TRANSPOWER

2026 Integrated Transmission Plan Narrative

September 2026

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1 Introduction

The Integrated Transmission Plan (ITP) comprises a suite of documents that describe our current service performance and our plans to invest in, maintain and enhance the national grid over the next 10 years. It consists of:

- The *2026 ITP Narrative* provides an overview of our strategy and plans, services and performance, forecast revenue, and expenditure forecasts.
- The *2026 Asset Management Plan* sets out our management approach, processes and investment requirements by asset class, covering our grid, ICT and business support assets.
- The *2026 Transmission Planning Report* identifies our grid security and capacity issues that could arise over the coming 15 years due to changes in demand and generation. It includes details on committed and potential grid enhancements.
- The *2026 Service Measures Report* summarises the performance over the preceding year of our regulated transmission business including service performance and asset health measures, quality standards, targets and output incentives.
- The *2026 ITP Schedules* provide detailed forecasts of our expenditure and service measures in Excel format.

This year's ITP covers the second year of Regulatory Control Period (RCP) 4, the five-year planning and investment period spanning 1 April 2025 to 31 March 2030.[1]

We prepared the Narrative to give our stakeholders and customers an overview of our transmission business, both now and over the coming 10 years. Unless otherwise stated, we present all expenditure values in constant 2025/26 dollars (i.e., excluding the impact of CPI).

[1] Note, 1 April to 31 March represents our pricing year - the information presented in this report, and assessed by the Commission, is on our financial year basis of 1 July to 30 June.

2 About us

2.1 Our role in the electricity industry

A secure, reliable and affordable electricity supply underpins New Zealand's economic productivity, community resilience and quality of life. As electrification gathers pace, Transpower's role at the centre of Aotearoa New Zealand's electricity system is becoming increasingly important. Our purpose is to deliver and operate a safe, reliable and cost-effective transmission grid that supports New Zealanders' needs today while preparing for future growth, increasing electrification and the challenges posed by a changing climate.

There are two key roles to our business:

- **Grid owner:** we own and operate the national grid, the high-voltage transmission network that transports electricity from where it is generated to where it is used across New Zealand.
- **System operator:** we are responsible for managing the real-time power system and operating the wholesale electricity market.

Both roles are essential to maintaining a secure and efficient electricity system. This ITP focuses on our role as grid owner and excludes services delivered by, and costs funded through, our System Operator Service Provider Agreement with the Electricity Authority (Authority).

We are one part of a wider electricity supply chain and work closely with generators, distributors, retailers, customers, regulators, iwi, communities and government agencies to support a secure, reliable and affordable transition to a more electrified energy system.

A secure, reliable and affordable electricity supply underpins New Zealand's economic productivity, community resilience and quality of life. As electrification gathers pace, Transpower's role at the centre of New Zealand's electricity system is becoming increasingly important. During RCP4 and beyond, we will help enable economic growth by ensuring the transmission grid and wider electricity system are ready to support increasing electricity demand, connect new renewable generation and meet the future needs of New Zealanders at least cost. Through our investments, planning activities and customer-initiated work, we aim to support a secure electricity supply, timely customer connections and an affordable transition to a highly electrified economy.

Where we fit in

We own and operate New Zealand's national electricity transmission network and run the electricity market system.

1 **Generation**
Generation companies generate power from wind, thermal, hydro and geothermal. They sell the power they generate on the electricity market. Emerging distributed generation includes electric vehicles, batteries and solar photovoltaic.

2 **New Grid Connects**
As New Zealand moves to electrify its economy, Transpower is receiving more requests to connect to the grid. This includes new generation such as solar and wind, as well as new industrial demand.

3 **Transmission**
Transpower transports high voltage electricity from where it is generated to distribution companies and some large directly connected customers.

4 **Industrial Customers**
A few major industrial companies receive their power directly from Transpower.

5 **Substations**
Substations reduce the voltage at the point where electricity is delivered to distribution companies – our customers.

6 **System Operator**
Operates the wholesale electricity market and manages system security.

7 **Distribution**
The lower voltage electricity is transported by distribution companies to homes and businesses throughout New Zealand.

8 **Commercial**
Some commercial customers that consume large quantities of energy purchase power directly from the wholesale electricity market.

9 **Retail**
Retailers buy power on the electricity market, package it together with other costs of delivering power (transmission and distribution), and on-sell it to customers.

10 **Domestic and Business Users**
Domestic and business users receive their electricity directly from retail companies, which deliver power to homes, businesses and commercial operations using distribution companies' lines.

There are many stakeholders we interact with in our roles as grid owner and system operator, including the Commerce Commission (Commission) and Authority. We discuss our stakeholders further in this section.

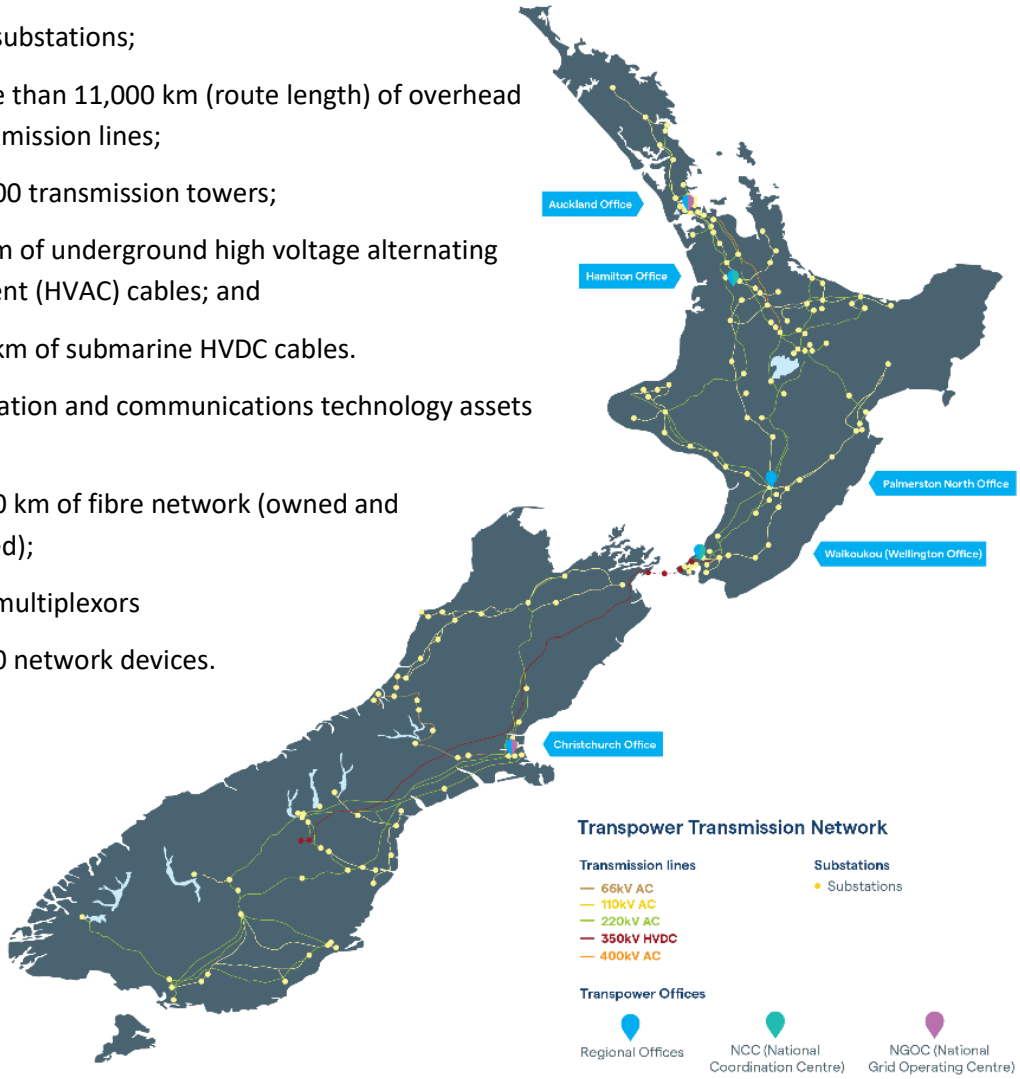
2.2 Our Grid

The grid extends from Kaikohe in the North Island to Tiwai Point in the South Island. As grid owner, we manage over $5.5 billion of transmission assets, including $700 million of high-voltage direct current (HVDC) assets and $200 million of telecommunications assets. Across the North and South Islands our transmission network covers:

- 175 substations;
- More than 11,000 km (route length) of overhead transmission lines;
- 25,000 transmission towers;
- 89 km of underground high voltage alternating current (HVAC) cables; and
- 114 km of submarine HVDC cables.

Our information and communications technology assets include:

- 7,500 km of fibre network (owned and leased);
- 560 multiplexors
- 2,700 network devices.



2.3 Our strategy

Transpower plays a key role in enabling Aotearoa New Zealand's long-term economic growth and decarbonisation. As the national grid owner, we must ensure the transmission system remains reliable, resilient and affordable while supporting significant increases in renewable generation and electricity demand.

Our Te Kanapu Future Grid initiative is developing a long-term Grid Blueprint for Aotearoa New Zealand. Through this work we are considering the transmission system required to support New Zealand's future energy needs and economic aspirations, working backwards from a 2050 vision to identify the investments, capabilities and system changes needed over time. This whole-of-system approach supports coordinated, least-cost development of New Zealand's electricity infrastructure while maintaining reliability and resilience for customers and communities.

Electrification is not only a decarbonisation opportunity but also an economic opportunity for Aotearoa New Zealand. Through Te Kanapu and our other planning activities, we are considering how the transmission system can support economic growth, regional development, energy affordability and resilience while enabling the transition to a more electrified economy and increased energy independence. Achieving this outcome will require coordination across the electricity sector and collaboration with customers, communities and policymakers.

Our strategy is discussed in the following documents, focussing on emerging and innovative technologies and supporting increased electrification. We intend to further embed these strategies while improving our performance over the next regulatory period.

In 2023, we refreshed *Transmission Tomorrow*. *Transmission tomorrow* identifies the external and internal factors influencing our operations. Our strategic priorities are as follows:

Table 1: Strategic priorities

Strategic Priority	Description
Enhance our social licence to operate	Electrifying the economy will require infrastructure investment on a scale not seen for generations. To deliver this transition, we need support from our shareholder, government, regulators, communities, iwi and other stakeholders. The electricity industry must also work together to build new transmission assets when needed and manage the cost for consumers.
Deliver services that meet our customers' needs	Transpower has specialist expertise to design, build, maintain and operate the grid and electricity market. We must use this expertise efficiently to meet customer needs. This includes prioritising connections, major capex projects, RCP work and system operator services consistently.
Facilitate delivery of an optimised transition path for Aotearoa New Zealand's energy system	Transpower plays a key role in enabling electrification. However, current transmission investment settings may not deliver the least-cost transition for New Zealand. We will support and advocate for regulatory settings that enable an efficient, reliable and stable electricity system. We will also develop innovative options and provide advice on the best transition path.
Accelerate electrification through our asset investments	Grid-supplied electricity will be vital to electrifying New Zealand's economy. Through the Te Kanapu programme, we will progress later phases of NZGP, including larger projects likely to be needed after 2035. We will also plan regional investment and resilience initiatives with electricity distribution businesses. Robust challenge, consultation and innovation will help us ensure these investments are prudent and efficient.

Advance our organisational effectiveness	All New Zealanders ultimately bear our regulated costs. We must build the capability and capacity needed for the country's energy future while keeping our organisation effective. We are strengthening asset management, modernising information systems and building leadership capability. We will continue to improve processes, business models and organisational structures where this offers better value.

