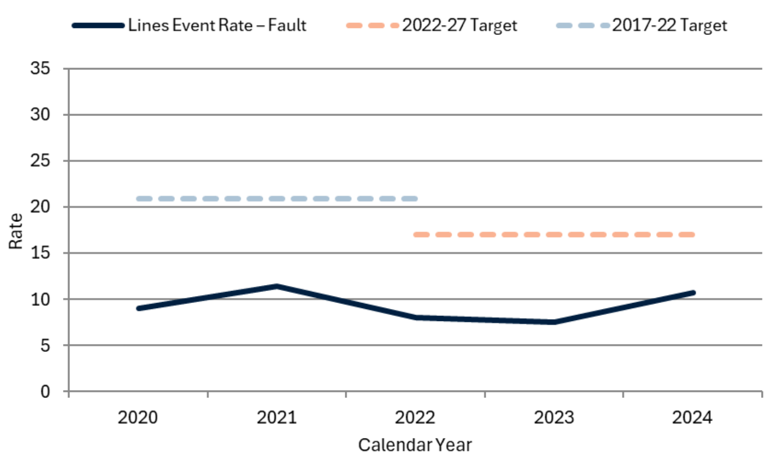
Unplanned outage circuit event rate – fault

A fault outage is any element outage that occurred as a result of an element being switched off (such as circuit breakers) unexpectedly, i.e. it did not occur as a result of intentional manual operation of switching devices. The fault outage circuit event rate parameter measures network reliability based on an aggregate number of fault outages per annum for each of the element transmission types: lines, transformers and reactive plant.

To minimise the impact on our customers and the market, we rapidly respond to and restore fault outages on our network. Deterioration in asset condition can contribute to fault outage events. Where prudent and efficient, we refurbish our deteriorating assets. This can restore asset performance, reduce fault level outage occurrences, and improve the overall reliability of our assets.

The historical performance of our fault outage circuit rates since 2020 for transmission lines, transformers and reactive plant is shown in Figures 14.1, 14.2 and 14.3.

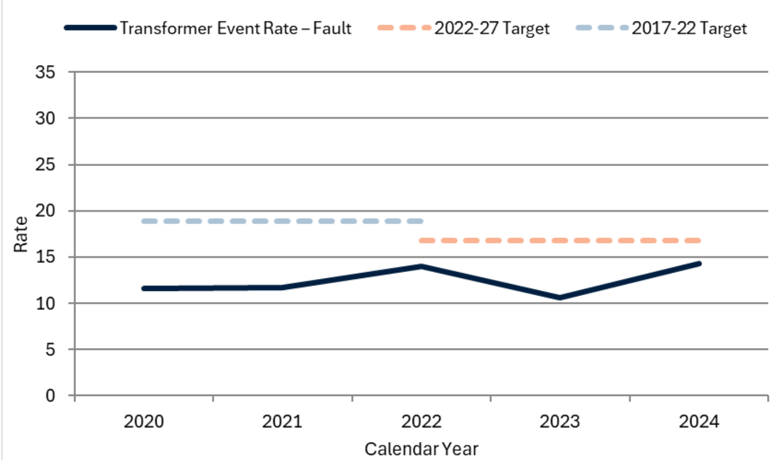
Figure 14.1 - Lines Event Rate – Fault 2020-2024



The lines fault event rate sub-parameter performed better than the target.

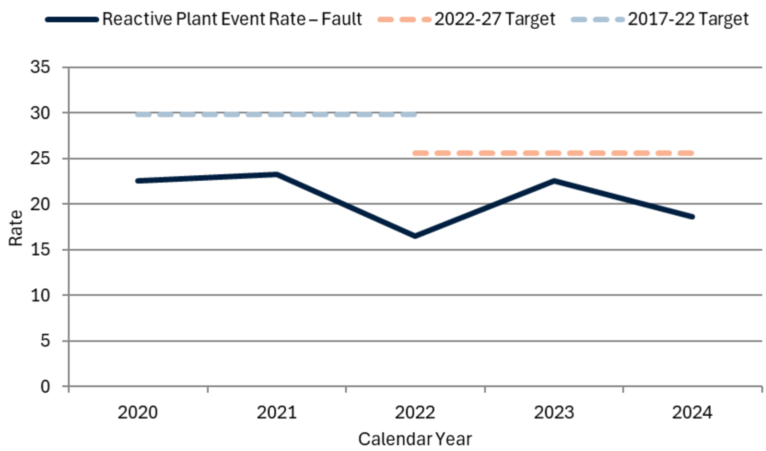
The sub-parameter remained within expected ranges based on long term trends and is consistent with annual environmental and equipment performance variabilities and volatilities.

