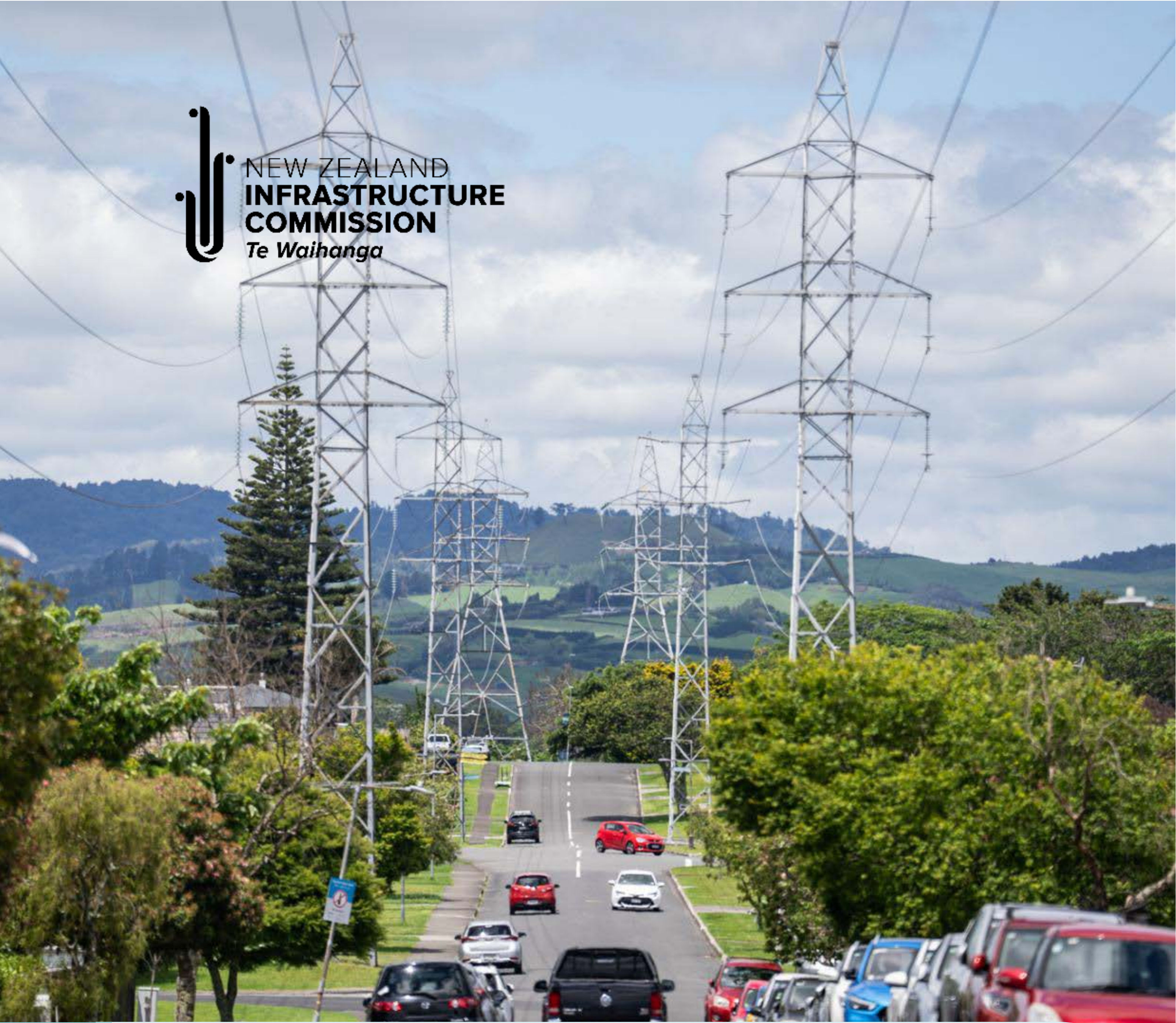

Shifting currents: Energy infrastructure in transition

Te Waihanga Research Insights series

June 2026

Tewaihanga.govt.nz

New Zealand Infrastructure Commission / Te Waihanga

Te Waihanga seeks to transform infrastructure for all New Zealanders. By doing so our goal is to lift the economic performance of Aotearoa and improve the wellbeing of all New Zealanders.

We are an autonomous Crown entity, listed under the Crown Entities Act 2004, with an independent board. We were established by the New Zealand Infrastructure Commission/Te Waihanga Act 2019 on 25 September 2019.

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Research Insights series contact

Graham Campbell
Director, Economics and Research
E: Graham.Campbell@tewaihanga.govt.nz
Website: tewaihanga.govt.nz
Linkedin: tewaihanga

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Cover Image: High-voltage transmission towers (pylons) over residential street in Auckland. Photo courtesy of **Transpower**

NEW ZEALAND INFRASTRUCTURE COMMISSION Te Waihanga

Contents

Cut to the chase

Energy infrastructure powers our lives and its future shape matters for all of us

Energy is at the heart of our wellbeing. It powers our homes, schools, and businesses. It enables us to make and grow goods we use and consume every day.

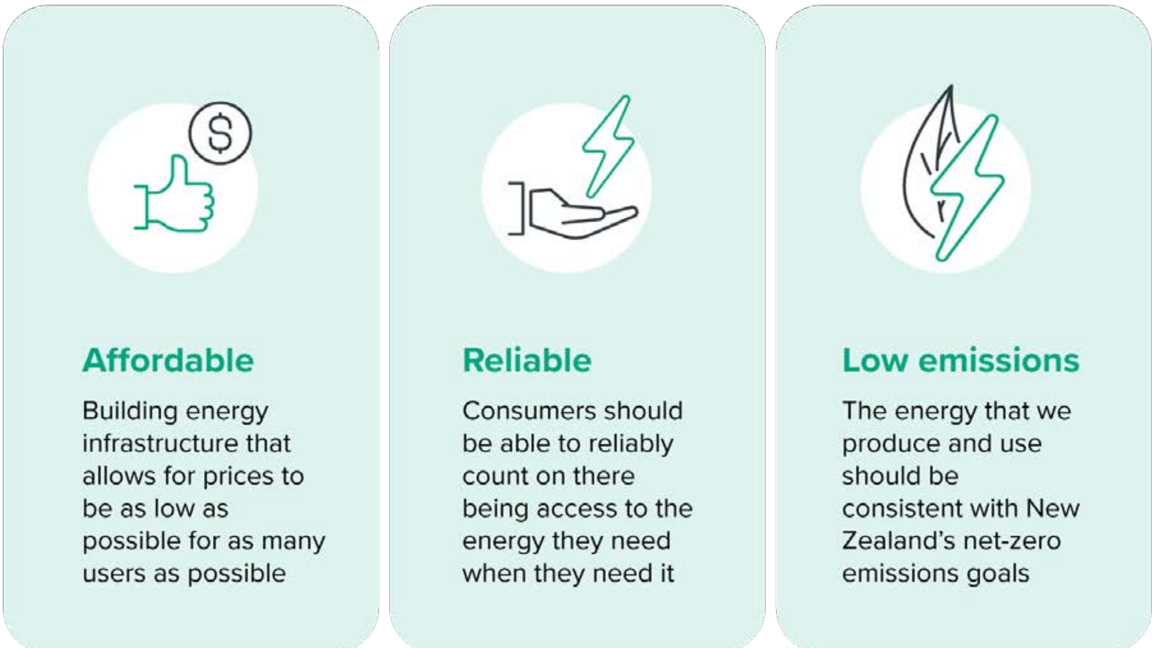
Our energy comes from many different sources, including electricity, gas, liquid fuels, and biomass such as wood or coal. Energy infrastructure stores, moves, transforms, and helps us use these sources of energy.

New Zealand has been building, transforming, and improving its energy system for over 150 years. As innovations across the economy spurred higher living standards, energy infrastructure has needed to keep pace. From New Zealand’s first electric power station in Reefton in 1888, the development of our gas fields in the 1960s and 1970s, to the Turitea Wind Farm in 2023, the way we create, move, and manage energy has become more sophisticated.

Our energy system should be low priced, reliably supplied, and low emitting

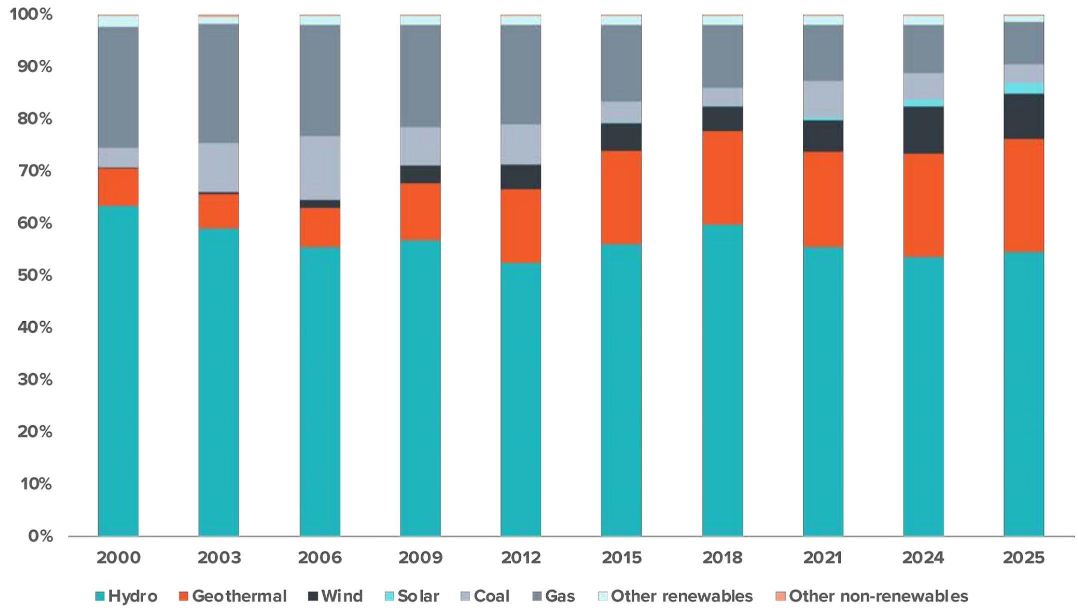
As we move into the future, we should expect continued changes to our energy system, but our focus should be on achieving balance between three key outcomes: affordability, reliability, and low emissions. This is often described as the “energy trilemma”.

Figure 1: The energy trilemma – goals that New Zealand's energy system must balance



New Zealand has traditionally performed well relative to international peers on these measures. The vast majority of our electricity generation relies on cost-effective renewable sources like hydro, wind, and geothermal.

Figure 2: Share of annual electricity generation by fuel source, 2000–2025



Source: MBIE, Electricity data tables.

Note: Data is displayed as snapshots of specific years, rather than period averages.

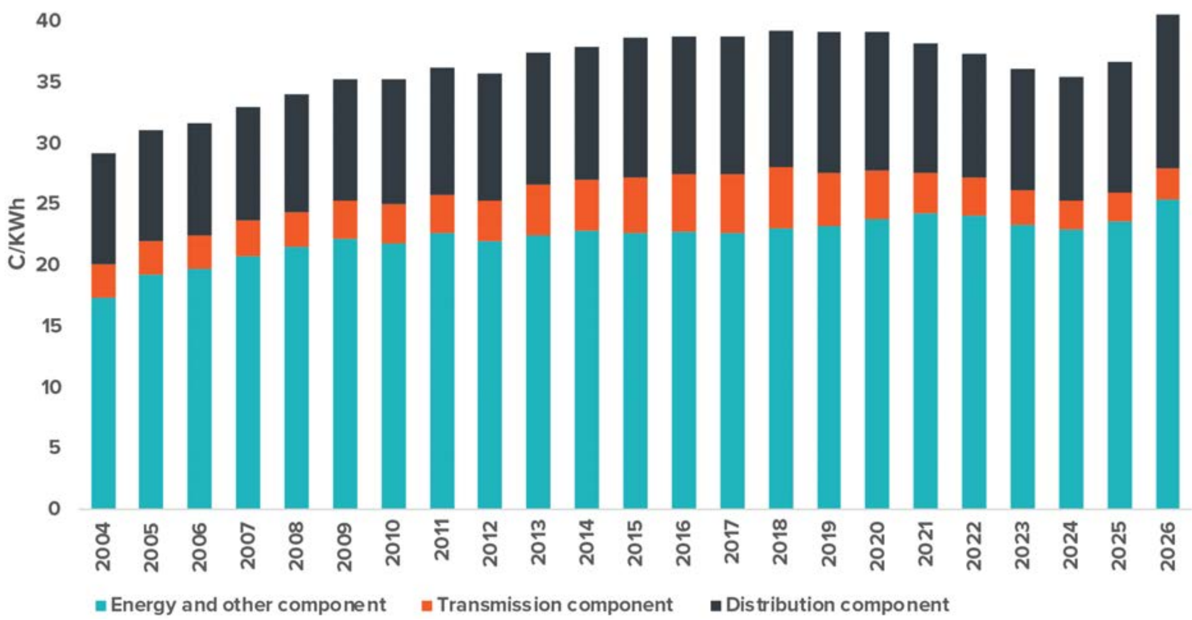
Maintaining this performance will be more challenging in the future. The cost and availability of different energy sources is changing, which in turn changes how our energy system must operate. To meet our emissions goals and take advantage of new technologies, the traditional ways that we have powered our vehicles, industries, and businesses are going to have to shift to low emission electricity.

Electricity prices usually track what it costs to build and operate electricity infrastructure

Paying for electricity infrastructure requires prices to be set at levels that can recover costs for the entities that build, maintain, and operate those pieces of equipment.

For electricity, the infrastructure parts of the bills primarily comprises two components: the cost to make the electricity and the cost to get it to customers. Each of these are set in different ways, so when consumers see changes to their bills, it could mean that one component has changed while other components have stayed the same. Over the last 20 years, the relative shares have moved in tandem.

Figure 3: Inflation adjusted household electricity charges by component, 2004–2026



Source: MBIE, Quarterly Survey of Domestic Electricity Prices (QSDEP) and Stats NZ, Consumers Price Index (CPI).

Note: Prices are as of February in a given year, adjusted to 2026Q1 prices using the CPI. Prices include GST, which is spread proportionately across all three components.

The cost to get electricity from where it's generated and where it's used (transmission and distribution) are subject to regulation in five-year periods that aims to replicate the effects of competition by ensuring prices are fair, cost reflective, and providers remain customer-responsive and innovative.

Increasingly, attention has been paid to the prices for the actual cost of generating electricity. These prices are determined in a wholesale market that ultimately shapes the cost of electricity across the whole system. This market operates in a classic supply versus demand framework, where electricity generators submit offers every half hour stating how much electricity they are willing to supply and at what price. The market price for that half-hour period is set at the price that satisfies demand forecasts generated by Transpower. Offers submitted under the clearing price provide electricity, while those offers over do not.

Over the long run, the cost of producing electricity should be closely related to its price, because if electricity prices go well above, there is incentive to increase supply. As more supply comes online, so long as that supply is provided at a cost that is lower than long-run prices, it will help to reduce prices.

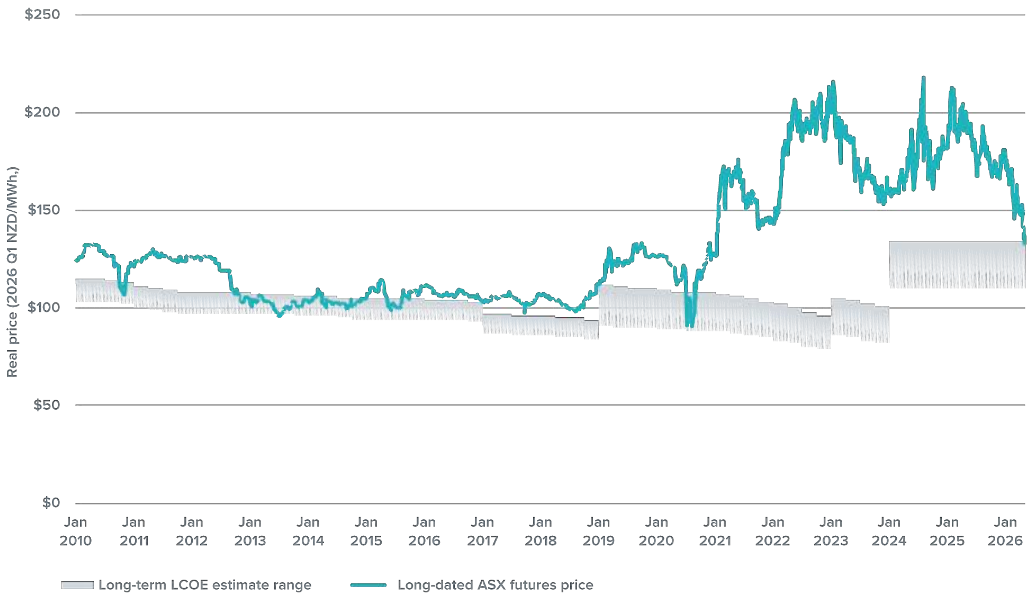
However, when demand outpaces supply, or when supply is constrained or becomes more expensive, prices go up.

The system has been out of balance since 2019 but is slowly returning to equilibrium

After a long period of stable electricity prices, the market has become increasingly volatile since 2019, and average prices have trended up. This volatility has had a significant impact on industrial consumers who are most exposed to price variability. After initially being protected by long-run price contracts, residential customers are starting to feel the impacts: 6.7% of households reported not being able to afford to keep their homes adequately warm in 2024.

What's happened? From 1995 through 2019 futures contract prices, which indicate electricity generators and buyers' expectations for future wholesale prices, were almost exactly in line with the estimated long-run cost of building new generation. Beginning in 2019, prices spiked upwards and remained elevated. While forward prices are beginning to come down, the normalisation of prices has been slower than most consumers would like and prices are still above estimates of the long-run cost to build new generation.

