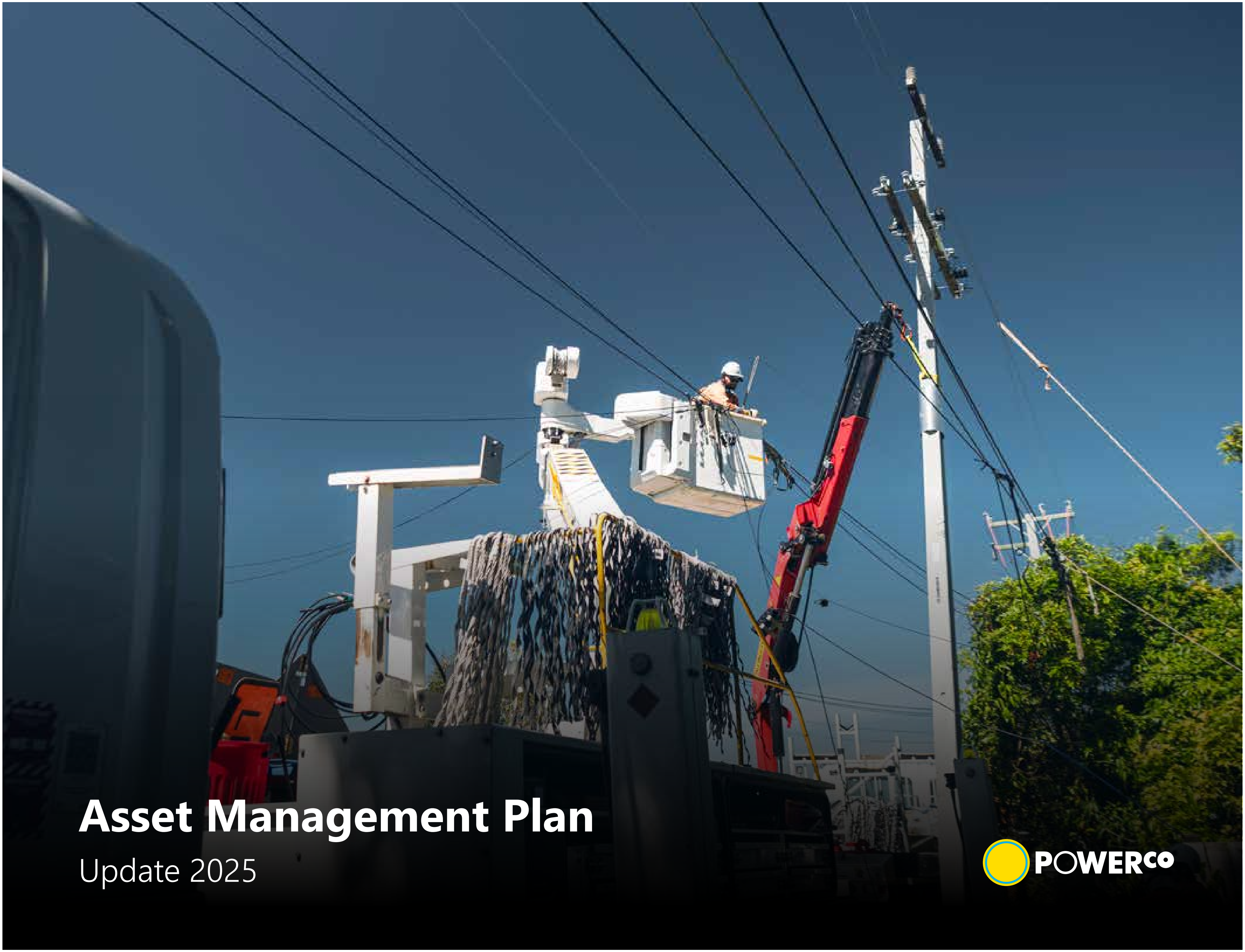


# Asset Management Plan

Update 2025

POWERCO

# Contents

Kia ora koutou

Our 2025 Asset Management Plan Update is a second update to our comprehensive 2023 Asset Management Plan, published in March 2023. It outlines the work needed during the next decade to continue to provide the safe, reliable, and resilient electricity network our customers will increasingly rely on for more of their energy needs. Our work is fundamental to facilitating Aotearoa New Zealand's decarbonisation and adaptation journey and realising its net-zero emissions targets by 2050.

Our vision for Aotearoa New Zealand is **Grow to zero**[1] – leveraging our abundance of renewable energy as a competitive advantage to produce low-emissions goods and services, which is an increasingly attractive proposition as global economies seek to decarbonise. It's also a call to action, to ensure the energy transition delivers the best future for Kiwis – enabling us to grow our economy relative to others as we transition so that we can afford to adapt to the challenges ahead.

This AMP Update supports this vision for Aotearoa New Zealand by outlining the investment required in our electricity infrastructure. At the heart of this are our customers – ensuring our investments provide overall **value for money** while managing the energy trilemma of reliability, sustainability, and affordability.

Timely and adequate investment is crucial. 'Just in time' investment risks being too late, while 'just enough' investment risks delivering too little. Our no-regrets plan favours progress over perfection to meet the required infrastructure build and support customers to invest with confidence.

Our outlook for electricity demand over the long term remains consistent with our earlier projections. Decarbonisation via electrification and continued underlying growth will increase peak electricity demands on our network. Recently, we have observed a flattening of demand, linked to tougher economic times for the country, but we believe these are short-term fluctuations, and our outlined growth plans remain necessary and prudent.

Our role also includes the enabling of new renewable generation. In recent years we have seen considerable interest in generation connections, particularly solar, and we are open and motivated to support connection investment.

In preparation for increasing infrastructure investment during the decade ahead, we are implementing two major transformation projects:

1. **Updating our contracting model for field services**. We are introducing a regional model to better support electrification while delivering value for customers.

2. **Transforming our approach to customer work**. We are taking on the end-to-end customer experience, to ensure efficiency, transparency, and consistency in service and engagement.

This AMP Update also confirms our commitment to becoming a fully functional distribution system operator (DSO) by 2030. By integrating new technology, commercial models, and enhanced business processes, we will improve network utilisation, support increasing electrification, and manage the need for new network infrastructure. This ultimately delivers value for our customers.

This is the first AMP Update since the finalisation of the default price-quality path (DPP) for 2025-2030, which sets revenue and reliability targets for us to manage. We are supportive of the process and decision reached by the Commerce Commission, including increasing the flexibility for expenditure reopeners, innovation funding and additional expenditure for our accelerated graduate and technician training programme. We have adjusted our capital expenditure plans to reflect the DPP4 allowances, balancing cost and risk, while recognising several investments carry uncertainties that may necessitate future reopeners.

[1] Grow to zero white paper

We foresee some potential risk in these expenditure allowances, however. As our DSO programme accelerates and becomes business as usual, additional operating expenditure in systems, data and flexibility contracts is likely to be required ahead of the next regulatory reset. Also, our contracting model update, last tendered more than 10 years ago, has the potential for price impacts on a significant portion of our works, with limited ability to absorb. As the regulatory period progresses, we will continue to monitor these expenditure pressures and engage with the Commerce Commission to ensure the best outcomes for our customers.

Our 2025 AMP Update is a well-prepared plan focused on delivering for our customers now and in the long term. It reflects our purpose: **We're here to connect communities.**

Ngā mihi nui
Chris Taylor
Acting Chief Executive Officer

# 1. Introduction

## 1.1 Purpose

Powerco is Aotearoa New Zealand's second-largest electricity distribution company by customer numbers, supplying about one of every six residential customers in the country. We have the largest supply territory by area and the largest overall network length. Our networks stretch across the North Island from the Coromandel to the Wairarapa.

We provide an essential service to more than 360,000 homes and businesses, serving approximately one million customers. The electricity distribution assets we manage have long lives and are capital-intensive to create and maintain. We consider ourselves long-term asset stewards, providing effective and efficient asset planning and investment for current and future generations.

In March 2024, we published an Asset Management Plan Update, which is available on our website www.powerco.co.nz. This 2025 Asset Management Plan Update (AMP Update) is limited to providing updates on material changes to the previous AMP Update, the latest information on our forecasts, and our long-term strategy for managing our electricity assets. We are experiencing some major shifts in our operating environment, requiring some substantial changes to our previously published plans and forecasts. These trends and our plans to respond are also highlighted in this AMP Update.

This AMP Update relates to the electricity distribution services supplied by Powerco, and covers the planning period from 1 April 2025 to 31 March 2035.

## 1.2 Information disclosure requirements

Clause 2.6.3 in the Electricity Distribution Information Disclosure Determination 2012 requires Powerco to complete and publicly disclose, before 1 April 2025, an AMP Update.

Clause 2.6.5 states that the AMP Update must:

- Relate to the electricity distribution services supplied by the electricity distribution business (EDB).
- Identify any material changes to the network development plans disclosed in the last AMP (or AMP Update) per clause 11 and clause 17.5-17.7 of attachment A.
- Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP (or AMP Update) per clause 12 of attachment A.
- Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b.
- Identify any changes to the asset management practices of the EDB that would affect Schedule 13 Report on Asset Management Maturity disclosure.

In addition, Clause 2.6.6 requires each EDB to publicly disclose the following reports before the start of each disclosure year:

- The Report on Forecast Capital Expenditure in Schedule 11a.
- The Report on Forecast Operational Expenditure in Schedule 11b.
- The Report on Forecast Cybersecurity Expenditure in Schedule 11c (disclosed to the Commission).
- The Report on Asset Condition in Schedule 12a.
- The Report on Forecast Capacity in Schedule 12b.
- The Report on Forecast Network Demand in Schedule 12c.
- The Report on Forecast Interruptions and Duration in Schedule 12d.

If an EDB has sub-networks, it must also complete the Report on Forecast Interruptions and Duration set out in Schedule 12d for each sub-network.

## 1.3 Structure

This AMP Update has been structured to meet disclosure requirements and is in a similar format to our previous AMP updates. In the interests of brevity, we have not attempted to duplicate detailed explanations where these are already available in our most recent comprehensive AMP. We encourage readers to refer to our previous AMP if a greater level of detail is required.

**Section 2** discusses our view of the emerging operating environment and how Powerco intends to position itself in this.

**Section 3** provides commentary on the changes to the planned construction, operational, and maintenance plans of our previous AMP Update, as necessitated by our customers' evolving requirements, and the changes we see in our future operation.

**Section 4** discusses the impact of the default price-quality path (DPP4) final decision.

**Section 5** provides an overview of aggregate forecast expenditure and outlines the changes that have materially affected our forecasts. It also provides information on material changes to the schedules since our previous disclosure.

**Section 6** contains Schedules 11a-12d, and 14a to meet information disclosure requirements.

**Section 7** addresses the certification requirements for this disclosure.

# 2. Context and strategy

## 2.1 Introduction

As we navigate the dynamic energy landscape of 2025, Powerco remains steadfast in our commitment to delivering a safe, reliable, and resilient electricity network that meets the evolving needs of our customers and communities. Building upon the foundations laid in our previous AMPs, we are embracing the future with a strategic focus on decarbonisation, electrification, and enhanced customer-centricity.

**Decarbonisation and electrification**

Aotearoa's journey towards a net-zero emissions future by 2050 presents both challenges and opportunities. At Powerco, we recognise our pivotal role in enabling this transition by supporting the electrification of transport, industry, and process heat, as well as facilitating the integration of renewable energy sources.

While short-term fluctuations in electricity demand can occur because of economic cycles, weather patterns, and changes in consumer behaviour, long-term demand remains stable. However, where and when energy is consumed is changing. As sectors decarbonise, we anticipate increasing peaks in demand driven by the uptake of electric vehicles (EVs), industrial electrification, and distributed energy resources. These shifts will require a more flexible and resilient network, capable of accommodating new demand profiles and bi-directional energy flows.

To support this transition, we are investing in:

- Modernised network architecture to integrate and optimise new energy technologies.
- Smart grid solutions that enhance visibility, forecasting, and real-time network management.
- Targeted capacity upgrades to support increasing electrification where needed.
- Enabling flexible energy use, including demand response and local energy trading.

By aligning with our *Grow to zero* vision, we see New Zealand's abundant renewable electricity as a competitive advantage, allowing us to decarbonise the economy without significant increases in total energy consumption, provided the right infrastructure and demand-side solutions are in place. Our role is to ensure that energy is available when and where it is needed, in a way that supports both affordability and sustainability.

**Becoming a digital-enabled distribution system operator**

The traditional role of electricity distribution is evolving. To adapt, Powerco is transitioning towards becoming a data-driven distribution system operator (DSO), where real-time intelligence, automation, and digital innovation will underpin how we operate and manage the network.

Our Data, Digital, and Innovation Strategy is central to this transformation:

- **Digital grid modernisation**: By investing in smart network technologies, sensors, and advanced analytics, we will gain real-time visibility of the grid, enabling proactive asset management and faster fault response.
- **Data-driven decision-making**: Enhanced forecasting, AI-driven analytics, and digital twins will allow us to model future demand scenarios, optimise network investments, and integrate new energy technologies effectively.
- **Customer and market integration**: By facilitating bi-directional energy flows and integrating distributed energy resources (DERs) such as solar, batteries, and EVs, we will enable customers to become active participants in the energy system.

- **Automation and flexibility**: Our network will evolve to be more dynamic, leveraging demand response, flexible connections, and grid-edge intelligence to optimise performance and resilience.

This transformation is essential to supporting New Zealand's energy transition and economic growth, ensuring our infrastructure can meet the demands of a low-emissions future while delivering greater efficiency, reliability, and customer value.

**Enhancing customer-centricity**

Our customers are at the heart of everything we do. We are committed to improving transparency and making it easier for customers to engage with us. By providing greater visibility of our operations and network status, we empower customers with the information they need to make informed energy choices.

Initiatives such as user-friendly digital platforms and streamlined connection processes are designed to enhance the overall customer experience. Embracing innovation and collaboration, we aim to deliver energy solutions that not only meet current needs but also anticipate future demands, supporting the prosperity and wellbeing of the communities we serve.

**Our commitment to the future**

By embracing decarbonisation, digitalisation, and customer-centricity, Powerco is dedicated to not only meeting today's energy needs but also laying the foundations for a more sustainable, resilient, and innovative electricity future.

## 2.2 Electricity consumption trends

### Historical electricity demand trends

We have observed a marginal decrease in coincident electricity demand and overall consumption across the Powerco footprint since 2022, following a period of steady increases. It is likely that economic factors have significantly influenced the observed changes in electricity demand. The trends, updated until the end of calendar year 2024, are shown in Figure 2.1.

Figure 2.1: Coincident maximum demand (MD) on Powerco's network

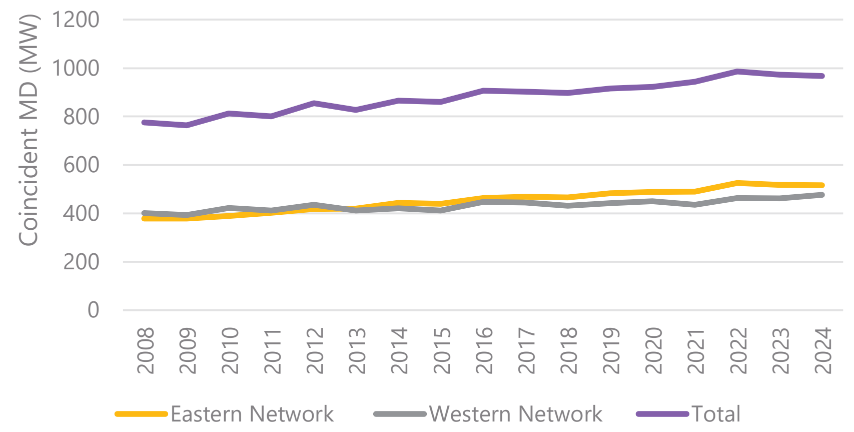
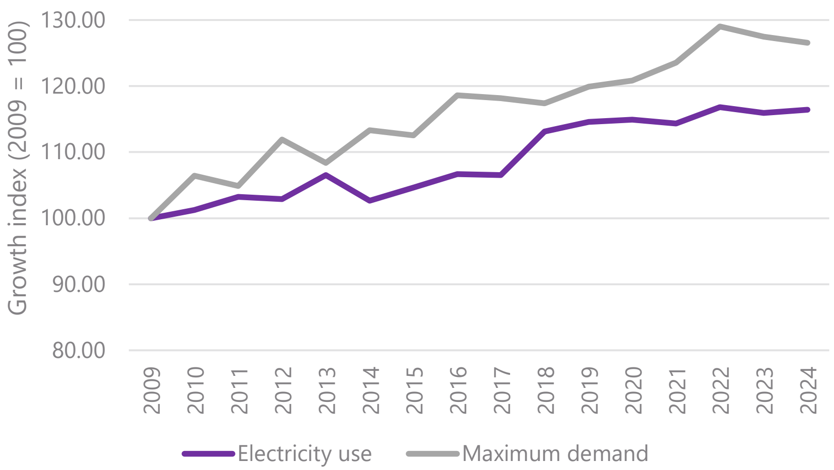
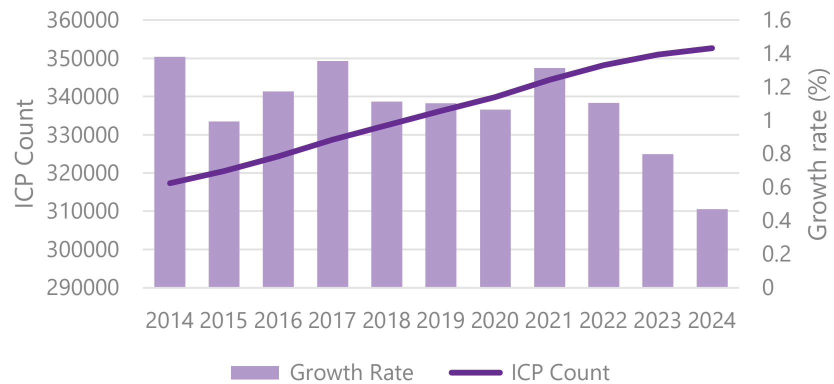


Figure 2.2 Peak demand and energy consumption trends




The growth rate of new connections (installation control points, or ICPs) has also slowed significantly in the past 2-3 years. It may be that the reduction in peak demand has resulted from the lower rate of new connections and reductions in household energy use. These are both related to the health of the New Zealand economy.

Figure 2.3: Annual ICP growth 2014-2024




## Demand forecast

While peak demand has seen a short-term decline, we expect the long-term growth trend, driven by population increases and economic activity, to continue.

Aotearoa's decarbonisation efforts will significantly impact future peak demand and energy consumption. To decarbonise, the energy system will need to transition to greater electrification. To make this efficient, new technologies and markets will be needed to manage peak demands, along with an increase in network utilisation.

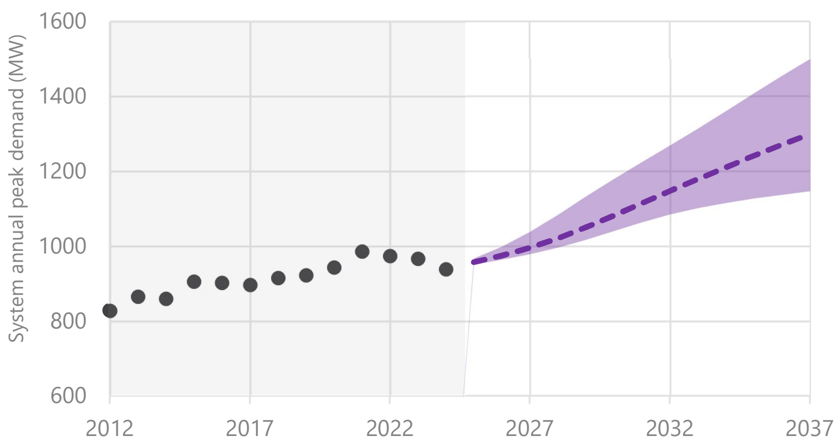
As well as organic growth, our current demand forecasts incorporate the following electrification impacts:

- **Process heat conversion**: Transitioning industrial processes from fossil fuels to electricity.
- **Domestic gas conversion to electricity**: More households converting from gas to electricity for heating and cooking, driven by environmental concerns and efficiency gains.