Figure 14.2 - Transformer Event Rate – Fault 2020-2024



The transformer fault event rate met the target during the five-year period. The sub-parameter remained within expected ranges based on long term trends and is consistent with annual environmental and equipment performance variabilities and volatilities.

Figure 14.3 - Reactive Plant Event Rate – Fault 2020-2024



The reactive plant fault event rate sub-parameter performed consistently better than the target due to less environmental related fault impacts.

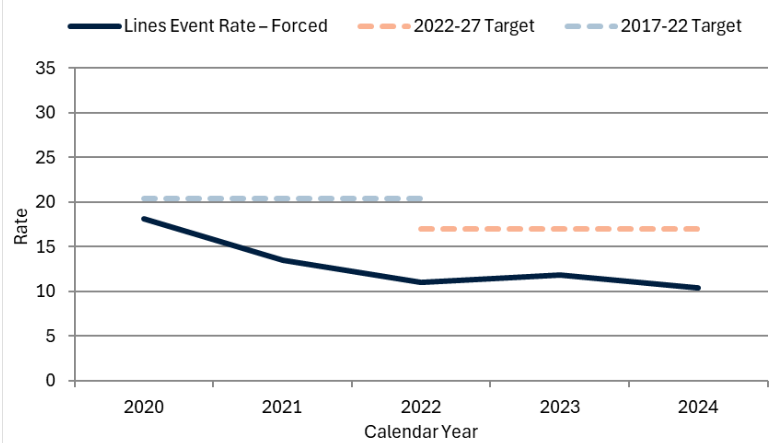
Unplanned outage circuit event rate - forced

A forced outage is any element outage that occurred as a result of intentional manual operation of switching devices based on the requirement to undertake urgent and unplanned corrective activity, where less than 24 hours' notice was given to the affected customer(s) and/or AEMO.

Similar to the fault outage rate, the forced outage circuit event rate parameter measures network reliability based on an aggregate number of forced outages per annum for each of the element transmission types (lines, transformers and reactive plant).

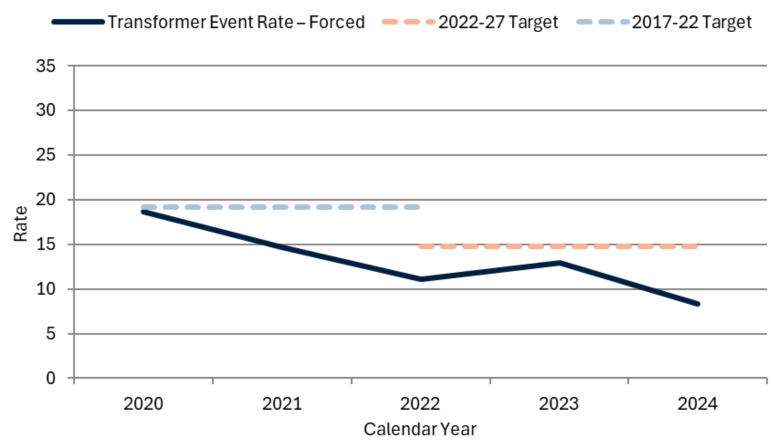
The historical performance of our forced outage circuit rates since 2020 for transmission lines, transformers and reactive plant is shown in Figures 14.4, 14.5 and 14.6.

Figure 14.4 - Lines Event Rate – Forced 2020-2024



The lines forced event rate performed consistently better than the target. The sub-parameter remained within expected ranges based on long term trends and is consistent with annual environmental and equipment performance variabilities and volatilities.