Figure 4: Long-dated ASX futures prices relative to the cost to build and operate new generation, January 2010 to early May 2026



Source: Chart recreated from futures contract price data and long-run LCOE estimates published by the Electricity Authority. Futures prices and LCOE estimates are inflation-adjusted using Stats NZ's CPI.

Note: "Long-dated" refers to the average price of long-dated ASX futures at the Otahuhu node. The blue line represents historic ASX daily closing prices of all long-dated contracts (meaning contracts for settlement more than 12 months in the future). The horizontal axis represents the trading day, rather than the settlement date. The grey bar shows the Electricity Authority's estimates of long-term LCOE for new generation investment, which change over time as the cost of building and fuelling generation has changed.

Rather than a single explanation, elevated prices likely reflect the confluence of several factors:

- **More expensive firming generation:** During years where there is less rainfall, we help meet demand by burning gas and coal to generate electricity, called firming generation. Since 2019, gas production has been significantly below expectations, increasing the cost of gas for generating electricity, flowing through to wholesale electricity prices. This makes the impact of dry years like 2024 on electricity prices more severe than it would otherwise be.

- **Uncertainty around future demand and prices:** Even as gas firming costs pushed prices higher, new generation was initially slow to be built for a few reasons. The New Zealand Aluminium Smelter, which consumes about 12% of New Zealand's electricity, faced an uncertain future until 2024. If it had closed, it would have freed up a significant amount of supply and made newly-built generation unprofitable. There was also uncertainty about whether government would build supply of its own to reduce prices, which would reduce revenues available for other generation investors.

In short, the high prices we've been experiencing appear to reflect a period of more expensive and less responsive electricity supply.

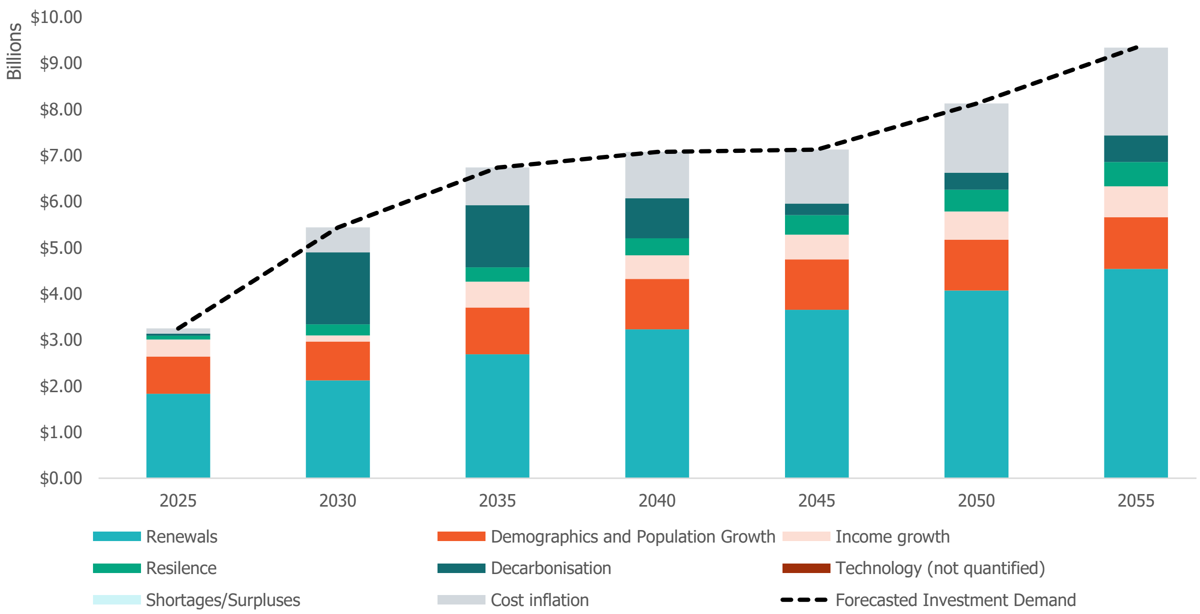
The good news is that this price signal now appears to have incentivised a significant amount of new investment. The result is that long-run price expectations of the market are trending downward towards long-run costs to produce electricity.

Meeting long-term goals of economic growth and decarbonisation

The New Zealand Climate Change Response Act 2002 requires the country to achieve net zero emissions for all greenhouse gases (except biogenic methane) by 2050. Electricity is expected to be the infrastructure network that is most heavily affected, as we replace the burning of fossil fuels and coal for energy.

The Commission forecasts that business-as-usual demand for electricity and gas infrastructure investment would equate to about $2 billion to $5 billion per year. However, because of our decarbonisation goals and related future demand, an additional $26 billion of investment will be required above business-as-usual investment needs.

Figure 5: Forward Guidance investment forecast for electricity and gas, 2025 to 2055, in 2025 NZD

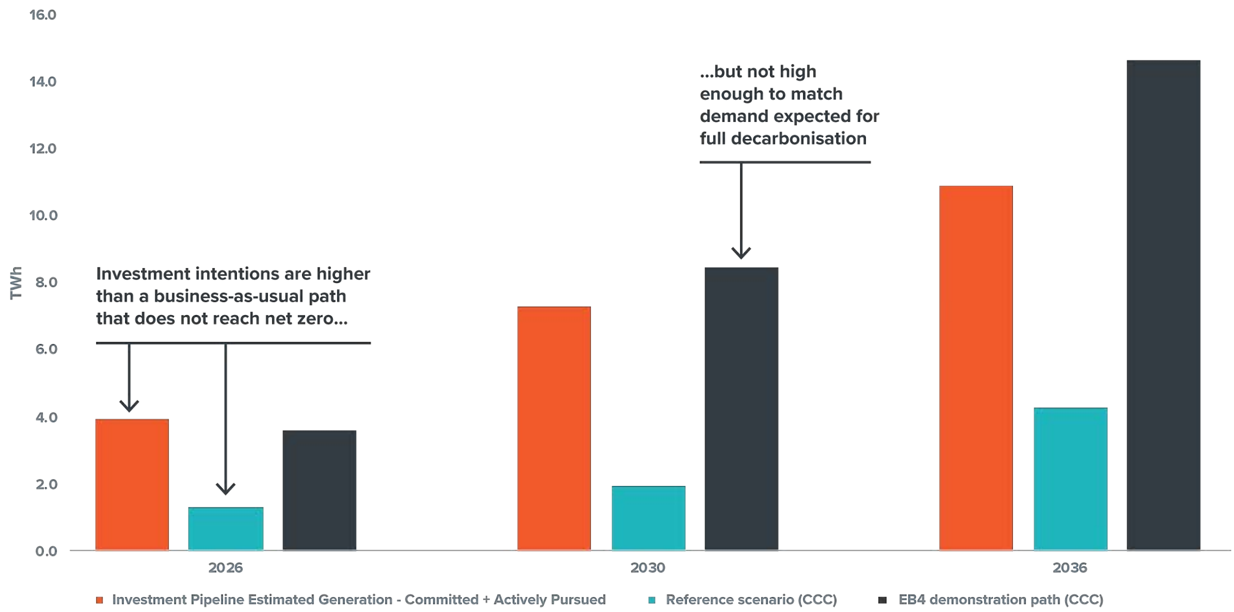


Source: New Zealand Infrastructure Commission modelling and analysis.

But because New Zealand's electricity market operates on a commercial basis, infrastructure providers won't build new generation, transmission, or distribution unless they have reasonable certainty that the demand will be there. Build too early, and they risk financial implications. However, the risk is that if they build too late, then demand will outpace supply, leading to higher prices than there needs to be.

Currently, developers believe there will be *some* increase in demand in the next 10 years, but not enough that would be consistent with decarbonisation of transport, heating, and industry. Medium- and longer-term investment intentions are not yet sufficient to meet the electricity demand required for full decarbonisation of the economy in line with the Climate Change Commission's recommendations.

Figure 6: Electricity generation investment intentions versus requirements to achieve CCC scenarios for demand. 2026, 2030 and 2036



Source: Electricity Authority, Generation investment pipeline, (March 2026), He Pou a Rangi Climate Change Commission, Modelling and data: Final reports on the fourth emissions budget and 2050 target review (November 2024), New Zealand Infrastructure Commission analysis.

Note: If a final investment decision hasn't been made but other significant milestones have been reached (a location being secured in addition to a consent application being submitted or contracts to finance the project executed) then the project is "actively pursued". Generation was estimated from the capacity values in the generation investment pipeline. It was estimated using the following formula: generation (MWh) = capacity (MW) * hours in a year * capacity factor. The assumption for capacity factors can be found in Table A1 in Appendix A. The additional demand to achieve the CCC scenarios is calculated by taking the demand at the relevant year (2026, 2030, and 2026) minus the base year 2022.

Unlike the period from 2019 to today, where new *supply* has been slow to force prices back towards long-run marginal costs, the challenge for the long-term transition to net zero is that *demand* uncertainty could constrain investment in new electricity infrastructure. Without confidence in future demand growth, full commitment to the required investment remains unlikely.

The path to affordable prices, stable supply, and low emissions

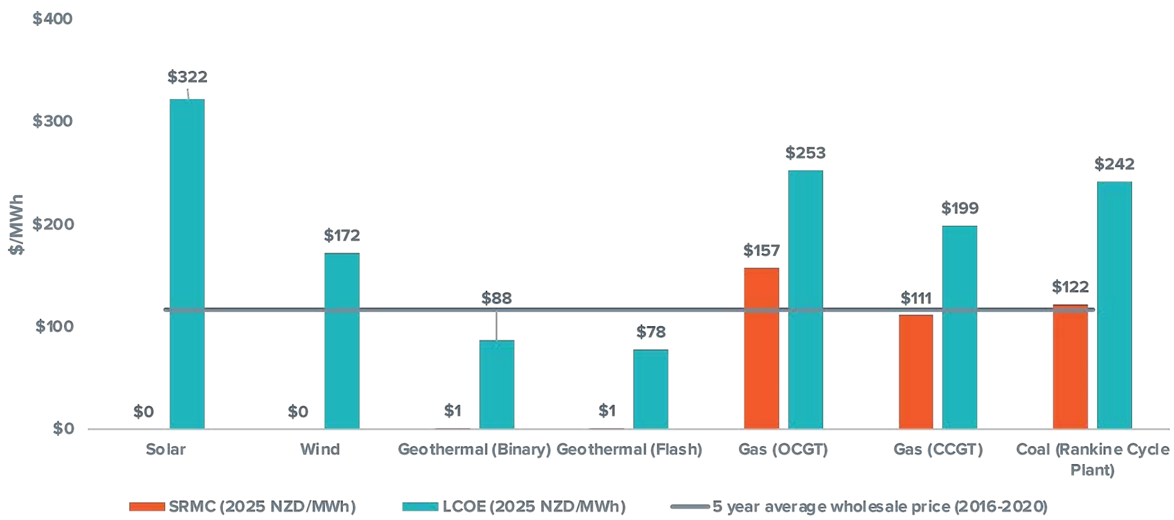
Our analysis of short- and long-run challenges in the energy system leads to four key implications for the planning and building of energy infrastructure, as well as the policy that enable the efficient delivery and operation of that infrastructure.

1) **Building low-cost electricity infrastructure will keep prices low in the long term.**

For the electricity network, the wholesale market means that the prices consumers pay reflect the most expensive offer bid into the market to meet demand. Those bids will be determined by the cost of producing electricity in the short term, as well as the long-run costs to recover their construction, maintenance, and eventual renewal.

Ten years ago, the cost of producing electricity was very different than it is today. In 2015, wind power required consistently high prices to be profitable to build, and building solar generation was far too costly to be profitable. Low gas prices meant that gas plants could be profitable to own and run so long as there were periods of high prices, like dry years.

Figure 7: Estimates of short run marginal costs and levelised cost of electricity, by type of plant, year 2015

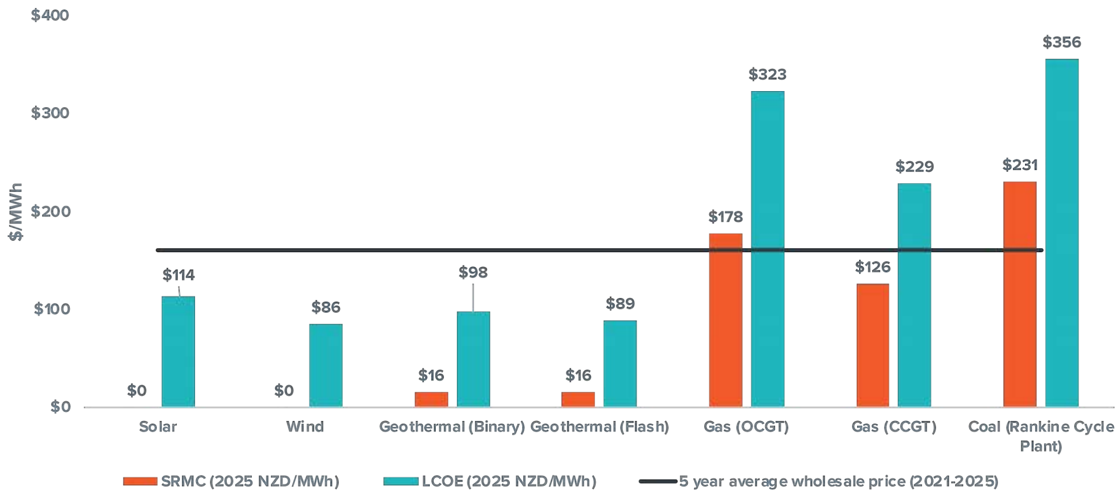


Source: New Zealand Infrastructure Commission analysis.

Note: Calculations and assumptions explained in Appendix A.

By 2025, renewable electricity sources have become much cheaper to build while continuing to have low to zero short-run operating costs, as they don't require fuel. Conversely, thermal electricity generation has become more expensive to run, meaning they now need higher prices to be commercially viable. These trends are expected to continue over the next 10 years.

Figure 8: Estimates of short run marginal costs and levelised cost of electricity, by type of plant, year 2025



Source: New Zealand Infrastructure Commission analysis.

Note: Calculations and assumptions explained in Appendix A.

This has had two important implications for our electricity infrastructure network. First, over the last 25 years, more expensive thermal generation has increasingly been retired, while building of cheaper renewable sources has accelerated. This should have the long-run impact of putting downward pressure on prices in normal periods.

The second is that for thermal firming generation that can be turned on as needed when variable renewables fall short or demand peaks, the commercial case is becoming increasingly more challenging. Low-cost renewables displace this type of generation during normal times, confining their use to low-supply periods. But because of high fuel prices, prices need to increase even higher to make their use worthwhile.

2) Policy certainty and coherence are critical in both the short and long term.

In the short term, policy clarity is important for ensuring the system can add supply confidently. This additional supply can help bring down prices. Two examples include the role of gas and government supply interventions.

For gas, the benefits of improved clarity around the transition are clear. For example, improved disclosure around downside risks to production may have reduced electricity wholesale price volatility post-2019, improving investment signals for alternative generation, storage, and fuel switching options for businesses and industry.

Similarly, interventions aimed at improving security of supply in dry years should consider the risk of unintended consequences, like reduced investment in additional supply. Supply interventions are often discussed as addressing security of supply challenges, but in practice are usually intended to reduce prices, which further undercuts the economic case for generation that is used infrequently. These risks can be mitigated through a well-developed business case that consider multiple options, including non-infrastructure solutions.

Over the long term, policy will play a critical role for demand. New Zealand has carefully considered paths for achieving net zero emissions by 2050, all of which require the switching of fuels towards low emissions electricity. This will naturally drive significant growth in demand. Infrastructure providers will require certainty of government's policy approaches towards net zero to invest confidently. Absent that certainty, large investments in generation capacity will be financially risky and are unlikely to happen.

3) An adaptable and flexible system will help keep energy affordable and reliable.

An energy system that can respond in many ways to increases in demand or risks to supply is one that will be more affordable and reliable for households and businesses. As our energy system changes over the next 30 years, there is likely a need for it to become increasingly sophisticated about handling situations and challenges. Infrastructure solutions should be only part of the answer.

Since 2019, the sustained period of prices above the cost of supply raises the question of whether a return to normal price levels could have been achieved sooner and if there are frictions preventing that adaptability. This includes regulatory barriers to quickly adding supply and ensuring the market is sufficiently competitive to incentivise new entrants to build new generation when prices are high. There would be value in exploring these barriers further.

Over the long term, the adaptability of the system is likely to become even more important. As the energy system transitions more to renewable electricity generation, it means prices will likely be lower more often, since costs of production are lower. However, it also means that demand peaks and dry years will need to be handled differently. We are already starting to see this: in recent years, wholesale prices have spent more time than before at the very low or high ends of the scale.

Figure 9: Distribution of inflation adjusted demand-weighted wholesale prices

Source: Electricity Authority, EMI wholesale prices and demand trends; Stats NZ, Consumers Price Index (CPI).

Note: The graph displays how many days each year wholesale prices fell within each price range (percentile). For example, in 2025, wholesale prices were in the highest range, the 95th to 100th percentile, for 50 of the days. P0-P5 represents the lowest price range, while P95-P100 represents the highest.

This means a greater value will be placed on demand flexibility, or technologies and practices that enable households and businesses to shift their energy consumption away from demand peaks and dry years. For instance, the Energy Efficiency & Conservation Authority (EECA) estimates that approximately 1,350 GWh of energy per year could be shifted from peak periods using demand flexibility measures at a procurement price of less than $500 per MWh.

Further, it will be important to monitor and improve financial hedging markets that enable electricity retailers and major users to manage their exposure to volatile prices. Possible ways to bolster the system we already have include improving market liquidity, developing disclosure requirements for over-the-counter contracts, and ensuring that both generators and users can access the products they need to manage risk effectively.