- **Electric vehicle uptake**: Growth in New Zealand's EV fleet, increasing electricity use.
- **Demand management**: More DERs on the network, such as batteries, coupled with the right market incentives, will allow for increased demand management. As a result of new commercial models, demand flexibility from existing customers is also expected to increase.

Our overall long-term peak demand forecast is shown in Figure 2.4, and is unchanged from last year's forecast.

Figure 2.4: Electricity peak demand forecast




[2] Powerco's climate scenarios can be found on page 12 of its Climate-Related Disclosures document: https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/climate-related-publications/climate-disclosures-document.pdf

We continue to monitor these electrification drivers, as the timing and scale of change is uncertain. Most recently, updated Government policy regarding EV rebates and industry decarbonisation co-funding has cooled the uptake of EVs and process heat decarbonisation projects respectively.

To help us better understand the range of potential demand scenarios, we have started work to align our demand forecasts to the Powerco climate scenarios[2] in an acknowledgement that electricity demand impacts and asset management decisions will differ under each climate scenario.

The policy drivers of each scenario correlate with national responses and have economic and ecological impacts. Under more extreme conditions, heating and cooling demand is expected to be higher, and the time of energy use by consumers may differ as a result.

The updated work on demand forecasts will be included in our 2026 AMP.

### Further drivers of electrification change we are investigating

There are several less understood but highly impactful drivers that could affect electricity demand. These are mostly centred on technological advancements, digital infrastructure surges, and the investment landscape in New Zealand because of increased 'green tech' adoption and the attractiveness of renewable resources for overseas investment.

Some key areas we will continue to monitor include:

- **Electrification of mass transport**: Monitoring the impact of heavy vehicle electrification and the adoption of alternative fuel sources (hydrogen, biofuels) on electricity demand, as well as the potential electrification of regional aeroplanes (with regional airports present on the Powerco footprint).

- **Public EV fast charging rollout**: The speed of rollout for public EV charging stations and the implementation of controlled charging setups will influence adoption rates.
- **Urbanisation trends**: The impact of urbanisation will have a significant impact on electricity demand and infrastructure.
- **Data centres**: The projected growth of data centres and their electricity demand in New Zealand, and the associated government response. Analysts estimate that electricity consumption from data centres, AI, and crypto currency could double by 2026. It's estimated that New Zealand data centre growth will match that of Sydney, with plans to double by 2030. Currently, 5-8% of world energy usage is attributed to data centres.
- **Emerging technologies and energy transformation**: Advances in technologies, such as energy storage, smart grids, and the Internet of Things, will enhance energy efficiency and electricity management and, in turn, electricity demand.

We also pay close attention to potential disrupters to electricity demand. These are often difficult to predict but can have substantial impacts on future electricity demand and will be crucial for our ongoing assessments and planning.

- **Supply chain disruptions**: The availability of critical components and materials for power generation and grid infrastructure can be affected by global supply chain disruptions. This will impact the reliability of electricity supply.
- **Policy and regulatory changes**: Government policies and regulations can impact the electricity supply by incentivising or restricting certain types of power generation. Policy changes related to emissions standards, renewable energy targets, and grid reliability will affect supply dynamics.
- **Market volatility and economic shifts**: Fluctuations in energy markets and broader economic trends will impact electricity demand and investment decisions.

## 2.3 DSO – Future-ready networks

### We will be a fully functional distribution system operator (DSO) by 2030

The electricity industry is in the midst of a major transformation – evolving from centralised, fossil-fuel dependent systems to a dynamic, decentralised and cleaner energy network. This change is driven by changing customer needs, technological innovation, distributed generation, policy shifts, and the growing need to address environmental concerns, particularly climate change. At the same time, we anticipate a significant medium- to long-term increase in electricity demand, as energy use shifts to electricity and away from traditional fossil fuels. We also anticipate a major increase in large new consumers, such as data centres.

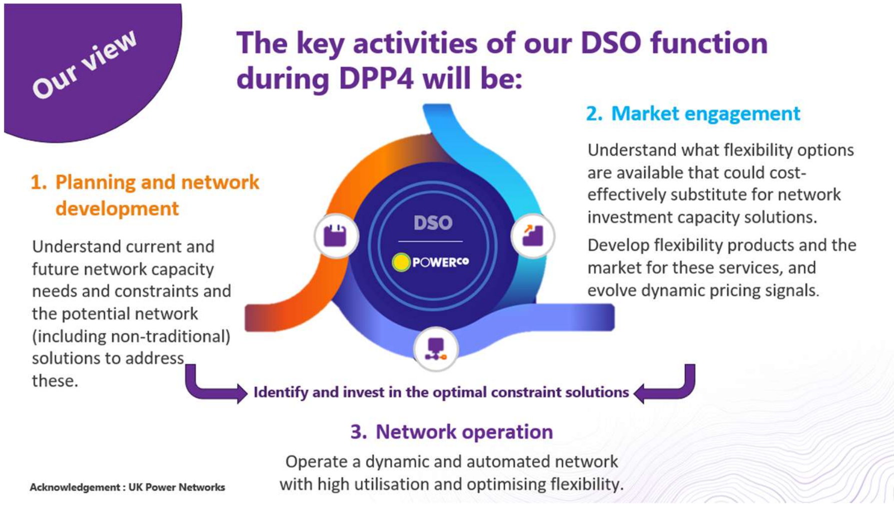
The shift to electrification is essential for New Zealand to reduce its carbon emissions and should, in the longer term, result in an overall reduction in energy cost. However, a substantial proportion of our customer base already faces considerable energy hardship. As we modernise our networks and add the capacity needed, substantial investment will be required. If this is not carefully managed, it could add considerably to the cost of electricity, with the likelihood that the burden may fall disproportionately on our lowest income customers[3].

[3] Lower income customers generally have more limited means of self-generation or management of their energy consumption patterns, which could otherwise help achieve cost reductions.

Powerco's Future-ready Networks Strategy is predicated on achieving an optimal balance between the competing requirements of energy affordability, energy security and sustainability[4], while adapting to the transforming electricity industry. With underlying open network principles, we consider that the DSO, and its core functions, provide a practical means of providing this balance. Accordingly, during 2024 we adopted the key strategic goal for Powerco to be a fully operational DSO by 2030 – giving us the current regulatory period (DPP4) to build and test the necessary systems and capability to achieve this.

The bulk of our network innovation and evolution activities, which previously made up our Future-ready Networks Strategy, now fall under the DSO transformation umbrella.

Transitioning to a DSO will require much more than only a technology transformation – it will be a whole-of-business transformation in its fullest sense. Network processes, from planning through to operations and maintenance, will change. New commercial capabilities and processes will have to be developed, and customer engagement and understanding taken to new levels. Our information technology systems, data management and data collection will require significant upgrades and expansions. Underpinning all of this will be the new capabilities we will help our people to develop.




[4] Otherwise known as the 'energy trilemma'.

**How would the shift to a DSO help address the energy trilemma?**

In essence, a DSO envisages working with customers and providers of other flexibility services on an integrated approach to electricity provision. Modified consumption patterns, distributed generation, or energy storage will become as much part of service provision as traditional poles and wires.

***Energy affordability***

- **Optimising network utilisation**. There is considerable scope for improving network utilisation by shifting demand away from peak periods. This would allow us to defer or avoid otherwise necessary reinforcements.
- **Right-sizing connections**. By better coordinating connection requirements (use patterns) with available network capacity and operating envelopes, it is often possible to materially reduce connection costs.
- **Monetising customer energy services**. Rewarding customers for changing their energy behaviour or offering spare generation/storage capacity to the network.

***Sustainability***

- **Facilitating renewable generation**. An open network, being flexible and inter-operable, supports DERs and peer-to-peer energy trading. This encourages the take-up of renewable generation.
- **Optimising energy use patterns**. By optimising energy use patterns, particularly avoiding sharp peaks, the overall infrastructure need (from generation through to end consumer) is reduced.
- **Supporting electrification**. As a net effect of lower energy costs, opportunities to monetise energy services and improving service reliability, switching to electricity from other energy sources is encouraged. Given our highly renewable electricity system, electrification is key to reducing carbon emissions.

**How would the shift to a DSO help address the energy trilemma? (Cont.)**

***Energy security***

- **Network modernisation**. Enabling a DSO requires the same underlying technology and systems as modernising networks. In addition, in seeking optimal network investment outcomes, non-traditional network solutions are actively adopted (alongside flexibility services and traditional solutions).
- **Improved reliability and resilience**. A DSO requires comprehensive, semi-real-time network visibility. This same visibility supports more efficient network operational response, fault isolation and restoration. It also provides options to reduce non-essential load (in exchange for more important operations).
- **Improved risk management**. Improved network visibility and understanding of customer behaviour and requirements allows more sophisticated risk-analysis and the ability to operate (safely) closer to operational limits – providing more operational headroom and flexibility.

## 2.4 Data and Digital Strategy

Investment in data and digital infrastructure and capabilities is essential to unlocking our next-generation digital platforms and supporting the energy transition. As we navigate electrification, our digital systems must also evolve to provide both high operational efficiency and enhanced customer value. This transformation requires a robust framework that integrates advanced digital systems with traditional network operations.

Our vision for a future-ready network positions customers as active participants in an evolving energy ecosystem. Digital interfaces will enable customers to monitor their energy resources, access real-time network insights, and make informed decisions that reflect both affordability and sustainability. This shift from passive consumption to dynamic engagement is fundamental to our strategic direction.

Enhanced network visibility remains a key pillar of our strategy. By investing in sensors and data collection systems, we can achieve much richer monitoring of network conditions. This visibility not only supports efficient asset utilisation but also empowers our operations team with greater situational awareness and, alongside increased automation, will deliver reliability benefits to customers.

Focused investments in digital tools for the DSO will help address the unique challenges of the low voltage (LV) network, where low diversity and dynamic demand require high-resolution data from multiple devices. Such enhancements are critical to maintaining system reliability amid rapid electrification.

Specific investments will drive improvements across our network, including vegetation management, advanced analytics, and system upgrades or replacements. These targeted initiatives ensure that our digital platforms remain resilient and responsive to emerging challenges. By leveraging advanced analytics, we can forecast network capacity, identify congestion points, and optimise investment decisions.

In summary, our Data and Digital Strategy is designed to deliver tangible value to our customers while enhancing operational efficiency. By building a resilient digital infrastructure and fostering a culture of data stewardship and digital excellence, we will not only meet current energy demands but also position ourselves to lead in a rapidly evolving energy landscape.

## 2.5 Customer transformation

The future value and long-term sustainability of our business relies on the value we deliver to our customers.

Our customer-centric vision includes delivering scalable, efficient customer service with improved digital engagement and self-service tools, which will improve our customers' experience and increase our capacity to deliver for our customers.

We are in the process of changing our customer works model from interposed to direct customer engagement. This new approach will make use of smart digital tools to manage and improve our customers' experience. Our pipeline of future initiatives also includes improving our customers' experience of both planned and unplanned network outages.

New capabilities to directly manage customer relationships will also enable deeper customer insights to support the development of flex solutions as part of the DSO transition.

# 3. Our 2025 Asset Management Plan Update

## 3.1 Introduction

The 2025 Asset Management Plan Update (AMP Update) provides a refresh of key planning outputs for the next 10 years. Our AMP is an essential part of our long-term asset planning and investment framework. The AMP Update is primarily informed by our 2023 Asset Management Plan, which we published two years ago.

The drivers of this AMP Update are largely consistent with our 2023 Asset Management Plan and 2024 AMP Update. Notably, our focus on investments to address anticipated demand increases driven by electrification. Five important areas with substantial changes from the previous AMP, owing to refinements and enhanced strategies, are:

- **Distribution system operator (DSO)**: As noted above, Powerco has refined its Future-ready Networks Strategy, and concluded that evolving to a DSO offers a practical approach to meeting the future needs. We have, therefore, adopted a core strategy to be a fully functional DSO by 2030. This is now largely the umbrella for our network innovation and evolution activities, as well as a major driver of our data and digital and customer engagement strategies.
- **Pricing**: We regularly consult customers and retailers about improvements to our pricing. This year we're planning two important innovations:
  - A new pricing sub-region in north Coromandel, where we experience very high network peaks during holiday periods.
  - Credits (negative variable charges) for customers who export power from generation or battery storage at their installation control point (ICP) to reflect the benefit of local supply into the grid during peak periods.
- **Electricity field services agreements (EFSAs) and customer delivery services contracts**: Powerco is tendering contracts for major electricity field services on its footprint, along with a tender for its new customer works delivery model. Taking effect from mid-2025, these contracts provide an opportunity to improve and enhance the services we provide, and develop sustainable partnerships to support Aotearoa's electrification through network investment and new technology.
- **Asset management improvement**: Asset renewal remains a priority, with evolving asset management practices, enhanced risk assessments, and a dedicated team driving improvements. We are also investing in satellite technology to assist in developing optimised workplans for vegetation management.
- **Workforce capability and capacity**: We continue the extensive investment and efforts required to meet the anticipated workforce demand fuelled by electrification. Successfully delivering this additional work and developing new skillsets will necessitate expanding several teams and programmes across the organisation.

A brief overview of our plans and the reasons for changes across these areas is provided below.

## 3.2 Distribution system operator (DSO)

Powerco's target of being a fully functioning DSO by 2030 is timed to allow the required enabling systems, technology and processes to be developed during the current regulatory period (DPP4). In addition, we plan to have a number of working flexibility contracts in place by no later than the start of FY28. This will help build a solid understanding of the complexity, effectiveness and cost of running these contracts. This information will be an essential part of our regulatory submission for DPP5, as we present the case for transitioning to a DSO.

A DSO will rely heavily on flexibility contracts and other non-network arrangements. This in turn will require broad, near real-time network visibility[5], with supporting communications and digital systems. All of this will see our operating expenditure rise considerably, continuing to do so over DPP5, but offset by a comparative reduction in capital investment, particularly on network reinforcement projects[6].

Flexible services, however, cannot indefinitely defer reinforcement needs or substitute for greenfield developments. Therefore, there will still be ongoing reinforcement expenditure, particularly in an environment of growing electrification – the DSO will moderate this expenditure and help ensure optimal network utilisation but cannot avoid it altogether.

Our initial DSO approach has been to have a number of short-term initiatives to test and prove concepts. Most of these have started during FY25 and will continue into FY26. In parallel, we have identified a number of larger, longer term enabling investments and initiatives that are essential for a future DSO. These will begin in FY25, spanning over the rest of DPP4. The main earlier initiatives are described below.

### LV visibility and network management

Traditionally, visibility of power flows on our LV network has been very limited. Now, as we see substantial increases in distributed generation and large new loads connected to LV networks, previously adequate, built-in capacity margins are being eroded. Capacity constraints on LV networks are, therefore, expected to become an increasing issue. Good visibility of power flows, constraints and available capacity is essential to ensure optimal asset utilisation, avoiding large, and possibly unnecessary reinforcement. Visibility also supports improved network reliability through improved response times and automation, and network safety, such as through the identification of broken neutrals on the LV network.

Developing a LV visibility platform and acquiring the necessary consumption and power-quality data is one of the fundamental building blocks for a DSO. Following several trials of monitoring devices and visualisation platforms, we will adopt the following approach to achieve this:

- Acquire ICP operational data from meter providers, including power quality information. To the extent available, this will be five-minute interval data, as near real-time as possible.
- Acquire historical, half-hourly ICP consumption data from meter providers.
- Acquire operational data from other providers who have 'intelligent' devices connected to our network. This could include owners of solar/PV installations, mobile generation sites etc.
- Procure a LV analytics and visualisation platform to make the operational data accessible to our planning and operations teams.
- Continue rolling out LV monitors on larger distribution transformers, including outgoing LV feeders. The information from this will also be integrated onto our LV visibility platform.
- Develop options for real-time monitoring of outages on the LV network. This may be through arrangements with meter providers or installing our own devices at strategic locations.

[5] As this capacity can only be developed over time, earlier on the DSO will rely more on simulations and generalised consumption patterns, which will gradually be replaced with real-time operational data.

[6] There is also scope to reduce renewal expenditure through increased use of distributed energy resources (DERs), through targeting optimal asset capacity and through better visibility allowing us to operate assets closer to realistic risk limits. However, the scope for expenditure reduction (relative to base case needs) is seen as more limited than for reinforcement expenditure.

Once the visualisation platform is operational, we will re-assess our approach to managing the LV network.  Our long-term goal is to plan and operate this network in a similar (active) fashion to the higher voltage networks. This will require substantial changes to existing processes as well as additional planning and operating resources.

It is also noted that, while our main focus is on extending LV network visibility, improvements to visibility (and automation) on the distribution and sub-transmission networks will also continue.

**BESS trials**

In what we understand to be a New Zealand first, Powerco is installing LV network battery energy storage systems (BESS) on power poles in Greerton, Tauranga. The units will alleviate power quality issues and provide peak demand lopping in an area where the LV network is capacity constrained.

With this installation, we will also trial the use of multiple BESS together as a virtual power plant. Analysis indicates that deep-network BESS units allow maximum value-stacking, with demand benefits not only for the immediate constrained area, but also for the higher voltage networks from which it is fed (as well as upstream transmission and generation benefits). Depending on the trial's success, we envisage rolling out increasing numbers to help defer network upgrades.

We may also use these units in future for further community benefits, such as providing storage capacity for excess local photovoltaic (PV) generation.

## Network model

A robust network model, covering our full network from sub-transmission to LV, is a key building block for future network operations and the DSO. Such a model is fundamental for current network state distribution power-flow analysis. This, in turn, is critical for our Advanced Distribution Management System (ADMS) to analyse network constraints and available capacity, to run granular simulations of future power flows, and to support commercial decisions in network operations and investment.

Powerco has a sophisticated network simulation system, but its application is limited to studying discrete parts of the network for planning, capacity and network stability assessment purposes. The intended network model will provide broad, automated network coverage and allow whole-of-system simulations.

The proposed network model will be seamlessly integrated with our network power-flow platforms, including the LV visibility platform, to collect consumption data (including distributed generation), as well as our demand forecasting models. It will also underpin the analysis for our capacity and constraint maps, through which we provide network capacity information to our customers. This is currently done via an in-house developed prototype model.

Before committing to further model development, we plan to conduct an extensive investigation into commercially available network model products, or options to formally develop an appropriate product. This will include liaison with suppliers and other users, internationally.

[7] We note that several initiatives in this regard are being undertaken, supported by EDBs, retailers, the ENA, FlexForum, research institutes and the like. Powerco is actively involved in a number of these initiatives.

### Signalling constraints and capacity

In 2023, in a first for New Zealand, Powerco published an interactive map on its website through which customers can determine the capacity across our network to accommodate distributed generation. This was followed up with a map indicating the available load connection capacity across our network.

We see this information as a major stepping stone, not only for helping customers conduct their own early feasibility studies when planning new connections, but also in future to assess where network constraints indicate a demand for flexibility services exists.

While the current maps offer a static, worst-case snapshot of capacity on our higher voltage distribution networks, we are working on expanding this to indicate capacity at different times of the year and, eventually, also show daily and weekly patterns. Constraint signalling will be added and, once we have the network model in place and acquired granular LV data, the capacity maps will be extended to the LV network as well. Our capacity and constraint maps will evolve with this information during the next three to five years.

## Flexibility product development

Flexibility services are integral to a DSO. At present, there is no functional flexibility services market in New Zealand[7]. Therefore, it is imperative that our programme helps develop a flexibility market and we engage with individual customers on potential flexibility contracts.

Our initial approach to developing the use of flexibility services broadly encompasses:

- Identifying upcoming (medium term) network constraints.

- Investigating options for flexibility services that could alleviate these constraints.
- Engaging with customers or third-party providers on procuring such services (through direct approach or advertising the need for services).
- Implementing the contracts for operation by our network control team.

By its nature, this approach relies on bilateral contracts with customers or third parties. However, in future, after our initial flexibility approach has been developed, we envisage this will be much extended.