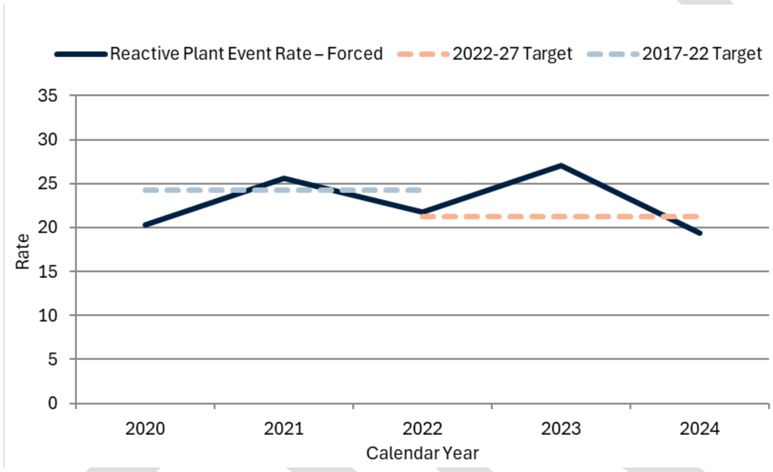
Figure 14.5 - Transformer Event Rate – Forced 2020-2024



The transformer forced event rate sub-parameter performed better than the target.

The sub-parameter remained within expected ranges based on long term trends and is consistent with annual environmental and equipment performance variabilities and volatilities.

Figure 14.6 - Reactive Plant Event Rate – Forced 2020-2024



The reactive plant forced event rate was influenced by opportunistic corrective work undertaken when operational conditions allowed. With alternate reactive plant available, activities such as weed removal, alarm investigations, and gas top-ups could be carried out cost-effectively without affecting network operations.

Loss of supply event frequency

We report performance against two loss of supply event targets based on the thresholds specified in the AER's 2015 STPIS:

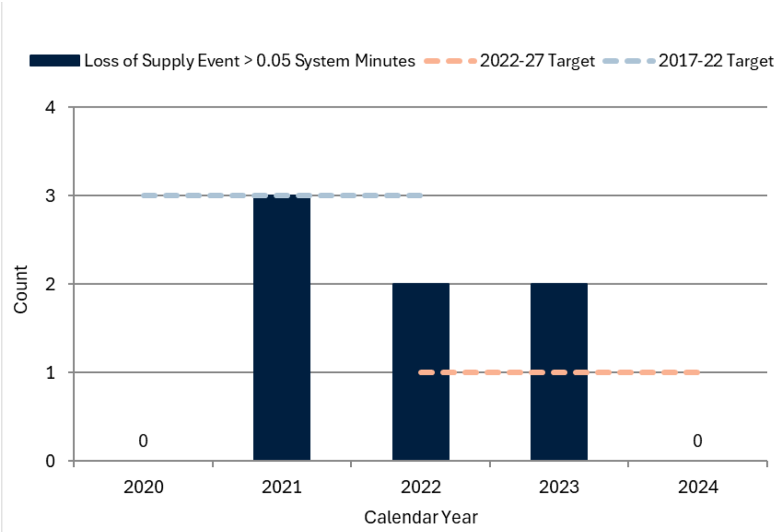
- the 'moderate' event (x) threshold is a loss of supply events greater than 0.05 system minutes; and
- the 'large' event (y) threshold is a loss of supply event greater than 0.40 system minutes.

For the 2022-27 regulatory period we remain subject to the same two sets of targets for loss of supply events. We have actively worked to minimise the impact of loss of supply events on our network.

Loss of supply event frequency greater than 0.05 system minutes (x)

Our historical performance for this parameter is shown in Figure 14.7.

Figure 14.7 - Loss of supply event frequency greater than 0.05 system minutes (x) 2020-2024



For the loss of supply event frequency sub-parameter under the 'moderate' (x) threshold, we met or performed better than the target in three years (2020, 2021 and 2024) out of the five.