4) Players in the energy system will need to adapt and coordinate.

The energy system has many different players including asset owners, regulators, and consumers. Through policy and regulation, the Government can set direction through high-level rules for markets and long-term strategies about the country's energy goals.

The complexity of the energy system means that policy and operational changes in one part of the system can have consequences in the other. As the energy transition progresses and the infrastructure mix changes, the various players will also need to adapt.

More active coordination across agencies and organisations will be needed, tracking how decisions in one part of the system affect outcomes in another and ensuring that interventions designed to solve one problem do not inadvertently create others. But coordination alone is not sufficient. The gas sector provides a cautionary example: limited visibility over production risks and the pace of decline in domestic gas availability caused problems for both the electricity sector and large industrial and commercial gas users. Institutional arrangements that actively tracked risks across the energy system and signalled them to infrastructure providers and users could have reduced the severity of this disruption.

The importance of this oversight and adaptation role will grow as the energy transition gathers momentum, especially to gauge whether the infrastructure investment the system needs is being delivered. This will require tracking and monitoring performance against long-term goals, establishing clear and consistent signals to all the players about long-run strategies, and providing visibility and analysis on how potential actions and policies affect the system.

1. Introduction

Energy is vital for our society

Energy is critical for our wellbeing. It powers our homes, schools, and hospitals. It is an essential input to production for businesses. Energy infrastructure underpins our economy.

Our energy comes from many different sources, including electricity, gas, liquid fuels, and biomass such as wood or coal. Infrastructure stores, moves, transforms, and helps us use these sources of energy.

Our energy infrastructure networks are significant and far-reaching. Electricity is one of the largest infrastructure networks in New Zealand by asset value. Gas and liquid fuel networks are smaller but important for the functioning of many different parts of the economy.[1]

Our energy system should be low priced, reliably supplied, and low emitting

Our energy system should seek to achieve a balance between three key outcomes – often described as the “energy trilemma”.[2]

First, to maintain affordability for households and businesses, we should build energy infrastructure that allows for prices to be low and as stable as possible, for as many users as possible. This means setting up our infrastructure system and related policies to achieve lowest costs in the long run.

Second, consumers should be able to reliably count on there being access to the energy they need. This means that the country should not have intermittent supply shortages that lead to undesired rationing like electricity blackouts, where consumers are unable to use electricity even if they highly valued it.

Third, to meet our emissions goals, our uses of energy, and the infrastructure that provide it will need to shift. The New Zealand Climate Change Response Act 2002 requires the country to achieve net zero emissions for all greenhouse gases (except biogenic methane) by 2050. This will require a change in the sources of energy we use over time to lower-carbon sources (referred to as the energy transition). And if our sources of energy must change, so too does the infrastructure that supports it.

New Zealand has traditionally performed well on all three dimensions of the energy trilemma. As of 2023, we ranked ninth on the World Energy Council’s Energy Trilemma Index, reflecting how we have invested in and operated energy infrastructure to date.[3]

Maintaining this performance will be more challenging in the future. The cost and availability of different energy sources is changing, which in turn changes how our energy system must operate. To meet our emissions goals and take advantage of new technologies, the traditional

[1] This definition of infrastructure excludes “upstream” assets in the network such as extraction and refining.
[2] World Energy Council, *World Energy Trilemma Framework*.
[3] World Energy Council, *World Energy Trilemma Index*.

ways that we have powered our vehicles, industries, and businesses will need to shift from higher-emitting fuels like oil and gas towards low-emission electricity.

This will change the mix of infrastructure that we need in future. Analysis from government, industry, academia, and other commentators does not necessarily form a consensus across the best approach to these future challenges.

Bringing an infrastructure perspective to the challenges ahead

The Commission's main function is to "co-ordinate, develop, and promote an approach to infrastructure that encourages infrastructure, and services that result from the infrastructure, that improve the wellbeing of New Zealanders".[4]

Relative to other players and agencies, this gives us two different perspectives.

First, our focus is on investment in and operation of *physical infrastructure assets,* rather than broader energy policy issues. In contrast to other government agencies or the Climate Change Commission, our focus is advising on how to optimise outcomes achieved from infrastructure in the long term, rather than how to achieve broader policy goals through energy policy. However, where broader policy choices affect infrastructure, we seek to understand this as context for our infrastructure advice.

Second, we take a system view of infrastructure issues across sectors in the long term. This distinguishes us from others such as the regulators (Electricity Authority, Gas Industry Company, or the Commerce Commission), where legislation may limit consideration to regulating specific aspects of energy infrastructure, rather than considering interdependencies between different sectors.

As energy sources and uses evolve and shift, it is worth exploring the challenges possibly preventing the efficient and effective delivery of low prices, reliable supply, and low emissions energy. That is the goal of this *Research Insights* report.

This paper expands on commentary about the energy sector and Recommendation 14 of the National Infrastructure Plan. Consistent with our role, it takes a system approach, highlighting that as we progress towards net zero through emissions reductions, we face complex, cross-sectoral challenges to keep energy affordable, reliable, and to use it more efficiently.

This paper is designed to explain in more depth the New Zealand Infrastructure Commission's view of the transition, with a focus on electricity and, where related, gas networks. This includes electricity infrastructure (generation, transmission, and distribution) and gas infrastructure (transmission and distribution but excluding extraction). While liquid fuels are significant and face partly related challenges, their physical infrastructure footprint is comparatively small, and as a result, this paper does not place significant emphasis on liquid fuel infrastructure and supply.[5]

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[4] New Zealand Infrastructure Commission/Te Waihanga Act 2019, ss 9-11.
[5] The paper does speak to these indirectly insofar as it discusses electrification of petrol/diesel using activities and their impact on electricity infrastructure.

Structure of this paper

This paper traces the story of New Zealand's energy transition – where the system has come from, what investment it needs, how the transition is unfolding in practice, and what structural challenges are making it harder than it needs to be.

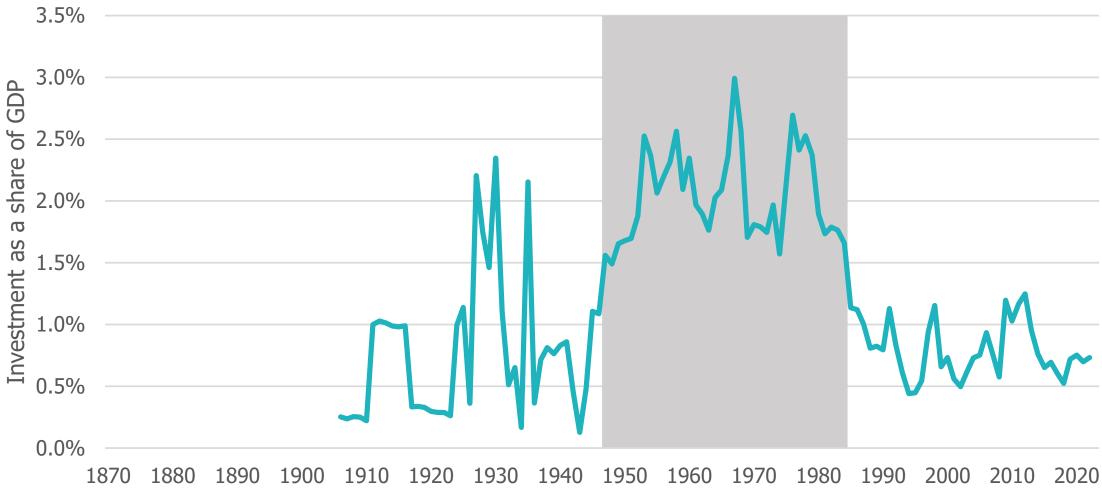
- **Section 2** describes New Zealand's electricity and gas networks – its historical development, the key players across generation, transmission, distribution and retail, the regulatory framework that governs it, and key aspects and statistics around demand, capacity, and usage.
- **Section 3** lays out how prices are set in the electricity sector and the implications for investment in new supply.
- **Section 4** describes the challenges faced by the energy system since 2019, a period of high volatility and prices, and infrastructure's role in normalising the market.
- **Section 5** lays out the long-run picture for the sector, defined by the need to meet New Zealand's net zero obligations. It describes the Commission's Forward Guidance, the long-run investment requirement to meet long-run energy demand, as well as the frictions preventing a smooth transition to a low-carbon system.
- **Section 6** concludes with key implications from this work.

2. Our energy system

2.1. The development of New Zealand's electricity system

Since our first hydroelectric power station was opened in Reefton in 1888,[6] there have been periods of significant infrastructure growth and electricity-driven industrialisation particularly between the late 1940s and late 1980s (**Figure 10**).[7] During this period, significant capacity was added to the electricity system through development of major hydroelectric power projects and schemes.[8] Towards the end of this period, multiple thermal power stations were commissioned to meet increasing electricity use and generate electricity during peak times when hydro generation is not sufficient. These power stations used domestic coal and new gas supplies from the Maui and Kapuni gas fields.[9] Investment has generally been lower since the 1990s, although new generation sources, like geothermal power stations and wind farms, have been added.[10]

Figure 10: Capital investment in electricity and gas as a share of GDP, 1906–2022



Source: New Zealand Infrastructure Commission, Nation Building: A Century and a Half of Infrastructure Investment in New Zealand (2025).

Note: Grey periods denote a boom period in investment, where investment was more than 0.5% of GDP higher than its historical average. Electricity and gas sector does not include "upstream" investment in extraction and refinery equipment.

In most cases, this investment was driven by technological innovation around energy use, population growth, and industrialisation, including development of heavy industries such as petrochemical, aluminium and steel manufacturing between the 1950s and 1980s.

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[6] Electricity Engineers' Association, *History of our industry*.
[7] For a more in-depth discussion on infrastructure history see New Zealand Infrastructure Commission, *Nation Building: A Century and a Half of Infrastructure Investment in New Zealand* (2025).
[8] Major hydro schemes such as the Waitaki, Clutha, Waikato, Tongariro and Manapouri.
[9] Including the development of the coal-fired power station at Huntly, operational from 1983.
[10] Wairākei, the first geothermal plant in New Zealand, was commissioned in 1958. Since the 1980s, supply from geothermal fields has been added at Rotokawa, Mokai, Ngā Tamariki, Ohaaki, Kawerau, Ngāwhā and Tauhara. Wind farm development started in the late 1990s, with subsequent waves of investment through to the present day.

While we rely heavily on this infrastructure today, there is evidence this investment came with high costs and years ahead of demand. Throughout this period, central government was subsidising power prices.[11] The Commission's research has identified that large portions of investment were likely subsequently written off after they were required to produce commercial returns when the government reformed large portions of the system in the late 1980s and 1990s.[12]

These reforms corporatised the sector, establishing the structures and functions within the electricity system that exist today. Major milestones include:

- **1987/88:** shifting of electricity generation and transmission from the responsibility of a government agency (New Zealand Electricity Department) to state-owned enterprises Electricity Corporation of New Zealand (ECNZ) for generation and Transpower for transmission. Corporatisation of electricity boards and authorities followed in 1990.
- **1993:** creating the wholesale market for electricity which began operating in 1996.
- **1996–1999:** splitting of ECNZ to create Genesis, Meridian, and Mighty River Power (1999), and privatising Contact (begun in 1996, full privatisation in 1999).

Since this time, capital investment in generation and supply infrastructure has tended to be more measured and incremental, following demand trends. Over the past 25 years, there has been a 21% net increase in utility scale electricity generation capacity.[13]

[11] Boshier, J., *Power Surge: How Think Big and Rogernomics Transformed New Zealand* (2022).
[12] See the Appendix of New Zealand Infrastructure Commission, *Nation Building: A Century and a Half of Infrastructure Investment in New Zealand* (2025).
[13] Concept Consulting Group Limited, consulting calculations, 2026 which were updated from Concept Consulting, *Past and future generation pipeline*, (11 October 2024). 21% increase net is from 1 April 1999 to 31 December 2025.

2.2. The energy system is complex with many players and layers

There are many players involved in system stewardship, oversight, regulation and support

The oversight and regulatory functions of the gas and electricity systems are spread across a range of government departments and Crown entities: the Electricity Authority; Ministry of Business, Innovation and Employment (MBIE); the Commerce Commission; the Gas Industry Company (GIC); and New Zealand Petroleum and Minerals (NZPM) (**Table 1**).

Table 1: Regulatory and oversight functions for the electricity and gas systems

				Ministry of Business, Innovation and Employment (MBIE)		
Agency functions	**Electricity Authority**	**Commerce Commission**	**Gas Industry Company**	Policy + strategy	System / regulatory oversight	New Zealand Petroleum + Minerals
Monitoring, reporting, review	✓	✓	✓	✓	✓	✓
Gathering information, data analytics	✓	✓	✓	✓	✓	✓
Certification, licensing, authorisations	✓	✓	✓			✓
Legislative tools (regulations, rules, codes, standards, directions, notices)	✓	✓	✓	✓	✓	✓
Investigations, inquiries, studies	✓	✓	✓	✓	✓	✓
Compliance monitoring, enforcement, dispute resolution	✓	✓	✓			✓
Communications, engagement, information, education, promotion	✓	✓	✓	✓	✓	✓

Source: Format based on the regulatory functions and activities diagram. Commerce Commission, *Enforcement Response Guidelines*.
Notes: Legislative tools includes regulation for competition (for example price controls), safety, licensing, and reporting.

The Electricity Authority oversees and regulates participants in the electricity system, through the Electricity Industry Participation Code, contracting for market operation services, monitoring and enforcing compliance, facilitating markets, and monitoring and reporting on the industry and markets. The Electricity Authority also regulates the structure of transmission and distribution pricing.

MBIE undertakes monitoring, reporting and policy functions across the energy sector, including publishing the Electricity Demand and Generation Scenarios.[14] MBIE provides system leadership and policy stewardship for energy and resources (electricity, petroleum, gas and minerals) and has responsibility for oversight of the Commerce Commission (including competition and consumer policy), the Electricity Authority, GIC and EECA. As there are interdependencies between the regulators, MBIE also convenes the informal Council of Energy Regulators group.

The Commerce Commission is the Crown entity with oversight of general competition and consumer issues and regulates markets where there is little or no competition which includes electricity and gas distribution and transmission networks. The Commerce Commission's economic regulation tools include information disclosure and setting price paths that limit allowable revenues for Transpower, electricity distribution businesses, and four gas pipeline businesses.[15]

The "downstream" gas sector (that is, everything post-exploration and production) is governed by regulations developed by the government and the GIC. The GIC is a form of industry co-regulation governed by the largest industry players, which makes recommendations to the Minister for Energy on rules and regulations.

EECA is another Crown entity that plays a role in the demand-side of the energy system. Its mandate is to encourage, promote, and support energy efficiency, energy conservation, and the use of renewable sources of energy.[16]

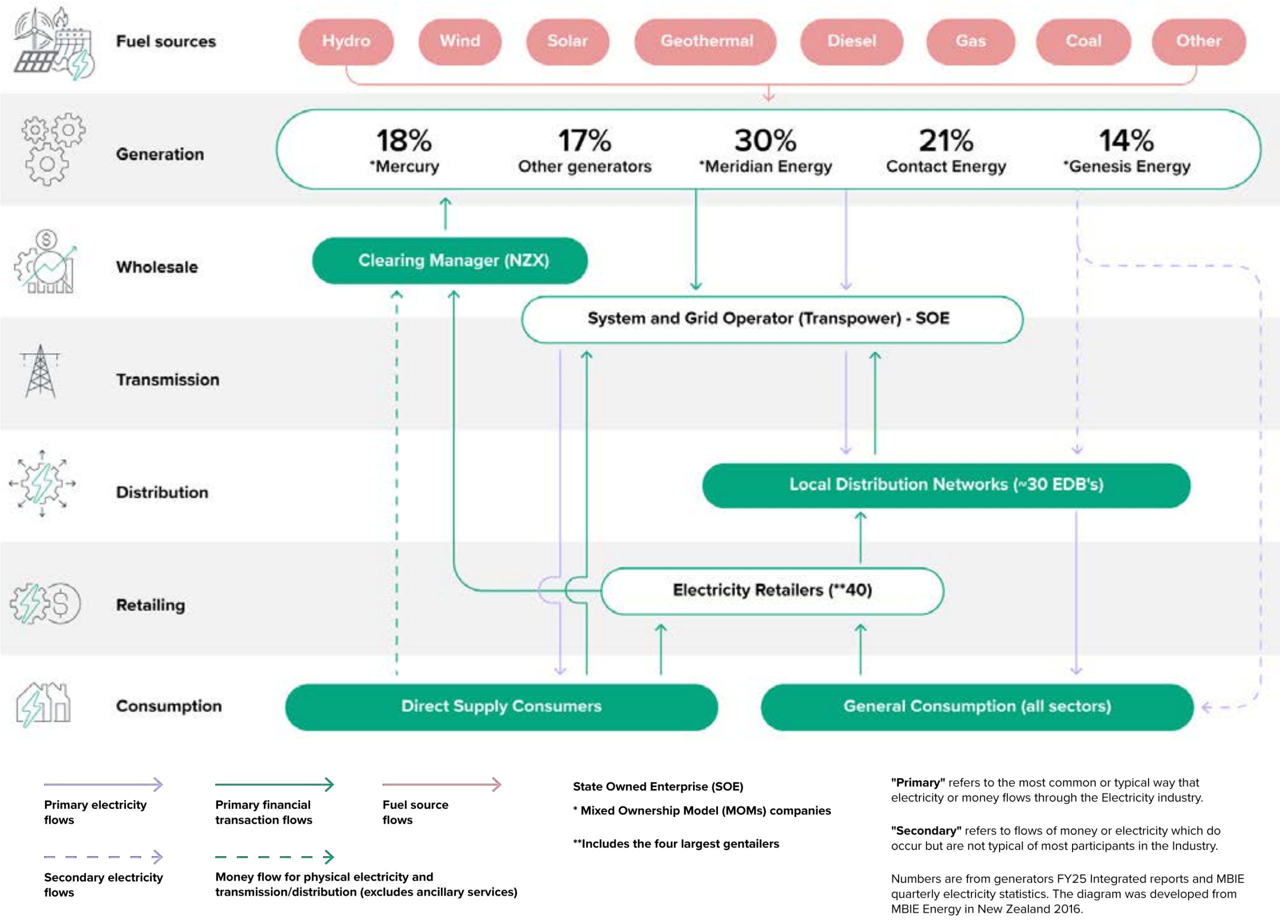
The system is defined in several different pieces of legislation. The key legislation governing the electricity sector are the Electricity Act 1992 (reform foundations and safety), and the Electricity Industry Act 2010 (established the Electricity Authority). The Gas Act 1992 provides for sector legislation around safety standards, a co-regulatory governance model and the establishment of the GIC. As noted above, the Commerce Commission has a significant role in the electricity system empowered through the Commerce Act 1986 (general competition and regulating electricity and gas networks) and the Fair Trading Act 1986 (consumer protection issues).[17]

The operational layers in New Zealand's electricity system

The day-to-day operation of the electricity system can be split into seven layers. **Figure 11** illustrates these key layers of the system, along with energy and money flows between participants.