- We will increasingly make information automatically available to customers or other interested parties about network constraints and capacity. This information will help potential flexibility service providers understand where these services are required and encourage such offers.
- Distribution network pricing will be a further key mechanism for signalling network constraints, particularly for mass market customers. Effective price signalling should encourage customers to adapt their consumption patterns or offer capacity in a manner that would help alleviate constraints.
- Closely related to the above will be the use of dynamic operating envelopes and signalling (in near real-time) the variations in network capacity and constraints, with associated pricing, to customers and flexibility providers.
- We also foresee an operating market platform that will bring together potential providers and users of flex services and set general commercial terms for these transactions.

As the basis for expanding our use of flexibility services during FY26, we have identified a number of planned reinforcement projects that could be deferred if suitable alternatives can be procured. Flexibility options to achieve this are being investigated, with commercial negotiations expected to be concluded early in the year.

**What are flexibility services?**

Flexibility services refer to the ability to vary the production or consumption of electricity at a specific location in response to signals. These signals can be delivered through various means, such as distribution or energy prices, managed tariffs, event-based contracts, or long-term agreements. The responses to these signals can be controlled by consumers, third parties, or remotely switched by EDBs, and can be delivered by any distributed energy technology, including generation, batteries, or controllable demand.

Flexibility services are essential for managing the load on electricity networks, especially during peak times or when there are constraints on the network. They help in deferring or avoiding the need for investing in new infrastructure, such as poles and wires.

## Demand forecast and improved planning models

Traditionally, electricity demand forecasting relied heavily on past consumption profiles and underlying growth trends, coupled with information on known planned developments in an area. Scenario planning was conducted on a network-wide basis, taking into account various growth scenarios resulting from key drivers, such as EV uptake or process heat electrification.

In a relatively steady-state environment this approach was appropriate, as actual investment commitments rarely needed to be made before we had sufficient certainty on demand (exceeding capacity). With slow growth rates there is normally ample scope to revise plans before commitment.

However, we are moving into a much more volatile period, with rapid, often unforeseen, demand growth in some areas. Growth patterns are becoming increasingly varied across the network, in response to different underlying drivers. Intra-year demand patterns are also more variable. In addition, we anticipate increasing constraints on LV networks, which have previously largely been considered 'set-and-forget'.

Therefore, we need a demand forecasting model that is much more responsive to real-time changes in input factors, and can reflect the impacts on a much more granular scale. Demand forecasts are a key input into network planning and their veracity is therefore very important for optimal network investment.

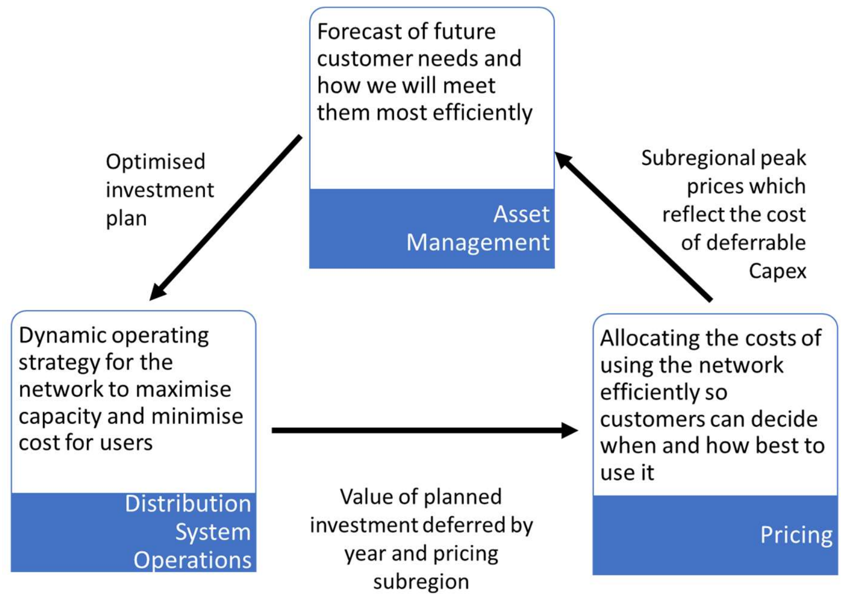
Therefore, we will be developing a much more granular demand forecasting tool that will provide both short-term profiles for operational management, and longer-term profiles for investment planning. This will take into account short-term factors influencing electricity use, such as response to weather or economic patterns and the most recent consumption patterns, as well as future anticipated factors, such as demographics, distributed generation and flex uptake, technology change, electrification, climate change factors, etc. The model will also be suitable for scenario analysis, not only on a network-wide level but carried through to LV feeder level.

Before committing to upgrading our demand forecasting model or planning approach, we plan to conduct an extensive investigation into approaches adopted internationally, and test whether demand forecasting tools are commercially available, or a suitable product can be procured from an existing user.

## 3.3 Pricing

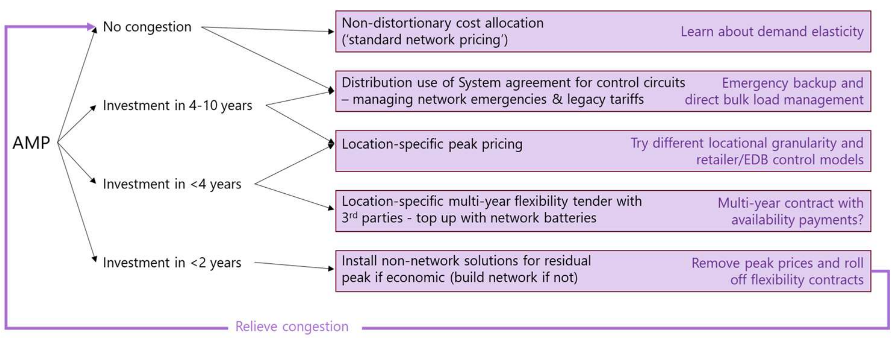
As we establish our DSO, we are learning more about how we can use additional local generation to avoid or defer investment in the network. Pricing is the first step in realising investment deferral opportunities, and as we build a more detailed picture of which projects can be deferred, where and when, we can signal the cost of the local planned investment in our pricing at times when the network is congested.

Figure 3.1: Relationship between pricing, asset management and DSO




Traditionally, to make sure we can meet new demand as load grows, we have to increase the capacity of the network by building and replacing physical assets – wires, transformers, substations etc. However, through pricing, we can potentially incentivise customer behaviour and reduce the size of peaks on our networks so that we avoid, or at least defer, spending money on these physical capacity upgrades. During the next decade, we will refine and align our four complementary flexibility programmes, working over different time horizons.

Figure 3.2: Flexibility time horizons




Because many of the costs of operating the network are fixed, Powerco cannot easily unbuild, re-use, or move parts of it, which is why it's important to delay making investments by using price signals and flexibility resources.

We are working to better integrate our AMP with our pricing. Where our AMP identifies that we'll need to expand the capacity of the network during the next 10 years, we will look to introduce a 'peak' charge during the periods where our network is congested to signal how much one extra unit of electricity would cost if we had to upgrade the network to meet increases in peak load[8]. The first step in bringing this to life was our 2024 change from grid exit point (GXP) to ICP pricing. In time, this will allow us to trial more localised peak prices than we have been able to do historically.

Where the AMP identifies the need for a planned upgrade within five years, and despite Powerco signalling this with peak prices, there may be an opportunity to defer the project by paying third-party flexibility providers or installing a battery to reduce demand in the particular area (refer to 'Flexibility product development' and 'What are flexibility services?' above).

**What's new in Powerco's FY 2026 pricing**

FY26 will see the introduction of:

- **Coromandel pricing sub-region**: A new pricing sub-region has been introduced in north Coromandel, where we experience very high network peaks during holiday periods. This is an important opportunity to learn how to integrate local peak pricing with our AMP effectively.
- **Export tariff rebates**: We have introduced a negative variable charge for customers who export power at peak periods from generation or battery storage. This is to reflect the benefit that local supply into the grid at peak periods delivers, which is the same as reducing demand. This, therefore, defers the need for planned investment.

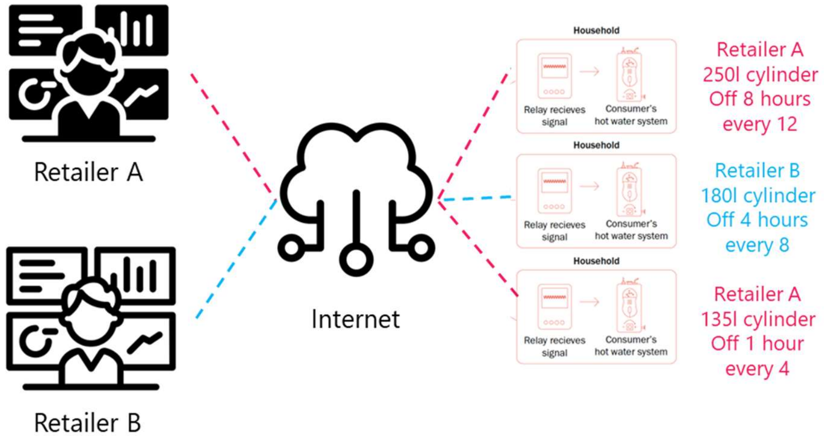
## Retailer load control trials

Like most electricity businesses in New Zealand, Powerco offers a 'controlled' tariff to customers whose hot water cylinders are attached to a dedicated circuit, which they allow us to turn on and off at times of congestion and network emergencies. While this technology has been a valuable tool for reducing load, it's a broad-based solution and all hot water cylinders on one circuit will turn off.

[8] Economists call this the 'long-run marginal cost'. It is a particularly important signal in a business such as Powerco, because while most of our costs are fixed in the short term, they are all variable in the long term, but only when we make large and irreversible investments. Therefore, if customers are prepared to pay it, it is a sign that it would be efficient to upgrade the network.

Technology advancements in smart meters have meant each individual connection can now be switched on and off at different times, by different parties, not just the EDBs.

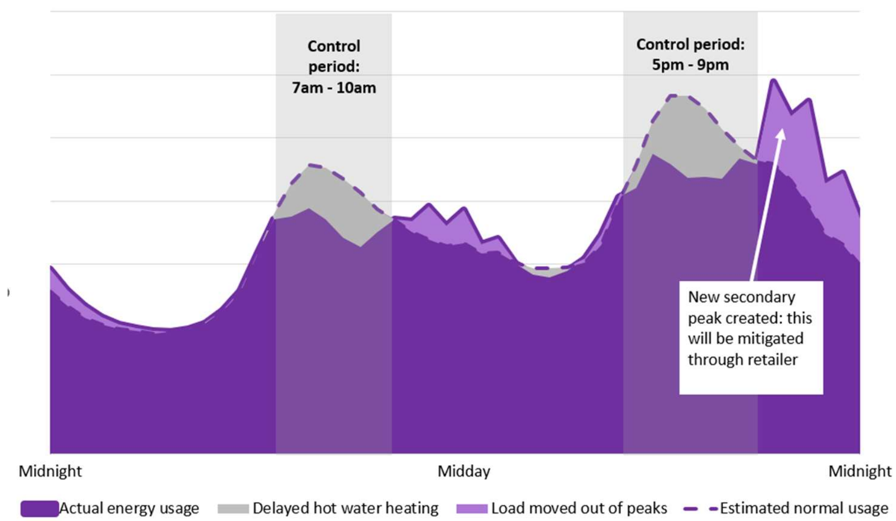
Figure 3.3: Retailer control of hot water cylinders




During winter 2024, we ran a trial with several retailers to pilot this model and we retained the ability to override retailer instruction in the event of a local or national system emergency. The impact of the trial on peak demand is illustrated in Figure 3.4. The trial was highly successful, with more than 30,000 customers participating, and nearly 10% of peak load demand reduced – achieved without the need to turn off large blocks of customer hot water cylinders.

Following this success, the approach has become business as usual and is now available to all retailers that register and comply with the Flexible Hot Water Protocol, enabling significant flexibility for customers through retailer product offerings.

Figure 3.4: Impact of hot water control trials on peak demand




We will continue to work with retailers to understand how we can use local pricing on the controlled network to defer specific planned investments. In the medium term, we expect an increased proportion of load on our network to be controlled by retailers and other parties, rather than us directly. A priority will be agreeing operating protocols for routine and emergency situations, before we look at the future of our pricing for investment in a control plant.

During the next five years, our priority is to build on our experience with the north Coromandel pricing sub-region and flexibility trials by introducing local pricing and flexibility initiatives to signal the cost of planned AMP investment at an increasingly granular level.

In parallel, we continue to work with retailers to review and adjust our pricing for controlled loads to contribute to these regional pricing and flexibility initiatives.

## 3.4 Electricity field services agreements (EFSAs) and customer delivery services contracts

Powerco is tendering contracts for major electricity field services, alongside a tender for its new customer works delivery model. These contracts will take effect from mid-2025.

### Electricity field services agreements

Our current EFSAs, which expire in 2025, have been reviewed to ensure they provide the partnerships we need to deliver for our customers of the future. Our electricity network is evolving, driven by changing customer needs, New Zealand's decarbonisation goals, and emerging technologies. This transition presents an opportunity to enhance the services we provide. Benefits for our customers include:

- A customer-first approach, ensuring customer needs are central to our services.
- Improved customer experience through enhanced contractor performance and outcomes.
- Introduction of new, customer-focused KPIs to align contractor performance with our commitments.
- Simplified processes so customers interact directly with Powerco rather than multiple contractors.

### Customer delivery services tender

Powerco is transforming the way it manages customer-initiated works (CIW). Instead of customers working directly with a Powerco-approved contractor, Powerco will oversee the end-to-end experience. Benefits for our customers include:

- Simplified network connections.
- Reduced duplication and inefficiencies in the commercial process (eg, multiple designs for the same job).
- Consolidated contractor pool, allowing us to develop better partnerships to improve performance (timeliness, communication, quality, and safety).
- Enhanced customer experience through Powerco-led scoping and design, with improved transparency.
- Introduction of fixed customer capital contributions for many work types, shifting cost-efficiency responsibility to Powerco.
- Aim to lower long-term costs by leveraging Powerco's bargaining power to secure competitive pricing and provide greater stability across economic cycles.

This change will also give us an improved relationship with, and understanding of, our customers, supporting our ability to deliver a better service.

### Impact on expenditure forecasts

There is a risk that these tenders could increase costs. Our aim is to manage expenditure within regulatory allowances as much as possible. If costs do rise, we will likely adjust by reprioritising or deferring other expenditure.

## 3.5 Asset management improvement

### Asset renewal planning

For asset renewals, this AMP Update is without material change to the asset management practices that supported our comprehensive AMP in 2023 and the AMP Update in 2024.

However, the opportunity to continually evolve, and improve our asset management system, processes, and people's knowledge, skills, and abilities remains an ever-important foundation. This has been supported by the consolidation of the asset fleet teams in 2024 to drive consistency in our approach, with an increased focus on our asset management practices.

The asset renewal programmes will continue to be a core part of our business and a means to ensure a safe, reliable, and resilient network. While other parts of the business are undergoing significant transformation, such as the initiatives to become a DSO, the asset fleet teams are evolving their systems and processes through a multi-disciplinary team of talented individuals.

This team is tasked with developing the comprehensive AMP for 2026, while achieving long-lasting outcomes in support of several key objectives, including a greater application of quantitative risk-based assessments. This will support our asset engineers in developing asset lifecycle plans in an environment that increasingly has more variables to consider, with more granularity required in the solutions deployed to deliver better outcomes for our customers.

**Climate resilience update**

We are working through the next steps of embedding resilience investment. Key aspects include:

- Increased engagement with regional lifelines groups regarding proposed resilience investment.
- Review of 'external hazard' risks in our asset-based risk modelling used in our value-based investment framework
- Continued engagement with remote communities exploring off-grid community hub opportunities.

### Vegetation management: AiDash

During the DPP3 period, we used the innovation allowance[9] to test the use of satellite technology plus AI for a cost-effective risk and criticality-based prioritisation methodology for vegetation management. With that trial success, we will invest in AiDash (satellite technology) to assist in developing optimised workplans for vegetation management. This cutting edge technology will enable us to ensure we are delivering the highest risk/investment outcomes for our vegetation investment.

The satellite data acquisition and remote monitoring can improve the effectiveness of Powerco's vegetation management, reducing the number and duration of interruptions caused by vegetation. Benefits are interlinked with better reliability and improved customer experience through:

- Reduction in consequential (faults) costs.
- Faster restoration times.

[9] Powerco innovation project allowance application, June 2024, pg.17 Available here: innovation-allowance-drawdown-application-to-commerce-commission-5-june-2024.pdf

- Reduction in the number of interruptions.
- Improved likelihood of overhead assets reaching their designed end of life.
- Optimised spend to manage appropriate risk levels.
- Demonstrate good regulatory stewardship and compliance through long-term visibility.

As the foundation of the programme is grounded in AI and machine learning, there is the unique opportunity to perform a detailed reliability analysis and simulate the impact of a chosen strategy in future years, based on constraint scenarios, fault history and vegetation growth rates. Through each capture and each trim record, the analysis and accuracy will improve and adapt to Powerco's needs.

The Climate Risk Intelligence System (CRIS) module is included in the package and can be leveraged to predict weather-related outages. This tool combines detailed vegetation information with real-time weather to inform Powerco where to pre-position storm restoration resources to reduce customer SAIDI/SAIFI, as well as highlight network weaknesses for weather patterns. We will explore how this tool supports our storm response work following the initial vegetation management deployment.

## 3.6 Workforce capability and capacity

We continue the extensive investment and efforts required to meet the anticipated workforce demand fuelled by electrification. Successfully delivering this additional work and developing new skillsets will necessitate expanding several teams and programmes across the organisation.

### Existing network growth

To accommodate increasing demands on our network, we will require additional workforce capacity to plan, manage, and execute projects associated with growing network investments.

### Data, digital, and future networks growth

Adapting to a more digitally driven operating model necessitates new skill sets, such as managing an LV network with significant DER penetration and creating innovative flexibility solutions to address peak demand challenges.

### Customer engagement and service growth

As our communities transition to lower carbon solutions, more Powerco representatives will be needed on the ground to provide direct engagement with individuals and businesses. We also aim to adjust our approach to smaller customer works by taking a more proactive role in customer experience management, moving away from an arm's-length model. This development necessitates a larger investment in customer-centric roles.

Our significant Customer Transformation and Contract 25 initiatives demand a focused approach to managing their impact on our people, contractors and customers. Investments will be made in change management and communication – both internal and external. Where possible, we will utilise internal talent, while outsourcing work that does not align with long-term organisational needs.

### Business support growth

The complexity and volume of work require a proportionate increase in back-office support, particularly in information technology, finance, people support, and legal functions. These roles are essential for managing the heightened throughput, improvement of service through data, and organisational complexity.

### Graduate programme

One of the challenges facing the sector is the availability of skilled labour. The Commerce Commission's DPP4 decision included an additional $5.6m in funding for Powerco during the period, recognising our role in supporting workforce development for the long-term benefit of the sector. A targeted programme to bring more graduates into the industry and support them to stay in the industry is an important part of addressing workforce challenges.

Our graduate programme has consistently proven to be a valuable talent pipeline. However, graduates are often placed into roles before completing their rotations, demonstrating the need for an expanded intake. Starting in 2026, we plan to increase our annual graduate intake to 10, encompassing disciplines such as electrical, mechanical, and civil engineering, as well as data science and business support. In addition, we envisage investment in the development of field staff where we see an increasing skills need, such as technicians who are vital for the delivery of a future-ready network.

We also aim to enhance the graduate programme's curriculum and delivery. Leveraging insights from our Leadership Development Programme (LDP), we will incorporate elements that focus on understanding self and others, preparing graduates for leadership roles within Powerco. This approach continues our commitment to nurturing future leaders.

### Leadership development

Investing in leadership remains a top priority as we grow. Our LDP continues to prepare emerging leaders, while the Elkiem programme supports high-performance leadership development. These initiatives are crucial to ensuring we have the capability to navigate the complexities of the energy transition.