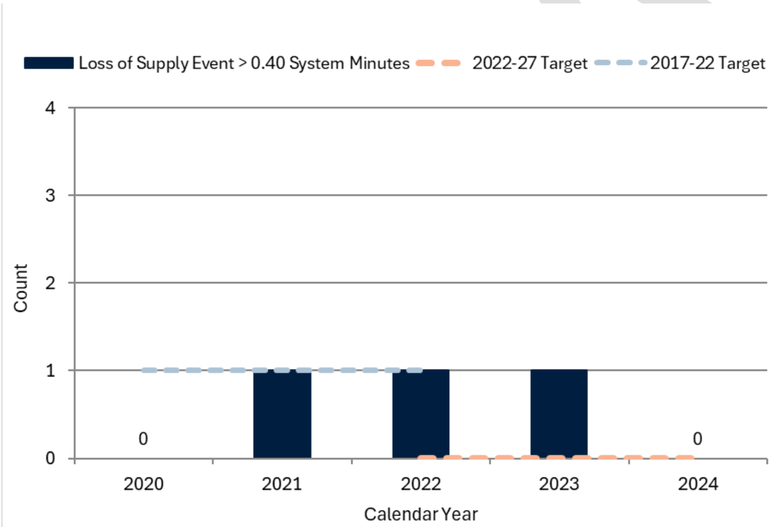
In 2022, the two events comprised de-energisation of two 110kV feeders in Brisbane to manage safety issues due to rising flood water, and a wildlife event resulted in loss of load in northern Queensland.

In 2023, there were two events – one because of plant failure and the other due to wildlife.

Loss of supply event frequency greater than 0.40 system minutes (y)

Our historical performance for this parameter is shown in Figure 14.8.

Figure 14.8 - Loss of supply event frequency greater than 0.40 system minutes (y) 2020-2024



We met or performed better than the target for the loss of supply event frequency sub-parameter under the 'large' (y) threshold in 2020, 2021 and 2024.

In 2022 the de-energisation of two 110kV feeders in Brisbane to manage safety issues due to rising flood water exceeded both x and y thresholds.

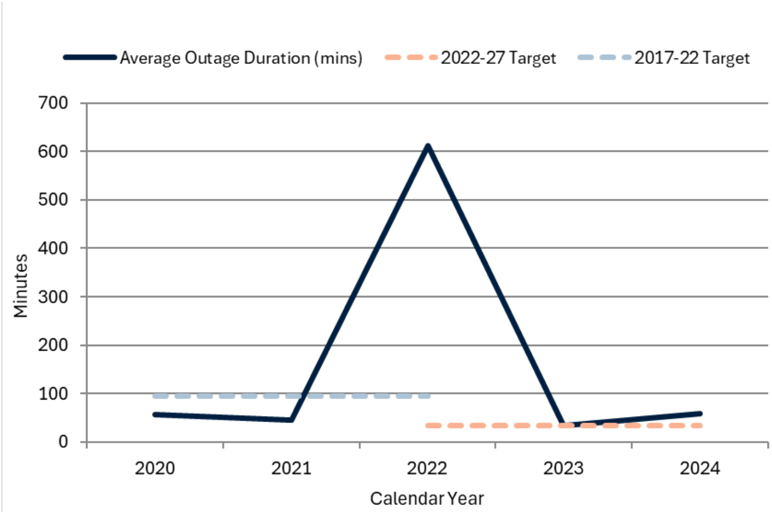
In 2023, plant failure resulted in a loss of supply to Townsville and surrounding areas.

Average outage duration

The average outage duration parameter measures the average time to restore loss of supply events. It is calculated by the division of the total duration of loss of supply events in a year by the number of loss of supply events in that year.

Our historical performance for this parameter is shown in Figure 14.9.

Figure 14.9 - Average outage duration 2020-2024



We performed better than the target for the average outage duration of loss of supply event parameter in 2020 and 2021.

In February 2022, an extreme rain event caused widespread flooding in Southeast Queensland. In response to this event, we de-energised two 110kV feeders which are connected to our Bundamba substation, located near Ipswich, to manage safety issues for the community due to rapidly rising flood water in Bremer River. The substation remained de-energised for approximately 18 hours until floodwaters receded, and inspections confirmed conditions allowed for the substation and transmission lines to be safely re-energised. There was no safety incident, and Powerlink assets did not suffer any material damage because of this 1:200-year flood event.

In 2023 and 2024, several events occurred where, on average, load restoration took slightly longer than the AER's target of 33 minutes.