[14] MBIE, *Electricity Demand and Generation Scenarios (EDGS)*.
[15] These are regulatory tools through Part 4 Commerce Act ranging from information disclosure through to price, and price-quality regulation. Note some electricity distribution businesses are exempt from price and quality controls. A description of this process follows in a future section.
[16] EECA, *Statement of Intent 2024-28* (2024).
[17] Commerce Commission, *Fact sheet: Electricity and the Commerce Commission's role* (August 2018).

Figure 11: Key money and energy flows in the electricity system in New Zealand



Source: Numbers from generators FY25 integrated reports and MBIE, Electricity data tables. Format based on MBIE, *Energy in New Zealand 2017* (2017).

There are many different **fuel sources** used to generate electricity. There are renewable sources such as hydro, geothermal, wind and solar and thermal fuels such as coal, diesel and gas.

The **generators** are companies that own and/or operate power plants. There are currently 151[18] generators listed on the Electricity Authorities participants register. The majority (83%[19]) of generation is provided by the four largest generator-retailers ("gentailers"), Mercury, Meridian and Genesis (State Mixed Ownership Model companies, or MOMs)[20] and Contact.

The **wholesale market** is where electricity is traded by generators and bought by retailers and large industrial users.[21] Transpower (State-owned enterprise[22]) is the system operator

[18] Electricity Authority, *Participant register* – Filtered for electricity generator (11 March 2026).
[19] For the year ended June 2025. Based on generation figures reported in FY25 integrated reports and MBIE electricity statistics.
[20] MOMs are a special category of company under Schedule 5, Public Finance Act 1989. "The Crown must hold at least a 51 percent shareholding and no other party may own more than 10 percent of the shares." Shareholding Ministers "have no formal powers to issue ministerial directions to the listed companies". Department of the Prime Minister and Cabinet, *Ministers and companies in the public sector* at 3.65–3.68.
[21] Electricity Authority, *Wholesale market*.
[22] The Treasury, *Transpower New Zealand Limited*.

responsible for operating the wholesale market and ensuring the real-time coordination of the electricity system.[23] As system operator, Transpower has a critical role of balancing supply from generators to demand from consumers. It also ensures the system is stable and resilient to unexpected sudden outages of major generation or transmission assets. The System Operator provides to the market operator and participants regular schedules of expected load, prices, generation dispatch, and constraints so that generators know how much electricity they need to make available.

The System Operator also has a key role in monitoring and reporting on security of supply and provides a view of potential future energy security in New Zealand's electricity system, into the next two years.[24] Action can be initiated to curtail demand and require contingent hydro storage to be accessed if there is risk of running out of controlled hydro storage. For further information on how security of supply is measured and how Transpower monitors it, see Appendix B.

The Market Operator is the New Zealand Stock Exchange (NZX), which supports the spot market with information, reconciliation and clearance services.

Transmission lines move electricity from the generation sites to both distribution networks and users who connect directly to the grid.[25] Transpower is the grid owner, that provides transmission infrastructure and points to feed power in to and draw from the grid.

Distribution networks take electricity from grid exit points to households and businesses across New Zealand. There are around 30 electricity distribution businesses (EDBs) in New Zealand that own and operate networks. These are a mix of large to small-scale networks. The largest four networks account for around 60% of consumers, while the smallest fifteen networks account for around 10% of consumers.[26]

Retailers (power companies) sell electricity to households and businesses. Consumers purchase electricity at a set price from their power company and are protected from the price fluctuations in the wholesale market. There are 40[27] retailers in the market, 87%[28] of the market is serviced by the four largest gentailers.

Consumers come from different sectors: residential (34% of consumption), commercial (23%), industrial (33%) and other sectors (almost 10%).[29] Most consumers receive electricity via the distribution network. However, there are large-scale industrial users who connect directly to the grid, such as New Zealand Aluminium Smelter.

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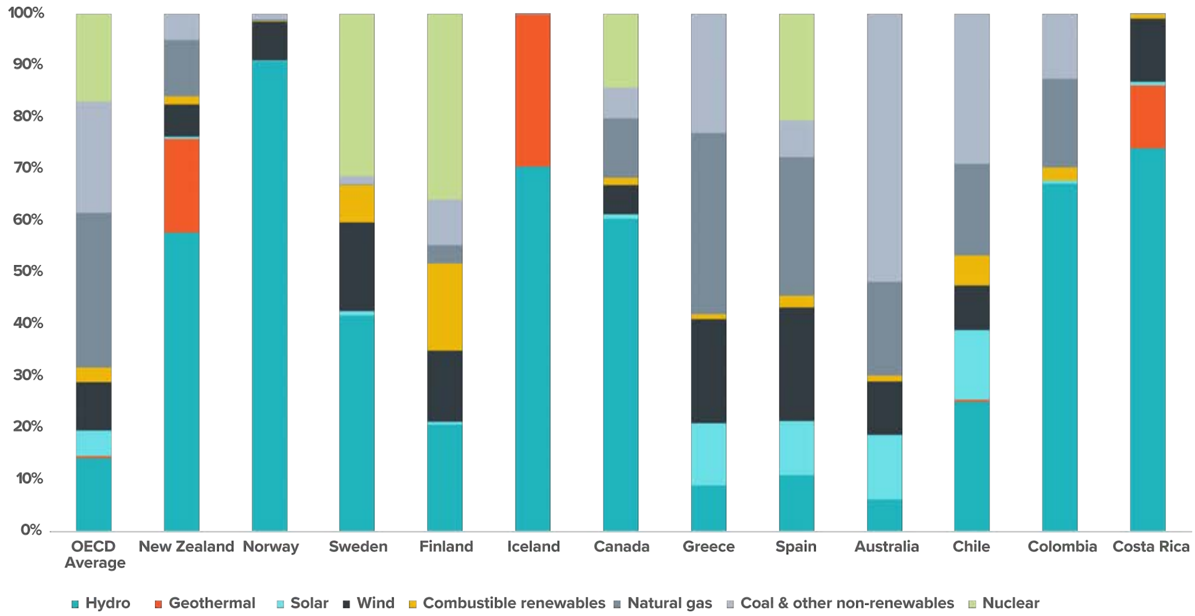
[23] New Zealand Infrastructure Commission, National Infrastructure Plan (2026) at p 149.
[24] Electricity risk curves have a Watch, Alert and Emergency status which are triggered if actual controlled hydro storage crosses the relevant electricity risk curve (1%, 4% and 10% respectively) or the contingent storage release boundary. Transpower, *Energy Security Outlook 101* (May 2025).
[25] Transpower, *What we do*.
[26] As of March 2026, based on the Electricity Authority's market share trends data. Electricity Authority, *EMI market statistics and tools*.
[27] As of January 2026, based on the Electricity Authority's market share trends data. Electricity Authority, *EMI market statistics and tools*.
[28] As of January 2026, based on the Electricity Authority's market share trends data. Electricity Authority, *EMI market statistics and tools*.
[29] Five-year average (2021–2025) from MBIE, *Electricity data tables*. Other sectors include agriculture, forestry, and fishing, transport, unallocated onsite consumption and unallocated demand.

2.3. The characteristics of our electricity system

The characteristics of electricity systems in any given country will depend on a variety of factors, including their natural resource endowments, their connections to other countries, their geography and the size and spread of their population.

New Zealand is a long, skinny, rugged country with a small, spread-out population. The country is fortunate to have many lakes, rivers, and geothermal reservoirs. Compared to other OECD countries, New Zealand's electricity generation relies more on renewable sources where output can vary with the weather (**Figure 12**).

Figure 12: New Zealand's electricity generation by source compared to OECD countries



Source: New Zealand Infrastructure Commission, Benchmarking our infrastructure: Technical Report (2026), based on data from the International Energy Administration.

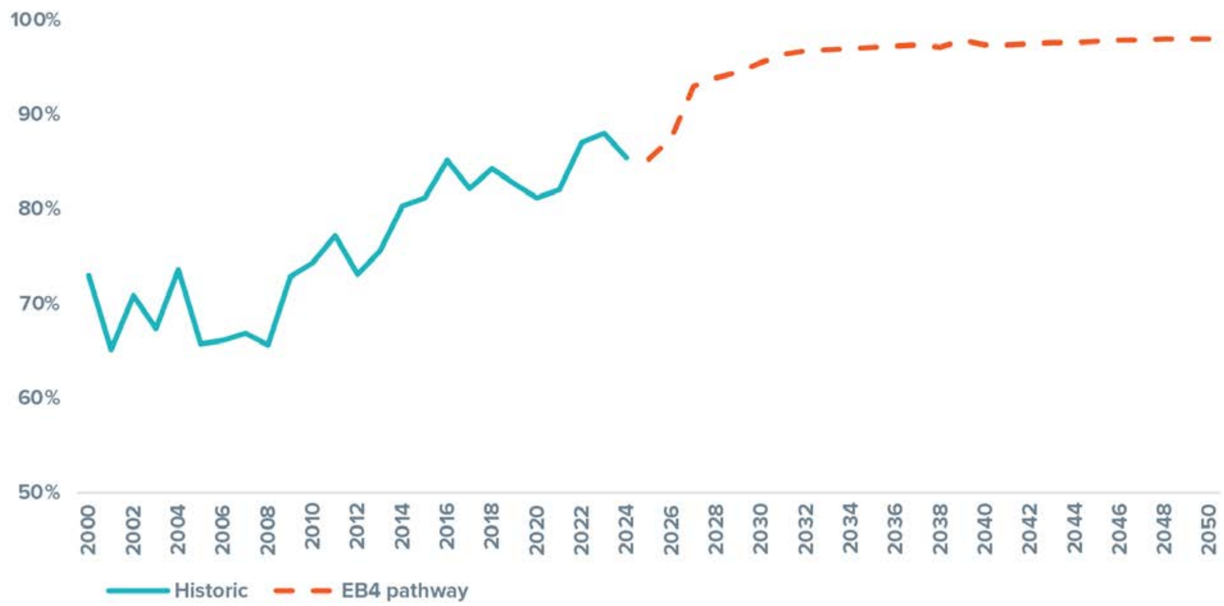
Note: Includes the average for the last five years of data.

Electricity generation is considered renewable when it draws on energy sources that are naturally replenished such as sunlight, wind, water flow, geothermal heat, and biomass, rather than finite fossil fuels that took millions of years to form. Renewable electricity generation in New Zealand reached 88% in 2023 and exceeded 95% in the last quarter of 2025.[30] It is predicted that it could reach as high as 98% by 2050, according to the Climate Change Commission's projections to meet net zero emissions (EB4 Demonstration Path) (**Figure 13**).[31]

[30] MBIE data shows for the quarter October – December 2025, electricity generation from renewables was at a record high of 96.4% based on strong hydro lake inflows and additional solar generation. MBIE, *Favourable hydro conditions see record high share of electricity generation from renewables*.

[31] Boston Consulting Group, *Energy to Grow: Securing New Zealand's future* (November 2025) at Section 3.2 and Exhibit 3; MBIE, *Electricity demand and generation scenarios: results summary* (July 2024).

Figure 13: Renewable share of electricity generation

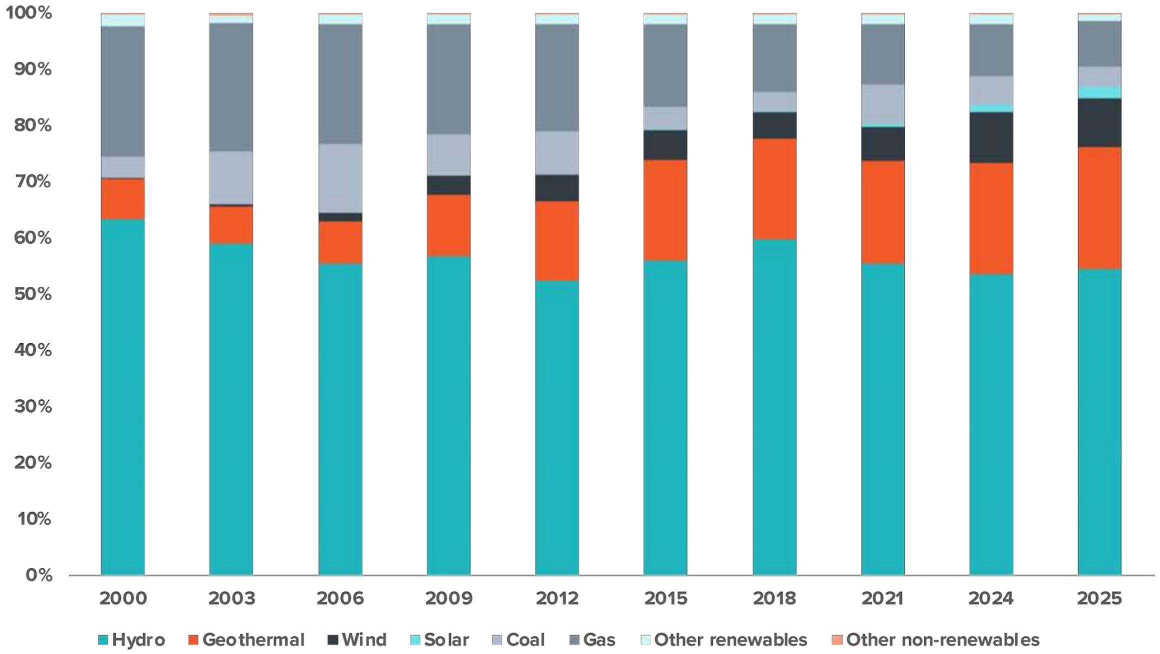


Source: MBIE, Electricity data tables; He Pou a Rangi Climate Change Commission, Modelling and data: Final reports on the fourth emissions budget and 2050 target review (November 2024).

Note: Co-generation using waste heat has been treated as non-renewable.

Electricity generation in New Zealand relies heavily on lakes and rivers. Today, around 57% of our electricity comes from hydroelectric sources (hydro). Over the last quarter-century, geothermal and wind have become important generation sources. In 2000, geothermal accounted for 8% of New Zealand's generation output and wind less than 1%. In 2025, geothermal had risen to 22% and wind had risen to 9% (**Figure 14**). Solar has also started to enter the mix, contributing 2% of output in 2025. Over this same time, generation using fossil fuels has reduced. Gas, which was the second most important source of generation at the turn of the century, has gradually been displaced by renewables.

Figure 14: Share of annual electricity generation breakdown by fuel source 2000–2025

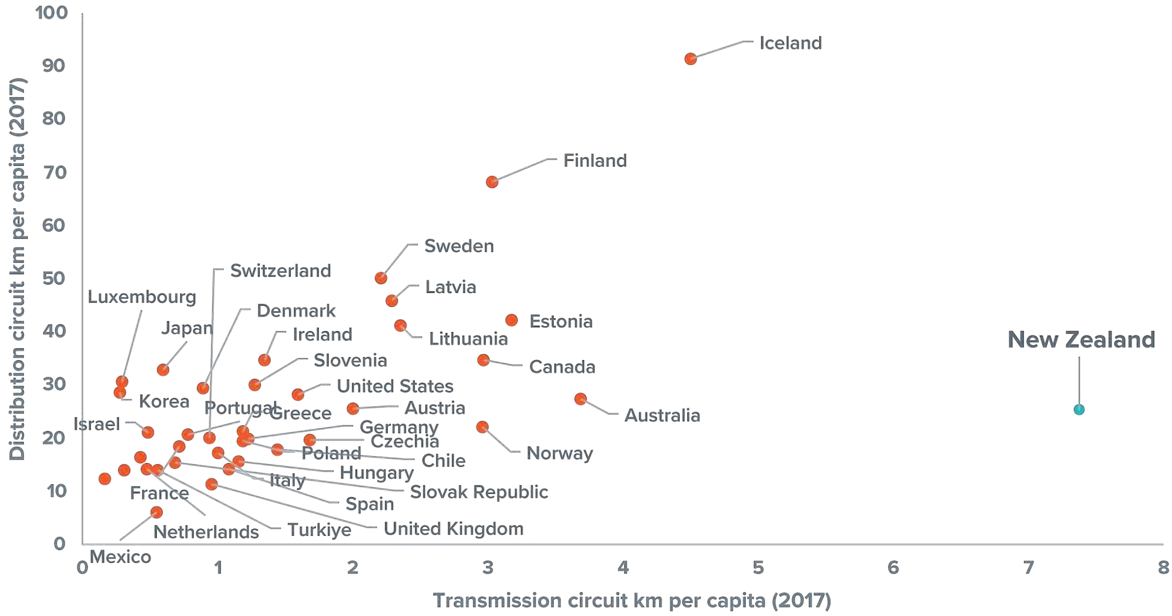


Source: MBIE, Electricity data tables.