### Industry work with Champions for Change

Powerco continues to work collaboratively across the electricity industry to enhance the participation of women, Māori and Pasifika, and other ethnicities. As part of the Champions for Change network, led in partnership with Transpower, we are working on:

- Closing the gender pay gap.
- Increasing women's participation in and completion of industry-related tertiary education.
- Supporting the development of women's leadership within the sector.
- Encouraging more young people, in particular under-represented groups, to explore careers in electricity.

These initiatives reflect our ongoing commitment to diversity and inclusion, driving meaningful change both within Powerco and across the wider industry.

# 4. The default price-quality path (DPP4) final decision

The regulatory landscape has become more settled with the Commerce Commission completing its DPP4 process in November 2024. Powerco had 91% and 88% of Capex and Opex approved respectively, compared with our 2024 AMP Update forecasts. DPP4 has also introduced several new mechanisms to deal with uncertainty throughout the DPP4 period.

With expenditure allowances less than investment signalled in the previous Powerco AMP, we anticipate making greater use of uncertainty mechanisms throughout the period to respond to customer needs and deliver customer benefits.

The 2025 AMP Update largely reflects changes in response to the final DPP4 decision, with forecasts broadly in line with DPP4 allowances. The impact of this is that:

- We are forced to make trade-offs in our short-term investment plans, which are likely to result in the deferral of growth-related investment and introduce some risk to New Zealand's long-term electrification transition.
- The reduced Opex allowance is likely to slow down our DSO transition, however, we remain committed to this path.

We have excluded from our forecast investment the programmes that have significant uncertainty attached to them.

In Table 4.1, we have signalled projects that may be funded by an uncertainty mechanism should certainty materialise within the DPP4 period. Noting that we expect to identify more as the DPP4 period progresses.

Table 4.1: Potential DPP4 investment not included in AMP forecast

| Expenditure type | Description | Uncertainty mechanism |
|---|---|---|
| System growth – customer timing | Timing and scope are dependent on additional commitment from customers' future load requirements. | Reopener |
| System growth – transmission | Investment required to connect new Transpower investment to our existing sub-transmission network. The timing of this investment is still uncertain. | Reopener |
| Asset relocation – NZTA | Asset relocation of the Ōmokoroa substation may be required, subject to timing of the TNL stage two highway. | Reopener |
| Resilience – community hubs | Several community hub resilience projects are underway. These projects, and further customer consultation, will inform a future reopener application. | Reopener |
| Flexibility services | Opex to fund third-party demand flexibility. | Reopener / innovation and non-traditional solutions allowance (INTSA) |
| DSO transformation | DSO-related trials and innovation. | INTSA |

Please see the below section for more information on how we are treating uncertain projects in the AMP Update.

# 5. Material changes

Schedules 11a-12d are included in Section 6. This section provides an overview of the rationale for changes to our 2024 forecasts, and an overview of the information provided in these schedules, as well as material changes to network development plans, asset lifecycle plans and asset management practices.

## 5.1 Network development plans

### Major projects

The revisions to our network development forecasts are primarily driven by a combination of lower-than-expected demand growth, delays in major customer upgrade timelines, and updates from major and minor projects planned at zone substations and on the sub-transmission network. We continue to apply a more probabilistic risk-based approach to project timing, considering the value of load at risk, while balancing cost and risk in a transparent and informed manner. This has allowed for more efficient use of capital, especially considering constraints from the DDP4 decision.

Where there is significant uncertainty around customer commitment and need, we have removed the associated upstream network expenditures from our forecasts and signalled that in the event they become more certain during the DPP4 period, we may rely on a reopener.

Non-network solutions, such as batteries, are actively being explored to defer or replace traditional network upgrades until load certainty is established. Flexibility-based customer product offerings, provided by third parties, are also under consideration to address certain network constraints.

Customer-driven decarbonisation plans remain a major factor driving our demand forecasts, although there is limited certainty regarding the required electricity capacity and project timing. Some customers are actively transitioning from gas to all-electric processes, driving short-term asset commissioning and load increases at the distribution network level.

However, given the uncertainty of the larger-scale decarbonisation load uptake, customer decarbonisation plans that have not been committed to have been excluded from the load and financial capital forecasts. This exclusion has led to a significant reduction in our forecasts compared with previous AMPs. Powerco will address large customer decarbonisation projects as customers make their commitments, using the appropriate regulatory mechanisms.

Additionally, we are actively engaging with customers who are planning for future decarbonisation to better understand their anticipated load requirements and timelines. Our goal is to maximise the value of proposed solutions, where possible, to meet network needs while reducing costs for customers.

Examples include:

- **Belk Road zone substation and Greerton-Belk Road 33kV circuits**: These are designed to supply the planned electrification of Winstone Wallboards’ process heat plants, but there is currently no formal customer commitment.
- **Kinleith bulk supply**: Intended to support the anticipated future load increase at Olam Food International. This project also is awaiting firm current customer commitment.
- **Maui Street substation**: This project will provide capacity to unlock decarbonisation opportunities for several customers in the Mount Maunganui industrial area, as outlined in EECA’s Regional Energy Transition Accelerator (RETA) report for the Bay of Plenty region. A collective approach to decarbonisation is considered more cost-effective than pursuing separate tailored solutions for each customer.

We are also working closely with Transpower to finalise options for additional supply capacity in the western Bay of Plenty. This collaboration led to Transpower submitting their major Capex proposal to the Commerce Commission at the end of 2024. Powerco's investment forecasts and project timings have been continually refined throughout this process, and we will firm up the scope of work as further details are defined together with Transpower.

The construction sector continues to experience significant cost increases. Where we have updated cost information, we have rolled this into our forecast models, such as for substation buildings, which have recently increased in cost. However, investment in growth on our distribution feeder network remains consistent with previous AMPs, and the assumptions made in last year's AMP Update remain valid.

## 5.2 Lifecycle asset management plans

On our network, and in our asset management practices, we continue to imbed the knowledge gained from the impact of the major storms in 2022 and 2023. This AMP Update continues to promote investment into network hardening.

## 5.3 Asset management practices

There have been no material changes to the asset management practices and ongoing improvement plans that underpinned our previous comprehensive AMP and 2024 AMP Update.

We continue to refine our asset health and risk models using our value-based decision tool, Copperleaf. Through ongoing refinement, Copperleaf gives us the best information possible to inform risk-based investment decisions. The continued evolution of this tool will strengthen our AMP process, empowering us to make more informed decisions and deliver better outcomes for our customers through data-driven asset lifecycle business cases.

## 5.4 Schedules 11a and 11b: Forecast capital and operating expenditure

### Capital expenditure (Capex)

In constant prices, 2025 AMP Update forecast Capex investment is $34m higher than the 2024 AMP Update (1%). With reference to Figure 5.1, the profile has shifted out from the current regulatory period (FY26-30). This is a combination of:

- Regulatory allowances being available during the preparation of this AMP Update, and our commitment to operate within those allowances.
- Short-term (1-5 years) uncertainty of major customer connections and decarbonisation plans has shifted the driver for network growth investment.
- Our exploration of non-traditional network solutions (eg, flexibility, storage etc) has pushed out planned investment.
- Increased investment requirements in renewal of our overhead network increased, offsetting the decreases forecast in network growth.

Figure 5.1: Capital expenditure

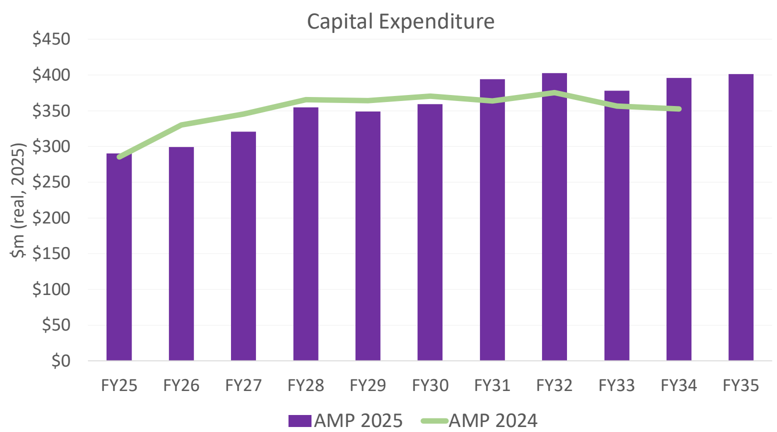
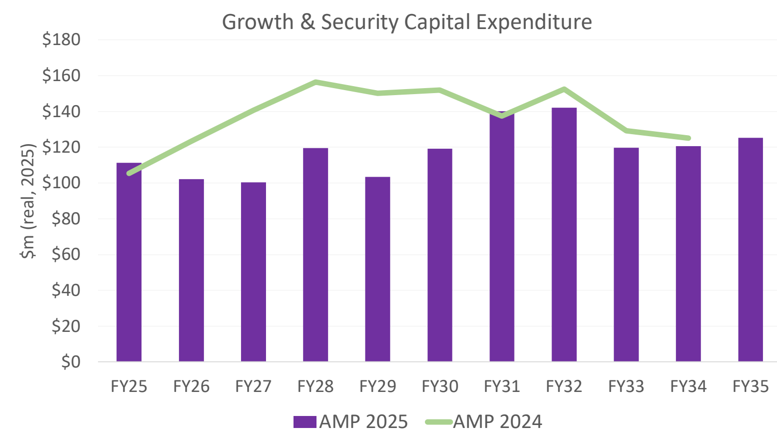



Figure 5.2: Growth & Security Capex




## Major projects

As noted in Section 5.1, we are continuously challenging our investment plans. As a result, the Growth & Security expenditure forecast has reduced by $193m during the period (FY26-35). This reduction is primarily driven by:

- Removing uncertain investments from the forecast pending customer commitment (see Section 4).
- Investment plans have been deferred outside of the forecast period to reflect this uncertainty.

Working within the regulatory framework allows us to maintain financial discipline and flexibility, while ensuring that the long-term interests of consumers are safeguarded. This approach demonstrates our commitment to prudent investment planning and alignment with the broader regulatory environment, all while prioritising service reliability and affordability for New Zealand's electricity customers.

Specifically, we have removed the projects in Table 5.1 from our expenditure forecast, pending further investigation of delivery timing and network demand drivers.

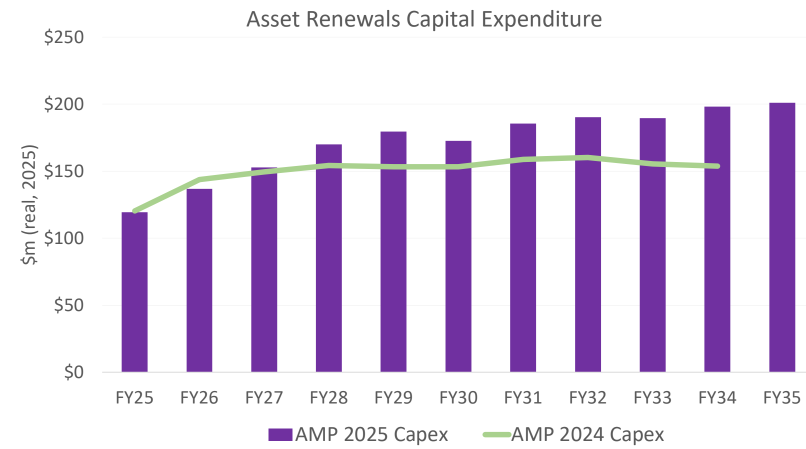
Table 5.1: Uncertain projects across DPP4

| Project name | Cost estimate | Uncertainty driver |
|---|---|---|
| Kinleith bulk supply | $13.9m | Customer timing |
| Triton substation upgrade | $4.3m | Customer timing |
| Greerton-Belk Road 33kV circuits | $16.6m | Customer timing |
| Belk Road substation | $18.0m | Customer timing |
| Linton Army Camp 33kV line | $5.9m | Customer timing |
| Normanby substation | $9.2m | Customer timing |
| Ōmokoroa substation and 33kV circuit | $10.0m | Govt project timing |
| Tauranga 33kV security constraints | $74.4m | Transpower |
| Maui St substation | $14.8m | Customer timing |
| Taotaoroa substation | $13.2m | Customer timing |
| Total | $180.0m | |

### Overhead renewals

We continue to invest in our pole top photography programme. The results of this programme indicate we need to increase investment in the replacement of our overhead network in the coming decade(s). There has also been an increase in replacements of associated assets when replacing overhead conductor, owing to changes in design standards and condition. We have increased the forecast Capex investment required in the second half of this AMP. As noted earlier in this AMP Update, we have established a seconded team to further develop our risk understanding and modelling relating to asset renewal. This work will inform an updated expenditure profile and strategy update in our full 2026 AMP, in 12 months.

Figure 5.3: Asset renewals capital expenditure




### Automation

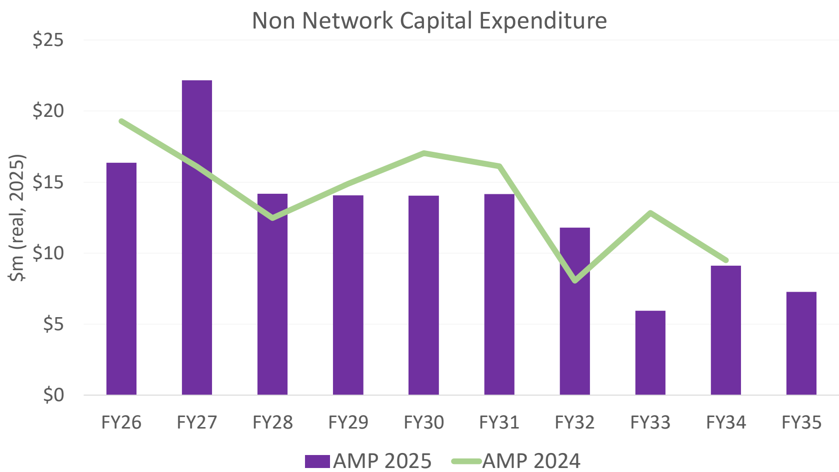
We continue our investment into network automation. This investment supports our commitment to reducing the impact of planned and unplanned outages. It also considers scenarios for storm events, helping us restore supply to more customers through increased switching points and faster identification of where faults originate.

### DSO initiatives

Sections 2.3 and 3.2 of this document outlined our journey to becoming a DSO by 2030. This will require investment into technologies and assets that are not traditional to distribution networks.

The expenditure forecast in Figure 5.4 represents our current scoping of the required systems and technologies, which has progressed significantly in the past 12 months. We also acknowledge there is further work needed to refine the requirements and associated costs. This will be updated in more detail in the 2026 AMP.

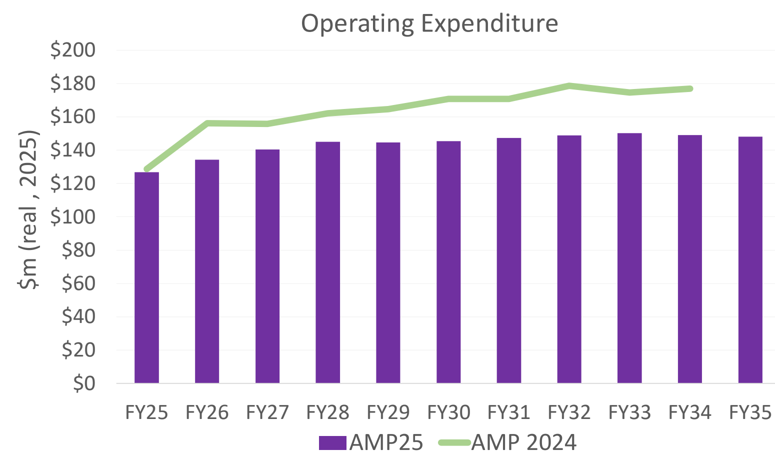
Figure 5.4: Non-network capital expenditure




### Operating expenditure (Opex)

In constant prices, 2025 AMP Update forecast operating investment is $207m lower than in the 2024 AMP Update (-13%). The primary driver for this reduction is the publication of final DPP4 allowances in November 2024, which forced us to prioritise our investment into network maintenance and non-network resourcing. Figure 5.5 illustrates the variance of the 2024 AMP Update to the 2025 AMP Update.

Figure 5.5: Operating expenditure




### Contract re-tender (network)

At the time of writing this AMP Update, we are assessing tender responses from the market to deliver our network fault response, maintenance, upgrade and replacement works. The 2024 AMP Update included an estimate of the impact this process might have on our network maintenance expenditure forecast, but we acknowledge it was difficult to accurately quantify.

In this AMP Update, we have removed any adjustment resulting from a potential price change due to re-tendering. We plan to work within regulatory allowances, but note there is still uncertainty as to what impact re-tendering may have on price or network risk.

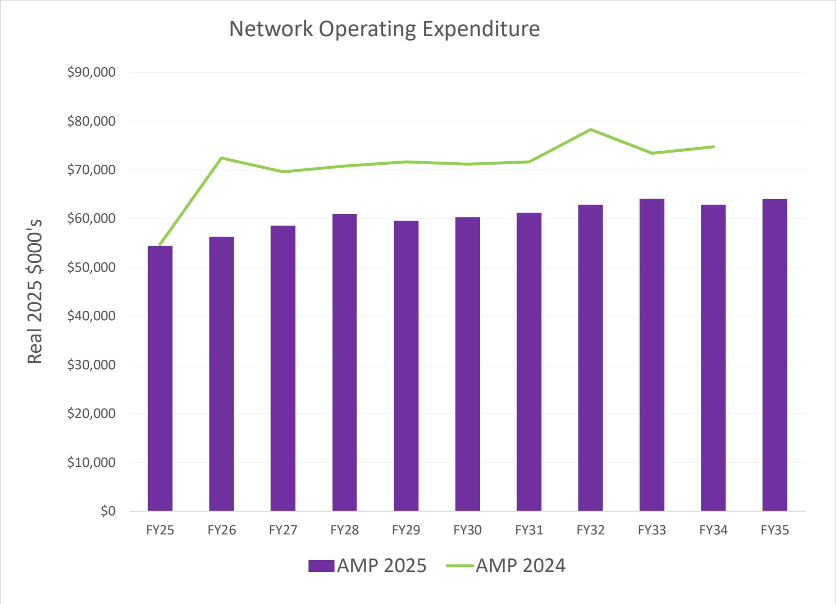
### Vegetation (network)

In this AMP Update, we have reduced the expenditure forecast for vegetation management for the 10-year period by $29m. This is driven by the limited scope for increased investment under the DPP4 regulatory reset. Our investment in satellite imagery to better manage vegetation works is expected to allow us to manage vegetation performance within this expenditure profile.

### Network Opex

We have reduced network maintenance estimates by $79m over the 10-year planning period, of which $45m relates to the removal of potential price impacts due to re-tendering. The remaining $35m reduction relates to modifications made to maintenance plans to ensure we remain within regulatory Opex allowances. We will manage in-year maintenance requirements on a risk and criticality approach, within the funding limits, and continue to evaluate the risk position we take on through this reduction.

Figure 5.6: Network operating expenditure




### Non-network Opex

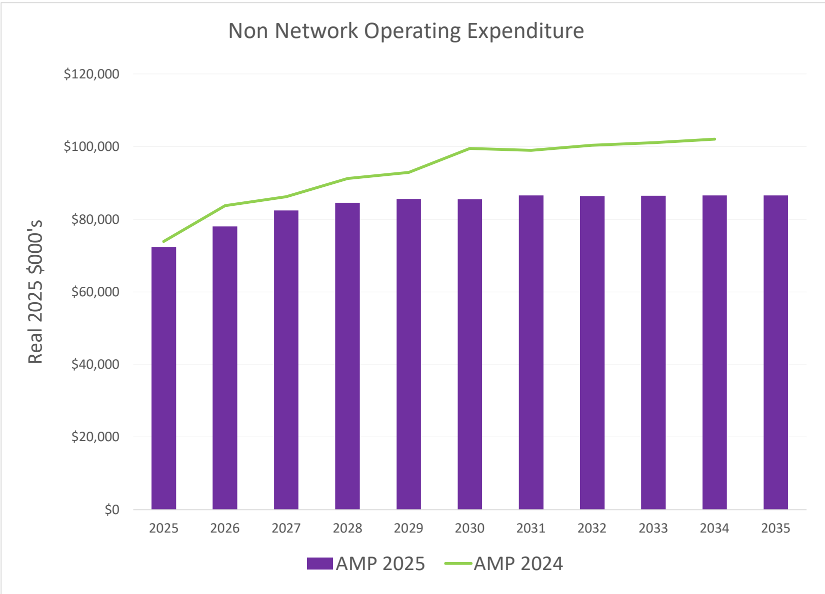
The forecast for non-network Opex expenditure has reduced by $96m (-10%) compared with the 2024 AMP Update. We have taken this approach to ensure we operate within the DPP regulatory allowances.