These strategic priorities will help Transpower manage costs efficiently, ensure competitive grid access and use, and meet New Zealand's future electricity needs.

2.4 Our customers and stakeholders

We coordinate electricity delivery from generators to distribution companies and retailers, partnering with technology providers to power New Zealand homes and businesses. Engaging with our stakeholders helps us to provide the reliable, cost-effective, and safe services our customers want. Our customers and main external stakeholders are:

- **Customers:** Our customers are companies that connect directly to the grid, including distribution companies, electricity generators and major industrial companies. This includes 28 electricity distribution businesses, 11 directly connected industrial loads, 11 generators with Default Transmission Agreements and six generation developers with Transpower Works or Development Agreements. Our ultimate customers are New Zealand's residential, commercial and industrial electricity consumers, who are mainly supplied through electricity distribution networks.
- **Landowners and communities:** Our key stakeholders in the community are those with towers and lines on their properties or who neighbour our substations. Others include those in communities impacted by our assets, such as the Department of Conservation as a landowner; landowner representative bodies such as Federated Farmers, Horticulture New Zealand and the New Zealand Forest Owners Association; and developers impacted by our assets.
- I**wi:** Some of our assets are located on land owned by mana whenua, or land where mana whenua have strong cultural connections.
- **Service providers and suppliers:** We contract service providers to build, maintain and service our infrastructure. They also provide project services, engineering design consultancy, facilities management, IT services and equipment.
- **Our regulators:** Our regulatory stakeholders include the Commerce Commission (regulating our economic return and performance, and representing the rights of consumers), the Authority (regulating the electricity market, setting industry standards and transmission pricing), the Financial Markets Authority (regulating our debt issuance) and the Reserve Bank (regulating the insurance activities of the company’s captive insurer – Risk Reinsurance Ltd).
- **Central and local government:** As a State-Owned Enterprise, the Government is a key stakeholder, as are local authorities, which manage compliance of our work with the Resource Management Act 1991 and are key contributors to our grid development plans.

We work proactively with our customers to understand their business and their needs, and to help them understand our business. We encourage customers to involve us in their thinking early on, which provides a greater opportunity for us to work together.[2]

Customer engagement is becoming more important as electrification and connection activity grow. We use customer needs and preferences to plan network investment, customer-funded work and resilience initiatives. This helps us maximise value for New Zealand consumers. Through Te Kanapu, our Transmission Planning Reports and broader engagement with customers and stakeholders, we seek to build understanding, incorporate diverse perspectives and support efficient investment across the electricity sector.

2.4.1 Customer feedback

Since the beginning of RCP3 in 2020, we have tracked customer sentiment through a headline satisfaction result. The survey continues to provide valuable insight into how customers perceive Transpower's engagement, consultation and delivery practices.

The initial survey established a baseline headline result of 57%. Under the Customer Engagement Plan, Transpower committed to improving this result by 15 percentage points over the baseline to 72%. We achieved the target during RCP3, and customer satisfaction has remained consistently above the target level since then. In the 2026 customer survey, 80% of customers reported being satisfied (or very satisfied) with the way Transpower engages and consults with them and meets their expectations. This was an increase from 70% in 2025 and matched the highest result since the survey began.

Results across individual survey categories were mixed but generally positive. Satisfaction with contracting with Transpower increased significantly from 59% in 2025 to 75% in 2026, while transmission network planning improved from 67% to 72%. Satisfaction with works delivery and outage planning also increased from 53% to 62%, partially reversing the decline observed in recent years. The only material reduction was in satisfaction with engagement around service levels and unplanned events, which decreased from 82% to 71%. While this remains broadly consistent with historical results, it highlights an area where we will continue to focus on improving customer engagement and communication.

Table 2: the overall satisfaction results for each section in the survey

Overall satisfaction with…	2021	2022	2023	2024	2025	2026
In summary, how satisfied are you with the way Transpower engages and consults with you, and meets your expectations?	80%	76%	73%	73%	70%	80%
Engagement around service levels and unplanned events	72%	78%	81%	78%	82%	71%

[2] Our customer engagement approach is set out here Customer information | Transpower.

Works delivery and outage planning	74%	74%	74%	68%	53%	62%
Transmission network planning	72%	69%	70%	77%	67%	72%
Contracting with Transpower	73%	71%	71%	54%	59%	75%

2.5 Our grid services

The reliability, safety, availability and cost effectiveness of our grid affect the quality of the service our customers receive.

Our network and system operations provide eight broad service categories. These include regulated transmission services, system operator services and activities outside our individual price-quality path. The first three categories drive the cost and quality of transmission services for consumers and are the focus of our performance measures.

The primary role of our service performance measures is in fine-tuning our performance by ensuring we deliver the services our customers value, in a safe and cost-effective manner.

Table 3: Our services framework

Service	Brief Description
Grid reliability	Keep interruptions to a very low level and restore supply quickly when there is an interruption.
Grid availability	Keep sufficient grid capacity and resilience available to allow New Zealand's lowest-cost sources of supply to be used to meet demand.
Event communications	Communicate with our customers when supply is interrupted so we can achieve the best outcomes for end-consumers.
Grid access	Work with customers to connect their assets to the grid, and plan and deliver changes to their connections.
Site access	Safely host customer equipment on our sites.
Information provision	Provide planning and other information to assist connected parties to make informed decisions.
Asset relocation	Assist in the identification, selection and execution of options to relocate transmission infrastructure.
System operation	Operate a competitive electricity market and deliver a secure power supply.

3 Overview of our plan

3.1 Introduction

This section provides an overview of our plans for our role as grid owner and shows how they have changed since our RCP4 proposal, which was provided to the Commission in November 2023, and the Commission's determination in November 2024.

During RCP4, we aim to deliver the following outcomes:

- **Deliver a reliable and safe grid.** We will deliver a transmission service that minimises interruptions at lowest whole of life costs, where assets are maintained and replaced in line with good electricity industry practice, and where risks to our staff, contractors, customers, and public are minimised.
- **Deliver a resilient network.** We will increase the resiliency of our network to avoid extended power outages and quickly restore power when major events occur.
- **Deliver and enhance the network.** We aim to ensure capacity is in the right place at the right time and customers continue to receive a reliable and secure transmission service that meets their needs.
- **Deliver a sustainable network**. We will aim to reduce our combined scope 1 and 2 (excluding transmissions loss emissions) and overall scope 1, 2 and 3 carbon footprint over RCP4 to ensure we can achieve a 44% reduction.[3]

Our service performance remained strong in FY2025/26: we achieved all our quality standards and continued to deliver reliable transmission services. However, base capex delivery was below the level planned. We expect delivery volumes to increase materially over the remainder of RCP4, supported by the new grid operating model, stronger end-to-end delivery discipline, and resources returning to the base programme after assisting in accelerating the generation connection pipeline. These measures are intended to restore delivery broadly in line with our RCP4 base capex forecast by the end of FY2027/28.

The rapid growth in connection activity required us to make deliberate trade-offs across our work programme. We temporarily reallocated investigation and protection-engineering resources to accelerate priority generation and demand connections and increase throughput through the front end of the connections process. This helped move more projects into investigation and delivery but contributed to slower progress in parts of the base capex programme. As discussed in section 3.6.6, we are continuing to improve readiness requirements, active queue management, regional batching and customer-led delivery options so that scarce resources are directed to projects that are ready and can deliver the greatest system and customer benefits.

[3] Note, in our RCP4 proposal we set out a 60% reduction of our scope 1 and 2 emissions (excluding transmission loss emissions) by FY2030, relative to FY2006. This year we updated our baseline year (reference point) to FY2021 from FY2006. We are still targeting the same volume of scope 1 and scope 2 reductions by FY2030, but the percentage reduction has been updated to reflect the new baseline year. Please refer to our Climate Statement 2025 for more detail.

Capacity remains constrained in some specialist disciplines, particularly protection engineering. Although we have achieved the overall FTE target associated with the deliverability risk adjustment mechanism, specialist capability cannot always be recruited or developed at the pace required. Protection engineering is needed across connection investigations, base renewals, major projects and operational work, creating competition for a limited pool of expertise. We are addressing this through recruitment, capability development, improved sequencing and batching of related studies, and clearer prioritisation across the portfolio. Residual exposure remains and is reflected in the skilled-resource and deliverability risks described in sections 3.6.1 and 3.6.2.

Higher equipment, materials and labour costs are also affecting the programme. Actual increases for some equipment have materially exceeded the base unit costs and real price effects assumed in our RCP4 proposal, while global demand has extended lead times for key transmission equipment. In some cases, updated estimates have required us to revisit project scope, timing or delivery approach to ensure the preferred solution remains prudent and offers the best whole-of-life value. We are responding by engaging suppliers earlier, expanding the approved supplier base, securing manufacturing capacity where appropriate, using strategic inventories, and reassessing scope and sequencing before committing expenditure. These responses align with the supply-chain and cost-escalation discussed in section 3.6.3.

Taken together, these factors explain why delivery is behind plan in some areas even though service outcomes remain strong and overall workforce numbers have increased. Our response is not simply to add resources or defer work. We are actively balancing connection demand, asset renewal, resilience investment and major projects; targeting expenditure using asset condition, criticality and risk; and revisiting scope where costs or delivery constraints materially change the value proposition. This approach supports recovery of the programme while maintaining safety, reliability and value for customers.

Alongside our work as grid owner, we have been developing a new strategy and workplan for our role as the System Operator. The System Operator plays a pivotal role in New Zealand's power system. We are responsible for maintaining power system security and operating the wholesale electricity market in real-time, providing security of supply information, managing supply emergencies, and ensuring the system remains stable. This work is becoming increasingly complex as the generation supply mix changes with increasingly inverter based, variable renewable generation connecting to the grid, large new users and more severe and variable weather. The task is no longer limited to managing a centralised, linear and predictable system, but instead requires embracing a more decentralised, data rich, and dynamic system involving a wider range of participants and technologies. It requires a proactive and forward-looking approach. Further details are set out here: System Operator Strategy 2026.

3.1.1 Revenue and prices

The revenue path and prices customers pay is incredibly important to us. When we plan, we seek the most efficient and effective solutions to maximise the value customers receive from the prices they pay.

We have published our latest figures regarding our revenue and indicative pricing on our website here: RCP4 updates, disclosures and price path reopeners | Transpower

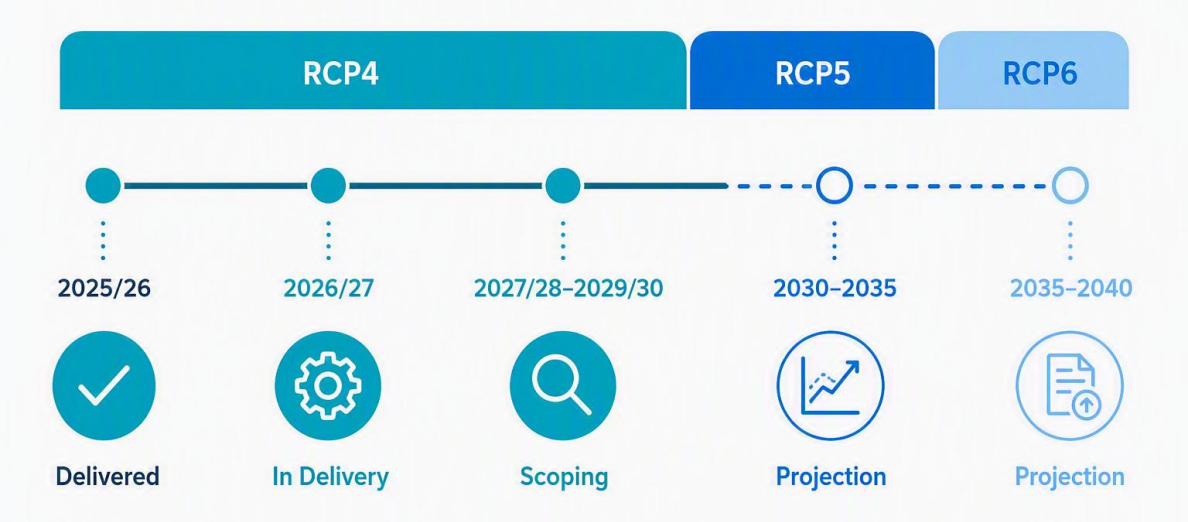
3.2 Regulatory cycle

In November 2024 the Commission approved our base capex and opex allowances, as well as the maximum allowable revenue we can recover each year under RCP4.