Note: Data is displayed as snapshots of specific years, rather than period averages.

Much of hydropower is generated in the South Island, but most electricity is used in population centres on the North Island. This means that New Zealand requires long transmission networks to move electricity, much more so than any other country (**Figure 15**).

Figure 15: Transmission and distribution infrastructure length per capita, OECD countries, 2017



Source: Kalt, G., Thunshirn, P. and Haberl, H., A global inventory of electricity infrastructures from 1980 to 2017: Country-level data on power plants, grids and transformers, Data in Brief, Vol 38 (2021).

New Zealand is an island country with no high voltage connections to other countries, meaning that it does not export electricity: what we produce is what we consume. There are other countries in the same position, but they often have their own particularities that make them different from New Zealand. For instance, Iceland does not export power and is 100% renewable. However, they have a large, energy-intensive aluminium smelting industry, which means they generate significantly more electricity per capita than we do.

Similarly, New Zealand has developed a gas sector, with no connections with other countries (via pipeline or for export), which requires our gas production and consumption to balance.

New Zealand's electricity depends on flexibility. Electricity is generated and sent to households and businesses almost contemporaneously when it is demanded, rather than generated and stored for future use. The system needs to be flexible to "turn on" generation when demand is high, during the day or during certain points in the year, like winter as people heat their homes and use lighting more. This is a feature in most electricity networks around the world.

During these times, there are two ways the system can meet these "peak" periods. First, prices can rise to temper demand, enabling existing generation to meet needs.[32] Second, the system can turn on additional flexible generation capacity to meet demand, called "firming generation", or use electricity that has been stored such as batteries. Usually, a combination of actions is required.

New Zealand's electricity system is in some ways weather dependent. Generating hydroelectric power requires our lakes and rivers to have plentiful water. Our wind turbines require consistent wind, and our solar panels require sustained sunlight. In most years, the weather cooperates. But occasionally, long periods of low rainfall mean that hydro generation is significantly lower than average through the winter demand peaks.

This situation is called "dry year risk". It is a risk that absent increases to supply or tempering of demand, there would be an undersupply of electricity. Similar situations occur in other electricity systems. For instance, "dunkelflaute" ("dark wind lull") is a German term that describes this sort of challenge within wind and solar-based electricity systems.[33]

In recent decades, New Zealand has addressed dry year risk by relying on a combination of price changes and flexible thermal generation (coal and gas). As gas has historically been the cheapest source of flexible generation, it plays a role in our electricity system even though it provides a relatively small and declining share of total generation.

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[32] In addition there are "demand-side participation" mechanisms available within the wholesale market to allow purchasers, large consumers and small scale aggregators (who consolidate demand from a group of consumers) to compete with generators to lower prices by bidding into the wholesale market how much electricity they are effectively willing to consume (or constrain) at different prices, which the System Operator can call on to reduce overall demand if needed. If a purchaser/consumer is called on, they immediately reduce their consumption and reduce the final spot price they pay. Electricity Authority, *Demand-side participation*.

[33] Honoré and Sharples, *Dunkelflaute: Driving Europe Gas Demand Volatility*, Oxford Institute for Energy Studies, Energy Insight #161 (December 2024).

Thermal generation plays an important role in managing dry year risk

Gas and coal provide flexible firming generation to meet demand during periods of high electricity use and low renewable output, including prolonged periods of low hydro output in dry years. **Table 2** shows various dry years in New Zealand over the past 25 years, how hydro generation declined, and how electricity demand was met to ensure consistent supply. Gas has played a key role in providing flexible generation, although less so in recent dry years.

Table 2: How New Zealand managed dry years from 2001 to 2024

Dry Year	Total winter electricity use	Drop in hydro generation…	…made up by coal generation	…made up by gas generation	…made up by other actions such as demand response
2001 (Q2-Q3)	20.0 TWh	-2.1 TWh	+0.3 TWh	+1.9 TWh	…
2008 (Q1-Q2)	20.2 TWh	-1.5 TWh	+0.7 TWh	+0.7 TWh	…
2021 (Q1-Q2)	21.2 TWh	-1.4 TWh	+1.7 TWh	-0.2 TWh	…
2024 (Q2-Q3)	23.1 TWh	-1.7 TWh	+1.1 TWh	+0.3 TWh	+0.3 TWh

Source: Adapted Exhibit 68 from Boston Consulting Group, *Energy to Grow: Securing New Zealand's future* (November 2025).

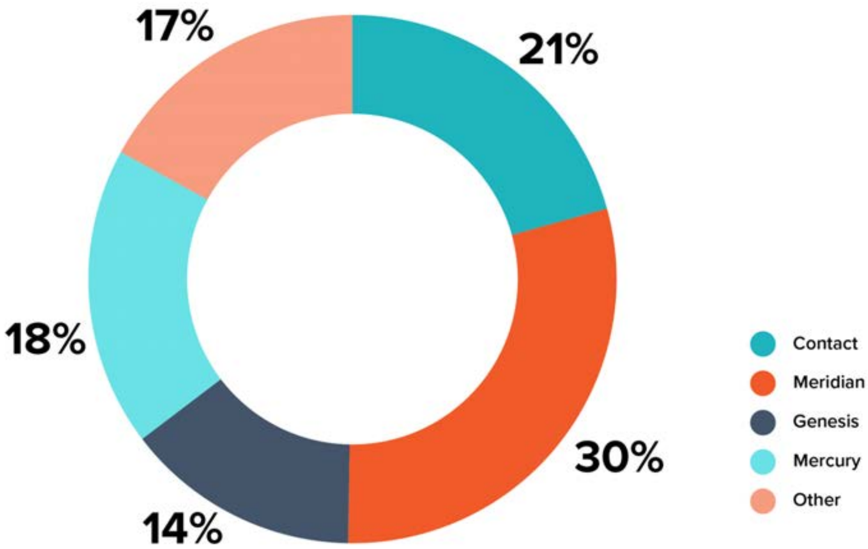
Note: This table is based on BCG's counterfactual exercise, which compares actual observed generation against what would have been generated assuming the average hydrological generation of the five previous, hydrologically typical years, actual renewable and "other" generation. Thermal generation is assumed to fill the remaining gap to meet demand.

2.4. Who makes, sells, and uses energy in New Zealand

Electricity provision is relatively concentrated among four large "gentailers"

There are currently 151 generators listed on the Electricity Authority's participants register.[34] Most generation is provided by the four largest generator-retailers ("gentailers") who both produce (generate) and sell (retail) electricity.[35] These are Mercury, Meridian and Genesis (State Mixed Ownership Model companies, or MOMs) and Contact.[36] In the year ended June 2025, 83% of the generation was produced by these gentailers (**Figure 16**).

Figure 16: Share of total electricity generation by generator for the year ended June 2025



Source: New Zealand Infrastructure Commission analysis of generators FY25 integrated reports and MBIE, Electricity data tables.

While the four largest gentailers produce most of the electricity, each tends to generate from a range of sources. Meridian holds the largest share of hydro, Mercury holds the largest share of wind, Contact holds the largest share of geothermal, and Genesis holds the largest share of thermal.[37]

For hydro, Meridian produces about 50%, Contact and Mercury produce roughly 15% each and Genesis and other generators make up the remaining 21%. For geothermal, Contact produces

[34] Electricity Authority, *Participant register* – Filtered for electricity generator (11 March 2026).
[35] For the year ended June 2025. Based on generation figures reported in FY25 integrated reports and MBIE quarterly electricity statistics.
[36] MOMs are a special category of company under Schedule 5, Public Finance Act 1989. "The Crown must hold at least a 51 percent shareholding and no other party may own more than 10 percent of the shares." Shareholding Ministers (Minister for State-owned Enterprise) "have no formal powers to issue ministerial directions to the listed companies." Department of the Prime Minister and Cabinet, *Ministers and companies in the public sector* at 3.65–3.68.
[37] Noting that these companies each have varied portfolios of assets. For example, as at June 2025, Mercury has 18% generation market share; produced 3,410 GWh of hydroelectric power (through its main generation assets on the Waikato River), along with 2,559 GWh of geothermal and 1,936 GWh of wind power (source: Mercury, *2025 Annual Report* (2025)). As at June 2025, Contact produced 4,544 GWh of geothermal power, 3,297 GWh hydro and 1,550 GWh from other sources.

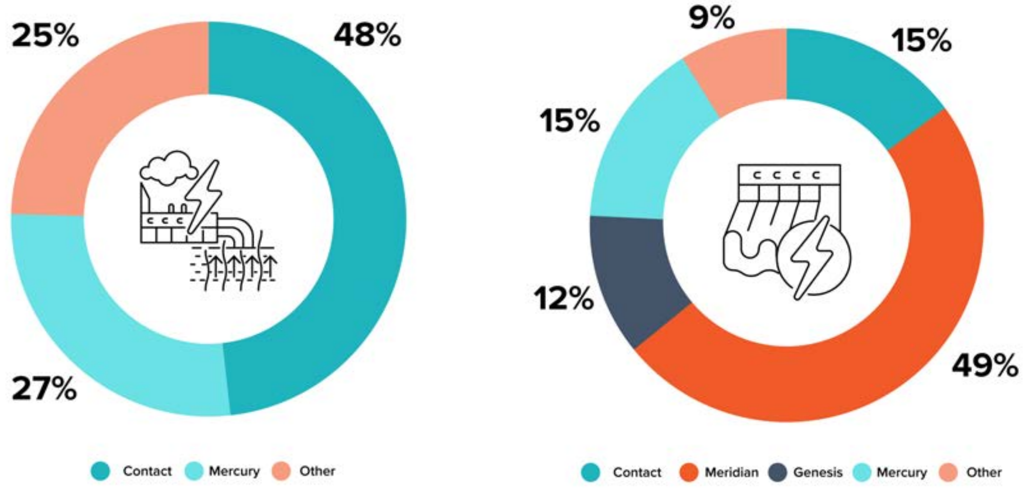
48% with the two other quarters held by Mercury and other generators (**Figure 17**). 50% of wind is generated by Mercury, 47% by Meridian and the remainder is produced by other generators.[38]

Thermal generation is predominantly provided by Contact and Genesis, which produced 76% of annual thermal generation in 2025.[39]

Figure 17: Share of electricity generation produced by generators for selected generation types

Panel A: Geothermal generation by generator

Panel B: Hydro generation by generator



Source: New Zealand Infrastructure Commission analysis of generators FY25 integrated reports and MBIE, Electricity data tables.

The same concentration exists in the retailing of electricity. 87% is held by four gentailers (Mercury, Genesis, Contact, Meridian). These gentailers hold between 20% to 25% of the total installed control points (ICPs). Small and medium retailers collectively have 13% market share. (**Figure 18**).

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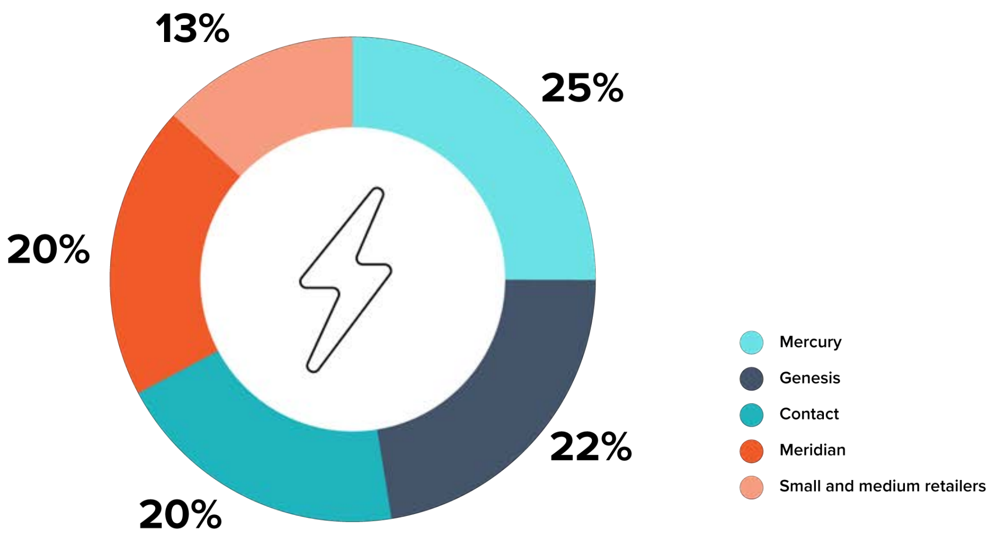
[38] Year ended June 2025. Calculated from generators FY2025 integrated reports and MBIE quarterly electricity statistics.
[39] Year ended June 2025. Calculated from generators FY2025 integrated reports and MBIE quarterly electricity statistics.

Figure 18: Retail market share by total installation control points (ICP) as of January 2026

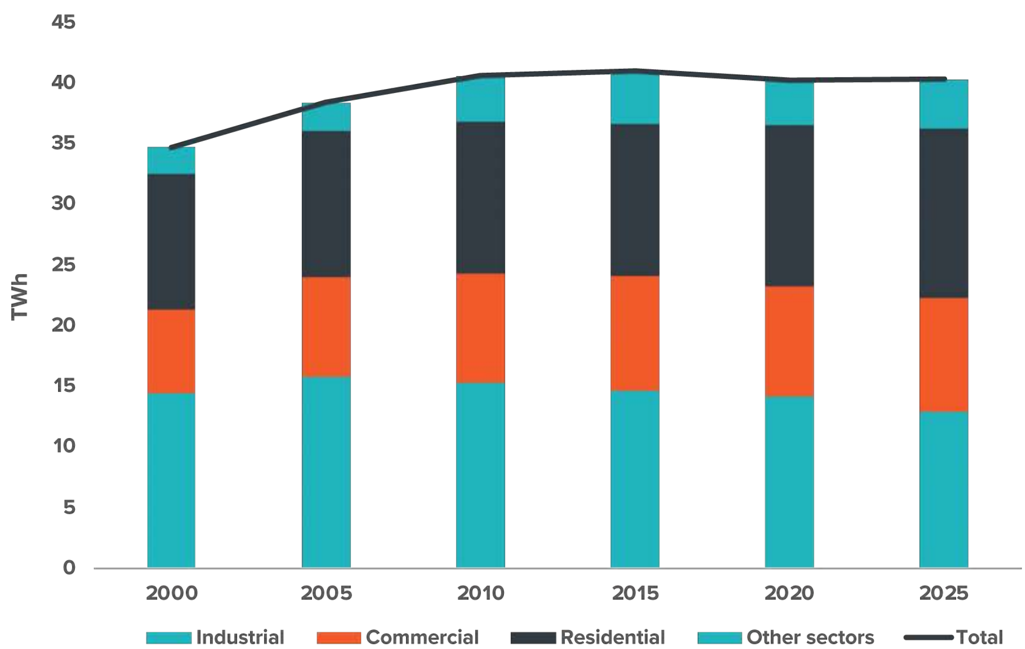


Source: Electricity Authority, EMI retail market share trends.

New Zealand's electricity usage growth has been flat, although the mix of use is changing

Electricity consumption is broken down into three main consumers: residential, commercial and industrial sectors. As of 2025, residential and industrial each consumed just over a third of total electricity, while commercial accounted for just under one-quarter (**Figure 19**).

Figure 19: Annual electricity consumption by major sectors



Source: MBIE, Electricity data tables. 2000–2010 from consumption – based on estimated sales series. 2015–2025 from consumption – based on actual sales series.

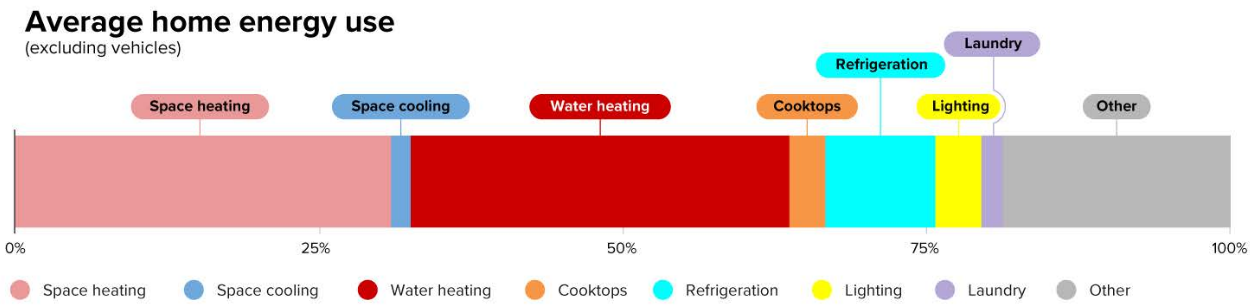
Note: Other sectors include agriculture, forestry, fishing, transport, unallocated onsite consumption and unallocated demand.