The primary changes relate to:

- Removal of flexibility costs (now replaced by reopener uncertainty mechanisms).
- Research and development spend increase has been removed from the forecast (replaced by the INSTA allowance mechanism).

This change is set out in Figure 5.7.

Figure 5.7: Non-network operating expenditure




### Flexibility

Our 2024 AMP Update expenditure forecast included an estimate for demand side flexibility services of ~$60m during the planning period. This forecast reflected best efforts at modelling the impact of our intent to engage with providers of flexibility projects. This investment is still uncertain. In particular, the timing and cost associated with large scale flexibility is still unknown. Therefore, we have removed these from this AMP Update, and anticipate using the reopener process should flexibility projects become more certain during the DPP4 period.

### Research and development

We removed ~$15m from the 10-year forecast, based on moving our process to more closely align with the INTSA allowances mechanism.

## 5.5 Schedule 12a: Asset condition

There have been no material changes to the approach for completing Schedule 12a since the 2024 AMP Update. The continued improvement in our asset health models is reflected in this schedule. Of note, we have transitioned our conductor fleets to a CNAIM health model in the past 12 months.

## 5.6 Schedule 12b: Forecast capacity

This schedule has been completed in line with the new requirements and guidelines set out by the Commerce Commission.

We have used our Powerco demand forecast to determine the timing of the need for additional capacity. This demand forecast is used consistently throughout our AMP preparation.

As this is the first year of this updated schedule, we have applied our best judgement in the interpretation of information to be provided, but we appreciate feedback on any inconsistencies with the wider industry.

## 5.7 Schedule 12c: Forecast network demand

There have been no material changes to the approach for completing Schedule 12c since the 2024 AMP Update.

## 5.8 Schedule 12d: Forecast interruptions and duration

We have updated our forecasting methodology for our unplanned SAIDI/SAIFI. The revised methodology now employs a single 'least squares' linear regression model to forecast SAIDI/SAIFI by incorporating all three inputs (number of customers, duration, and number of outages). This approach aims to provide more accurate predictions by minimising the impacts caused by data skewness and modelling each input separately. Our forecasts for unplanned SAIDI/SAIFI are approximately 25% lower than the 2024 AMP Update across the five-year disclosure period.

Accurately forecasting unplanned reliability is challenging, but this approach takes into account the overall improved network performance we have observed in the past two years. Overall, we aim to maintain reliability within regulatory targets, but will proceed with network investment to improve reliability where there is clear customer benefit.

We have updated our forecasting methodology for planned SAIDI /SAIFI to use a historical ratio of incurred SAIDI/SAIFI for planned expenditure and applied this ratio to our forecast expenditure profile. This refinement is reflective of our intended capital investment on the network and the resulting impacts to customers.

# 6. Schedules

## 6.1 Schedule 11a

| | |
|---|---|
| *Company Name* | Powerco |
| *AMP Planning Period* | 1 April 2025 – 31 March 2035 |

**SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE**

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary Explanatory Notes).

This information is not part of audited disclosure information.

| *sch ref* | | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* | *CY+6* | *CY+7* | *CY+8* | *CY+9* | *CY+10* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 | 31 Mar 31 | 31 Mar 32 | 31 Mar 33 | 31 Mar 34 | 31 Mar 35 |
| 9 | | **11a(i): Expenditure on Assets Forecast** | $000 (in nominal dollars) | | | | | | | | | | |
| 10 | | Consumer connection | 96,619 | 94,685 | 96,808 | 128,186 | 140,625 | 150,197 | 161,326 | 176,358 | 194,498 | 216,110 | 220,727 |
| 11 | | System growth | 100,431 | 78,811 | 84,233 | 107,451 | 92,492 | 112,422 | 136,841 | 137,831 | 114,033 | 117,830 | 126,610 |
| 12 | | Asset replacement and renewal | 110,422 | 133,557 | 148,305 | 172,008 | 182,498 | 183,424 | 201,066 | 213,779 | 219,511 | 238,594 | 245,278 |
| 13 | | Asset relocations | 1,544 | 1,604 | 4,716 | 6,972 | 4,584 | 4,684 | 4,786 | 5,630 | 4,998 | 5,108 | 5,220 |
| 14 | | Reliability, safety and environment: | | | | | | | | | | | |
| 15 | | Quality of supply | 13,425 | 28,148 | 22,966 | 22,956 | 23,015 | 23,708 | 26,645 | 31,745 | 32,509 | 33,290 | 34,091 |
| 16 | | Legislative and regulatory | 2,401 | - | - | - | - | - | - | - | - | - | - |
| 17 | | Other reliability, safety and environment | 6,411 | 7,401 | 13,376 | 12,190 | 16,370 | 12,307 | 14,058 | 11,825 | 10,572 | 7,362 | 9,768 |
| 18 | | **Total reliability, safety and environment** | 22,237 | 35,549 | 36,342 | 35,146 | 39,385 | 36,015 | 40,703 | 43,570 | 43,081 | 40,652 | 43,859 |
| 19 | | **Expenditure on network assets** | 331,253 | 344,206 | 370,404 | 449,763 | 459,584 | 486,742 | 544,722 | 577,168 | 576,121 | 618,294 | 641,694 |
| 20 | | **Expenditure on non-network assets** | 13,579 | 16,706 | 23,067 | 15,032 | 15,211 | 15,488 | 15,926 | 13,519 | 6,961 | 10,882 | 8,851 |
| 21 | | **Expenditure on assets** | 344,832 | 360,912 | 393,471 | 464,795 | 474,795 | 502,230 | 560,648 | 590,687 | 583,082 | 629,176 | 650,545 |
| 22 | | | | | | | | | | | | | |
| 23 | *plus* | Cost of financing | 2,078 | 2,078 | 2,078 | 2,078 | 2,078 | 2,078 | 2,078 | 2,078 | 2,078 | 2,078 | 2,078 |
| 24 | *less* | Value of capital contributions | 54,230 | 52,375 | 54,569 | 80,905 | 88,595 | 95,524 | 103,618 | 113,267 | 124,266 | 137,702 | 140,456 |
| 25 | *plus* | Value of vested assets | - | - | - | - | - | - | - | - | - | - | - |
| 26 | | | | | | | | | | | | | |
| 27 | | **Capital expenditure forecast** | 292,680 | 310,615 | 340,980 | 385,968 | 388,278 | 408,784 | 459,108 | 479,498 | 460,894 | 493,552 | 512,167 |
| 28 | | | | | | | | | | | | | |
| 29 | | Assets commissioned | 277,800 | 303,013 | 348,384 | 360,492 | 407,379 | 375,681 | 408,236 | 555,449 | 457,465 | 483,875 | 525,914 |

| 30 | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* | *CY+6* | *CY+7* | *CY+8* | *CY+9* | *CY+10* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31 | | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 | 31 Mar 31 | 31 Mar 32 | 31 Mar 33 | 31 Mar 34 | 31 Mar 35 |
| 32 | | $000 (in constant prices) | | | | | | | | | | |
| 33 | Consumer connection | 96,619 | 92,267 | 92,268 | 119,783 | 128,718 | 134,654 | 141,647 | 151,610 | 163,709 | 178,096 | 178,096 |
| 34 | System growth | 100,431 | 76,439 | 79,636 | 99,285 | 83,565 | 99,280 | 118,112 | 116,304 | 93,963 | 94,939 | 99,625 |
| 35 | Asset replacement and renewal | 110,422 | 129,513 | 140,157 | 158,821 | 164,735 | 161,866 | 173,419 | 180,241 | 180,942 | 192,254 | 193,270 |
| 36 | Asset relocations | 1,544 | 1,561 | 4,487 | 6,491 | 4,178 | 4,178 | 4,178 | 4,809 | 4,178 | 4,178 | 4,178 |
| 37 | Reliability, safety and environment: | | | | | | | | | | | |
| 38 | Quality of supply | 13,425 | 27,296 | 21,665 | 21,135 | 20,691 | 20,815 | 22,842 | 26,568 | 26,568 | 26,568 | 26,568 |
| 39 | Legislative and regulatory | 2,401 | - | - | - | - | - | - | - | - | - | - |
| 40 | Other reliability, safety and environment | 6,411 | 7,175 | 12,647 | 11,255 | 14,784 | 10,859 | 12,138 | 9,971 | 8,720 | 5,923 | 7,701 |
| 41 | **Total reliability, safety and environment** | 22,237 | 34,471 | 34,312 | 32,390 | 35,475 | 31,674 | 34,980 | 36,539 | 35,288 | 32,491 | 34,269 |
| 42 | **Expenditure on network assets** | 331,253 | 334,252 | 350,859 | 416,771 | 416,670 | 431,653 | 472,336 | 489,503 | 478,080 | 501,958 | 509,438 |
| 43 | Expenditure on non-network assets | 13,579 | 16,350 | 22,160 | 14,168 | 14,063 | 14,042 | 14,157 | 11,781 | 5,946 | 9,114 | 7,269 |
| 44 | **Expenditure on assets** | 344,832 | 350,602 | 373,019 | 430,939 | 430,733 | 445,695 | 486,493 | 501,284 | 484,026 | 511,072 | 516,707 |
| 45 | | | | | | | | | | | | |

**Subcomponents of expenditure on assets (where known)**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy efficiency and demand side management, reduction of energy losses | | | | | | | | | | | |
| Overhead to underground conversion | 1,760 | 1,760 | 1,760 | 1,760 | 1,760 | 1,760 | 1,760 | 1,760 | 1,760 | 1,760 | 1,760 |
| Research and development | | | | | | | | | | | |

| | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* | *CY+6* | *CY+7* | *CY+8* | *CY+9* | *CY+10* |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** | **31 Mar 28** | **31 Mar 29** | **31 Mar 30** | **31 Mar 31** | **31 Mar 32** | **31 Mar 33** | **31 Mar 34** | **31 Mar 35** |
| **Difference between nominal and constant price forecasts** | **$000** | | | | | | | | | | |
| Consumer connection | - | 2,418 | 4,540 | 8,403 | 11,907 | 15,543 | 19,679 | 24,748 | 30,789 | 38,014 | 42,631 |
| System growth | - | 2,372 | 4,597 | 8,166 | 8,927 | 13,142 | 18,729 | 21,527 | 20,070 | 22,891 | 26,985 |
| Asset replacement and renewal | - | 4,044 | 8,148 | 13,187 | 17,763 | 21,558 | 27,647 | 33,538 | 38,569 | 46,340 | 52,008 |
| Asset relocations | - | 43 | 229 | 481 | 406 | 506 | 608 | 821 | 820 | 930 | 1,042 |
| Reliability, safety and environment: | | | | | | | | | | | |
| Quality of supply | - | 852 | 1,301 | 1,821 | 2,324 | 2,893 | 3,803 | 5,177 | 5,941 | 6,722 | 7,523 |
| Legislative and regulatory | - | - | - | - | - | - | - | - | - | - | - |
| Other reliability, safety and environment | - | 226 | 729 | 935 | 1,586 | 1,448 | 1,920 | 1,854 | 1,852 | 1,439 | 2,067 |
| **Total reliability, safety and environment** | - | 1,078 | 2,030 | 2,756 | 3,910 | 4,341 | 5,723 | 7,031 | 7,793 | 8,161 | 9,590 |
| **Expenditure on network assets** | - | 9,954 | 19,545 | 32,992 | 42,914 | 55,089 | 72,386 | 87,665 | 98,041 | 116,336 | 132,256 |
| Expenditure on non-network assets | - | 356 | 907 | 864 | 1,148 | 1,446 | 1,769 | 1,738 | 1,015 | 1,768 | 1,582 |
| **Expenditure on assets** | - | 10,310 | 20,452 | 33,856 | 44,062 | 56,535 | 74,155 | 89,403 | 99,056 | 118,104 | 133,838 |

**Commentary on options and considerations made in the assessment of forecast expenditure**

*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15*

## 11a(ii): Consumer Connection

| | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
|---|---|---|---|---|---|---|---|
| | | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** | **31 Mar 28** | **31 Mar 29** | **31 Mar 30** |
| | *Consumer types defined by EDB** | **$000 (in constant prices)** | | | | | |
| | All Consumers | 96,619 | 92,267 | 92,268 | 119,783 | 128,718 | 134,654 |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | **include additional rows if needed* | | | | | | |
| | **Consumer connection expenditure** | 96,619 | 92,267 | 92,268 | 119,783 | 128,718 | 134,654 |
| *less* | Capital contributions funding consumer connection | 53,608 | 50,638 | 50,638 | 73,674 | 80,247 | 84,945 |
| | **Consumer connection less capital contributions** | 43,011 | 41,629 | 41,630 | 46,109 | 48,471 | 49,709 |

## 11a(iii): System Growth

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Subtransmission | 13,284 | 7,694 | 7,719 | 18,473 | 9,680 | 19,588 |
| | Zone substations | 36,683 | 32,658 | 29,912 | 35,398 | 12,827 | 16,173 |
| | Distribution and LV lines | 9,459 | 8,570 | 9,844 | 10,872 | 13,575 | 16,352 |
| | Distribution and LV cables | 7,826 | 6,974 | 8,494 | 9,958 | 13,069 | 14,017 |
| | Distribution substations and transformers | 1,944 | 1,589 | 2,033 | 1,710 | 2,246 | 2,336 |
| | Distribution switchgear | 7,692 | 7,453 | 8,437 | 9,320 | 11,636 | 14,017 |
| | Other network assets | 23,543 | 11,501 | 13,197 | 13,554 | 20,532 | 16,797 |
| | **System growth expenditure** | 100,431 | 76,439 | 79,636 | 99,285 | 83,565 | 99,280 |
| *less* | Capital contributions funding system growth | - | - | - | - | - | - |
| | **System growth less capital contributions** | 100,431 | 76,439 | 79,636 | 99,285 | 83,565 | 99,280 |

## 11a(iv): Asset Replacement and Renewal

| | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|
| | | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 |
| | | **$000 (in constant prices)** | | | | | |
| | Subtransmission | 4,250 | 5,486 | 6,843 | 8,382 | 13,715 | 11,994 |
| | Zone substations | 26,299 | 26,684 | 22,967 | 30,236 | 23,951 | 15,690 |
| | Distribution and LV lines | 44,968 | 64,071 | 69,982 | 74,532 | 78,516 | 83,034 |
| | Distribution and LV cables | 10,224 | 9,539 | 13,018 | 17,525 | 20,148 | 24,143 |
| | Distribution substations and transformers | 10,741 | 10,027 | 10,843 | 11,351 | 11,355 | 11,499 |
| | Distribution switchgear | 12,963 | 13,505 | 15,149 | 15,224 | 16,369 | 14,826 |
| | Other network assets | 977 | 201 | 1,355 | 1,571 | 681 | 680 |
| | **Asset replacement and renewal expenditure** | 110,422 | 129,513 | 140,157 | 158,821 | 164,735 | 161,866 |
| *less* | Capital contributions funding asset replacement and renewal | - | - | - | - | - | - |
| | **Asset replacement and renewal less capital contributions** | 110,422 | 129,513 | 140,157 | 158,821 | 164,735 | 161,866 |

## 11a(v): Asset Relocations

| | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|
| | | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 |
| | *Project or programme** | **$000 (in constant prices)** | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | **include additional rows if needed* | | | | | | |
| | All other project or programmes - asset relocations | 1,544 | 1,561 | 4,487 | 6,491 | 4,178 | 4,178 |
| | **Asset relocations expenditure** | 1,544 | 1,561 | 4,487 | 6,491 | 4,178 | 4,178 |
| *less* | Capital contributions funding asset relocations | 621 | 621 | 1,786 | 2,583 | 1,663 | 1,663 |
| | **Asset relocations less capital contributions** | 923 | 940 | 2,701 | 3,908 | 2,515 | 2,515 |

## 11a(vi): Quality of Supply

| | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|
| | | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 |
| | *Project or programme** | **$000 (in constant prices)** | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | **include additional rows if needed* | | | | | | |
| | All other projects or programmes - quality of supply | 13,425 | 27,296 | 21,665 | 21,135 | 20,691 | 20,815 |
| | **Quality of supply expenditure** | 13,425 | 27,296 | 21,665 | 21,135 | 20,691 | 20,815 |
| *less* | Capital contributions funding quality of supply | - | - | - | - | - | - |
| | **Quality of supply less capital contributions** | 13,425 | 27,296 | 21,665 | 21,135 | 20,691 | 20,815 |

### 11a(vii): Legislative and Regulatory

| Project or programme* | Current Year CY 31 Mar 25 | CY+1 31 Mar 26 | CY+2 31 Mar 27 | CY+3 31 Mar 28 | CY+4 31 Mar 29 | CY+5 31 Mar 30 |
|---|---|---|---|---|---|---|
| | $000 (in constant prices) | | | | | |
| Secondary systems (relay replacement for extended reserves) | 2,401 | - | - | - | - | - |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| *include additional rows if needed | | | | | | |
| All other projects or programmes - legislative and regulatory | | | | | | |
| **Legislative and regulatory expenditure** | 2,401 | - | - | - | - | - |
| *less* Capital contributions funding legislative and regulatory | | | | | | |
| **Legislative and regulatory less capital contributions** | 2,401 | - | - | - | - | - |

### 11a(viii): Other Reliability, Safety and Environment

| Project or programme* | Current Year CY 31 Mar 25 | CY+1 31 Mar 26 | CY+2 31 Mar 27 | CY+3 31 Mar 28 | CY+4 31 Mar 29 | CY+5 31 Mar 30 |
|---|---|---|---|---|---|---|
| | $000 (in constant prices) | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| *include additional rows if needed | | | | | | |
| All other projects or programmes - other reliability, safety and environment | 6,411 | 7,175 | 12,647 | 11,255 | 14,784 | 10,859 |
| **Other reliability, safety and environment expenditure** | 6,411 | 7,175 | 12,647 | 11,255 | 14,784 | 10,859 |
| *less* Capital contributions funding other reliability, safety and environment | - | - | - | - | - | - |
| **Other reliability, safety and environment less capital contributions** | 6,411 | 7,175 | 12,647 | 11,255 | 14,784 | 10,859 |

### 11a(ix): Non-Network Assets

| | Current Year CY 31 Mar 25 | CY+1 31 Mar 26 | CY+2 31 Mar 27 | CY+3 31 Mar 28 | CY+4 31 Mar 29 | CY+5 31 Mar 30 |
|---|---|---|---|---|---|---|
| **Routine expenditure** | | | | | | |
| *Project or programme** | $000 (in constant prices) | | | | | |
| ICT capex | 2,813 | 7,222 | 7,393 | 8,177 | 5,310 | 6,708 |
| Facilities | 3,485 | 2,890 | 5,440 | 2,040 | 765 | 340 |
| Leases | 1,301 | 484 | 4,761 | 1,136 | 5,368 | 1,017 |
| | | | | | | |
| | | | | | | |
| *include additional rows if needed | | | | | | |
| All other projects or programmes - routine expenditure | | | | | | |
| **Routine expenditure** | 7,599 | 10,597 | 17,594 | 11,353 | 11,443 | 8,065 |
| **Atypical expenditure** | | | | | | |
| *Project or programme** | | | | | | |
| ICT capex | 5,980 | 5,754 | 4,566 | 2,815 | 1,770 | 1,727 |
| Facilities | - | - | - | - | 850 | 4,250 |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| *include additional rows if needed | | | | | | |
| All other projects or programmes - atypical expenditure | - | - | - | - | - | - |
| **Atypical expenditure** | 5,980 | 5,754 | 4,566 | 2,815 | 2,620 | 5,977 |
| **Expenditure on non-network assets** | 13,579 | 16,350 | 22,160 | 14,168 | 14,063 | 14,042 |