We are incentivised to improve efficiency over time. Where we achieve efficiency gains during RCP4, those benefits are shared with customers and ultimately flow through to lower transmission charges.

In our RCP4 proposal, we submitted an ITP to the Commission summarising our expected expenditure over the 10 years to 2035. This 2026 ITP provides the second update since our proposal. We are developing our projections for RCP5 and RCP6, from 2030 onwards, and we will consult on our RCP5 proposal this time next year.

Table 4: RCP Timelines



The regulatory framework we operate under has different processes to approve our expenditure based on the driver of the work (e.g. demand growth, enabling new generation, asset replacement, and the value of work).

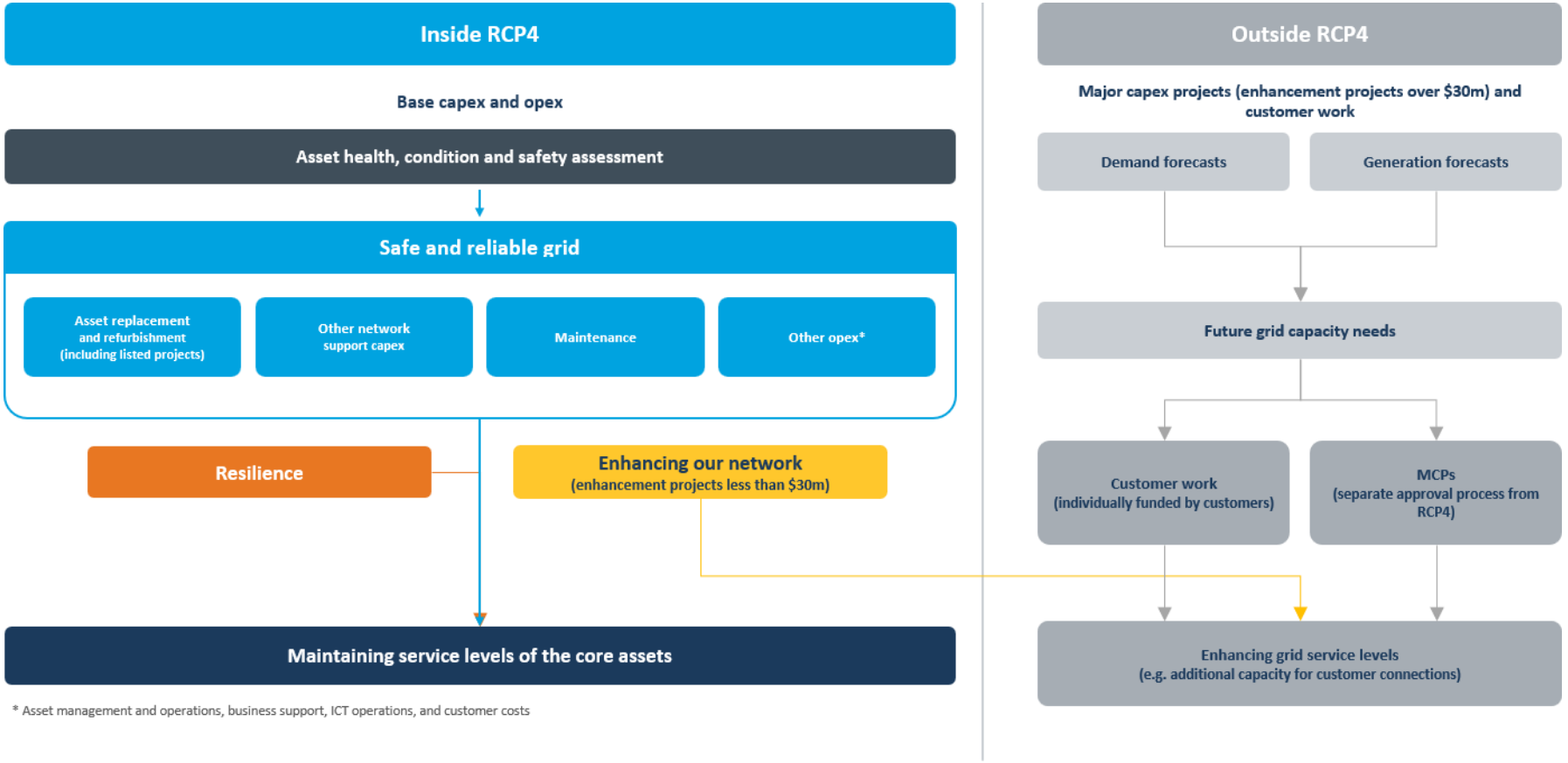
The RCP4 approval process covered our 'base' expenditure; it excludes:

- system operator service costs, which are covered under a separate contract with the Authority;
- customer- and third party-funded work, which includes adding new grid connections for customers or modifying existing connections to improve their individual service levels, as well as moving or modifying our existing lines and assets to enable other new infrastructure developments;
- major capex proposals (MCPs) that are related to enhancing and developing the network and are over $30 million (MCPs have their own consultation and approval process separate from our RCP proposal);
- listed projects that are related to refurbishment and replacement capex identified at the time of the RCP proposal and valued at over $30 million. Listed projects have their own application process separate from our RCP proposal.

While demand and generation forecasts play a critical role in Transpower's future work, most of the expenditure to support demand growth falls outside of our RCP4 proposal.

As can be seen in Figure 1, the majority of the RCP4 spend is driven by the need to replace, refurbish, or maintain our existing assets.

Figure 1: Scope of RCP4 allowance



3.3 RCP4 grid and asset performance measures

Table 5 summarises our performance measures for RCP4. Our *2026 Service Measures Report* provides further information on our service performance[4].

Table 5: Our measures for RCP4

Measure Name	Revenue at risk per annum ($M)	Quality Standard	RCP4 measure description
GP1 – Grid Performance 1	7.6	Yes	Number of unplanned interruptions across all points of service (POS) in a sub-category during a disclosure year
GP2 – Grid Performance 2	7.6	Yes	Average duration of unplanned interruptions greater than one minute, across all POS in a subcategory during a disclosure year.
AP1: Asset Performance 1 – HVDC capacity availability	1.0	Yes	HVDC capacity availability (%) of the inter-island HVDC system.
AP2: Asset Performance 2 – HVAC selected asset availability	2.0	Yes	Average percentage of time selected HVAC assets are available during a disclosure year.
AH: Asset Health	-	Yes	Proportion of assets in poor health for seven asset classes.
AP1.2: HVDC operational availability	-	No	Measures HVDC link's operational capacity limit calculated as the available operating capacity limit against the maximum capacity of the HVDC link.
AP3: Asset Performance 3 – Return to service	-	No	Extent that Transpower keeps to planned outage times in relation to selected HVAC assets.
AP4: Asset Performance 4 – Return to services communications	-	No	Extent that Transpower communicates delays to planned outage return times in relation to selected HVAC assets
GP4: Energy not served (previously labelled NR and GP3)	-	No	Amount of energy demand that is not supplied due to a transmission interruption to supply.
CS1: Customer Service 1 – Overall customer satisfaction	-	No	Average level of overall customer satisfaction based on responses in an annual customer engagement survey.
CS2: Customer Service 2 – New and enhanced grid connections	-	No	Reports on delivery of new and enhanced grid connections

[4] See, Transpower Service Measures Report, 2026

3.4 Our FY25/26 performance

The GP1 and GP2 measures assess the reliability of the transmission grid from a customer perspective. GP1 measures the annual number of unplanned interruptions affecting transmission customers, while GP2 measures the average duration of those interruptions. Both measures are assessed across six point-of-service sub-categories covering supply and generation customers with differing levels of economic consequence and are linked to revenue through incentive mechanisms established by the Commerce Commission.

For disclosure year 2026, Transpower met the quality standards for both GP1 and GP2. GP1 performance was generally strong, with four of the six sub-categories performing at or better than target levels and positive incentives achieved for N-1 Material Economic Consequence, N Material Economic Consequence and N-1 Generator customers. Performance for N Security Generator customers exceeded our target performance, and the quality limit, resulting in a modest penalty.

Table 6: 2025/26 GP1 (number of interruptions)

Measure	Compliance
N-1 Security High Economic Consequence	Achieved
N-1 Security Material Economic Consequence	Achieved
N Security High Economic Consequence	Achieved
N Security Material Economic Consequence	Achieved
N-1 Security Generator	Achieved
N Security Generator	Limit exceeded
Total GP1 Output Adjustment ($)	**$758,382**

GP2 results were more mixed. While interruption durations for N-1 Generator customers were substantially better than target, several supply-related categories experienced longer outage durations than anticipated, particularly N Security Material Economic Consequence customers (which also was above the quality limit). As a result, we incurred a penalty regarding our GP2 performance. Notwithstanding these results, Transpower achieved the required quality standards and continues to focus on asset management, outage planning, system resilience and operational practices to improve long-term reliability performance. Transpower has also submitted a normalisation application relating to Cyclone Vaianu to the Commerce Commission; if approved, it would remove several interruption events from the reported GP1 and GP2 results.

Table 7: 2025/26 GP2 (average duration of interruptions)

Measure	Performance
N-1 Security High Economic Consequence	Achieved
N-1 Security Material Economic Consequence	Achieved
N Security High Economic Consequence	Achieved
N Security Material Economic Consequence	Limit exceeded
N-1 Security Generator	Achieved
N Security Generator	Achieved
Total GP2 Output Adjustment ($)	**-$3,214,588**

AP1 and AP2 are Transpower's revenue-linked asset performance measures and assess the availability of critical transmission assets. AP1 measures the annual availability of the HVDC link, while AP2 measures the availability of selected HVAC assets that have the greatest impact on market outcomes when out-of-service. Both measures are subject to quality standards and financial incentives under the RCP4 regulatory framework.

Transpower performed strongly against both asset performance measures in disclosure year 2026. HVDC availability (AP1) was 98.22%, exceeding the target of 98.00% and resulting in a small incentive payment. HVAC asset availability (AP2) was 98.50%, above the target of 98.25%, resulting in an incentive payment. Transpower met the quality standards for both measures. These results reflect the effectiveness of Transpower's asset management, maintenance and outage planning practices in supporting high levels of grid availability and reliability.

Table 8: Asset performance and health targets

Measure	Performance
AP1: HVDC availability	Achieved
AP1 Output ($)	$220,000
AP2: HVAC availability	Achieved
AP2 Output ($)	$1,330,141

3.5 Update on our RCP4 plan

Since submitting our RCP4 proposal in 2023, we have updated our expenditure forecasts to reflect changes in work programmes, input costs, project scopes and forecast delivery requirements. Table 9 compares the expenditure forecast in this 2026 ITP with both our original RCP4 proposal and the Commission's approved allowances.