Within industrial and commercial sectors, consumption can be highly concentrated. For example, a single industrial customer, the New Zealand Aluminium Smelter at Tiwai Point, is responsible for around 12% of total consumption in New Zealand, and almost 37% of total industrial consumption.[40]

Total electricity consumption has remained relatively flat since 2010, although consumption in the residential sector has slightly increased in recent years. There are several reasons for this, but a major factor is the decline of industrial electricity use, particularly in wood processing. In the mid-2000s, wood processing was consuming around 3 to 4 TWh of electricity each year. By 2025, it was less than 1 TWh. Offsetting this has been growth in residential demand.[41]

Within the residential sector, water and space heating comprise most energy use, although these two purposes use both gas and electricity (**Figure 20**). About 70% of homes use an electric heat pump as the main source of heat in their home, while only 10% use a gas heater.[42] For hot water heating, about two-thirds of New Zealand homes rely on electricity while one-third use gas.[43]

Figure 20: Proportional energy use in an average New Zealand home



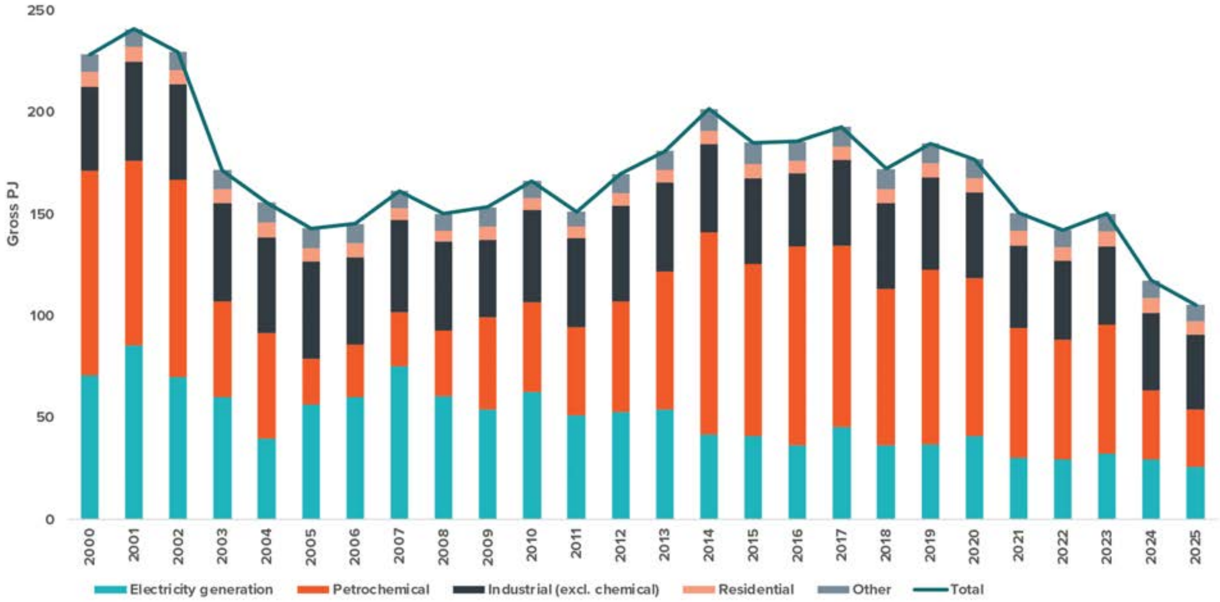
Source: Rewiring Aotearoa, *Electric Homes Report*, (March 2024).

New Zealand's gas usage has been declining and is expected to continue falling

Most gas is produced and consumed domestically in New Zealand and used for different purposes. Over the last 10 years, 22% of gas usage has gone towards electricity generation, which has been trending downward. The production of petrochemicals, in large part Methanex producing methanol, has historically comprised a large share of gas usage, but this has also declined. Around 40% of industrial usage goes towards the processing of foods, mostly dairy products, while 11% of total gas consumption goes towards residential use.[44]

[40] Five-year average (2021–2025) of electricity consumption from MBIE, *Electricity data tables* and Electricity Authority, *Demand trends*, Node TWI2201 – Tiwai
[41] MBIE, *Electricity data tables*.
[42] Environmental Health Intelligence New Zealand, *Home heating* (2025).
[43] Stats NZ, *2023 Census population, dwelling and housing highlights* (2024).
[44] MBIE, *gas consumption statistics* five-year average 2021–2025.

Figure 21: Natural gas use by sector, 2000–2025



Source: MBIE, Gas data tables, December quarter.

Note: The petrochemical category includes industrial chemical use and non-energy use sector. Industrial (excl. chemical) includes all other industrial sectors and cogeneration. Other end use consumption includes the commercial, agriculture/ forestry/ fishing and transport sectors.

According to latest projections commissioned by the Gas Industry Company, absent any new discoveries or a new liquified natural gas terminal, gas production and use is expected to fall even further from about 112 petajoules (PJ) today to close to 51 PJ over the next 10 years.[45]

To accommodate declining gas production, the Gas Industry Company expects that demand will reduce across all gas-using activities. It projects that 34% of the total decline in demand will be related to Methanex exiting the market, 21% will be due to reduced electricity generation from gas, and around 45% of the total reduction will come from the industrial, commercial, and residential sectors.[46] Furthermore, it projects that remaining industrial gas users will have to temporarily curtail their own use even further during dry years to enable gas-fired electricity generation to flex up to meet electricity demand.

This highlights that while the decline in gas availability is a risk to electricity generation, it is even more of a concern for other large gas users in the industrial and commercial sectors.

[45] PricewaterhouseCoopers, *2026 Gas Supply and Demand Study* (prepared for Gas Industry Company, 2026).
[46] PricewaterhouseCoopers, *2026 Gas Supply and Demand Study* (prepared for Gas Industry Company, 2026).

3. Prices and investment

Across all infrastructure networks, pricing performs several critical functions.

We use prices to raise most of the money we need to pay for infrastructure. In the most general sense, prices are the cost that we must pay to obtain what we want. For electricity and gas, residential and commercial users receive monthly bills. For large industries, they pay for their consumption directly from wholesale markets.

But beyond this, prices can help infrastructure providers with information to understand when the system is out of balance. Well-functioning prices can send signals about what we should do more or less of.

Without good price signals, infrastructure providers face greater challenges identifying the highest-value areas for investment. Poorly priced networks also tend to operate less efficiently, as users lack good information and incentives to optimise their use. This was a key message of the Commission's National Infrastructure Plan.[47]

As New Zealand moves to achieve balance between net zero goals, low prices, and security of supply, it is first important to understand the role that prices play in the energy system, how they've changed, and what they might be able to tell us about what's likely to come.

This section will primarily focus on pricing with the electricity system as it is expected to be the primary infrastructure network achieving our energy goals. Gas networks are comparatively smaller, and as discussed later, are expected to become phased out over time as we move towards low-emissions energy sources. However, the same pricing and revenue considerations that are important in electricity would also hold for our gas extraction, storage, transmission and distribution networks.

This section lays out how pricing and incentives work in an average year and time, but following sections will discuss how future short- and long-term shifts are affecting these prices.

As context for this section, the Commission's 2024 Network Infrastructure Pricing Study assessed network infrastructure sector alignment with a set of best-practice pricing principles.[48] A key finding was that while there are areas for improvement in all sectors, the energy sector is generally more aligned with best practices than the land transport or water sectors. Subsequent research indicated that weaker pricing practices were contributing to higher investment and affordability pressures in land transport and water, relative to energy.[49]

[47] New Zealand Infrastructure Commission, *National Infrastructure Plan* (2026) at Section 3.2.
[48] New Zealand Infrastructure Commission, *Network Infrastructure Pricing Study: How well does network infrastructure pricing work in New Zealand* (January 2024).
[49] New Zealand Infrastructure Commission, *Buying time: toll roads, congestion charges, and transport investment* (July 2024) and New Zealand Infrastructure Commission, *Valuing water: sustainable water services and the role of volumetric charging* (July 2024).

3.1. The infrastructure components of electricity prices

Electricity prices reflect the costs of generating, moving, and retailing electricity

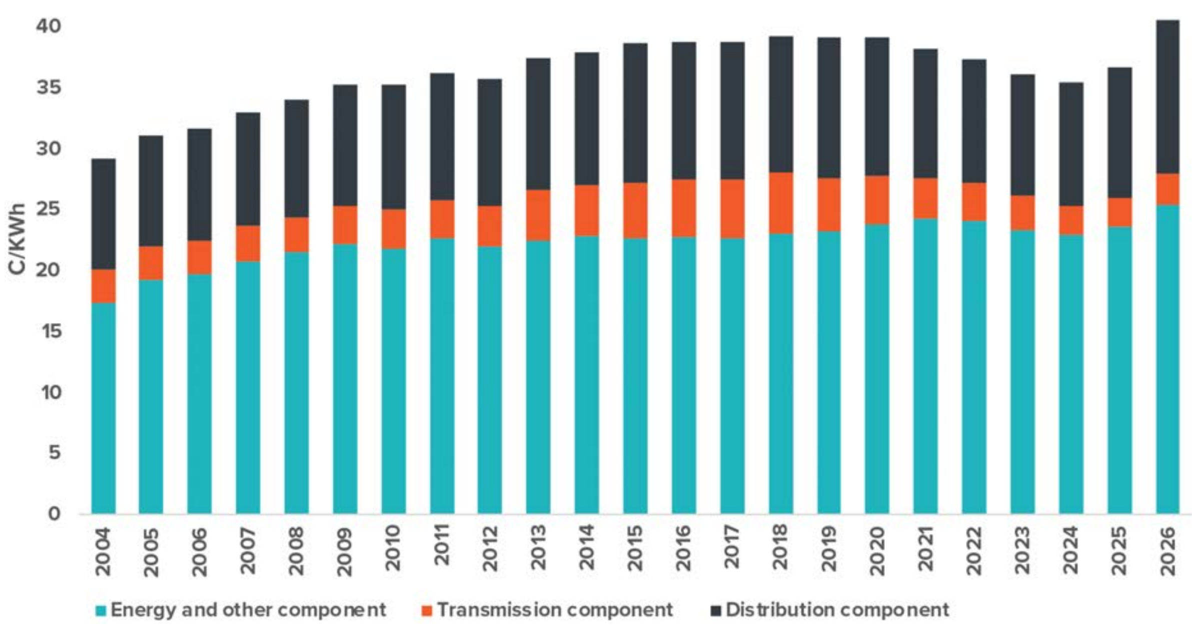
The infrastructure parts of the bills are primarily comprised of two components: the cost to make the electricity, and the cost to get it to customers.

- The generation component, which helps recover the cost of generating electricity. This includes operation costs, fuel costs (such as water for hydro, gas for thermal generation), but also the long-run costs of maintaining and renewing the facilities.
- The transmission component, which recovers the cost of building, maintaining and renewing the high voltage wires that transport electricity from generation plants over long distances.
- The distribution component, which recovers the cost of building, maintaining and renewing the low voltage wires that transport electricity from high-voltage transmission wires to people's homes and businesses.

Other non-infrastructure charges such as retail markups (including costs of providing billing and metering services), taxes, and administrative fees are in addition to these charges on a typical household bill. As described in the previous section, different entities are involved in setting different parts of electricity prices.

In 2025, 63% of retail prices were due to the generation, retail and administrative costs (reported together as "energy and other component"), while 37% were due to the transmission and distribution components (**Figure 22**). These shares have been largely steady over time.

Figure 22: Inflation adjusted household electricity charges by component, 2004–2026



Source: MBIE, Quarterly Survey of Domestic Electricity Prices (QSDEP) and Stats NZ, Consumers Price Index (CPI).

Note: Prices are as of February in a given year, adjusted to 2026 Q1 prices using the CPI. Prices include GST, which is spread proportionately across all three components.

Retail prices have fluctuated over time, but in inflation-adjusted terms, they were only slightly higher in 2026 than they were in 2016. Since 2019, prices of transmission have fallen, while distribution costs have increased by over 20%. Energy and retailing costs have increased 5% in real terms.

The prices for various components of electricity are set differently

Although electricity generation charges, transmission charges, and distribution charges are all bundled together in consumer energy bills, prices for these components are set differently. When consumers see changes to their bills, it could mean that one component has changed while other components have stayed the same.

Prices are set to cover the cost of providing and operating infrastructure, but through different mechanisms. Charges for transmission and distribution infrastructure are subject to regulation by the Commerce Commission and Electricity Authority. By contrast, prices for electricity generation are set through a wholesale market, overseen by the Electricity Authority, combined with various financial arrangements to smooth prices.[50]

How transmission and distribution charges are set

Electricity transmission and distribution are natural monopolies. It would be inefficient to duplicate these networks to provide users with a choice between different suppliers. Under Part 4 of the Commerce Act, these entities are subject to economic regulation by the Commerce Commission.

The aim of economic regulation is to replicate the effects of competition by ensuring prices are fair, consumers are protected, and providers remain customer-responsive and innovative. Forms of economic regulation include information disclosure, which promotes transparency, and price-quality regulation, which sets limits on revenue, minimum service quality standards, and penalties for non-compliance.

All transmission and distribution infrastructure providers are subject to information disclosure regulation, which includes information on spending, revenues, and asset condition. Transpower and some electricity distribution businesses are also subject to price-quality regulation based on criteria and thresholds in the Commerce Act. This involves the Commerce Commission regulating the revenue they can earn and quality standards they must meet over a five-year period. Currently, price-quality regulation applies to 15 electricity distribution businesses, with the remaining 13 being exempt as they meet the statutory definition for being consumer-owned.[51]

Revenue allowances enable existing assets to be maintained and new assets to be built in line with expected demand. They also accommodate cost pressures like construction price inflation and changes to interest rates, while giving infrastructure providers an incentive to lift efficiency.

[50] Electricity Authority, *Wholesale market*.
[51] Pt 4, Subpt 9, Commerce Act 1986.

The Commerce Commission's final decisions for the 2025–2030 regulatory period, published in November 2024, increased allowable revenues significantly.[52] Relative to the previous regulatory period, Transpower and electricity distributors were provided with a 44% increase in nominal revenue. This increase is driven by a combination of increased interest rates (which raise the cost of capital), significant input cost inflation, and an increase in forecast expenditure, including investment to serve growing demand.

After the Commerce Commission sets revenue allowances, transmission and distribution prices are set to spread costs between different consumers. The Electricity Authority directly regulates the structure of transmission prices, under a transmission pricing methodology that seeks to ensure that the grid is paid for by those who are expected to benefit from investment in it.[53] It also requires electricity distribution businesses to follow a set of distribution pricing principles and publish their pricing methodology.[54]

How New Zealand's wholesale price market works

New Zealand's wholesale electricity market determines the price generators receive for the electricity they produce and ultimately shapes the cost of electricity across the whole system.

Every half hour, electricity generators submit offers to an information and trading platform stating how much electricity they are willing to supply and at what price.[55] These offers are then ordered from lowest cost to most expensive, and the cumulative power that is available at each price.

The System Operator (Transpower) then forecasts demand (load) for each trading period plus a reserve. This is based on customer requests, modelling historical demand, forecast weather, actual load trends, and risk. The eventual market price for that half hour period is set at the price that satisfies the demand forecast. Offers submitted under the clearing price provide electricity, while those offers over do not.

New Zealand's wholesale electricity market is an energy-only market. Generators are paid only for the electricity they actually produce (plus a small reserve to cover any unexpected outages that could lead to blackouts). There is no separate payment for simply building generation capacity.

Figure 23 shows this graphically for a few different trading periods. The flat left-hand portion of the curve reflects the large volume of low-cost generation available at low prices. As demand approaches the right-hand side of the curve, offers rise steeply, reflecting the much higher cost of generation being called on. On 26 July 2017 (**Panel A**), the wholesale price that cleared the market was $232.

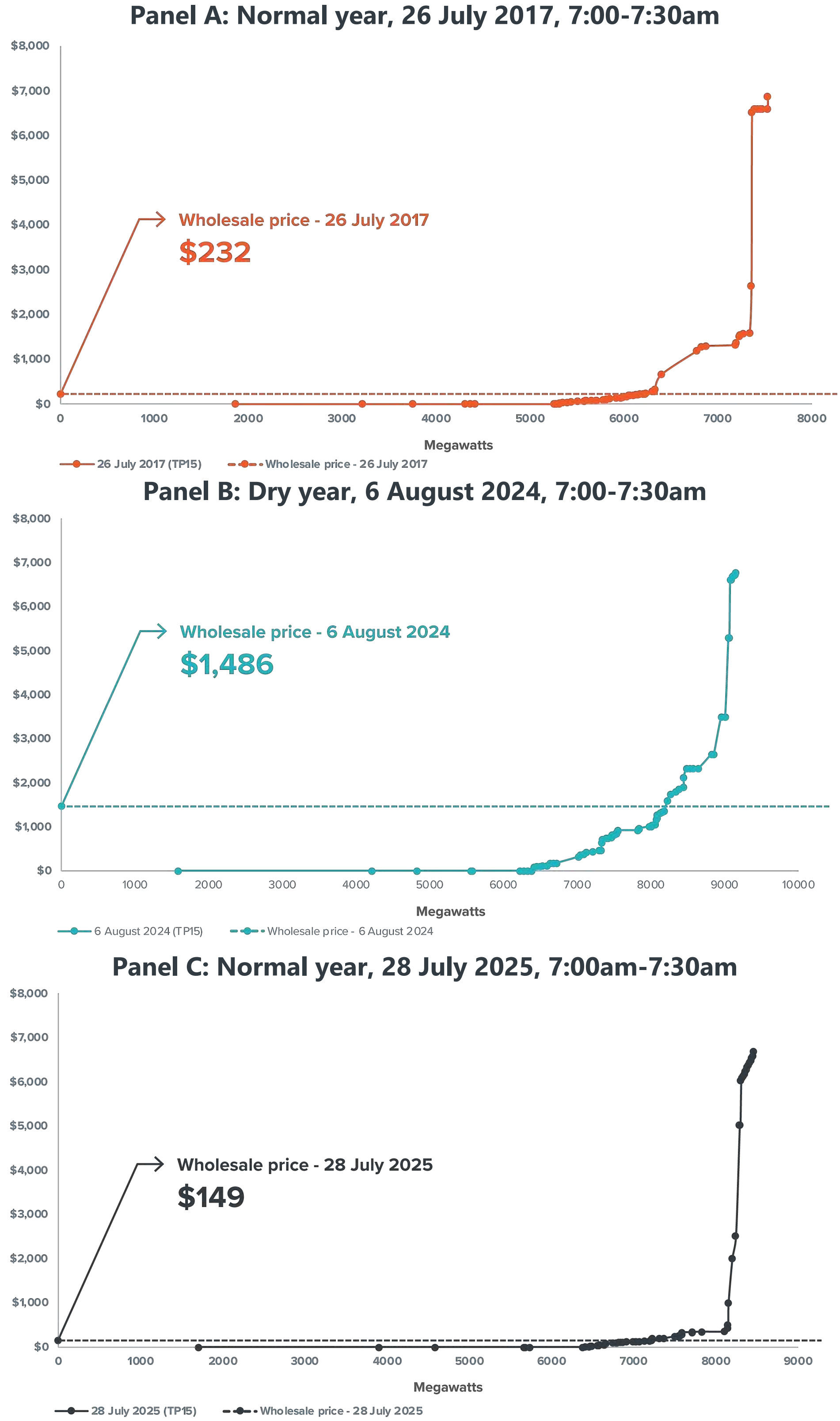
By contrast, for the period of 6 August 2024 (**Panel B**), which was a dry year, we see normally lower priced bids offering at higher prices, creating more of a steady upward curve rather than

[52] Commerce Commission, *Joint RCP4 – DPP4 Final Decisions Stakeholder slides* (20 November 2024).
[53] Electricity Authority, *Transmission Pricing Methodology*.
[54] Electricity Authority, *Distribution pricing*.
[55] This is the Wholesale Information and Trading System, managed and administered by the Market Operator (the NZX) that also acts as reconciliation and settlement agent for market participants.

a sharp L-shape. This led to the wholesale price clearing the market at over $1,400 for that period.