15 Pricing Methodology

15.1 Introduction

This chapter sets out proposed amendments to our current Australian Energy Regulator (AER) approved Pricing Methodology, which will apply to Powerlink's 2027-32 regulatory period.

Our Pricing Methodology describes how we allocate our annual prescribed revenue to the various categories of prescribed services and transmission network connection points and determines the structure of our prescribed transmission charges.

Key highlights:

- We reviewed our prescribed transmission pricing arrangements and propose only minor amendments to our Pricing Methodology to:
    - reflect two recent changes to the National Electricity Rules (Rules), and
    - continue implementation of a decision from the AER in its Final Determination on Powerlink's 2023-27 Revenue Proposal.
- A marked up copy of our Proposed Pricing Methodology, showing changes from our current Pricing Methodology, is included in Appendix 15.01.

15.2 Regulatory requirements

The Rules[164] require us to submit a proposed Pricing Methodology with our Revenue Proposal. The Rules also specify the requirements for a Pricing Methodology, which include consistency with the pricing principles for prescribed transmission services[165], the AER's 2025 Transmission Pricing Methodology Guidelines[166] and any relevant regulatory information instrument.

15.3 Our Proposed Pricing Methodology

15.3.1 Review of pricing arrangements

Affordability remains a key concern for both our large directly connected customers and distribution connected end-users as discussed in Chapter 2 Business and Operating Environment. We recognise that transmission plays a role in addressing these concerns and putting downward pressure on prices.

Our customers are changing the way they use the transmission network, as transformational changes take place throughout the electricity system. To adapt to the changing environment, we are currently transitioning to locational prices based on peak demand only. This approach was supported by customers after an extensive engagement process and approved by the AER in its Final Determination on Powerlink's 2023-27 Revenue Proposal[167].

[164] National Electricity Rules, clause 6A.10.1.
[165] National Electricity Rules, clause 6A.23.
[166] Pricing Methodology Guidelines, Australian Energy Regulator, July 2025.
[167] Final Decision Powerlink Queensland Transmission Determination 2022 to 2027, Australian Energy Regulator, April 2022, page 71.

This change provides stronger signals to our customers to encourage more efficient use of the network and enables customers to reduce their costs by changing their network usage.

We will continue to implement this transition over the 2027-32 regulatory period. No other material amendments have been proposed to our Pricing Methodology.

15.3.2 Customer and stakeholder engagement

We engaged with a range of stakeholders as part of our detailed review of the factors impacting transmission service prices. This included Powerlink's Revenue Proposal Reference Group (RPRG) and other Transmission Network Service Providers (TNSPs).

In July 2025, we provided an overview to the RPRG of our proposed amendments to the Pricing Methodology, which includes:

- changes to implement two recent Rule changes by the Australian Energy Market Commission (AEMC), and
- a minor administrative change to continue implementation of a decision approved by the AER in its Final Determination for our 2023-27 Revenue Proposal.

The RPRG supported the changes and acknowledged that the amendments were largely to ensure compliance with Rule changes.

In addition, in the normal course of business we engage regularly with our directly connected customers. Powerlink reviewed issues raised by our directly connected customers in recent years and considered that no further changes to our Pricing Methodology were necessary.

15.3.3 Proposed amendments to our Pricing Methodology

The three proposed amendments to our Pricing Methodology are summarised in Table 15.1. Each of the proposed changes are permitted under the current Rules.

Table 15.1 - Proposed Pricing Methodology amendments

Amendment	Description
National Electricity Rule Change Implementation	
1. Provide for the recovery of non-network system security contracts	We must comply with the Improving Security Frameworks for the Energy Transition (ISF) Rule change[168]. It requires Pricing Methodology amendments to provide for TNSPs to forecast and recover their expected annual non-network system security contracts for the coming regulatory year and recover these expected contracts through prescribed transmission prices for that year. This includes the recovery, or return to our customers, of any differences between the actual and forecast costs incurred under the contracts through prescribed transmission service prices, subject to AER approval. This Rule was implemented in our 2025/26 prescribed transmission service prices but must now also be reflected in our Pricing Methodology.

[168] Improving Security Frameworks for the Energy Transition, Australian Energy Market Commission, March 2024.