Relative to our RCP4 proposal, forecast base capex has increased while forecast opex has decreased. The increase in forecast expenditure reflects a combination of higher-than-anticipated equipment and materials costs, changes in project scope, additional resilience investment, and updates to our asset replacement and maintenance programmes. Consistent with our Asset Management Plan, we continue to refine our work programme using updated asset condition information, criticality assessments and risk-based investment planning to ensure expenditure is targeted at areas of highest need and greatest customer value.

The Commission applied a deliverability risk adjustment mechanism to our RCP4 allowances, which allows additional revenue recovery if specified workforce targets are achieved. The 2026 ITP forecast assumes Transpower meets the recruitment requirements associated with this mechanism.

Table 9: 2026 ITP RCP4 expenditure forecast compared to our RCP4 Proposal and allowances (constant 2025/26 $m)

$m	Base capex	Opex
RCP4 Proposal	2,412.3	2,162.9
2026 ITP forecast	2,520.8	2,143.4
Movement relative to our proposal and the ITP update	**108.5**	**-19.5**
RCP4 allowance (if deliverability risk adjustment criteria met)**	2,437.3	2,144.9
2026 ITP forecast relative to allowances if the remaining delivery risk adjustment mechanism criteria are met	**83.5**	**-1.4**

** Excludes capitalised leases. Note, the capex allowance is higher than RCP4 Proposal as it includes additional resilience allowances.*

*** Allowance values have been adjusted to include approved listed projects and any reduction due to base capex allocation to MCPs.*

Our major capex forecast and Listed Projects under development remains a substantial part of our RCP4 and RCP5 plan. These forecasts are shown in the table below.

Table 10: Forecast major capex projects and Listed Projects during RCP4 and RCP5 (constant 2025/26 $m)

	RCP4	RCP5
Approved MCPs	811.8	598.7
MCPs under development	715.0	2619.0
Listed Projects under development	74.8	693.0

Further details on our expenditure forecasts for RCP4 and RCP5 are provided in Section 4.

3.6 Key risks and uncertainties for our plan

Our plan is based on the best information currently available, but the timing, scope and cost of work will continue to change as asset condition, customer requirements, delivery constraints and technology evolve. We will respond to new information by reprioritising the work programme using asset health, criticality, risk reduction, customer value and deliverability. Our principal risks and mitigations are set out below.

3.6.1 Delivery programme and connection demand

We must deliver a larger programme of asset renewal, maintenance, resilience investment, major projects and customer-funded connections. The timing, location and maturity of connection requests remain uncertain, creating competing demands for scarce investigation, protection-engineering, outage and delivery resources.

We manage this risk through stronger project-readiness criteria, active queue management, coordinated regional planning and improved sequencing and packaging of work. We will continue to align condition-driven investment with enhancement, resilience and customer work where this can reduce outages, avoid duplicated effort and lower whole-of-life cost. If all work cannot be delivered by its need date, we will reprioritise using safety, service performance, asset risk, customer benefit and delivery feasibility.

3.6.2 Workforce and specialist capability

Competition for skilled engineering, project-delivery, operational and field resources is increasing domestically and internationally. Some specialist disciplines cannot be recruited or developed at the pace required, creating concentration risks across connections, renewals, major projects and operational work.

Our response combines recruitment with graduate and early-career pathways, specialist training, Grid Skills development and capability building across our service-provider workforce. We are also improving work sequencing, standardisation and batching so that constrained disciplines can be deployed more efficiently. Workforce capacity and productivity assumptions will continue to be reflected in delivery forecasts.

3.6.3 Cost escalation and supply-chain constraints

Global grid expansion is increasing demand for essential transmission equipment, which has resulted in electrical infrastructure rising faster than general inflation. We are also experiencing increasing ICT costs driven by growing demand for compute capacity, global supply constraints affecting ICT hardware and cloud services, and increasing complexity across the technology landscape.

Lead times for some equipment are extended, and, for highly specialised assets, supplier choice is limited. These factors can affect project timing, affordability and the preferred intervention.

We are responding through earlier market engagement and ordering, closer supplier and logistics monitoring, qualification of alternative suppliers, strategic inventory and expanded warehouse

capacity. Cost estimates are updated through the Transpower Enterprise Estimation System using current market rates, contracts and delivery information. Where costs change materially, we will reconsider scope, timing, life-extension opportunities and alternative solutions before committing expenditure.

3.6.4 Asset condition, performance and information

A significant proportion of the grid is ageing, but asset age alone does not determine the timing of intervention. Condition information, failure modes and asset criticality can change as inspections, testing and forensic analysis improve. Long-term forecasts are therefore less certain than near-term plans.

We use asset health models to estimate deterioration and probability of failure and combine these outputs with monetised consequences across service performance, public and workplace safety, environmental impacts and direct cost. This information supports risk-based prioritisation and option selection. We are continuing to improve data quality and model coverage through field mobility tools, drone inspections, targeted testing, analytics and feedback from completed work.

3.6.5 Natural hazards, climate change and resilience

Our infrastructure is exposed to earthquakes, flooding, land instability, volcanic hazards, severe wind, fire, space weather and common-mode failures. Climate change is increasing the frequency or severity of several hazards and may also affect asset ratings and access for maintenance and restoration.

Our resilience approach covers risk reduction, readiness, response and recovery. During RCP4, targeted work includes seismic strengthening, flood protection, fire detection and suppression, volcanic-ash readiness, land-stability interventions, strengthening of vulnerable towers and accessways, portable equipment and emergency exercises. We are also integrating climate adaptation into asset planning and will progressively refine the programme as hazard, vulnerability and cost information improves. As our understanding of asset vulnerability, hazard exposure, customer expectations and the effectiveness of potential mitigations continues to mature, the timing, scope and prioritisation of resilience investments may continue to evolve over future planning periods.

3.6.6 Digital delivery, integration and cybersecurity

Grid operations and asset management increasingly rely on digital systems, telecommunications, data and connected assets. Modernisation can improve safety, efficiency and decision-making, but introduces transition, integration, obsolescence and cybersecurity risks.

We are managing these risks through staged implementation, testing, governance and risk-based cybersecurity investment. Key initiatives include digital substations, digital switch management, the TransGO network refresh, modernised enterprise platforms and improved asset-information and analytics capabilities. We will maintain flexibility in longer-term ICT forecasts because technology, commercial models and the mix of capital and subscription-based expenditure will continue to evolve.

3.6.7 Enterprise risk management and flexibility

Our asset management system integrates risk management into strategy, planning, delivery, operation, maintenance and review. Bow-tie analysis identifies causes, consequences and preventive and mitigative controls, while control self-assessments and assurance activities test whether critical controls remain mature and effective.

Investment decisions consider whole-of-life cost, residual risk, benefits and sensitivity to timing. We always consider the status quo and, where appropriate, refurbishment, life extension, staged investment and non-transmission alternatives alongside replacement or conventional grid solutions. This preserves flexibility and helps us select the option with the highest net benefit while maintaining safety, reliability and prudent expenditure.

3.7 Continuous improvement

A key focus of RCP4 is improving the information, models and tools that support investment and operational decisions. We are enhancing asset health and criticality models, risk and maintenance optimisation, field data collection, drone inspections and analytics so expenditure can be targeted to areas of greatest customer value.

Digital and operational initiatives—including Control Room of the Future, digital substations, TransGO and enterprise platform improvements—will strengthen operational resilience, cybersecurity and delivery efficiency. Advanced analytics will help identify event and outage patterns, detect emerging failures, test scenarios and assess environmental impacts.

Most of the following initiatives were identified in our RCP4 proposal. However, the continuing sharp increase in input costs, supply chain pressures and material growth in connections mean that we need to prioritise some of our work programmes. Our reprioritisation initiatives include:

- **Change management practices as a key part of continuous improvement**. These practices support adaptation of our approach to improve delivery throughput. We will continue to develop our change management capability by adopting new technologies and reviewing the way we operate to become more efficient.
- **End-to-end process across value streams**. Business process efficiencies can speed up the connection of new customers to the network and enhance stakeholder relationships. Improvements to services like delivering customer work and procurement will be enabled by ICT initiatives such as customer engagement tools, asset management, and business capability. We are making a strategic shift by implementing a modular enterprise business capability platform. This will empower us to respond effectively to internal and external changes, including managing the evolving business landscape.
- **Modern data practices & decision tools**. Our applications will improve integration and reduce manual data handling by streamlining and automating processes and dataflows. This will enhance efficiency and productivity by freeing up our workforce to focus on meeting our RCP4 outcomes and delivering greater value to our customers. We continue to invest and develop our field workforce and provide improved applications, such as our mobility application. This app allows us to accurately collect grid maintenance information and is key to providing information and informing our asset planning process.

- **Innovation for cost-effective service delivery**. Innovation in both new grid technology and the way that we approach and manage change is key to optimising resources in delivering value to our customers, and will result in better solutions, better practices, avoided costs, and improved reliability and resilience.

3.7.1 Deliverability risk adjustment

The Commission's deliverability risk adjustment is contingent on Transpower meeting workforce targets needed to deliver the RCP4 programme. Recruitment is progressing, although international competition for highly skilled specialists remain a constraint.

Table 11: Our target full time equivalent (FTEs) targets set by the Commission

Disclosure year ending	RCP3	RCP4				
	30 June 2025	30 June 2026	30 June 2027	30 June 2028	30 June 2029	30 June 2030
FTE target	1003	1050	1055	1054	1056	1043

We have met our recruitment target for 2025/26 with 1,051.7 FTEs as of 30 June 2026. This represents a similar level of staffing in 2025. RCP4 marks one of the largest employment growth periods in our recent history. We remain confident that we will meet our recruitment targets to deliver our work programme going forward.

3.7.2 New connections pipeline

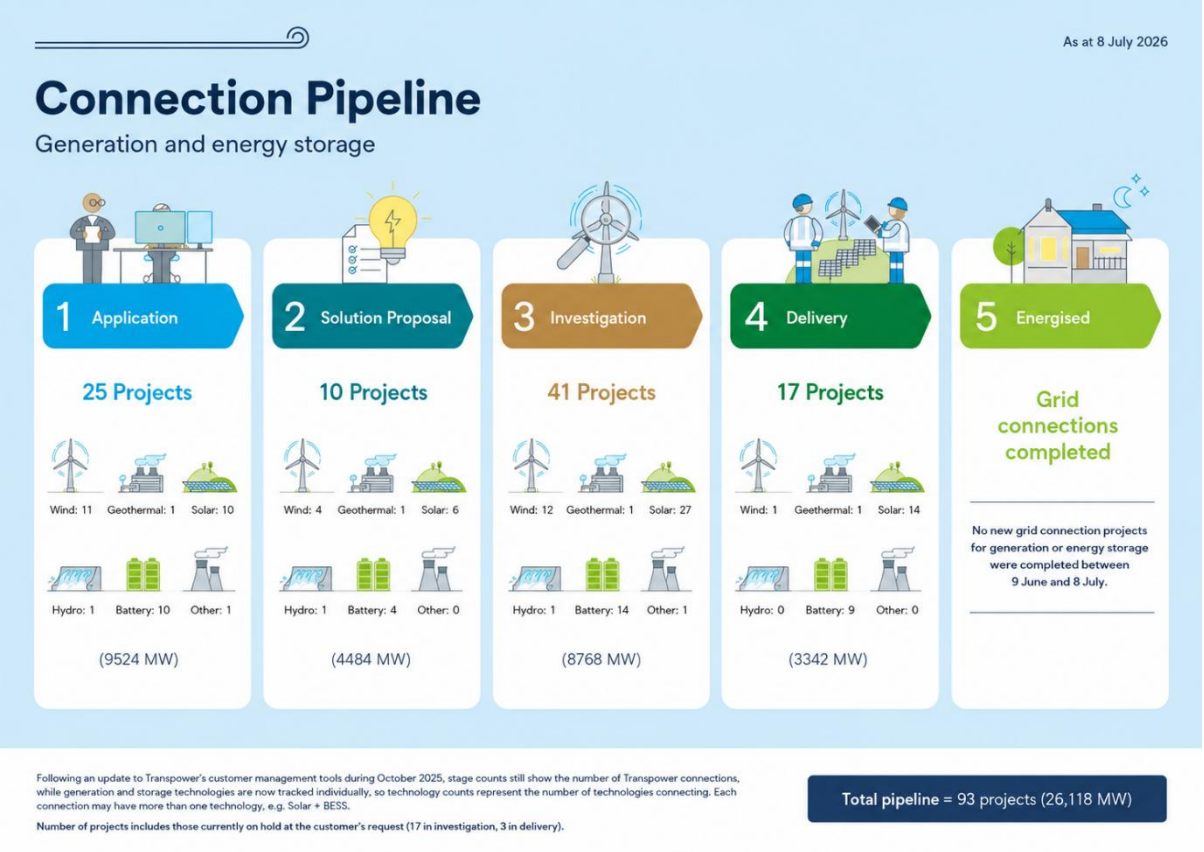
Connection activity is a key indicator of New Zealand's accelerating energy transition. During FY2026 we supported new generation, storage and demand connections while improving process efficiency. This growing pipeline reinforces the need for coordinated long-term transmission planning.