## 6.2 Schedule 11b

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | Company Name | Powerco | |
| | | | | | | | | | | | AMP Planning Period | 1 April 2025 – 31 March 2035 | |

### SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

| sch ref | | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 | CY+6 | CY+7 | CY+8 | CY+9 | CY+10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 | 31 Mar 31 | 31 Mar 32 | 31 Mar 33 | 31 Mar 34 | 31 Mar 35 |
| 9 | **Operational Expenditure Forecast** | | $000 (in nominal dollars) | | | | | | | | | | |
| 10 | Service interruptions and emergencies | | 9,059 | 9,558 | 9,860 | 10,151 | 10,468 | 10,795 | 11,134 | 11,483 | 11,842 | 12,212 | 12,595 |
| 11 | Vegetation management | | 13,016 | 13,045 | 13,986 | 14,399 | 14,575 | 13,913 | 13,789 | 14,241 | 14,707 | 15,188 | 15,685 |
| 12 | Routine and corrective maintenance and inspection | | 20,205 | 22,926 | 24,593 | 27,290 | 26,249 | 28,361 | 29,764 | 31,947 | 33,685 | 32,477 | 34,191 |
| 13 | Asset replacement and renewal | | 12,163 | 12,510 | 13,296 | 13,708 | 14,152 | 14,609 | 15,565 | 16,063 | 16,578 | 17,109 | 17,657 |
| 14 | **Network Opex** | | 54,443 | 58,039 | 61,735 | 65,548 | 65,444 | 67,678 | 70,252 | 73,734 | 76,812 | 76,986 | 80,128 |
| 15 | System operations and network support | | 25,097 | 26,502 | 30,195 | 32,393 | 33,946 | 34,690 | 36,271 | 36,832 | 37,664 | 38,516 | 39,286 |
| 16 | Business support | | 47,232 | 53,242 | 55,625 | 57,312 | 58,613 | 59,596 | 61,092 | 62,314 | 63,561 | 64,832 | 66,128 |
| 17 | Non-network solutions provided by a related party or third party | *Not Required before DY2025* | | | | | | | | | | | |
| 18 | **Non-network opex** | | 72,329 | 79,744 | 85,820 | 89,705 | 92,559 | 94,286 | 97,363 | 99,146 | 101,225 | 103,348 | 105,414 |
| 19 | **Operational expenditure** | | 126,772 | 137,783 | 147,555 | 155,253 | 158,003 | 161,964 | 167,615 | 172,880 | 178,037 | 180,334 | 185,542 |
| 20 | | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* | *CY+6* | *CY+7* | *CY+8* | *CY+9* | *CY+10* |
| 21 | | | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 | 31 Mar 31 | 31 Mar 32 | 31 Mar 33 | 31 Mar 34 | 31 Mar 35 |
| 22 | | | $000 (in constant prices) | | | | | | | | | | |
| 23 | Service interruptions and emergencies | | 9,059 | 9,265 | 9,355 | 9,446 | 9,537 | 9,629 | 9,723 | 9,818 | 9,913 | 10,008 | 10,106 |
| 24 | Vegetation management | | 13,016 | 12,645 | 13,270 | 13,398 | 13,278 | 12,410 | 12,042 | 12,176 | 12,311 | 12,447 | 12,585 |
| 25 | Routine and corrective maintenance and inspection | | 20,205 | 22,219 | 23,303 | 25,337 | 23,848 | 25,213 | 25,892 | 27,194 | 28,058 | 26,471 | 27,268 |
| 26 | Asset replacement and renewal | | 12,163 | 12,123 | 12,599 | 12,727 | 12,857 | 12,988 | 13,540 | 13,674 | 13,808 | 13,945 | 14,082 |
| 27 | **Network Opex** | | 54,443 | 56,252 | 58,527 | 60,908 | 59,520 | 60,240 | 61,197 | 62,862 | 64,090 | 62,871 | 64,041 |
| 28 | System operations and network support | | 25,097 | 25,937 | 29,007 | 30,532 | 31,385 | 31,452 | 32,243 | 32,099 | 32,180 | 32,263 | 32,263 |
| 29 | Business support | | 47,232 | 52,108 | 53,438 | 54,020 | 54,190 | 54,033 | 54,307 | 54,307 | 54,307 | 54,307 | 54,307 |
| 30 | Non-network solutions provided by a related party or third party | *Not Required before DY2025* | | | | | | | | | | | |
| 31 | **Non-network opex** | | 72,329 | 78,045 | 82,445 | 84,552 | 85,575 | 85,485 | 86,550 | 86,406 | 86,487 | 86,570 | 86,570 |
| 32 | **Operational expenditure** | | 126,772 | 134,297 | 140,972 | 145,460 | 145,095 | 145,725 | 147,747 | 149,268 | 150,577 | 149,441 | 150,611 |
| 33 | **Subcomponents of operational expenditure (where known)** | | | | | | | | | | | | |
| 35 | | | | | | | | | | | | | |
| 36 | Energy efficiency and demand side management, reduction of energy losses | | | | | | | | | | | | |
| 37 | Direct billing* | | | | | | | | | | | | |
| 38 | Research and Development | | | | | | | | | | | | |
| 39 | Insurance | | 2,147 | 2,714 | 2,714 | 2,714 | 2,714 | 2,714 | 2,714 | 2,714 | 2,714 | 2,714 | 2,714 |
| 41 | ** Direct billing expenditure by suppliers that direct bill the majority of their consumers* | | | | | | | | | | | | |
| 42 | | | | | | | | | | | | | |
| 43 | | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* | *CY+6* | *CY+7* | *CY+8* | *CY+9* | *CY+10* |
| 44 | | | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 | 31 Mar 31 | 31 Mar 32 | 31 Mar 33 | 31 Mar 34 | 31 Mar 35 |
| 45 | **Difference between nominal and real forecasts** | | $000 | | | | | | | | | | |
| 46 | Service interruptions and emergencies | | - | 293 | 505 | 705 | 931 | 1,166 | 1,411 | 1,665 | 1,929 | 2,204 | 2,489 |
| 47 | Vegetation management | | - | 400 | 716 | 1,001 | 1,297 | 1,503 | 1,747 | 2,065 | 2,396 | 2,741 | 3,100 |
| 48 | Routine and corrective maintenance and inspection | | - | 707 | 1,290 | 1,953 | 2,401 | 3,148 | 3,872 | 4,753 | 5,627 | 6,006 | 6,923 |
| 49 | Asset replacement and renewal | | - | 387 | 697 | 981 | 1,295 | 1,621 | 2,025 | 2,389 | 2,770 | 3,164 | 3,575 |
| 50 | **Network Opex** | | - | 1,787 | 3,208 | 4,640 | 5,924 | 7,438 | 9,055 | 10,872 | 12,722 | 14,115 | 16,087 |
| 51 | System operations and network support | | - | 565 | 1,188 | 1,861 | 2,561 | 3,238 | 4,028 | 4,733 | 5,484 | 6,253 | 7,023 |
| 52 | Business support | | - | 1,134 | 2,187 | 3,292 | 4,423 | 5,563 | 6,785 | 8,007 | 9,254 | 10,525 | 11,821 |
| 53 | Non-network solutions provided by a related party or third party | *Not Required before DY2025* | - | - | - | - | - | - | - | - | - | - | - |
| 54 | **Non-network opex** | | - | 1,699 | 3,375 | 5,153 | 6,984 | 8,801 | 10,813 | 12,740 | 14,738 | 16,778 | 18,844 |
| 55 | **Operational expenditure** | | - | 3,486 | 6,583 | 9,793 | 12,908 | 16,239 | 19,868 | 23,612 | 27,460 | 30,893 | 34,931 |
| 56 | | | | | | | | | | | | | |

## 6.3 Schedule 12a

| | | Company Name | Powerco |
|---|---|---|---|
| | | AMP Planning Period | 1 April 2025 – 31 March 2035 |

### SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

| sch ref | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | | | | | Asset condition at start of planning period (percentage of units by grade) | | | | | | | |
| 8 | Voltage | Asset category | Asset class | Units | H1 | H2 | H3 | H4 | H5 | Grade unknown | Data accuracy (1–4) | % of asset forecast to be replaced in next 5 years |
| 9 | | | | | | | | | | | | |
| 10 | All | Overhead Line | Concrete poles / steel structure | No. | 0.6% | 5.2% | 6.8% | 64.1% | 23.3% | - | 4 | 8.4% |
| 11 | All | Overhead Line | Wood poles | No. | 1.2% | 10.4% | 24.4% | 61.9% | 2.1% | - | 3 | 9.0% |
| 12 | All | Overhead Line | Other pole types | No. | - | 0.1% | 52.7% | 37.9% | 9.3% | - | 3 | 5.4% |
| 13 | HV | Subtransmission Line | Subtransmission OH up to 66kV conductor | km | 0.4% | 5.3% | 8.9% | 37.4% | 48.0% | - | 4 | 3.3% |
| 14 | HV | Subtransmission Line | Subtransmission OH 110kV+ conductor | km | - | - | - | - | 100.0% | - | 4 | - |
| 15 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (XLPE) | km | - | 0.7% | 6.3% | - | 93.0% | - | 3 | 3.6% |
| 16 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Oil pressurised) | km | - | - | 100.0% | - | - | - | 4 | 100.0% |
| 17 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (Gas pressurised) | km | | | | | | | N/A | - |
| 18 | HV | Subtransmission Cable | Subtransmission UG up to 66kV (PILC) | km | - | - | - | 24.6% | 75.4% | - | 3 | - |
| 19 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (XLPE) | km | - | - | - | - | 100.0% | - | 4 | - |
| 20 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (Oil pressurised) | km | | | | | | | N/A | - |
| 21 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (Gas Pressurised) | km | | | | | | | N/A | - |
| 22 | HV | Subtransmission Cable | Subtransmission UG 110kV+ (PILC) | km | | | | | | | N/A | - |
| 23 | HV | Subtransmission Cable | Subtransmission submarine cable | km | | | | | | | N/A | - |
| 24 | HV | Zone substation Buildings | Zone substations up to 66kV | No. | 5.0% | 28.8% | 18.7% | 33.1% | 14.4% | - | 2 | 13.6% |
| 25 | HV | Zone substation Buildings | Zone substations 110kV+ | No. | | | | | | | N/A | - |
| 26 | HV | Zone substation switchgear | 22/33kV CB (Indoor) | No. | - | - | - | 1.5% | 98.5% | - | 3 | 0.5% |
| 27 | HV | Zone substation switchgear | 22/33kV CB (Outdoor) | No. | - | 20.2% | 7.3% | 5.7% | 66.8% | - | 3 | 23.9% |
| 28 | HV | Zone substation switchgear | 33kV Switch (Ground Mounted) | No. | - | - | - | - | 100.0% | - | 2 | - |
| 29 | HV | Zone substation switchgear | 33kV Switch (Pole Mounted) | No. | 0.7% | 10.1% | 39.2% | 10.4% | 39.6% | - | 3 | 12.0% |
| 30 | HV | Zone substation switchgear | 33kV RMU | No. | - | - | - | - | 100.0% | - | 3 | - |
| 31 | HV | Zone substation switchgear | 50/66/110kV CB (Indoor) | No. | | | | | | | N/A | - |
| 32 | HV | Zone substation switchgear | 50/66/110kV CB (Outdoor) | No. | - | 21.1% | 10.5% | 31.6% | 36.8% | - | 3 | - |
| 33 | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (ground mounted) | No. | 0.1% | 2.0% | 6.3% | 15.1% | 76.4% | - | 3 | 23.0% |
| 34 | HV | Zone substation switchgear | 3.3/6.6/11/22kV CB (pole mounted) | No. | 2.9% | - | - | - | 97.1% | - | 3 | - |
| 35 | | | | | | | | | | | | |

| Row | Voltage | Asset category | Asset class | Units | H1 | H2 | H3 | H4 | H5 | Grade unknown | Data accuracy (1–4) | % of asset forecast to be replaced in next 5 years |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 36 | | | | | | | | | | | | |
| 37 | | | | | Asset condition at start of planning period (percentage of units by grade) | | | | | | | |
| 38 | | | | | | | | | | | | |
| 39 | HV | Zone Substation Transformer | Zone Substation Transformers | No. | 3.1% | 9.3% | 24.0% | 22.7% | 40.9% | - | 4 | 16.4% |
| 40 | HV | Distribution Line | Distribution OH Open Wire Conductor | km | 2.4% | 11.1% | 27.5% | 30.0% | 29.1% | - | 3 | 5.5% |
| 41 | HV | Distribution Line | Distribution OH Aerial Cable Conductor | km | | | | | | | N/A | - |
| 42 | HV | Distribution Line | SWER conductor | km | - | 24.7% | 20.8% | 27.9% | 26.6% | - | 3 | - |
| 43 | HV | Distribution Cable | Distribution UG XLPE or PVC | km | - | 10.0% | 13.3% | - | 76.6% | - | 3 | 6.2% |
| 44 | HV | Distribution Cable | Distribution UG PILC | km | - | - | 2.4% | 12.8% | 84.7% | - | 3 | 15.9% |
| 45 | HV | Distribution Cable | Distribution Submarine Cable | km | - | - | 14.5% | - | 85.5% | - | 3 | - |
| 46 | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers | No. | 0.4% | - | 0.1% | 0.1% | 99.3% | - | 3 | 1.3% |
| 47 | HV | Distribution switchgear | 3.3/6.6/11/22kV CB (Indoor) | No. | - | 2.5% | 19.6% | 15.0% | 62.9% | - | 3 | 15.5% |
| 48 | HV | Distribution switchgear | 3.3/6.6/11/22kV Switches and fuses (pole mounted) | No. | 1.4% | 2.6% | 10.2% | 17.7% | 68.1% | - | 3 | 7.8% |
| 49 | HV | Distribution switchgear | 3.3/6.6/11/22kV Switch (ground mounted) - except RMU | No. | 0.5% | 2.3% | 16.8% | 26.1% | 54.3% | - | 3 | 7.6% |
| 50 | HV | Distribution switchgear | 3.3/6.6/11/22kV RMU | No. | 0.2% | 0.5% | 6.1% | 8.9% | 84.3% | - | 3 | 6.7% |
| 51 | HV | Distribution Transformer | Pole Mounted Transformer | No. | 2.1% | 2.1% | 8.0% | 13.9% | 73.8% | - | 3 | 6.9% |
| 52 | HV | Distribution Transformer | Ground Mounted Transformer | No. | 1.2% | 15.2% | 3.7% | 13.4% | 66.5% | - | 4 | 3.2% |
| 53 | HV | Distribution Transformer | Voltage regulators | No. | 1.7% | - | 0.6% | 0.3% | 97.4% | - | 3 | 1.3% |
| 54 | HV | Distribution Substations | Ground Mounted Substation Housing | No. | 1.2% | 1.2% | 4.9% | 8.6% | 84.1% | - | 2 | 0.6% |
| 55 | LV | LV Line | LV OH Conductor | km | 0.0% | 6.4% | 22.6% | 42.3% | 28.8% | - | 2 | 4.2% |
| 56 | LV | LV Cable | LV UG Cable | km | 1.7% | 0.9% | 9.3% | 22.7% | 65.4% | - | 2 | 0.6% |
| 57 | LV | LV Streetlighting | LV OH/UG Streetlight circuit | km | 3.9% | 2.5% | 18.5% | 27.8% | 47.2% | - | 2 | 1.8% |
| 58 | LV | Connections | OH/UG consumer service connections | No. | 1.4% | 6.3% | 60.7% | 1.4% | 30.2% | - | 2 | 1.0% |
| 59 | All | Protection | Protection relays (electromechanical, solid state and numeric) | No. | 15.2% | 4.7% | 8.4% | 28.8% | 43.0% | - | 3 | 6.5% |
| 60 | All | SCADA and communications | SCADA and communications equipment operating as a single system | Lot | 50.7% | 6.9% | 25.2% | 11.9% | 5.3% | - | 2 | 6.0% |
| 61 | All | Capacitor Banks | Capacitors including controls | No. | - | - | - | 2.0% | 98.0% | - | 3 | - |
| 62 | All | Load Control | Centralised plant | Lot | - | 10.7% | 50.0% | 39.3% | - | - | 3 | - |
| 63 | All | Load Control | Relays | No. | 37.4% | 1.5% | 2.6% | 7.4% | 51.1% | - | 1 | - |
| 64 | All | Civils | Cable Tunnels | km | | | | | | | N/A | - |

# 6.4 Schedule 12b

| | | Company Name | Powerco |
|---|---|---|---|
| | | AMP Planning Period | 1 April 2025 – 31 March 2035 |