Amendment	Description
2. Reflect the new term 'aggregate annual revenue requirement (AARR)' as the Co-ordinating Network Service Provider (CNSP)	This change reflects the AEMC's final Rule for Providing Flexibility in the Allocation of Interconnector Costs[169] and the AER's Pricing Methodology Guidelines[170]. While we currently do not have an interconnector cost allocation agreement in place, as the CNSP for Queensland, we must update our Pricing Methodology to reflect the new terminology in the Rules.
Other Minor Administrative Change	
3. Continue the transition to peak demand locational pricing for the remaining 5 years of the 10-year transition.	In our 2023-27 Revenue Proposal, customers supported, and the AER approved a transition to locational prices based on peak demand only. To facilitate this transition, the average demand component of the locational price is decreasing by 10 percent each year over the 2022-27 and 2027-32 regulatory periods. Our 2023-27 Pricing Methodology includes transitional arrangements for the period. Minor amendments are needed to implement the continuation of the transition in the 2027-32 regulatory period.

[169] Providing Flexibility in the Allocation of Interconnector Costs, Australian Energy Market Commission, October 2024.
[170] Electricity Transmission Network Service Providers Pricing Methodology Guidelines, Australian Energy Regulator, July 2025.

Glossary

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AGN	Australian Gas Networks
ATO	Australian Taxation Office
BAU	Business as usual activities
BESS	Battery Energy Storage System
BISOE	BIS Oxford Economics
CAM	Cost Allocation Methodology
CA RIN	Category Analysis Regulatory Information Notice
CCP	AER’s Consumer Challenge Panel
CCP23	AER’s Consumer Challenge Panel, sub-panel 23
CESS	Capital Expenditure Sharing Scheme
COGATI	Coordination of Generation and Transmission Investment
COTA	Council on the Ageing
CPI	Consumer Price Index
CQ-SQ	Central Queensland to Southern Queensland
CRNP	Cost Reflective Network Pricing
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAE	Deloitte Access Economics
DEPW	Department of Energy and Public Works
DER	Distributed Energy Resources
DI	Dispatch Interval
DMIAM	Demand Management Incentive Allowance Mechanism
DNSP	Distribution Network Service Provider
DOF	Delivery Optimisation Framework
DV	Diminishing Value
EB RIN	Economic Benchmarking Regulatory Information Notice
EBSS	Efficiency Benefit Sharing Scheme

ECA	Energy Consumers Australia
EGWWS	Electricity, Gas, Water and Waste Services
EMS	Energy Management System
ENA	Energy Networks Australia
ERP	Enterprise Resource Planning
ESB	Energy Security Board
ESG	Environmental, Social and Governance
ESOO	AEMO's Electricity Statement of Opportunities
EUAA	Energy Users Association of Australia
EV	Electric Vehicle
F&A	Framework and Approach
GDP	Gross Domestic Product
GIS	Geographical Information System
GSP	Gross State Product
GTPS	Generator Technical Performance Standards
IAP2	International Association for Public Participation
IBR	Inverter-Based Resources
ISP	Integrated System Plan
IT	Information Technology
ITAA	Income Tax Assessment Act 1997
KPI	Key Performance Indicators
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt hours
MAR	Maximum Allowed Revenue
MCC	Marginal Constraint Cost
MIC	Market Impact Component
MLEC	Modified Load Export Charge
MNSP	Market Network Service Provider
MPFP	Multilateral Partial Factor Productivity
MTFP	Multilateral Total Factor Productivity
MW	Megawatts

MWh	Megawatt hours
NCC	Network Capability Component
NCIPAP	Network Capability Incentive Parameter Action Plan
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NGNO	Next Generation Network Operations
NIO	Network Investment Outlook
NSP	Network Service Provider
NSW	New South Wales
NTP	National Transmission Planner
OEFs	Operating Environment Factors
OT	Operating Technology
PFP	Partial Factor Productivity
PMUs	Phasor Monitoring Units
PPFP	Preliminary Positions and Forecasts Paper
PPI	Partial Performance Indicators
PRS	Portfolio Risk System
PTRM	Post-Tax Revenue Model
PV	Photovoltaic
QAO	Queensland Audit Office
QCA	Queensland Competition Authority
QFF	Queensland Farmers' Federation
Qld	Queensland
QNI	Queensland/New South Wales Interconnector
QRC	Queensland Resources Council
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
Repex	Replacement Expenditure
Reset RIN	AER's Reset Regulatory Information Notice
RET	Renewable Energy Target
REZs	Renewable Energy Zones
RFM	Roll Forward Model