The volume of customer-related work agreed through transmission works agreements, outside base funding, has increased sharply. There were 340 new connection enquiries in the pipeline in August 2026.

At this stage we envisage that this work will be able to be undertaken with the workforce and resources which we have, inclusive of the delivery risk recruitment, to deliver these projects.

Connection applications are progressing more quickly than in prior years. As at August 2026, 41 projects were in investigation and 17 were in delivery, as shown in Figure 3.

Figure 2: the connection pipeline



We intend to improve our ability to understand our customers price-quality preferences, and to take these into account in our decision making and to communicate our decisions clearly to our customers including how we have, or have not, taken their views into account. This year our focus is on establishing individual engagement plans for each of our customers to enable improved price-quality trade-offs.

3.8 Base scenarios

Our demand and generation scenarios support our long-term planning for the grid and help ensure our investment decisions remain robust under a range of plausible futures. This is particularly important as electrification, renewable generation development, customer connection activity and new large loads continue to change the way the transmission network is used.

For the 2026 ITP, we have updated this section to reflect the scenarios now being used across our planning processes. Our Transmission Planning Report and base enhancement and development expenditure forecasts use Transpower's Accelerated Electrification scenario as the central, prudent demand forecast. This scenario reflects strong growth in electrification, including industrial heat, electric vehicle charging, process heat, data centres and distributed energy resources, and is calibrated using EDB-supplied information and Transpower's system planning view.

We also test major transmission investment needs against the Ministry of Business, Innovation and Employment's Electricity Demand and Generation Scenarios.[5] EDGS is an independent national scenario suite that explores potential future electricity demand and the generation capacity needed to meet that demand out to 2050. It has an explicit role in the Investment Test for assessing Transpower's major capital investment proposals under the Capex IM.

The 2024 EDGS scenarios provide a range of plausible demand and generation futures. They include a Reference scenario, where current economic, technology and policy trends continue, and four sensitivity scenarios: Growth, Constraint, Innovation and Environmental. These scenarios test different assumptions about economic growth, technology uptake, electrification, emissions-reduction ambition and the pace of change in the electricity sector.

In parallel, our Te Kanapu Future Grid work develops longer-term scenarios to inform the future Grid Blueprint. Te Kanapu is intended to guide potential investment in the grid up to and beyond 2050, supporting New Zealand's economic growth and net-zero aspirations. The scenarios are not forecasts; they are plausible, coherent futures that allow us to test potential investment pathways against a wide range of uncertainty. [6]

Across the Te Kanapu scenarios,[7] national electricity demand in 2050 ranges from 56 TWh in Patchwork Nation to 97 TWh in Made in Aotearoa, while peak demand ranges from 9.1 GW in Patchwork Nation to 13.7 GW in Made in Aotearoa. This range illustrates the scale of uncertainty Transpower must plan for as electrification, industrial growth, customer energy resources, data centres and regional development evolve over time.

Figures 4 and 5 compare the electricity demand scenarios used to inform Transpower's long-term planning. The figures show annual energy demand and peak demand under the 2026 Transmission Planning Report (TPR) expected scenario, the five Te Kanapu future scenarios, and the MBIE Electricity Demand and Generation Scenarios (EDGS). [8] The TPR expected scenario is based on Accelerated Electrification and reflects Transpower's central planning view of future electricity demand. Together, these scenarios help us assess a range of plausible futures and ensure transmission investment decisions remain robust under different assumptions regarding electrification, economic growth, technology uptake and consumer behaviour.

[5] Electricity Demand and Generation Scenarios (EDGS) | Ministry of Business, Innovation & Employment

[6] Te Kanapu Grid Blueprint | Transpower

[7] Te Kanapu Our Energy Scenarios | Transpower

[8] Our process converts top-down scenario assumptions into demand profiles, disaggregates demand to individual GXPs, reconciles the results with customer-based bottom-up forecasts and incorporates assumed customer step loads. Scenario demand values are presented net of rooftop solar and battery generation. Annual energy demand values are higher than those published by MBIE because Transpower includes an allowance for distribution losses (approximately 3.5% of demand). Peak demand values are higher than those published by the System Operator because they include demand otherwise supplied by embedded generation at peak times (approximately 160–180 MW).

Figure 3: Comparison of annual electricity demand scenarios (TWh)

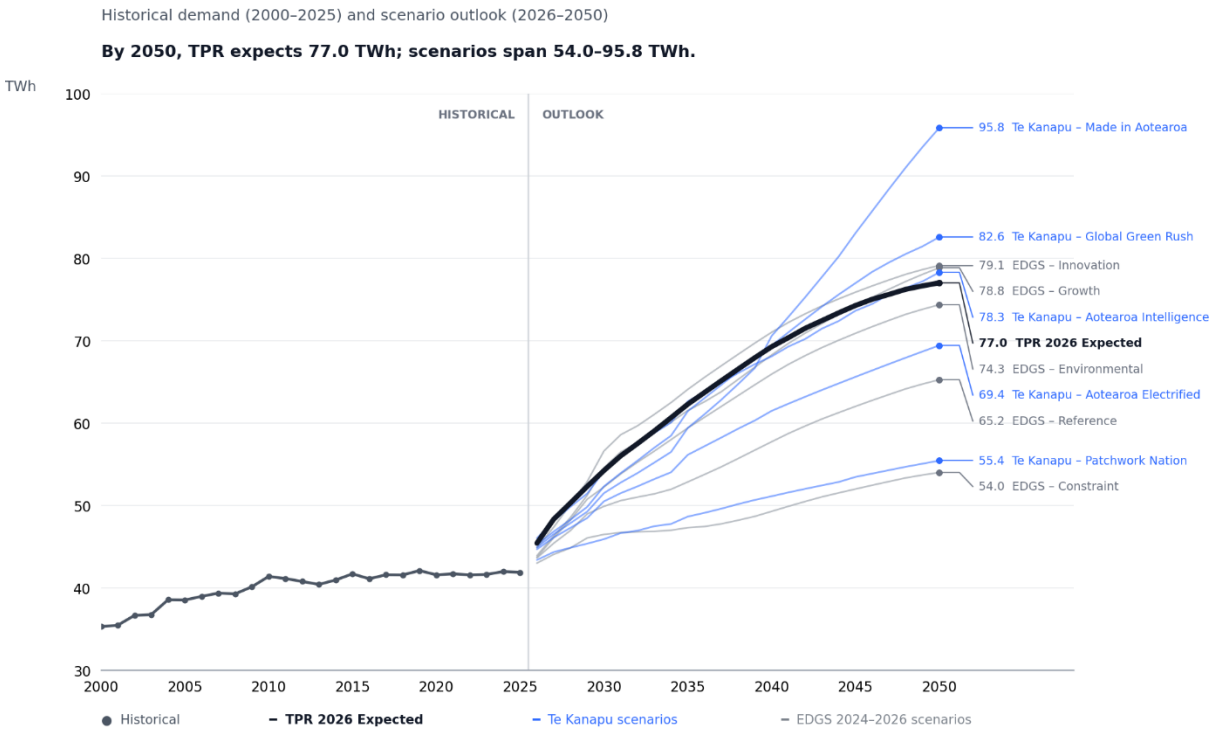
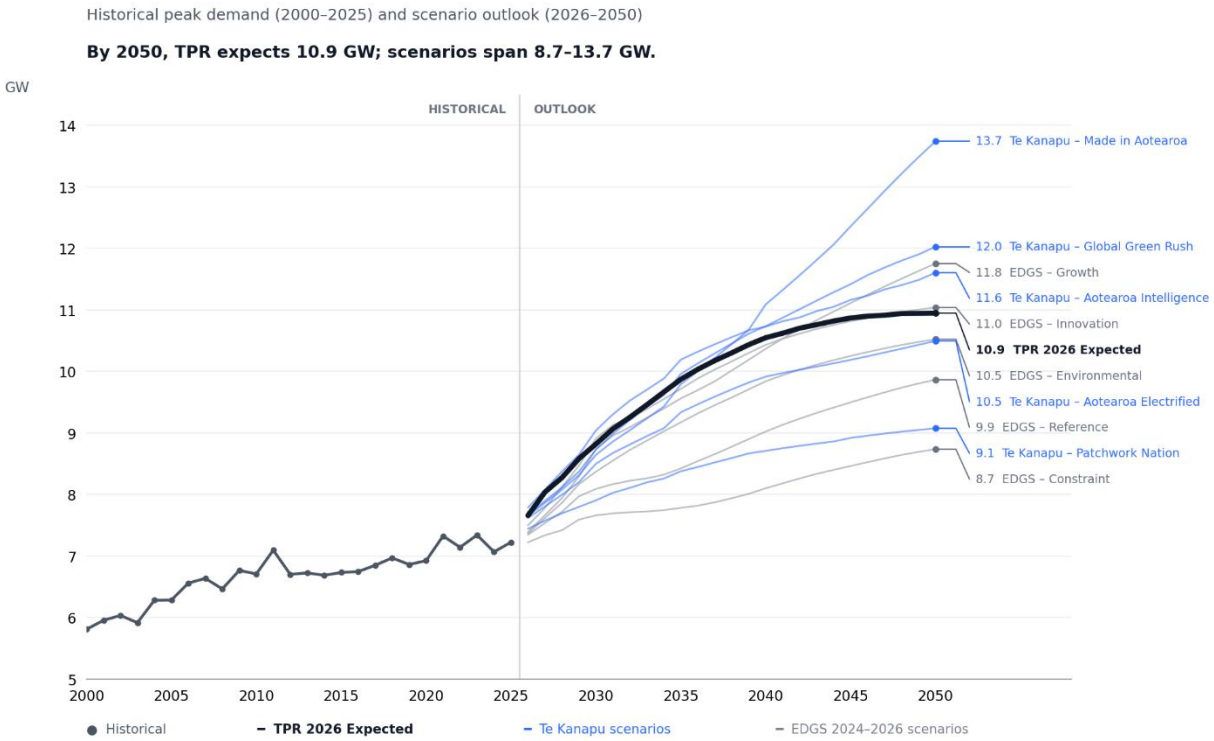


Figure 4: Comparison of peak demand scenarios (GW)



The scenarios illustrate the significant uncertainty associated with New Zealand's energy transition. By considering a range of demand outcomes, from more moderate growth pathways through to highly electrified futures, Transpower can identify investment pathways that support reliable and efficient network development while maintaining flexibility as future demand patterns evolve.