**SCHEDULE 12b: REPORT ON FORECAST CAPACITY**

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

*sch ref*

| sch ref | Existing Zone Substations | Current peak load (MVA) | Current peak load period | Installed operating capacity (MVA) | Current security of supply classification (type) | Current constraint type | Current available capacity (MVA) | Peak load period +5 yrs | Available capacity +5 yrs (MVA) | Security of supply classification +5 yrs (type) | Peak load period +10 yrs | Min. available capacity +10 yrs (MVA) | Max. available capacity +10 yrs (MVA) | Security of supply classification +10 yrs (type) | Forecast constraint type | Year of any forecast constraint | Constraint primary cause | Constraint solution type | Constraint solution progress | Temporary constraint solution remaining lifespan | Explanation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | **12b(i): System Growth - Zone Substations** | | | | | | | | | | | | | | | | | | | | |
| 8 | | | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | *Not Required before DY2025* | |
| 10 | Coromandel | 4.3 | Winter | 5.0 | N-1 switched | No constraint | 0.7 | Winter | 0.5 | N-1 switched | Winter | 5.3 | 5.3 | N-1 switched | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | Backup generation avalible to provide switched N-1 security |
| 11 | Kerepehi | 11.7 | Winter | 8.6 | N-1 switched | Capacity | -3.1 | Winter | -5.6 | N-1 switched | Winter | -0.1 | 0.5 | N-1 switched | No constraint | None | Subtransmission circuit | Divert load to alternative substation | Planning stage | Not applicable | Proposed Mangatarata substation to offload Kerepehi. Reduced load lowers security class |
| 12 | Matatoki | 4.6 | Winter | 7.5 | N-1 switched | Security | 2.9 | Winter | -1.1 | N-1 switched | Winter | 1.0 | 5.4 | N-1 switched | No constraint | None | Subtransmission circuit | Divert load to alternative | Planning stage | Not applicable | 11 kV backfeed to support subtransmission N security |
| 13 | Tairua | 9.3 | Winter | 7.5 | N-1 | Capacity | -1.8 | Winter | -2.4 | N-1 | Winter | 7.1 | 7.1 | N-1 | No constraint | None | Zone substation transformer | Network upgrade | Planning stage | Not applicable | |
| 14 | Thames T1 & T2 | 12.1 | Winter | 17.0 | N-1 | Security | 4.9 | Winter | 4.4 | N-1 | Winter | 4.4 | 4.4 | N-1 | No constraint | None | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | Proposed Kopu-Kaueranga line to improve the security for Thames from N-1 switched to N-1 |
| 15 | Thames T3 | 1.5 | Winter | 5.0 | N-1 switched | No constraint | 3.5 | Winter | 3.5 | N-1 switched | Winter | 3.5 | 3.5 | N-1 switched | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | Dedicated customer connection. |
| 16 | Whitianga | 17.1 | Winter | 17.0 | N-1 | Capacity | -0.1 | Winter | -1.9 | N-1 | Winter | -3.4 | -2.2 | N-1 | No constraint | None | Zone substation transformer | Distributed Generation | Solution confirmed | Not applicable | Transformer N-1 capacity shortfall managed with generator and 11kV backfeed |
| 17 | Paeroa | 8.1 | Winter | 7.2 | N-1 | Capacity | -0.9 | Winter | -1.2 | N-1 | Winter | 8.3 | 8.3 | N-1 | No constraint | None | Zone substation transformer | Network upgrade | Planning stage | Not applicable | Transformer replacement in LTP FY30/31 |
| 18 | Waihi | 18.5 | Winter | 13.4 | N-1 | Capacity | -5.1 | Winter | -2.5 | N-1 | Winter | 7.8 | 7.8 | N-1 | No constraint | None | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | Dedicated customer substation will offload Waihi substation |
| 19 | Waihi Beach | 5.7 | Winter | 3.1 | N-1 switched | Capacity | -2.5 | Winter | -1 | N-1 switched | Winter | -2.1 | -1.3 | N-1 switched | Capacity | 6 | Subtransmission circuit | Demand response | Planning stage | Not applicable | Proposed backup generation to provide support for 11kV backfeed |
| 20 | Whangamata | 11.4 | Winter | 7.0 | N-1 switched | Capacity | -4.4 | Winter | -1.7 | N-1 switched | Winter | 0.1 | 0.1 | N-1 switched | Security | 6 | Zone substation transformer | Network upgrade | Solution confirmed | Not applicable | Transformers to be upgraded within AMP period |
| 21 | Aongatete | 4.6 | Winter | 5.2 | N-1 switched | Security | 0.6 | Winter | -0.6 | N-1 switched | Winter | -1.3 | -0.3 | N-1 switched | Capacity | 4 | Subtransmission circuit | Network upgrade | Implementation stage | > 3 years | Transformers and small section of 33kV circuit will be upgraded |
| 22 | Bethlehem | 11.3 | Winter | 24.0 | N-1 switched | No constraint | 12.7 | Winter | 8.4 | N-1 switched | Winter | 8.4 | 11.6 | N-1 switched | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 23 | Hamilton Street | 10.9 | Winter | 24.0 | N-1 | No constraint | 13.1 | Winter | 11.8 | N-1 | Winter | 11.5 | 12.5 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 24 | Katikati | 11.2 | Winter | 11.5 | N-1 switched | No constraint | 0.3 | Winter | -3.6 | N-1 switched | Winter | -4.2 | -2.6 | N-1 switched | Security | 1 | Zone substation transformer | Network upgrade | Planning stage | > 3 years | Exploring flex options to mitigate transformer N-1 capacity risk. |
| 25 | Kauri Point | 2.8 | Winter | 3.2 | N-1 switched | Security | 0.4 | Winter | 0.2 | N-1 switched | Winter | 0.1 | 0.1 | N-1 switched | Security | 10+ | Subtransmission circuit | Network upgrade | No active planning | > 3 years | 11 kV backfeed available. Flex solution possible. |
| 26 | Matua | 9.8 | Winter | 14.3 | N-1 switched | Security | 4.5 | Winter | 4.3 | N-1 switched | Winter | 4.2 | 4.2 | N-1 switched | Security | None | Subtransmission circuit | Network upgrade | No active planning | Not applicable | Transformer to be relocated from Atuaroa zone substation ~FY29. |
| 27 | Omokoroa | 12.6 | Winter | 10.6 | N-1 switched | Capacity | -2 | Winter | -4.5 | N-1 switched | Winter | -5.6 | -4.6 | N-1 switched | Capacity | 1 | Zone substation transformer | Network upgrade | Implementation stage | > 3 years | Load transfer to proposed Pahoia Zone Substation reduces load at Omokoroa sub. |
| 28 | Otumoetai | 15.0 | Winter | 13.2 | N-1 switched | Capacity | -1.8 | Winter | -2.5 | N-1 switched | Winter | -3.1 | -3.8 | N-1 switched | Capacity | 1 | Zone substation transformer | Network upgrade | Planning stage | > 3 years | |
| 29 | Pyes Pa | 17.4 | Spring | 24.0 | N-1 switched | No constraint | 6.6 | Spring | 4.6 | N-1 switched | Spring | 3.0 | 3.0 | N-1 switched | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 30 | Sulphur Point | 8.5 | Autumn | 17.0 | N-1 switched | No constraint | 8.5 | Autumn | 8.5 | N-1 switched | Autumn | 4.5 | 8.5 | N-1 switched | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | Customer agreed security |
| 31 | Waihi Road | 18.4 | Winter | 24.0 | N-1 | No constraint | 5.6 | Winter | 4.9 | N-1 | Winter | 4.3 | 2.0 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 32 | Welcome Bay | 24.6 | Winter | 18.6 | N-1 switched | Capacity | -6 | Winter | -8.3 | N-1 switched | Winter | -10.2 | -10.2 | N-1 switched | Capacity | 1 | Zone substation transformer | Network upgrade | Planning stage | > 3 years | Load transfer to proposed Welcome Bay East sub ~FY32 |
| 33 | Atuaroa Avenue | 10.2 | Autumn | 17.0 | N-1 switched | Security | 6.8 | Autumn | 6.2 | N-1 switched | Autumn | 5.8 | 12.8 | N-1 switched | Capacity | 5 | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | Upgrade with the Atuaroa suite of projects. |
| 34 | Matapihi | 13.5 | Winter | 24.0 | N-1 | No constraint | 10.5 | Winter | 9.9 | N-1 | Winter | 9.4 | 9.4 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 35 | Omanu | 13.3 | Winter | 24.0 | N-1 | No constraint | 10.7 | Winter | 8.8 | N-1 | Winter | 7.1 | 8.6 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 36 | Paengaroa | 6.0 | Winter | 17.0 | N-1 switched | Security | 11 | Winter | 8.1 | N-1 switched | Winter | 7.8 | 10.3 | N-1 switched | Security | 1 | Subtransmission circuit | Network upgrade | Implementation stage | 1 - 3 years | Paegoroa 2nd cct project in FY27 |
| 37 | Papamoa | 17.0 | Winter | 18.6 | N-1 | No constraint | 1.6 | Winter | 4.1 | N-1 | Winter | 2.0 | 3.2 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 38 | Pongakawa | 4.5 | Summer | 5.8 | N-1 switched | Security | 1.3 | Summer | 0.8 | N-1 switched | Summer | 0.3 | 1.3 | N-1 switched | No constraint | None | Not applicable | Divert load to alternative | Solution confirmed | 1 - 3 years | Shifting ~1MVA to Paengaroa |
| 39 | Te Maunga | 12.1 | Winter | 17.0 | N-1 switched | Security | 4.9 | Winter | 3.2 | N-1 switched | Winter | 1.7 | 1.7 | N-1 switched | No constraint | 1 | Zone substation transformer | Network upgrade | Planning stage | < 1 year | Second transformer proposed for FY33 |
| 40 | Te Puke | 21.0 | Winter | 24.0 | N-1 | No constraint | 3 | Winter | -10.5 | N-1 | Winter | -11.4 | 1.1 | N-1 | Capacity | 1 | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | New Rangiuru Zone Substation will commission ~2026, and 20MVA will be transferred to Rangiuru over the next 10 years. |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41 | Triton | 18.4 | Winter | 24.0 | N-1 | No constraint | 5.6 | Winter | 4.8 | N-1 | Winter | 4.1 | 4.1 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 42 | Wairakei | 11.0 | Winter | 24.0 | N-1 switched | No constraint | 13 | Winter | 8.2 | N-1 switched | Winter | 2.3 | 11.8 | N-1 switched | No constraint | 10+ | Zone substation transformer | Divert load to alternative substation | No active planning | Not applicable | Golden Sands proposed 10MVA load growth in 10 years, proposed to shift load to proposed sub Te Tumu in FY2042 |
| 43 | Browne Street | 11.0 | Winter | 8.3 | N-1 switched | Capacity | -2.7 | Winter | -3.4 | N-1 switched | Winter | -4.1 | -4.1 | N-1 switched | No constraint | None | Zone substation transformer | Divert load to alternative substation | Planning stage | > 3 years | Peaky load means constraint appears infrequently. 5 MVA of transfer capacity at 11 kV. Routine projects in planning stage to permanently offload to adjacent substation. |
| 44 | Farmer Road | 6.8 | Winter | 5.8 | N-1 switched | Capacity | -1 | Winter | 1.8 | N-1 switched | Winter | 1.4 | 1.4 | N-1 switched | No constraint | None | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | New substation under construction to reduce load. |
| 45 | Inghams | 4.4 | Summer | 7.5 | N-1 switched | No constraint | 3.1 | Summer | 3.1 | N-1 switched | Summer | 3.1 | 3.1 | N-1 switched | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | Customer dedicated substation with no forecast demand increases. Customer accepts their security level with a limited 11 kV back feed available. |
| 46 | Lake Road | 6.9 | Spring | 5.8 | N-1 switched | Capacity | -1.1 | Spring | -2.3 | N-1 switched | Spring | -2.8 | -2.1 | N-1 switched | No constraint | None | Zone substation transformer | Network upgrade | Planning stage | > 3 years | Existing transfer capacity at 11 kV is sufficient. |
| 47 | Mikkelsen Road | 12.2 | Summer | 17.0 | N-1 | No constraint | 4.8 | Summer | 4.3 | N-1 | Summer | 3.7 | 3.7 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 48 | Morrinsville | 8.2 | Winter | 8.6 | N-1 switched | No constraint | 0.4 | Winter | 1.4 | N-1 switched | Winter | 1.2 | 1.9 | N-1 switched | Capacity | 1 | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | New substation under construction to off take load from Morrinsville & Piako subsations. |
| 49 | Piako | 15.0 | Winter | 17.0 | N-1 | No constraint | 2 | Winter | 4 | N-1 | Winter | 3.6 | 5.1 | N-1 | Capacity | 3 | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | New substation under construction to off take load from Morrinsville & Piako subsations. |
| 50 | Putaruru | 12.1 | Winter | 17.0 | N-1 switched | No constraint | 4.9 | Winter | 4.5 | N-1 switched | Winter | 4.0 | 4.0 | N-1 switched | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 51 | Tahuna | 5.5 | Summer | 5.5 | N-1 switched | No constraint | 0 | Summer | 4.2 | N-1 switched | Summer | 3.9 | 3.9 | N-1 switched | Capacity | 1 | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | Transformers to be replaced by FY28 |
| 52 | Tatua | 6.1 | Summer | 7.2 | N-1 switched | No constraint | 1.1 | Summer | 9.9 | N-1 switched | Summer | 9.9 | 9.9 | N-1 switched | Capacity | 2 | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | Customer dedicated substation. Customer accepts their security level with a limited 11 kV back feed available. |
| 53 | Tirau | 9.1 | Spring | 8.8 | N-1 switched | Capacity | -0.3 | Spring | -0.9 | N-1 switched | Spring | -1.1 | -1.1 | N-1 switched | No constraint | None | Zone substation transformer | Undecided | Planning stage | > 3 years | 11kV backfeed capacity adequate for now. Smaller power transformer to be upgraded in future |
| 54 | Tower Road | 8.6 | Winter | 17.0 | N-1 switched | No constraint | 8.4 | Winter | 7.9 | N-1 switched | Winter | 7.5 | 7.5 | N-1 switched | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 55 | Waharoa | 8.2 | Summer | 8.3 | N-1 switched | No constraint | 0.1 | Summer | -0.2 | N-1 switched | Summer | -0.4 | -0.4 | N-1 switched | Capacity | 3 | Zone substation transformer | Undecided | Planning stage | > 3 years | 11 kV back feeds are sufficient to meet security rating for the foreseeable future. |
| 56 | Waitoa | 12.7 | Autumn | 16.5 | N-1 switched | No constraint | 3.8 | Autumn | -1.6 | N-1 switched | Autumn | -1.6 | -1.6 | N-1 switched | Capacity | 1 | Zone substation transformer | Demand response | Planning stage | Not applicable | Customer agreed security level |
| 57 | Walton | 5.2 | Spring | 7.5 | N-1 switched | No constraint | 2.3 | Spring | 2.1 | N-1 switched | Spring | 1.9 | 1.9 | N-1 switched | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | 11kV backfeed capacity adequate |
| 58 | Baird Road | 10.2 | Winter | 9.8 | N-1 | Capacity | -0.4 | Winter | -0.8 | N-1 | Winter | 6.0 | 6.0 | N-1 | No constraint | None | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | Proposal to upgrade KIN GXP 33kV switchboard and cabling project |
| 59 | Maraetai Road | 9.6 | Winter | 9.2 | N-1 | Capacity | -0.4 | Winter | -2.1 | N-1 | Winter | 5.5 | 7.0 | N-1 | No constraint | None | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | New Tokoroa South substation to offload 1.3MW from Maraetai Road |
| 60 | Midway / Lakeside | 2.0 | Winter | 3.0 | N | No constraint | 1 | Winter | 1 | N | Winter | 1.0 | 1.0 | N | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | Dedicated supply for customer |
| 61 | Bell Block | 15.1 | Winter | 21.1 | N-1 | No constraint | 6 | Winter | 1.7 | N-1 | Winter | 0.7 | 4.1 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 62 | Brooklands | 18.0 | Winter | 24.0 | N-1 | No constraint | 6 | Winter | 2.9 | N-1 | Winter | 2.3 | 4.8 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 63 | Cardiff | 1.7 | Summer | 2.4 | N | Security | 0.7 | Summer | 0.7 | N | Summer | 0.6 | 0.6 | N | No constraint | None | Zone substation transformer | Network upgrade | No active planning | > 3 years | Substation presently has single transformer. However, there is adequate 11kV backup supply from neighbouring substations. |
| 64 | City | 15.1 | Winter | 20.2 | N-1 | No constraint | 5.1 | Winter | 3.8 | N-1 | Winter | 3.2 | 4.1 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 65 | Cloton Road | 11.0 | Winter | 11.4 | N-1 | No constraint | 0.4 | Winter | -0.5 | N-1 switched | Winter | -0.9 | -0.4 | N-1 switched | Capacity | 2 | Zone substation transformer | Network upgrade | Planning stage | > 3 years | Load has exceeded N-1 transformers capacity. However, there is adequate 11kV backup supply from neighbouring substations |
| 66 | Douglas | 1.6 | Summer | 5.0 | N | Security | 3.4 | Summer | 3.4 | N | Summer | 3.3 | 3.3 | N | No constraint | None | Zone substation transformer | Network upgrade | No active planning | > 3 years | Substation has single transformer & single 33kV line. However, there is adequate 11kV backup supply from neighbouring substations. |
| 67 | Eltham | 9.6 | Summer | 17.0 | N-1 | No constraint | 7.4 | Summer | 7.1 | N-1 | Summer | 6.8 | 6.8 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 68 | Inglewood | 5.7 | Winter | 5.0 | N-1 switched | Capacity | -0.7 | Winter | 4 | N-1 switched | Winter | 3.7 | 3.7 | N-1 switched | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | Alternate 33kV circuit can be remotely switched on within 20 seconds |
| 69 | Kaponga | 3.6 | Summer | 2.4 | N-1 switched | Capacity | -1.2 | Summer | -1.4 | N-1 switched | Summer | 6.1 | 6.1 | N-1 switched | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 70 | | Katere | 16.4 | Winter | 24.0 | N-1 | No constraint | 7.6 | Winter | 6.6 | N-1 | Winter | 5.6 | 5.6 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 71 | | McKee | 0.8 | Summer | 4.8 | N | Security | 4 | Summer | 4 | N | Summer | 4.0 | 4.0 | N | No constraint | None | Zone substation transformer | Network upgrade | No active planning | > 3 years | Substation has single transformer. However, there is adequate 11kV backup supply from neighbouring substation. |
| 72 | | Motukawa | 1.5 | Summer | 5.1 | N | Security | 3.6 | Summer | 3.5 | N | Summer | 3.4 | 3.4 | N | No constraint | None | Zone substation transformer | Network upgrade | No active planning | > 3 years | Substation has single transformer & single 33kV line. However, there is adequate 11kV backup supply from neighbouring substations. |
| 73 | | Moturoa | 18.3 | Winter | 24.0 | N-1 | No constraint | 5.7 | Winter | 4.6 | N-1 | Winter | 2.5 | 3.8 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 74 | | Oakura | 4.0 | Winter | 10.0 | N | Security | 6 | Winter | 5.7 | N | Winter | 5.4 | 5.4 | N | No constraint | 10+ | Zone substation transformer | Network upgrade | Planning stage | > 3 years | Substation has single 10MVA tx & single 33kV line. A 0.8MW BESS is being installed in 2025. |
| 75 | | Waihapa | 0.5 | Summer | 4.8 | N | Security | 4.3 | Summer | 4.3 | N | Summer | 4.3 | 4.3 | N | No constraint | None | Zone substation transformer | Network upgrade | No active planning | > 3 years | Customer agreed security |
| 76 | | Waitara East | 5.1 | Winter | 7.9 | N-1 | No constraint | 2.8 | Winter | 2.5 | N-1 | Winter | 2.1 | 2.1 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 77 | | Waitara West | 6.5 | Winter | 12.5 | N-1 | No constraint | 6 | Winter | 5.8 | N-1 | Winter | 5.7 | 5.7 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 78 | | Cambria | 15.2 | Winter | 17.0 | N-1 | No constraint | 1.8 | Winter | 1.3 | N-1 | Winter | 0.9 | 0.9 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 79 | | Kapuni | 5.8 | Summer | 8.2 | N-1 switched | No constraint | 2.4 | Summer | 2.3 | N-1 switched | Summer | 2.2 | 2.2 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 80 | | Livingstone | 2.9 | Summer | 2.5 | N-1 switched | Capacity | -0.4 | Summer | 2.1 | N-1 switched | Summer | 2.0 | 2.0 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | In 2025, Livingstone transformers will be upgraded to 2X 5MVA |
| 81 | | Manaia | 5.5 | Summer | 7.8 | N-1 switched | Security | 2.3 | Summer | 2.1 | N-1 switched | Summer | 2.0 | 2.0 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 82 | | Mokoia | 3.5 | Summer | 10.0 | N-1 switched | Security | 6.5 | Summer | 6.4 | N-1 switched | Summer | 6.2 | 6.2 | N-1 switched | No constraint | None | Zone substation transformer | Not required | Not applicable | Not applicable | Increase 11kV backfeed capacity is likely or flex solution |
| 83 | | Ngariki | 3.0 | Summer | 6.3 | N-1 switched | Security | 3.2 | Summer | 3.1 | N-1 switched | Summer | 3.0 | 3.0 | N | Security | None | Zone substation transformer | Not applicable | No active planning | Not applicable | |
| 84 | | Pungarehu | 3.1 | Summer | 4.0 | N-1 switched | No constraint | 0.9 | Summer | 0.7 | N-1 switched | Summer | 0.5 | 0.5 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | |
| 85 | | Tasman | 6.4 | Summer | 5.0 | N-1 switched | Capacity | -1.4 | Summer | -1.6 | N-1 switched | Summer | 3.2 | 3.2 | N-1 | No constraint | None | Not applicable | Not applicable | Not applicable | Not applicable | Proposed transformer upgrade |
| 86 | | Beach Road | 10.4 | Summer | 7.5 | N-1 switched | Capacity | -3.1 | Summer | -1.8 | N-1 switched | Summer | -2.3 | 4.0 | N-1 switched | No constraint | None | Transpower | Network upgrade | Implementation stage | Not applicable | Brunswick ODID project will remove the primary constraint in 2029. There is adequate 11kV backup supply from neighbouring substations. |
| 87 | | Blink Bonnie | 2.6 | Winter | 6.0 | N-1 switched | Security | 3.3 | Winter | 3.2 | N-1 switched | Winter | 3.1 | 3.1 | N-1 switched | No constraint | None | Subtransmission circuit | Not required | No active planning | Not applicable | There is adequate 11kV backup supply from neighbouring substations. |
| 88 | | Castlecliff | 9.4 | Winter | 8.5 | N-1 switched | Capacity | -0.9 | Winter | -7.5 | N-1 switched | Winter | -7.9 | -1.6 | N-1 switched | No constraint | None | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | 33kV overhead conductor upgrade in LTP FY28/30. |
| 89 | | Hatricks Wharf | 12.6 | Winter | 15.8 | N-1 switched | Security | 3.2 | Winter | 2.8 | N-1 switched | Winter | 2.5 | 2.5 | N-1 switched | No constraint | None | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | There is a 11kV bus tie between Hatricks Wharf and Taupo Quay, but capacity limited by Taupo Quay transformer capacity. Proposed Taupo Quay transformer upgrade |
| 90 | | Kai Iwi | 2.2 | Summer | 4.8 | N-1 switched | Security | 2.6 | Summer | 2.6 | N-1 switched | Summer | 2.5 | 2.5 | N-1 switched | No constraint | None | Subtransmission circuit | Undecided | No active planning | Not applicable | There is adequate 11kV backup supply from neighbouring substations. |
| 91 | | Peat Street | 16.8 | Winter | 9.4 | N-1 | Capacity | -7.4 | Winter | -8.2 | N-1 | Winter | -3.4 | -0.4 | N-1 | No constraint | None | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | 33kV substransmission circuit upgrade in LTP FY26-27 There is adequate 11kV backup supply from neighbouring substations. |
| 92 | | Roberts Avenue | 4.9 | Winter | 8.5 | N-1 switched | Security | 3.6 | Winter | 3.5 | N-1 switched | Winter | 3.4 | 3.4 | N-1 switched | No constraint | None | Zone substation transformer | Network upgrade | Planning stage | Not applicable | 11kV backfeed capacity increase between Roberts Ave and Wanganui East |
| 93 | | Taupo Quay | 4.5 | Winter | 12.5 | N-1 switched | Security | 8 | Winter | 18.5 | N-1 switched | Winter | 18.4 | 19.4 | N-1 switched | No constraint | None | Zone substation transformer | Not required | No active planning | Not applicable | There is adequate 11kV backup supply from Hatricks Wharf substations. |
| 94 | | Wanganui East | 6.9 | Winter | 11.0 | N-1 switched | Security | 4.7 | Winter | 4.6 | N-1 switched | Winter | 4.5 | 4.5 | N-1 switched | No constraint | None | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | 11kV bus tie between Roberts Ave and Wanganui East proposed |
| 95 | | Waverley | 4.7 | Summer | 10.0 | N | Security | 5.3 | Summer | 4.3 | N | Summer | 4.3 | 5.3 | N | No constraint | None | Transpower | Not required | Not applicable | Not applicable | Increase 11kV backfeed capacity to Waverley |
| 96 | | Arahina | 7.9 | Winter | 9.6 | N-1 switched | Security | 1.7 | Winter | -0.6 | N-1 switched | Winter | -0.8 | 1.4 | N-1 switched | Capacity | 4 | Zone substation transformer | Not required | Not applicable | Not applicable | |
| 97 | | Bulls | 5.4 | Summer | 9.6 | N-1 switched | Security | 4.2 | Summer | 1.9 | N-1 switched | Summer | 0.9 | 0.9 | N-1 switched | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 98 | | Ohakune | 2.2 | Winter | 20.0 | N | No constraint | 17.8 | Winter | 17.7 | N | Winter | 17.7 | 17.7 | N | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 99 | | Pukepapa | 4.7 | Summer | 10.0 | N-1 switched | Security | 5.3 | Summer | 5 | N-1 switched | Summer | -5.3 | 4.7 | N-1 switched | Capacity | 8 | Zone substation transformer | Network upgrade | No active planning | Not applicable | Customer driven load increase |
| 100 | | Rata | 2.1 | Summer | 7.5 | N-1 switched | Security | 5.4 | Summer | 4.9 | N-1 switched | Summer | 4.9 | 5.3 | N-1 switched | No constraint | None | Subtransmission circuit | Undecided | No active planning | Not applicable | Evaluating network upgrade and flex options |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 101 | Taihape | 4.5 | Winter | 10.0 | N-1 switched | Security | 5.5 | Winter | 5.4 | N-1 switched | Winter | 5.3 | 5.3 | N-1 switched | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 102 | Waiouru | 2.8 | Winter | 7.2 | N-1 switched | Security | 4.4 | Winter | 4.4 | N-1 switched | Winter | 4.4 | 4.4 | N-1 switched | No constraint | None | Subtransmission circuit | Undecided | No active planning | Not applicable | Customer has backup generators. Improve 11kV backfeed capacity to Waiouru |
| 103 | Feilding | 25.6 | Winter | 24.0 | N-1 | Capacity | -1.6 | Winter | -2.8 | N-1 | Winter | -4.0 | -4.0 | N-1 | No constraint | None | Zone substation transformer | Network upgrade | Planning stage | Not applicable | Offload to proposed Feilding 2nd substation |
| 104 | Ferguson Street | 10.9 | Winter | 24.0 | N-1 | No constraint | 13.1 | Winter | 12.9 | N-1 | Winter | 12.7 | 12.7 | N-1 | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 105 | Kairanga | 19.6 | Spring | 17.0 | N-1 | Capacity | -2.6 | Spring | -4.8 | N-1 | Spring | -5.5 | -4.0 | N-1 | No constraint | None | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | Kairanga Transformer upgrade |
| 106 | Keith Street | 19.6 | Winter | 23.0 | N-1 | No constraint | 3.4 | Winter | 2.8 | N-1 | Winter | 2.1 | 2.1 | N-1 | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 107 | Kelvin Grove | 19.7 | Winter | 17.0 | N-1 | Capacity | -2.7 | Winter | -5.4 | N-1 | Winter | -6.5 | -5.0 | N-1 | No constraint | None | Zone substation transformer | Divert load to alternative | Planning stage | Not applicable | Offload to proposed Ashhurst substation |
| 108 | Kimbolton | 3.3 | Spring | 6.3 | N | Security | 2.9 | Spring | 2.8 | N | Spring | 2.8 | 2.8 | N | No constraint | None | Zone substation transformer | Undecided | No active planning | > 3 years | Single 33kV circuit & Single transformer. Remote sub. 11kV backfeed in place as a temporary solution. |
| 109 | Main Street | 19.8 | Winter | 20.0 | N-1 | No constraint | 0.2 | Winter | -5.4 | N-1 | Winter | -5.9 | -0.7 | N-1 | Capacity | 2 | Zone substation transformer | Divert load to alternative | Solution confirmed | Not applicable | Offload to proposed Hospital substation. |
| 110 | Milson | 16.9 | Winter | 17.0 | N-1 | No constraint | 0.1 | Winter | -5.2 | N-1 | Winter | -5.7 | -1.0 | N-1 | Capacity | 1 | Zone substation transformer | Divert load to alternative | Solution confirmed | Not applicable | Offload to proposed Hospital substation. |
| 111 | Ohakea | 2.4 | Winter | 10.0 | N-1 switched | No constraint | 7.6 | Winter | 5.6 | N-1 switched | Winter | 5.6 | 5.6 | N-1 switched | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 112 | Pascal Street | 16.2 | Winter | 20.0 | N-1 | No constraint | 3.8 | Winter | 3.5 | N-1 | Winter | 3.1 | 3.1 | N-1 | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 113 | Sanson | 9.5 | Summer | 7.5 | N-1 switched | Capacity | -2 | Summer | -2.6 | N-1 switched | Summer | -3.3 | -3.3 | N-1 switched | No constraint | None | Zone substation transformer | Divert load to alternative | Not applicable | Not applicable | Transfer military load to the new Ohakea substation. |
| 114 | Turitea | 15.0 | Winter | 17.0 | N-1 switched | No constraint | 2 | Winter | -2.7 | N-1 | Winter | -3.9 | -0.4 | N-1 | Capacity | 4 | Zone substation transformer | Network upgrade | Implementation stage | Not applicable | Switched 33kV security - second 33kV circuit and transformer upgrade post 2025. |
| 115 | Alfredton | 0.3 | Winter | 1.5 | N | No constraint | 1.2 | Winter | 1.2 | N | Winter | 1.2 | 1.2 | N | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 116 | Mangamutu | 15.5 | Winter | 13.1 | N-1 | Capacity | -2.4 | Winter | -2.8 | N-1 | Winter | -3.1 | -3.1 | N-1 | No constraint | None | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | |
| 117 | Parkville | 2.1 | Winter | 5.0 | N-1 switched | Security | 2.9 | Winter | 2.9 | N-1 switched | Winter | 2.9 | 2.9 | N-1 switched | No constraint | None | Zone substation transformer | Not required | Not applicable | Not applicable | There is limited 11kV backup supply from neighbouring substations. |
| 118 | Pongaroa | 0.8 | Winter | 5.0 | N | No constraint | 4.2 | Winter | 4.2 | N | Winter | 4.2 | 4.2 | N | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 119 | Akura | 13.7 | Winter | 8.5 | N-1 | Capacity | -5.2 | Winter | -7.7 | N-1 | Winter | 0.0 | 2.0 | N-1 | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 120 | Awatoitoi | 1.2 | Summer | 3.0 | N | No constraint | 1.8 | Summer | 1.8 | N | Summer | 1.7 | 1.7 | N | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 121 | Chapel | 17.1 | Winter | 13.8 | N-1 | Capacity | -3.3 | Winter | -3.9 | N-1 | Winter | -4.5 | -4.5 | N-1 | No constraint | None | Subtransmission circuit | Network upgrade | Planning stage | Not applicable | Chapel-Norfolk 33kV Subtransmission Upgrade |
| 122 | Clareville | 12.7 | Winter | 8.5 | N-1 switched | Capacity | -4.2 | Winter | 2.4 | N-1 switched | Winter | 0.5 | 1.5 | N-1 switched | No constraint | None | Zone substation transformer | Network upgrade | Solution confirmed | Not applicable | Clareville Transformers upgrade proposed |
| 123 | Featherston | 5.7 | Summer | 5.5 | N-1 switched | Capacity | -0.2 | Summer | -0.5 | N-1 switched | Summer | -0.9 | -0.9 | N-1 switched | No constraint | None | Zone substation transformer | Network upgrade | Planning stage | Not applicable | Transformer upgrade proposed ~FY29 There is limitied 11kV backup supply from neighbouring substations. |
| 124 | Gladstone | 1.2 | Summer | 1.5 | N | No constraint | 0.3 | Summer | 0.3 | N | Summer | 0.2 | 0.2 | N | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 125 | Hau Nui | 0.3 | Winter | 5.5 | N-1 switched | Security | 5.2 | Winter | 5.2 | N-1 switched | Winter | 5.2 | 5.2 | N-1 switched | No constraint | None | Subtransmission circuit | Not required | Not applicable | Not applicable | Customer agreed security |
| 126 | Kempton | 6.6 | Winter | 5.5 | N-1 switched | Capacity | -1.1 | Winter | -1.5 | N-1 switched | Winter | -1.9 | -1.9 | N-1 switched | No constraint | None | Zone substation transformer | Network upgrade | Planning stage | Not applicable | 2nd Transformer proposed ~FY34 |
| 127 | Martinborough | 6.4 | Winter | 5.5 | N-1 switched | Capacity | -0.9 | Winter | -1.3 | N-1 switched | Winter | -1.7 | -1.7 | N-1 switched | No constraint | None | Zone substation transformer | Network upgrade | Planning stage | Not applicable | 2nd Transformer proposed FY30-32 |
| 128 | Norfolk | 6.8 | Summer | 6.8 | N-1 switched | No constraint | 0 | Summer | -6.6 | N-1 switched | Summer | -8.2 | -2.3 | N-1 switched | Capacity | 2 | Subtransmission circuit | Undecided | No active planning | Not applicable | Customer driven load increase |
| 129 | Te Ore Ore | 7.9 | Winter | 7.9 | N-1 switched | Security | 0 | Winter | -0.3 | N-1 switched | Winter | 1.5 | 1.5 | N-1 switched | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 130 | Tinui | 0.9 | Summer | 1.5 | N | No constraint | 0.6 | Summer | 0.5 | N | Summer | 0.5 | 0.5 | N | No constraint | None | Not applicable | Not required | Not applicable | Not applicable | |
| 131 | Tuhitarata | 3.4 | Summer | 5.0 | N-1 switched | Security | 1.6 | Summer | 1.4 | N-1 switched | Summer | 1.2 | 1.2 | N-1 switched | No constraint | None | Zone substation transformer | Network upgrade | Planning stage | Not applicable | 2nd Transformer proposed There is limitied 11kV backup supply from neighbouring substations. |