The grey line shows the offer curve for 28 July 2025 (**Panel C**), a period where lakes are relatively full. We see many more bids offering into the market at very low prices, driving the wholesale price to the low level of $149.

Figure 23: Inflation adjusted offer curves, various dates



Source: New Zealand Infrastructure Commission analysis of the Electricity Authority, Wholesale offers datasets, Wholesale price trends and Stats NZ, Consumers Price Index (CPI). Note: Prices are in 2025 Q4 values.

This illustrates that wholesale prices will be lower if more lower cost bids are submitted. If electricity demand cannot be met by lower cost bids, the process will continue to the next highest price until demand is met.

Furthermore, for a given set of generation offers, if demand is lower, the eventual wholesale price will be lower.

The combination of both points means that in times of high demand or low supply, two actions can be used to address it. First, prices can rise so that higher cost generators are willing and able to generate to meet excess demand. Second, higher prices can help temper demand, putting downward pressure on prices.

Hedging and demand flexibility can smooth volatility

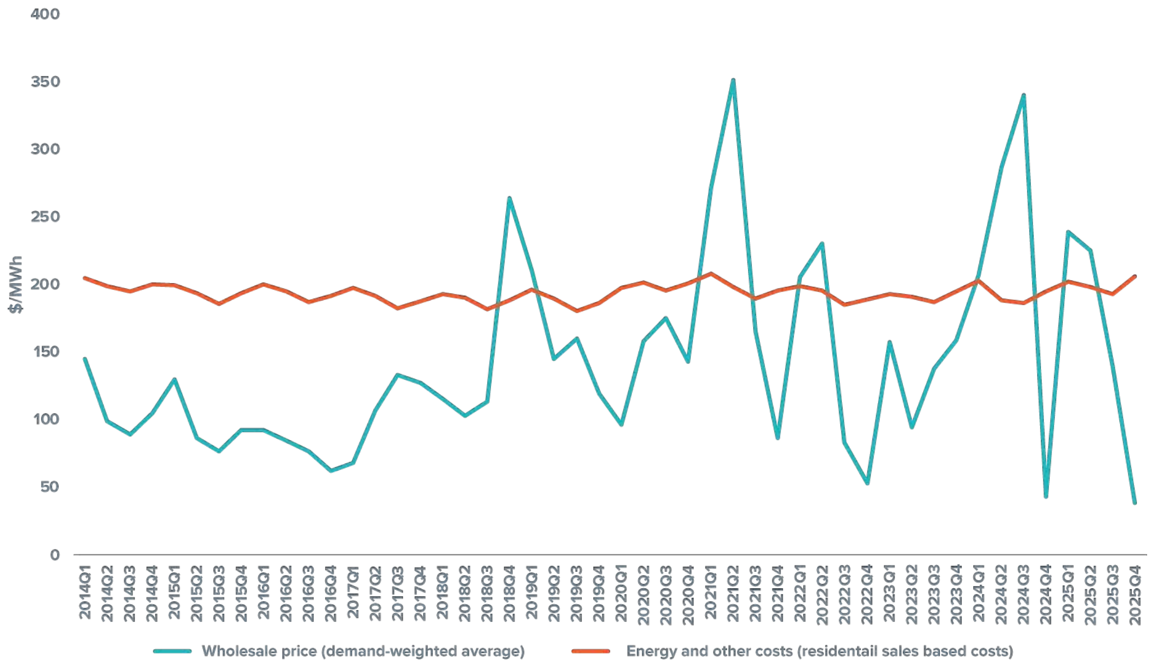
The wholesale market runs every half hour, and demand fluctuates over the course of a day and over the year. This means that wholesale prices are typically volatile.

For some electricity users, particularly large ones, it is more efficient to purchase electricity directly on the wholesale market. This includes large industrial customers whose machinery can utilise high-voltage electricity directly. Doing so allows industrial consumers to access electricity cheaper in the long run but also exposes them to more volatility in prices.

For other consumers, like residential and smaller commercial customers, smoother and more predictable prices are more preferred. This smoother price profile means that they are not exposed to wholesale volatility, but they also pay higher prices, both because they pay for transmission and distribution costs, but also retail and administrative costs. It also means they face little financial incentive to change consumption during high demand periods.

Figure 24 illustrates this in detail. Quarterly average wholesale prices are highly variable, swinging from below $100/MWh in low-demand or high lake-inflow periods to over $300/MWh. Retail prices are notably stable by comparison, declining gradually through the mid-2010s before rising more recently.

Figure 24: Real wholesale prices (demand-weighted) and residential electricity costs (energy and other costs component), 2014–2025



Source: New Zealand Infrastructure Commission calculations based on Electricity Authority, Wholesale price trends; MBIE, Household sales-based electricity cost data; and Stats NZ, Consumers Price Index (CPI).

Note: Costs and dollars in Q1 values for 2026. GST has been removed from the residential sales-based electricity costs series for comparability with wholesale prices, which exclude GST.

Both large industrial users and electricity retailers who are selling to customers at fixed price contracts manage their exposure to wholesale price volatility through financial markets. Hedge contracts allow generators (on one side) and retailers or large industrials (on the other side) to agree a fixed price for future delivery, giving both sides certainty over revenue and costs. Power purchase agreements (PPAs) work similarly, typically over longer terms, and can underwrite the business case for new supply capacity by locking in a revenue stream before construction begins.

Both sit alongside the wholesale market rather than replacing it and are typically priced relative to expected wholesale prices. These instruments help manage price level risk, but they do not address utilisation risk. A generator still needs to actually produce energy to earn revenue under a hedge or PPA.

The depth of these markets is important. New Zealand's ASX futures market currently offers several hedge contracts with a horizon of up to three years. Beyond that, developers must rely on over-the-counter arrangements or PPAs, which require finding a willing counterparty and negotiating bespoke terms.

The Electricity Authority has several tools to support hedge market function and monitor financial risk to wholesale market participants. It supports market-making for ASX-traded futures, contracting paid providers to improve liquidity for selected products. It is also developing disclosure requirements for over-the-counter hedge contracts to improve transparency.

Separately, the Electricity Authority requires large wholesale market participants, such as electricity generators, retailers, and large industrial users, to conduct standardised quarterly stress tests of their market positions. The results are reported to their boards and to an independent registrar, but are not published. The aim of these stress tests is to ensure participants understand the risks arising from their hedging decisions, including any decision not to hedge against volatile prices.

Electricity price mechanics: the bottom line

To summarise key points on this description of electricity pricing:

- The price consumers pay for electricity is not just a function of the costs of electricity generation. Transmission and distribution costs make up a sizeable portion of overall costs to deliver electricity.
- Transmission and distribution pricing is set by regulation. Revenue allowances are reviewed and approved by the Commerce Commission for five-year periods, the structure of transmission prices is regulated by the Electricity Authority, and distribution prices must follow principles published by the Electricity Authority.
- Generation of electricity is priced through the wholesale market. If lower priced generation offers into the market, wholesale prices will be lower.
- Only some large industrial users are directly exposed to the wholesale market. Residential, commercial and smaller industrial customers typically purchase their power through retailers. This means that in periods of high demand or low supply, prices are felt most acutely in the large industrial market.
- The wholesale market can be volatile, so retailers and large industrial customers use financial market products, such as hedging and long-term power purchase agreements, to reduce risk and smooth the prices they face. Such contracts can also provide longer term revenue security for generators.
- Rising wholesale electricity prices will affect retail customers if there is a consistent increase in prices on the wholesale market, or if there is growing volatility, both in magnitude and frequency of price changes.

3.2. Incentivising investment with prices

How prices incentivise new investment in electricity

New Zealand's electricity market is energy only but also operates primarily on a commercial basis. An individual generator will not build new capacity unless the revenue they expect to earn with that new plant is greater than its lifetime costs (fuel, capital, financing, and maintenance). The question is whether prices being offered by the market are below or higher than what is required to make a long-run return.

The cost concepts that capture this threshold are the levelised cost of electricity (LCOE) and the long-run marginal cost (LRMC). LCOE measures the full lifetime cost of building and operating a plant per unit of electricity produced – a useful project-level benchmark.[56]

The LRMC of an electricity generating technology is equal to the LCOE plus the cost of power required to 'firm' the electricity for periods where the generating technology is not operating. The LCOE and LRMC are broadly equivalent for baseload generation technology such as geothermal, but for variable technologies like wind or solar, the LCOE is typically lower than LRMC. The reason for this is that when conditions are ideal for wind and solar, there is less need for firming generation (typically thermal stations), but when conditions aren't ideal, there is greater need for firming generation. In general, this tends to result in lower market prices in periods with a lot of wind and solar generation compared to periods with low or no wind and solar generation.

LRMC is a market-level concept: it reflects not just a given generation technology's costs, but the market price at which a new entrant could profitably operate in a specific market context, accounting for how often and at what price the plant is likely to run.

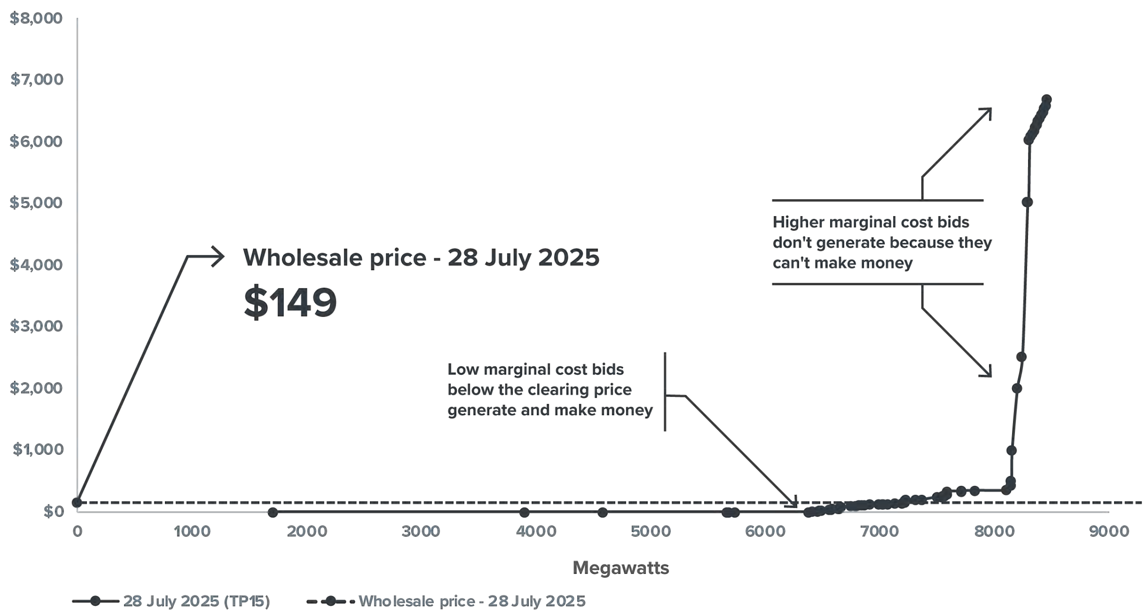
Because there is no difference in quality between the electricity generated from different sources, different generator types compete on price. In a competitive market, baseline wholesale prices would be expected to converge toward the LRMC of the cheapest available technology. If prices are persistently above that level, new generators have an incentive to enter. As new generation is brought online, more suppliers will offer into the wholesale market, tending to lead to the market clearing at lower prices. Likewise, if prices fall below LRMC, new investment becomes unviable. If this is sustained, this may result in decreasing generation capacity as plants reach their end of life and aren't replaced.

What does this look like in New Zealand's wholesale market? Most generators will bid in their generation at the short-run marginal cost of their generation (SRMC), that is, the variable costs of operating the plant. For a thermal generator this will include the fuel costs. For a renewable generator such as wind or solar, this will be very low – often close to zero. The market will clear at the price of the highest offer required to meet forecast demand.

[56] Electricity Authority, *The levelised cost of electricity*.

Generators with SRMCs lower than this price will supply electricity and earn a return from that trading period, while generators with SRMCs higher than this price will not supply electricity and not make money during that trading period (**Figure 25**).

Figure 25: Inflation-adjusted offer curve 7:00–7:30 am, 28 July 2025



Source: New Zealand Infrastructure Commission analysis of Electricity Authority, Wholesale offers datasets, Wholesale price trends and Stats NZ, Consumers Price Index (CPI).

Note: Prices are in 2025 Q4 values.

Over the life of an asset, generators of electricity need sufficient returns to cover LRMC of the plant. The overall return for a generator over its lifetime will depend on how often it supplies electricity into the market, the average margin it earns when supplying electricity, and the size of the fixed costs it needs to cover. Those bidders/generators who continually bid in at low prices are those who currently operate lower cost plant. So long as the market clearing price settled above their bids, they can make money, and they have good incentive to invest more.

Because there is no separate payment for being available, firming capacity must recover its full costs – both fuel and capital – from the revenue it earns during the relatively few times it actually runs. This means prices during those periods must not only cover fuel costs but exceed them substantially to recover fixed costs compressed into limited operating hours.

This energy-only market design has consequences for the average price of electricity to consumers and for the reliability of electricity supply. First, low electricity prices for consumers requires a generation portfolio that has low LRMC so it can offer in the market at lower prices, and generation that can be utilised consistently to produce a return.

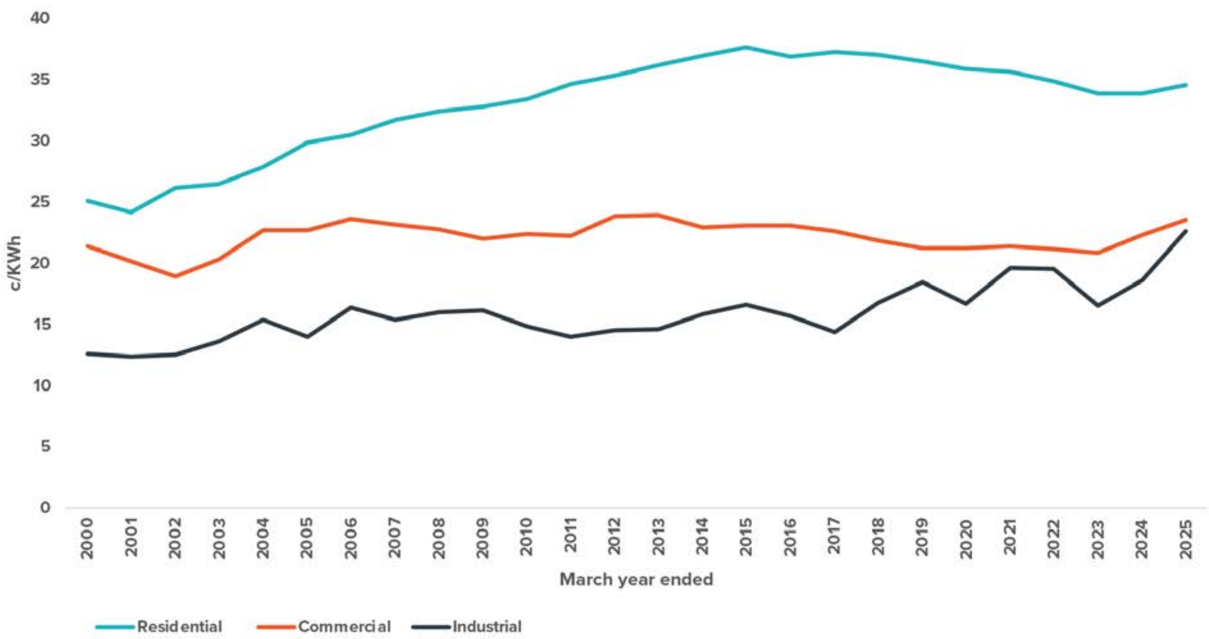
Second, the firming capacity requires high prices when demand is high or baseline supply is low, to recover its fixed costs. This means that interventions which reduce prices during scarcity periods, such as price caps or government supply measures, also reduce the revenue available during precisely the periods when firming capacity most needs to earn its return. This can affect the investment case for the very capacity the intervention is intended to complement.

4. The turbulent recent years

After several years of stable electricity prices, the market has become increasingly volatile since 2019, and with prices trending upwards. This has had a significant impact on unhedged industrial consumers who are exposed to wholesale volatility and hedged industrial consumers who face more frequent re-pricing as wholesale prices increase.

Over time, in addition to growing regulatory costs, this volatility and upward price trend in the wholesale market has begun to lead to higher prices for residential and commercial users. The energy and other component of residential electricity costs increased 5.8% between December quarter 2024 and 2025, the highest increase since 2020.[57]

Figure 26: Inflation-adjusted average electricity costs by sector



Source: MBIE, Energy price data tables.

Note: Costs are excluding goods and services tax (GST) and are expressed in March 2025 dollars.