4 Expenditure forecasts

4.1 Summary

This section provides the detailed expenditure forecasts underpinning the RCP4 update in section 3.5. Forecasts are refreshed for changes in scope, sequencing, input costs and deliverability, with projects prioritised using asset condition, criticality, risk and customer value

International competition for high-voltage equipment is increasing prices and lead times beyond the real price effects assumed in our RCP4 allowances. The implications and mitigations are discussed in section 3.6.3.

4.1.1 Base capex

The table below provides further detail on changes in our base capex portfolios between the RCP4 Proposal and the 2026 ITP forecast (excluding Listed Projects). The forecast reflects changes in investment priorities, updated asset condition information, the maturation of asset strategies and delivery plans, and ongoing optimisation of expenditure.

Table 12: RCP4 forecast base capex (constant 2025/26 $m)*

Category	RCP4 Proposal	2026 ITP	Movement from RCP4 Proposal	
	$m	$m	$m	%
Substations	543.3	542.4	-0.9	-0.2%
Buildings & Grounds	86.7	89.6	2.9	3.3%
Transmission Lines	764.8	788.7	23.9	3.1%
HVDC & Reactive Assets	177.5	203.2	25.8	14.5%
Secondary Assets	310.0	293.2	-16.9	-5.4%
Enhancement and development (excluding resilience)	122.9	134.7	11.8	9.6%
Resilience	144.9	169.4	24.5	16.9%
ICT capex	230.4	208.5	-21.9	-9.5%
Business support capex	31.9	41.8	9.9	31.1%
Total	**2,412.3**	**2,471.5**	**59.2**	**2.5%**

4.1.2 Operating expenditure

The table below provides further detail on our base opex forecast. Overall forecast opex is slightly below the RCP4 Proposal. This reflects ongoing optimisation of maintenance and operational activities, improved asset health information and refinement of work programmes. Forecast network expenditure is lower than proposed, while non-network expenditure has increased modestly due to higher ICT and digital service costs associated with supporting a more complex and increasingly digital transmission system. We continue to actively refine expenditure forecasts and

prioritise activities to ensure efficient delivery of services while maintaining a safe, reliable and resilient transmission network.

Table 13: RCP4 forecast opex (constant 2025/26 $m)

Category	RCP4 Proposal	2026 ITP	Movement from RCP4 Proposal	
	$m	$m	$m	%
Network*	1288.7	1,259.5	-29.2	-2.3%
Non-network**	874.2	883.9	9.7	1.1%
Total	**2162.9**	**2143.4**	**-19.5**	**-0.9%**

* Network opex includes 'grid maintenance' and 'asset management and operations'.

** Non-network opex includes ICT opex and ICT anything-as-a-service (XaaS), and insurance.

4.2 Forecasting approach

We have used several forecasting methods since RCP1 and have refined them over time. We generally build grid and non-grid capex forecasts from the bottom up and test them against top-down planning assumptions.

Table 14 provides an overview of the approaches we applied to each expenditure category.

Table 14: Forecasting approaches

Expenditure category	Forecast approach
Refurbishment and replacement capex	Asset health in combination with criticality; condition assessment where asset health models are unavailable
ICT capex and opex	Bottom-up based on programme, investment type and category, and base-step-trend approach
Business support capex	Bottom-up (in combination with top-down planning frameworks)
Enhancement and development capex	Scenario-based forecasting based on bottom-up and top-down assumption
Resilience capex	Bottom-up based on assessed need
Maintenance opex	Bottom-up and base-step-trend
Asset management and operations opex	Base-step-trend
Business support opex	Base-step-trend
Insurance opex	Based on expert actuary and broker information

4.2.1 Bottom-up cost estimation

We base grid renewal capex estimates on historical costs, adjusted for the expected scope. We use two types of estimate:

- **Volumetric work:** routine, lower-value work with a consistent scope and delivery method. We estimate this work using average rates and an assumed scope.
- **Non-volumetric work:** higher-value work that needs a project-specific investigation and tailored estimate.

4.2.2 Base-step-trend

For most opex, we use a base-step-trend approach. This suits recurring costs because historical expenditure provides a useful starting point. The approach has three components:

- base year identification for an efficient base year, assessing the efficiency of the expense and then adjusting for atypical cost items;
- step changes to allow for external requirements not already captured in the scope of the base amount;
- trends reflecting any changes in cost due to output growth and can include adjustments for ongoing productivity and cost efficiency.

Further details of our forecasting approaches can be found in our *RCP4 Main Proposal*.

4.3 Cost estimation

The Transpower Enterprise Estimation System (TEES) is our database for estimating grid capital and maintenance costs. It links to our planning and financial systems, centralises estimates, applies foreign-exchange and commodity changes, and updates forecasts when delivery dates change.

Using TEES, the two methods for estimating projects are as follows:

- **TEES building blocks:** used mainly for routine renewal or maintenance work delivered by service providers. Each building block has an agreed scope and includes materials, equipment, design and overheads. We update building blocks using completed-project data, benchmarking and tailored estimates for new activities.
- **Custom estimates:** used for large or complex projects with site-specific design or optioneering. We define the project deliverables through a basis of design and build the estimate in TEES using current cost data.

We update cost data each year to reflect market rates and delivery methods. Better feedback and analysis improve both programme delivery and estimate accuracy.

4.4 Replacement and refurbishment capex

Replacement and refurbishment capex is our largest single expenditure category. It covers all replacement and refurbishment expenditure on grid assets (excluding ICT). We split replacement and refurbishment expenditure into the following asset categories.

- **AC substations** include power transformers, indoor switchgear, outdoor switchgear, structures and buswork, power cables, outdoor 33kV switchyards and other AC substation equipment.
- **Buildings and grounds** assets provide accommodation, services, and physical security for critical grid equipment and systems. Our objective is to ensure substation primary and secondary network assets are properly secured against physical and environmental risks, at the least whole of-life cost. Assets include buildings, site infrastructure, building services, and access ways to our substation sites. The asset class covers the physical buildings containing AC substations, warehouses, leased depots, and our national operating centres. Our buildings and grounds comprise approximately 670 buildings across 200 sites.
- **Transmission lines** assets transport electricity from generation sources around the country to where it is consumed within our homes and places of business. They consist of transmission towers, poles, foundations, conductors, earth wires, insulators, and other hardware. Transmission lines is our largest aggregate asset class portfolio of spend.
- **HVDC and reactive assets** are a critical part of the network. The HVDC link enables the North Island to access South Island hydro-electricity generation and the South Island to access North Island thermal electricity generation. The link is critical to the operation of an efficient national electricity market. The HVDC link comprises:
    - converter stations;
    - submarine cables and cable substations;
    - electrode stations.

  Reactive power is needed in the AC transmission system to support the transfer of real power over the network and incorporate:
    - synchronous condensers;
    - static VAR compensators (SVCs) and static synchronous compensators (STATCOMs);
    - capacitor banks and reactors.

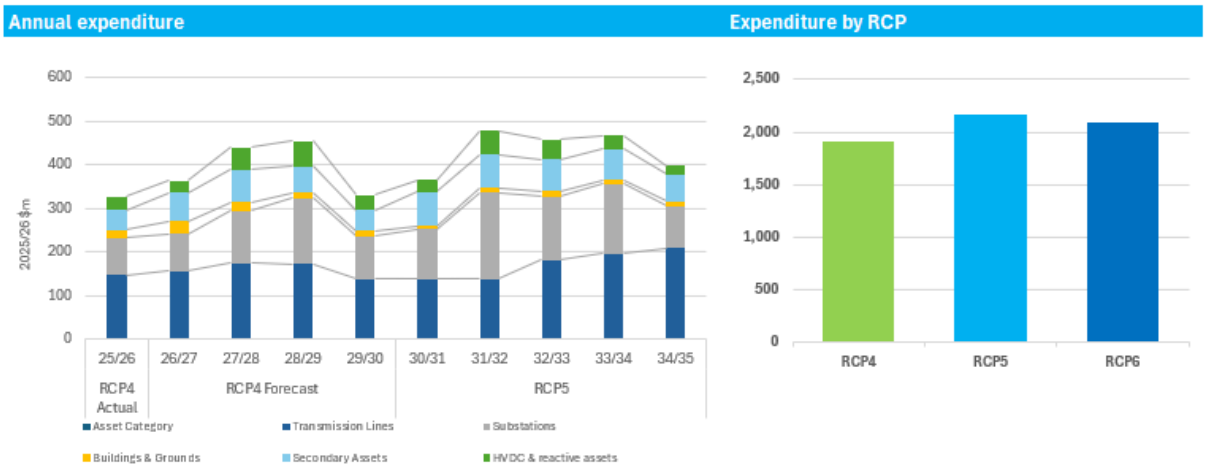
  There are currently only a small number of qualified suppliers of suitable equipment. Due to the high demands for this type of equipment, prices have increased and are forecast to continue to increase. In addition, the time taken to source equipment may be more volatile, due to increased lead times.
- **Secondary assets** support the overall operation of the grid and provide essential services for the monitoring and control of equipment. Secondary assets include:
    - **protection schemes**: used throughout the grid to detect and initiate isolation of electrical faults, protect primary equipment, and ensure people's safety;
    - **revenue meters**: supply electricity volume information and are used for wholesale market reconciliation and billing;
    - **station DC systems:** provide power (even when the local AC service supply has failed) to protection schemes, circuit breaker trip and close coils, control, and metering;

- **Substation Management Systems SMS:** a telemetry system based on computers and local area networks that have been designed to operate in electricity utility environments.

The primary driver of the protection, battery systems, and revenue meters renewal forecast is asset health. The wide range of asset life expectations means that required work volumes fluctuate.

More detailed information on grid expenditure can be found in the "Grid expenditure" section of the 2026 Asset Management Plan[9].

Figure 5: Historical and forecast replacement and refurbishment expenditure (constant 2025/26 $m)



4.4.1 Listed Projects

Listed projects are large R&R projects or programmes with significant uncertainty about timing and costs, where the estimated project cost is likely to exceed the $30 million base capex threshold. Detailed engineering and economic analysis will determine their timing and cost. We identify these base capex projects when compiling the RCP proposal, but the Commission does not approve allowances for them during the IPP reset. Once we have reduced the uncertainty and met the required timeframe, we can apply to amend our base capex allowance and revenue so the Commission can consider the projects for regulatory approval during RCP4.

[9] See, *Transpower Asset Management Plan, 2026.*

Table 15: Listed projects (constant 2025/26 $m)

Project	Estimated/approved project capex	Status	Estimated project start
Huntly - Ōtāhuhu A (OTA – DRY) reconductoring	$45.3m	Application anticipated for Q4 2026	2028
Ōtāhuhu - Whakamaru A and B (Rest of Auckland) reconductoring	$45.4m*	Approved by the Commission in July 2026	2026
Haywards bus rationalisation	TBD	TBD	TBD
Rangipō gas insulated switchgear replacement	N/A	Project is not currently progressing as a Listed Project	N/A
HVDC cables replacement	N/A	This is no longer a listed project as it has been combined with the HVDC upgrade project	N/A

* The approved capex has been reflected in our base capex allowance

4.5 Enhancement and development (E&D) capex

We report on three different categories of E&D expenditure:

- base E&D capex on projects less than $30m to enhance the capacity of the grid or to meet reliability requirements;
- network resilience capex;
- MCPs (costing over $30m) to enhance the capacity of the grid or to meet reliability requirements.