132 [1] *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

## 6.5 Schedule 12c

| | |
|---|---|
| Company Name | Powerco |
| AMP Planning Period | 1 April 2025 – 31 March 2035 |

### SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

| *sch ref* | | | | | | | |
|---|---|---|---|---|---|---|---|
| 7 | **12c(i): Consumer Connections** | | | | | | |
| 8 | *Number of ICPs connected during year by consumer type* | | | Number of connections | | | |
| 9 | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| 10 | | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 |
| 11 | *Consumer types defined by EDB** | | | | | | |
| 12 | Small | 4,855 | 4,855 | 4,855 | 4,855 | 4,855 | 4,855 |
| 13 | Commercial | 62 | 62 | 62 | 62 | 62 | 62 |
| 14 | Industrial | 19 | 19 | 19 | 19 | 19 | 19 |
| 15 | | | | | | | |
| 16 | | | | | | | |
| 17 | **Connections total** | 4,936 | 4,936 | 4,936 | 4,936 | 4,936 | 4,936 |
| 18 | **include additional rows if needed* | | | | | | |
| 19 | | | | | | | |
| 20 | | | | | | | |
| 21 | | | | | | | |
| 22 | **Distributed generation** | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| 23 | Number of connections made in year | 1,920 | 2,090 | 2,250 | 2,420 | 2,590 | 2,760 |
| 24 | Capacity of distributed generation installed in year (MVA) | 45 | 75 | 47 | 48 | 49 | 51 |
| 25 | **12c(ii) System Demand** | | | | | | |
| 26 | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
| 27 | **Maximum coincident system demand (MW)** | 31 Mar 25 | 31 Mar 26 | 31 Mar 27 | 31 Mar 28 | 31 Mar 29 | 31 Mar 30 |
| 28 | GXP demand | 856 | 868 | 883 | 900 | 922 | 947 |
| 29 | *plus* Distributed generation output at HV and above | 127 | 131 | 135 | 139 | 142 | 146 |
| 30 | **Maximum coincident system demand** | 983 | 999 | 1,018 | 1,039 | 1,064 | 1,093 |
| 31 | *less* Net transfers to (from) other EDBs at HV and above | - | - | - | - | - | - |
| 32 | **Demand on system for supply to consumers' connection points** | 983 | 999 | 1,018 | 1,039 | 1,064 | 1,093 |
| 33 | **Electricity volumes carried (GWh)** | | | | | | |
| 34 | Electricity supplied from GXPs | 4,800 | 4,878 | 4,967 | 5,071 | 5,195 | 5,338 |
| 35 | *less* Electricity exports to GXPs | 124 | 126 | 128 | 131 | 134 | 137 |
| 36 | *plus* Electricity supplied from distributed generation | 731 | 742 | 756 | 772 | 791 | 812 |
| 37 | *less* Net electricity supplied to (from) other EDBs | | | | | | |
| 38 | **Electricity entering system for supply to ICPs** | 5,407 | 5,495 | 5,595 | 5,713 | 5,851 | 6,013 |
| 39 | *less* Total energy delivered to ICPs | 5,126 | 5,209 | 5,304 | 5,416 | 5,547 | 5,700 |
| 40 | **Losses** | 281 | 286 | 291 | 297 | 304 | 313 |
| 41 | | | | | | | |
| 42 | **Load factor** | 63% | 63% | 63% | 63% | 63% | 63% |
| 43 | **Loss ratio** | 5.2% | 5.2% | 5.2% | 5.2% | 5.2% | 5.2% |

## 6.6 Schedule 12d

| | |
|---|---|
| *Company Name* | **Powerco** |
| *AMP Planning Period* | **1 April 2025 – 31 March 2035** |
| *Network / Sub-network Name* | **Powerco - combined** |

### SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

| sch ref | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
|---|---|---|---|---|---|---|---|
| 8 | | | | | | | |
| 9 | | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** | **31 Mar 28** | **31 Mar 29** | **31 Mar 30** |
| 10 | **SAIDI** | | | | | | |
| 11 | Class B (planned interruptions on the network) | 111.1 | 130.3 | 136.8 | 162.5 | 162.4 | 168.3 |
| 12 | Class C (unplanned interruptions on the network) | 165.2 | 159.5 | 154.7 | 150.9 | 148.0 | 145.9 |
| 13 | **SAIFI** | | | | | | |
| 14 | Class B (planned interruptions on the network) | 0.70 | 0.61 | 0.64 | 0.76 | 0.76 | 0.76 |
| 15 | Class C (unplanned interruptions on the network) | 1.48 | 1.44 | 1.42 | 1.40 | 1.39 | 1.39 |

| | |
|---|---|
| *Company Name* | **Powerco** |
| *AMP Planning Period* | **1 April 2025 – 31 March 2035** |
| *Network / Sub-network Name* | **Powerco - Eastern Region** |

### SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and

| sch ref | | *Current Year CY* | *CY+1* | *CY+2* | *CY+3* | *CY+4* | *CY+5* |
|---|---|---|---|---|---|---|---|
| 8 | | | | | | | |
| 9 | | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** | **31 Mar 28** | **31 Mar 29** | **31 Mar 30** |
| 10 | **SAIDI** | | | | | | |
| 11 | Class B (planned interruptions on the network) | 111.1 | 130.3 | 136.8 | 162.5 | 162.4 | 168.3 |
| 12 | Class C (unplanned interruptions on the network) | 165.2 | 159.5 | 154.7 | 150.9 | 148.0 | 145.9 |
| 13 | **SAIFI** | | | | | | |
| 14 | Class B (planned interruptions on the network) | 0.70 | 0.61 | 0.64 | 0.76 | 0.76 | 0.76 |
| 15 | Class C (unplanned interruptions on the network) | 1.48 | 1.44 | 1.42 | 1.40 | 1.39 | 1.39 |

| | |
|---|---|
| *Company Name* | **Powerco** |
| *AMP Planning Period* | **1 April 2025 – 31 March 2035** |
| *Network / Sub-network Name* | **Powerco - Western Region** |

## SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and

*sch ref*

| | | Current Year CY | CY+1 | CY+2 | CY+3 | CY+4 | CY+5 |
|---|---|---|---|---|---|---|---|
| 9 | | **31 Mar 25** | **31 Mar 26** | **31 Mar 27** | **31 Mar 28** | **31 Mar 29** | **31 Mar 30** |
| 10 | **SAIDI** | | | | | | |
| 11 | Class B (planned interruptions on the network) | 111.1 | 130.3 | 136.8 | 162.5 | 162.4 | 168.3 |
| 12 | Class C (unplanned interruptions on the network) | 165.2 | 159.5 | 154.7 | 150.9 | 148.0 | 145.9 |
| 13 | **SAIFI** | | | | | | |
| 14 | Class B (planned interruptions on the network) | 0.70 | 0.61 | 0.64 | 0.76 | 0.76 | 0.76 |
| 15 | Class C (unplanned interruptions on the network) | 1.48 | 1.44 | 1.42 | 1.40 | 1.39 | 1.39 |

## 6.7 Schedule 14a

| | |
|---|---|
| Company Name | **Powerco** |
| For Year Ended | **31 March 2025** |

**Schedule 14a mandatory explanatory notes on forecast information**

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

   This Schedule is mandatory – EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

*Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)*

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

**Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts**

Our approach involves applying different cost escalators to our constant price expenditure forecasts. Our escalators have been developed using:

- Independent forecast of input price indices that reflect the various costs that we face including material and labour components.
- Weighting factors for asset types, such as transformers, that are made up of a range of inputs.

We have used the above inputs to develop tailored cost escalators for our cost categories. These are then applied to our constant price capital expenditure forecasts to produce the forecasts in nominal dollars for Schedule 11a.

*Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)*

3. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

**Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts**

Our approach involves applying different cost escalators to our constant price expenditure forecasts. Our escalators have been developed using:

- Independent forecast of input price indices that reflect the various costs that we face including material and labour components.
- Weighting factors for Opex cost categories.

We have used the above inputs to develop tailored cost escalators for our cost categories. These are then applied to our constant price operating expenditure forecasts to produce the forecasts in nominal dollars for Schedule 11b.

# Directors' Certificate – 2025 Electricity AMP

## CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

Pursuant to clause 2.9.1 of Section 2.9

We, John Loughlin and Michael Bessell being directors of Powerco Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Powerco Limited prepared for the purposes of clauses 2.6.1, 2.6.6, and 2.7.2 of the Electricity Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Powerco's corporate vision and strategy and are documented in retained records.

Director

Director

26 March 2025

Date

26 March 2025

Date