RIN	Regulatory Information Notice
RIT-T	Regulatory Investment Test for Transmission
RoR	Rate of Return
RPRG	Revenue Proposal Reference Group
the Rules	National Electricity Rules
SAUR	Shared Asset Unregulated Revenues
SAP	Powerlink’s Enterprise Resource Planning Database
SC	Service Component
SCADA	Supervisory Control and Data Acquisition
SG	Superannuation Guarantee
SIPS	System Integrity Protection Scheme
STPIS	Service Target Performance Incentive Scheme
SVC	Static Var Compensators
SynCon	Synchronous Condenser
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Life
WPI	Wage Price Index

Appendices

Note for the draft Revenue Proposal: The appendices in black are included for this draft Revenue Proposal. Appendices shaded light grey will be completed for lodgement of our Revenue Proposal in January 2026. This is not a comprehensive list at this stage and is subject to change.

The following table lists all appendices associated with Powerlink's Revenue Proposal. The author of all documents is Powerlink unless otherwise stated.

List of Appendices	
1.01	Board Certification of Key Inputs and Assumptions
1.02	Statutory Declaration on Powerlink's Reset RIN
1.03	NER Compliance Checklist
1.04	RIN Compliance Checklist
1.05	Document Register
2.01	Business Narrative
3.01	Engagement Plan
3.02	Submissions on our draft Revenue Proposal
3.03	Customer Panel Statement on Engagement
3.04	Terms of Reference for the Revenue Proposal Reference Group
3.05	Customer Panel Evaluation Survey
3.06	2025 Stakeholder Perception Survey Summary
3.07	Transmission Network Forum Participant Feedback Summary 2025
4.01	HoustonKemp – Efficiency of Powerlink's Base Year Operating Expenditure Report
4.02	Historical expenditure in the previous control period (FY21-25)
5.01	Operating and Capital Expenditure Criteria and Factors
5.02	2025 Transmission Annual Planning Report
5.03	Expenditure Forecasting Methodology
5.04	Non Load-Driven Network Capex Forecasting Methodology
5.05	IT Plan 2027-32
5.06	Guide to Non-Network Capital Expenditure
5.07	Contingent Projects
5.08	OT Plan 2027-32
6.01	Forecast Operating Expenditure Methodology and Model
6.02	Operating Expenditure Productivity Approach and Potential Initiatives
6.03	Operating Expenditure Step Changes Approach

6.04	Marsh – Insurance Projections
6.05	Incenta – Benchmark Debt and Equity Raising Costs Report
7.01	OEA – Labour Cost Escalation Forecasts to FY2032 Report
7.03	Cost Estimating Methodology
8.01	Regulatory Asset Base Transfers – confidential
9.01	Nominated Averaging Periods – confidential
10.01	Depreciation Tracking Approach
12.01	Marsh - Nominated Pass-Through Events
14.01	Setting STIPS Values
15.01	Proposed Pricing Methodology

Models

Note for the draft Revenue Proposal: No models have been included for this draft Revenue Proposal. Models shaded light grey will be completed for lodgement of our Revenue Proposal in January 2026. This is not a comprehensive list at this stage and is subject to change.

All models associated with Powerlink's Revenue Proposal are provided in the list below. Models can be accessed via the AER's website for Powerlink's revenue determination under the Proposal tab.

List of models
Capital Expenditure Model
Capital Expenditure Sharing Scheme (CESS) Model
Depreciation Tracking Module
Efficiency Benefit Sharing Scheme (EBSS) Model
Operating Expenditure Model
Post-Tax Revenue Model (PTRM)
Roll Forward Model (RFM)

Contact us

Registered office	33 Harold St Virginia Queensland 4014 ABN 82 078 849 233
Postal address	PO Box 1193 Virginia Queensland 4014
Telephone	+61 7 3860 2111 (during business hours)
Email	revenueresetteam@powerlink.com.au
Website	powerlink.com.au
Social	