4.5.1 E&D base capex

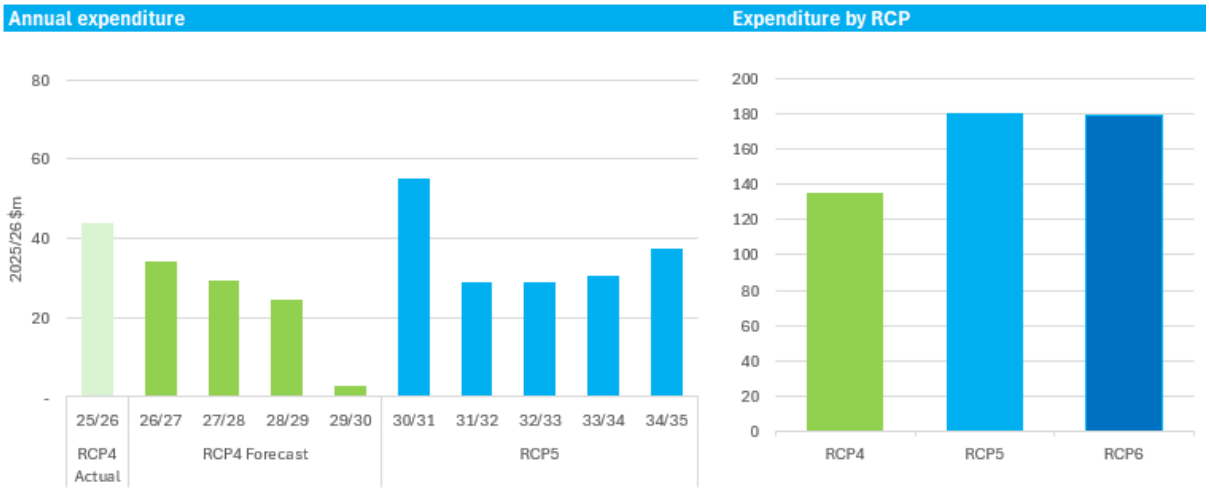
E&D projects aim to maintain and improve grid reliability and efficiency. The Commission assesses each application against the need for the project and its potential benefits to consumers.

The Commission approved $111.7 million as E&D base capex for RCP 4, which includes $5 million in corridor management. The E&D expenditure can be accessed for asset replacement and refurbishment, resilience, business support and ICT assets. These projects include funding for:

- **Voltage Management**: Projects to manage voltage levels in the Upper South and North Islands;
- **Interconnecting Capacity**: Enhancements at the Kawerau substation to improve interconnecting capacity;
- **Variable Line Ratings**: Installation of variable line ratings at the Ōtāhuhu-Whakamaru line to optimize transmission capacity.

Transpower intends on applying for this expenditure in the second year of the RCP4 regulatory period.

Figure 6: Historical and forecast base enhancement and development expenditure (constant 2025/26 $m)



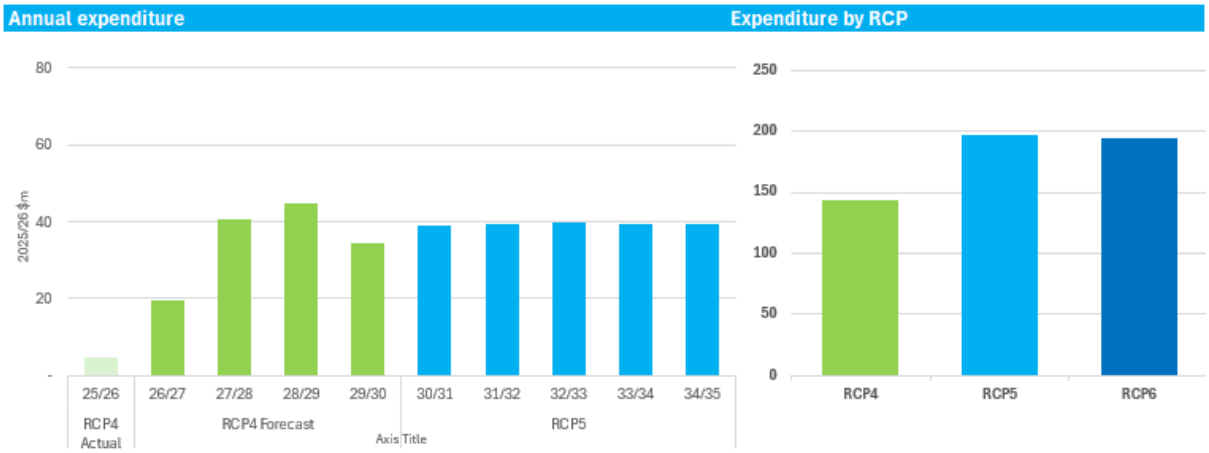
4.5.2 Resilience expenditure

Consumers have become more concerned about the electricity industry's resilience to extreme weather events, like the Auckland floods and Cyclone Gabrielle in 2023. Transpower is investing in mitigations to improve network resilience.

Our resilience programme includes improving readiness and risk reduction for substation flooding, seismic risks, building fire, volcanic ash impacts, land stability, common mode failure, and wind and flood strengthening for towers. Some of the climate related investments will form part of the *Transpower Climate Change Adaptation Plan*. Mitigation of solar storm impacts on transformers was also part of this programme of work but was not approved under the allowance for RCP4.

In the RCP4 proposal, we classified some cybersecurity and transmission systems expenditure within the resilience category. The Commission disallowed this expenditure. We continue to refine and re-evaluate the proposed initiatives and will seek funding for priority projects through substitution mechanisms and our internal productisation governance process.

Figure 7: Historical and forecast base resilience expenditure (constant 2025/26 $m)



4.6 Major capex projects

Enhancement and development projects above $30 million are considered MCPs. We are initiating major capex work through RCP4.

These projects are subject to a separate approval process under the Commerce Commission's Capex IM framework and are critical to maintaining the reliability, resilience and capacity of the national grid as electrification accelerates.

Several MCPs are now progressing through delivery during RCP4. These include the Redclyffe 220 kV switchyard resilience project, which is strengthening network resilience in Hawke's Bay following the impacts of Cyclone Gabrielle, the Western Bay of Plenty Regional project to address forecast demand growth and maintain reliability in one of New Zealand's fastest-growing regions, and HVDC Stage 1, a significant investment in the inter-island link that will increase transfer capability and improve the resilience of New Zealand's electricity system.

The Upper South Island Upgrade is currently under consideration by the Commerce Commission and has received draft approval. The project is intended to address forecast demand growth and reliability requirements in the Upper South Island and support increasing electrification across the region.

Alongside these projects, we are continuing to investigate a range of potential future MCPs across the country. These include transmission capacity upgrades in the Waikato and Upper North Island, Auckland and Northland, the Central North Island and the Lower South Island, as well as future stages of the HVDC programme. These investigations form part of our longer-term planning to ensure the grid can continue to support growing demand, new renewable generation and New Zealand's transition to a more electrified economy.

The scale and number of major projects currently being delivered, assessed and investigated creates increasing demands on workforce capability and delivery resources. We continue to prioritise investment across our programme of work to ensure we maintain core service performance, meet customer expectations and develop the grid in a prudent and efficient manner.

Table 16: MCPs

Region	Project name	Indicative commissioning	Estimated cost constant 25/26 $m	Economic or Reliability?	Status
Approved major capex projects					
Hawkes Bay	Redclyffe 220 kV switchyard resilience	2027	50.8	Reliability	In delivery
Western Bay of Plenty	Western Bay of Plenty regional	2029-2032	63.4	Reliability	In delivery
Grid Backbone	HVDC Stage 1	2031	1031.7	Economic	In delivery
Major capex projects under consideration by the Commerce Commission					
Upper South Island	Upper South Island upgrade	2031+	282.3	Reliability	Draft approval
Unapproved major capex projects - under investigation					
NI Grid Backbone	Waikato and Upper North Island Transmission Capacity (WUNI 2)	2030-2036	687.6	Reliability	Investigation currently underway
Waikato	220/110 kV interconnection capacity	Tentatively 2030	48.1	Reliability	Investigation currently underway
Central North Island	Tararua enabling renewables	Tentatively 2030	52.1	Economic	Investigation currently underway
Central North Island	Wairakei-Whakamaru capacity	Tentatively 2032	266	Economic	Investigation currently underway
Auckland and Northland	Cross-Auckland transmission capacity	Early-mid 2030s	800	Reliability	Investigation underway
Otago-Southland	Lower South Island transmission capacity	TBC	TBC	Economic	Needs identification
Grid Backbone	HVDC Stage 2 (control systems)	Early-mid 2030s	416.5	Economic	Investigation currently underway
Unapproved major capex projects - investigation scheduled for options analysis					
Taranaki	Brunswick-Stratford	TBC	TBC	Economic	Needs identification
Unapproved major capex projects - investigation scheduled to confirm need					
Northland	Northland 220kV transmission capacity	TBC	TBC	Economic	Needs identification

More detailed information on E&D capex and MCPs can be found in the 2026 Transmission Planning Report (TPR)[10].

[10] See, Transpower *Transmission Planning Report* (TPR), 2026.

4.7 ICT expenditure

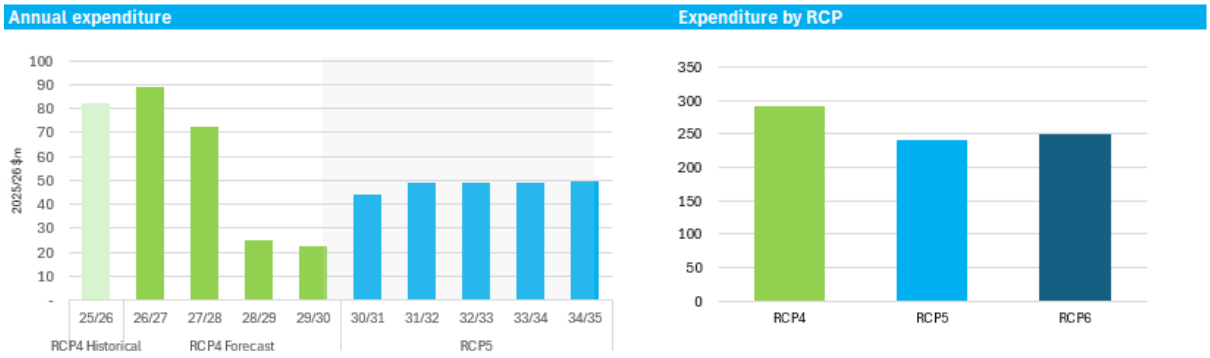
4.7.1 ICT base capex and Anything-as-a-Service

Our delivery model is shifting to incorporate increasingly more Anything-as-a-Service (XaaS) solutions, including but not limited to any Software as a Service (SaaS), Platform as a Service (PaaS), and Infrastructure as a Service (IaaS). Historically, these costs have been accounted for as capex.

The strategic direction for our base capex and XaaS opex forecast is listed below by portfolio:

- Asset Management Systems;
- Transmission Systems;
- Corporate Systems;
- ICT Shared Services;
- Telecommunications, Network and Security Services (including TransGo and Enterprise Business Capability Programmes);
- Transmission Pricing Methodology (TPM) ICT enablement and enhancement in RCP4.

Figure 8: Historical and forecast base ICT capex and XaaS opex (constant 2025/26 $m)

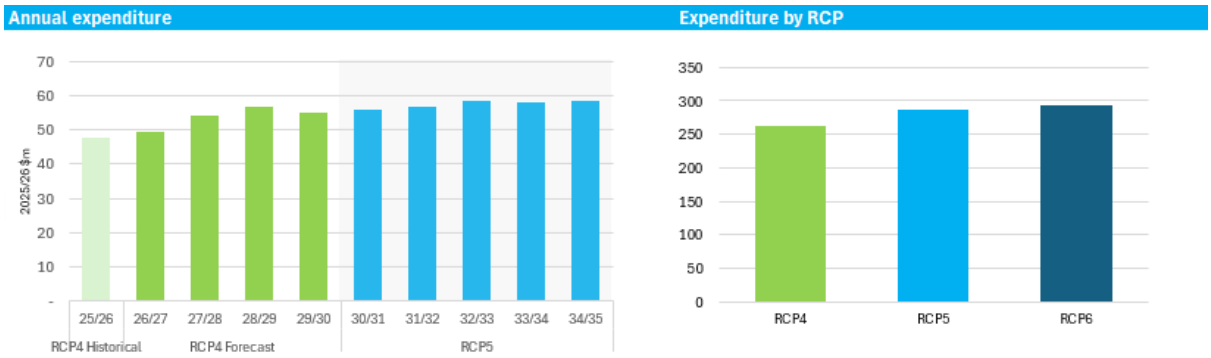


4.7.2 ICT opex

Our ICT opex covers the external costs to run our ICT function and comprises non-capitalised leases, third-party support and maintenance, outsourced services, licences, communications and control and investigations.

We continually review the balance between in-house and outsourced solutions to ensure operational support is cost-effective.

Figure 9: Historical and forecast base ICT opex (constant 2025/26 $m)



More information on our ICT expenditure can be found in the 2026 Asset Management Plan in the "ICT expenditure" section[11].

4.8 Grid maintenance

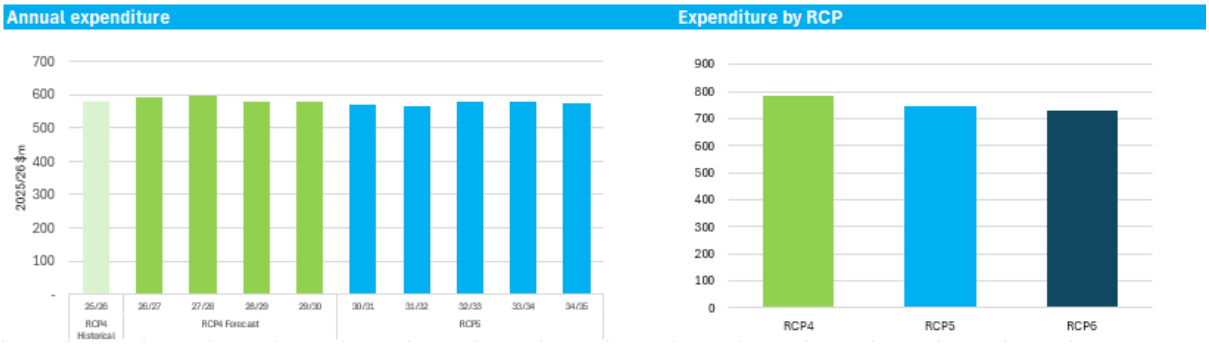
Grid maintenance is categorised as follows:

- preventive maintenance (routine servicing or inspections);
- predictive maintenance (maintenance performed based on condition prior to asset failure);
- corrective maintenance; and
- proactive maintenance.

RCP4 grid maintenance expenditure shown in the figure below reflects an increase in work to enable deferral of capex, specifically an increase in our coverage of condition assessment information on conductors, increase maintenance on some towers to enable the tower to pole programme, and our improvements in sulphur hexafluoride (SF6) management. These increases are partially offset by improvements made through our preventive maintenance optimisation programme, which has allowed us to reduce preventative maintenance activities while maintaining the reliable and safe performance of the grid. Additionally, there is a reduction in capex spend, e.g. reconductoring, as maintenance activities allow deferral of replacement of assets. We are forecasting a reduction in RCPs 5 & 6 due to expected realisation of maintenance efficiency opportunities, and the completion or near completion of some of our maintenance programmes.

[11] See, *Transpower Asset Management Plan*, 2026, p. 15.

Figure 10: Historical and forecast maintenance opex (including resilience) (constant 2025/26 $m)



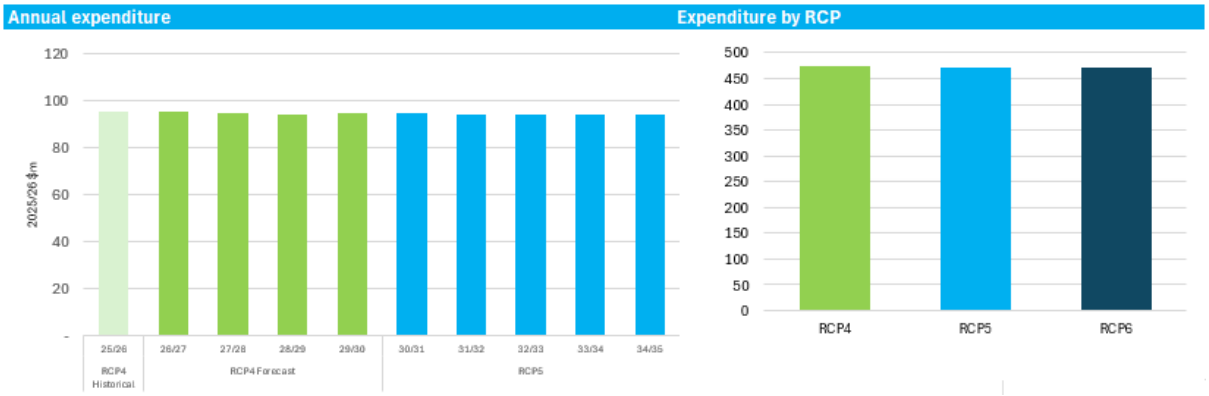
4.9 Asset management and operations

Asset management and operations cover the costs related to internal staff and consultancy associated with the grid divisions such as:

- investigations relating to the enhancement and improvement of our transmission system;
- investigations related to condition-driven replacement projects;
- innovation and exploring new technology for the grid; and
- funding of our internal workforce, which is essential to enabling all work on our network, i.e., asset management, planning, and network operations.

Expenditure is primarily driven by the increased internal resources necessary to plan and deliver the increased investment programme over RCP4 and RCP5.

Figure 11: Historical and forecast asset management and operations (including sustainability) opex (constant 2025/26 $m)



4.10 Business support

4.10.1 Business support base capex

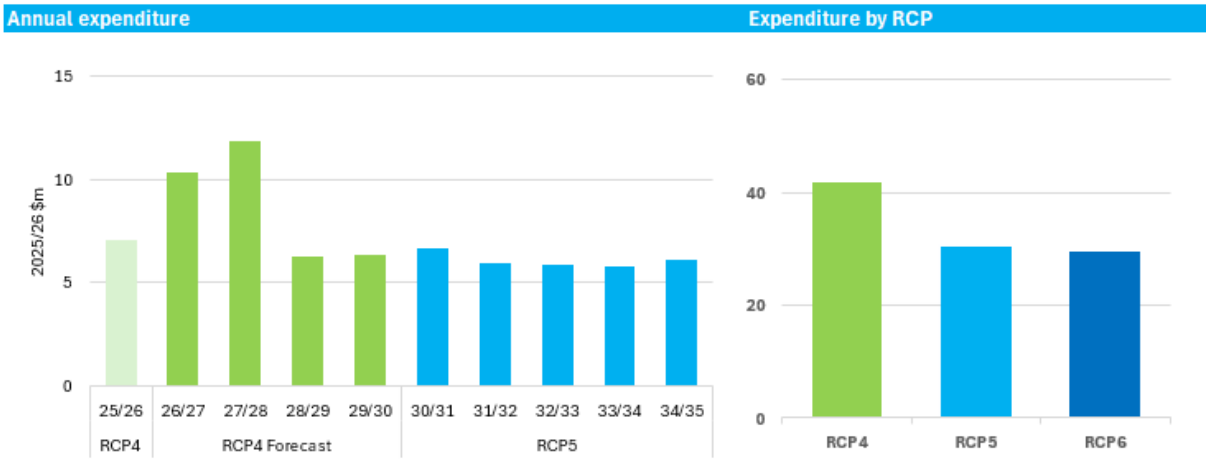
Business support assets cover our office buildings, vehicles and office equipment including office desks, chairs, meeting room furniture, laptops, and mobile phones.

Our business support assets are categorised as:

- Office buildings;
- Vehicles;
- Minor fixed assets - office equipment;
- Minor fixed assets – IT;
- Residential houses.

Our management objective for business support assets is to provide the appropriate level of capability at the least cost but also reflect the diversity of the asset types.

Figure 12: Historical and forecast business support capex (constant 2025/26 $m)

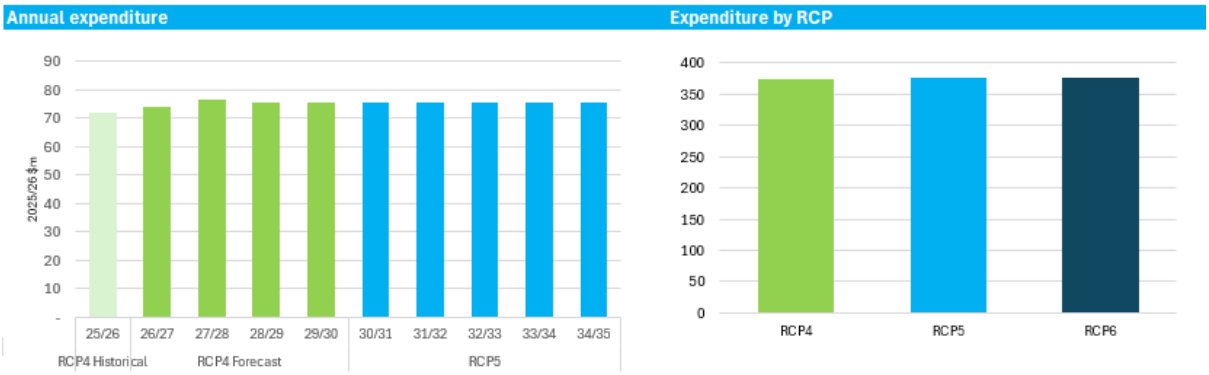


4.10.2 Business support opex

Business support functions encompass the staff and consultancy costs associated with activities that support the delivery of our investment programme and support our asset management and operations activities. It covers the internal costs of permanent employees and contractors of six divisions.

- IST;
- External affairs;
- Corporate services;
- Corporate governance;
- People;
- Customer and strategy.

Figure 13: Historical and forecast business support opex (constant 2025/26 $m)



4.11 Insurance

Insurance expenditure for RCP4 includes both external and captive (self-insurance) premiums. Primary determinants of insurance costs are the insurance type and volume of insurance cover we purchase, including market premium pricing.

To insure prudently, we compare ourselves to other similar sized organisations' insurance approach and advice from insurance brokers. Insurance premiums are driven by market factors such as perception of risk, loss experience and availability of capital and not simply inflationary pressure.

Insurance market capacity is declining as insurers reduce exposures to catastrophic event risk, or exit the insurance class entirely, which has impacted premiums significantly. Utilities with catastrophic natural disasters exposure, like Cyclone Gabrielle are experiencing considerable challenges securing insurance cover risks. For example, the Cook Strait submarine cables, full insurance cover is unavailable resulting in Transpower retaining more self-insurance. The growth in costs in later RCPs is a function of a growing insured regulated asset base, as we build the transmission network to meet customer needs over time, and expected premium increases due to market risks to which insurers are exposed.

Figure 14: Historical and forecast insurance costs (constant 2025/26 $m)