The impact of high energy costs is unevenly distributed, with 6.7% of households not being able to afford to keep their homes adequately warm in 2024.[58] This has contributed to New Zealand households' declining trust in the system. In 2021, 54% of New Zealanders agreed that there was enough electricity to keep New Zealand powered into the future. By 2024, that number was 39%. New Zealanders also expressed concern in 2024 that electricity prices may not reflect actual costs and that the electricity sector may not be competitive.[59]

The Commission has an interest in ensuring that the infrastructure system is delivering for New Zealanders. This section explores whether there are any infrastructure issues that might be preventing low priced, stable, and abundant electricity in the near term.

[57] MBIE, *sales-based electricity costs for residential*, in 2026 Q1 dollars.
[58] MBIE, *Report on energy hardship measures: year ended June 2024* (2025).
[59] New Zealand Infrastructure Commission, *Getting what we need: Public agreement and community expectations around infrastructure* (2025).

4.1. A period of supply and demand imbalance

Supply and demand appear to have become unbalanced beginning in mid-2019

In the previous section, we highlighted that over the long run, the cost of producing electricity should be closely related to its price, because if prices go well above, generators have a financial incentive to increase supply. As long as new supply is profitable to build – meaning that it costs less than expected wholesale prices – it will help to reduce prices. However, electricity prices that are much lower than the cost of new supply are not sustainable, as they mean electricity generators are making financial losses.

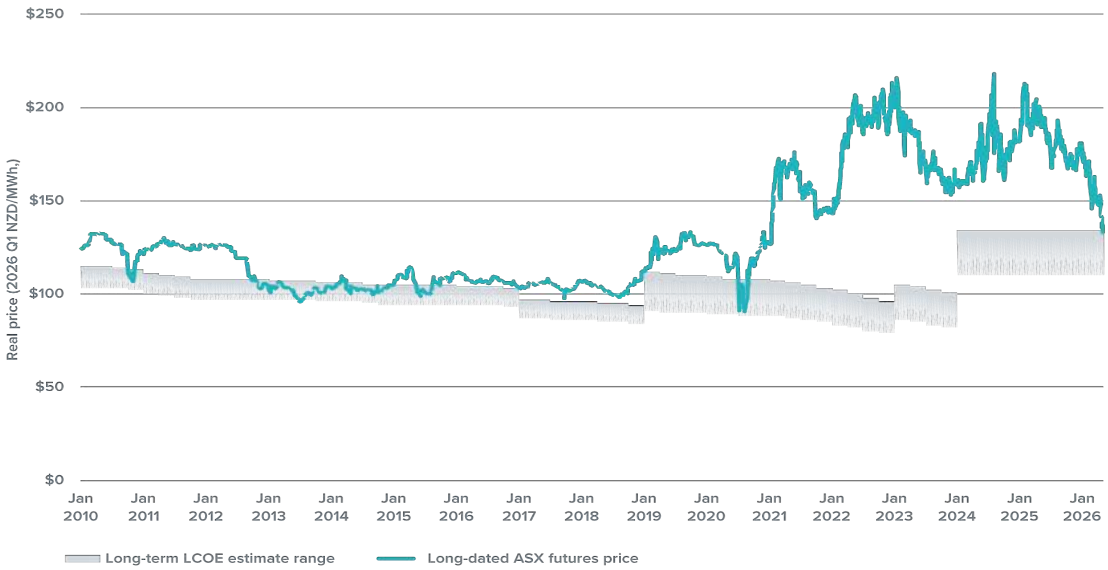
Figure 27 compares futures contract prices, which indicate electricity generators' and buyers' expectations for future wholesale prices at a point in time, with estimated long-run LCOE, which is a measure of the cost to build and operate new generation, from 2010 to mid-2026. This comparison provides a high-level indicator of whether supply and demand are in balance with each other.

Between the mid-1990s and 2019, futures prices were almost exactly in line with estimated LCOE.[60] There were periods where prices were above or below the cost to build and operate new generation, but these did not last long. This suggests that, during this period, new generation development was closely tracking demand.

Starting in 2019, futures prices spiked upwards and remained elevated above estimated LCOE until recently. This is a signal that electricity generators and buyers expect there to be a shortfall of generation, relative to what is needed to meet demand at the lowest feasible cost.

[60] For pre-2010 estimates, see Electricity Price Review | Hikohiko Te Uira, *First report for discussion* (August 2018).

Figure 27: Long-dated ASX futures prices relative to the cost to build and operate new generation, January 2010 to early May 2026



Source: Chart recreated from futures contract price data and long-run LCOE estimates published by the Electricity Authority. Futures prices and LCOE estimates are inflation-adjusted using Stats NZ's CPI.

Note: Long dated refers to the average price of long-dated ASX futures at the Otahuhu node. The blue line represents historic ASX daily closing prices of all long-dated contracts (meaning contracts for settlement more than 12 months in the future). The horizontal axis represents the trading day, rather than the settlement date. The grey bar shows the Electricity Authority's estimates of long-term LCOE for new generation investment, which changes over time as the cost of building and fueling generation has changed.

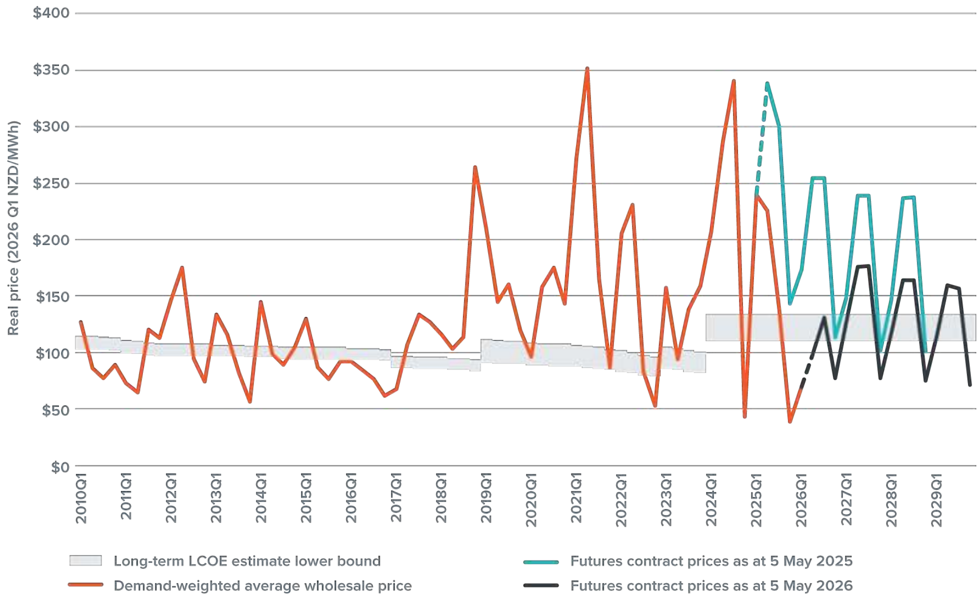
Figure 27 also shows that futures prices have declined significantly over the last year and recently moved into the Electricity Authority's range for estimated long-run LCOE for new generation.

Figure 28 unpacks the market expectations shown in **Figure 27**, breaking them down by quarter rather than averaging across all long-dated contracts. This reveals not just the expected level of future prices, but how they are expected to vary across seasons. It compares current expectations against what market participants were expecting a year ago, and against historical wholesale prices.

Like futures prices, historical wholesale prices generally tracked the long-run cost of new generation up to around 2019 but started to spike significantly above this level after 2019. Futures prices in early May 2025 (the teal line) indicated that market participants expected prices to remain well above LCOE over the next four years, and that prices were expected to be much higher in the winter.

By contrast, futures prices in early May 2026 (the black line) indicate that market participants now expect average prices, across the year, to converge towards estimated LCOE for new generation. Prices are expected to be lower than LCOE in the summer, when electricity output from renewables will easily meet demand, and higher than LCOE in the winter, due to the need to run more expensive firming generation to meet higher demand.

Figure 28: Quarterly average wholesale electricity prices, 2010 to early 2026, and quarterly ASX futures contract prices as at 5 May 2025 and 5 May 2026



Source: New Zealand Infrastructure Commission analysis of the Electricity Authority's published wholesale price and demand data and forward contract settlement price data, plus long-run LCOE estimates published by the Electricity Authority. Historical data and LCOE estimates are inflation-adjusted using Stats NZ's CPI, while futures prices have been adjusted for inflation using Treasury's Fiscal Strategy Model – BEFU 2025 forecast CPI.

Note: Forward contract price curves show prices for contracts that will be settled in each quarter for the next four years. They indicate the expected future path of wholesale prices, and hence we compare them with historical wholesale prices. The horizontal axis represents the trading quarter (for historical price data) or date of settlement (for futures contracts). The grey bar shows the Electricity Authority's estimates of long-term LCOE for new generation investment, which change over time as the cost of building, operating, and firming generation has changed.

The trends shown in **Figure 27** and **Figure 28** suggest new generation investment might be succeeding in bringing down expected electricity costs. However, exploring what caused prices to increase after 2019 can help us understand if there are any infrastructure interventions that can be used to bring the market back into balance.

Electricity generation became increasingly renewable and cheaper, rendering much thermal generation uneconomic

Over the last 20 years, New Zealand's electricity generation mix has become increasingly renewable. Geothermal, wind, and solar generation have displaced thermal generation.

While this is beneficial from an emissions perspective, from a market perspective, the reason this has occurred is that these forms of electricity have become cheaper to build and operate than thermal power stations.

Figure 29 shows estimates of short run marginal cost (SRMC), which reflect what it costs to fuel and operate generation plant after it is built, and estimated LCOE, which includes the cost to build a plant and run it, of different generation technologies in New Zealand from 2015 through 2035. It compares estimated SRMC and LCOE against average wholesale electricity prices, which provide a rough estimate of how much electricity generators can earn from these plants.[61]

Ten years ago, the cost of building and operating different generation technologies was very different than it is today. In 2015, wind power required consistently high prices to be profitable to build, and solar generation was far too expensive to build to be profitable. Comparatively abundant and low-cost gas meant that gas plants could be profitable to own and run so long as there were periods of high prices, like dry years (**Panel A**).

Today, renewable technologies – solar, wind, geothermal – still have near-zero short-run marginal costs, as they require no fuel to generate.[62] The LCOE for wind and solar generation has decreased substantially, reflecting sustained cost reductions in manufacturing wind turbines and solar photovoltaic cells. Conversely, thermal electricity generation has become more expensive to run because fuel costs have increased and carbon prices in New Zealand's Emissions Trading Scheme have risen (**Panel B**).

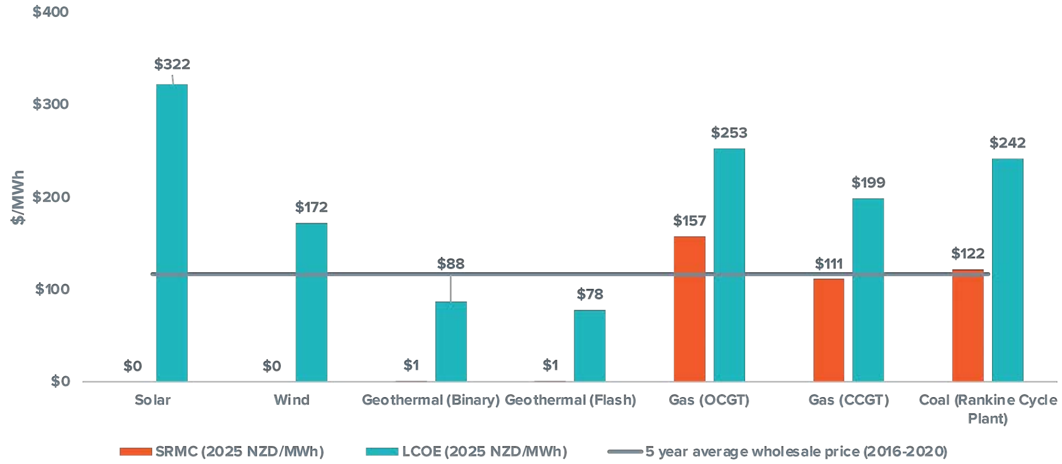
These trends are expected to continue over the next 10 years. Wind and solar costs are forecast to continue declining. Fuel and carbon costs for thermal plants are expected to stay high or increase further, suggesting that price bids from these plants will enter higher into the wholesale market (**Panel C**).

[61] This is only a rough estimate as the price that individual generation plants earn will depend on what wholesale prices tend to be at the time that they are generating electricity. Intermittent renewable generation options, like wind and solar, will tend to earn lower-than-average prices (revenue per unit of energy produced will be less than 100%), as they are not always on during periods of high prices. In addition, solar output tends to be lower during the winter when wholesale prices are higher. In contrast, thermal generation may earn higher-than-average prices (revenue per unit of energy produced will be greater than 100%), as it is more likely to run during periods of high prices when thermal firming is required.

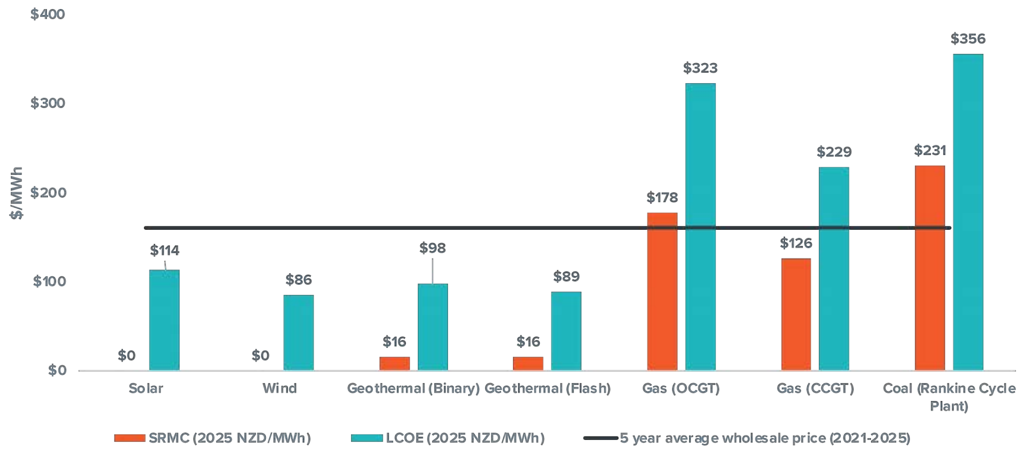
[62] Beca Limited and Concept Consulting Group Limited, *2025 generation stack report* (prepared for Transpower New Zealand Ltd, September 2025), Section 5.1.5. Operating and maintenance costs and fuel costs for solar and wind given as zero in Graham, P., Hayward, J. and Foster, J. (CSIRO), *GenCost 2024-25* (July 2025).

Figure 29: Estimates and projections of short-run marginal cost and levelised cost of electricity, by type of plant. 2015, 2025, 2035

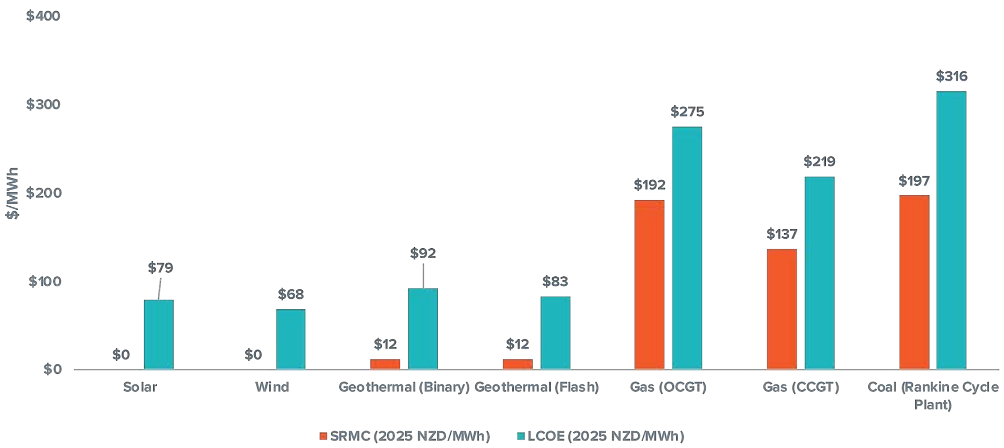
Panel A: Year 2015



Panel B: Year 2025



Panel C: Year 2035



Source: New Zealand Infrastructure Commission analysis.

Note: Calculations and assumptions are explained in Appendix A.

Over time, these cheaper forms of electricity have allowed generators to bid into the wholesale market at lower prices and make it easier for them to generate returns. This explains in part why prices growth was relatively muted up until 2019, in addition to flat demand. This renewable generation largely replaced, rather than added to, thermal generation.

However, what this has meant is that flexible thermal generation, which was providing baseload power and could be run profitably in earlier years, increasingly became uneconomic and largely limited as a firming source. As cheaper renewable electricity entered the market, existing thermal plants were closed. Between 2007 and 2026, seven thermal power stations closed, representing almost 1.9 TW worth of capacity.

Table 3: Thermal power station closures since 2007

Power Station	Type	Capacity (MW)	Date Closed
Te Awamutu	Gas turbine	54	2007
New Plymouth	Gas/oil turbine	600	2008
Huntly 3	Coal/gas steam turbine	250	2012
Otahuhu B	Gas combined cycle	404	2015
Southdown	Gas combined cycle/cogeneration	170	2015
Te Rapa	Gas cogeneration	44	2023
Stratford	Gas combined cycle	377	2026

Source: Electricity Authority, *Existing generation plant*.

This is important because when demand is high or supply is low, such as in dry years, to mitigate price spikes, not only do prices need to rise high enough to incentivise higher cost, more flexible thermal generation to provide power, but also that the capacity needs to exist to do so. By 2019, this capacity was markedly less available than it was in 2001 or 2008.

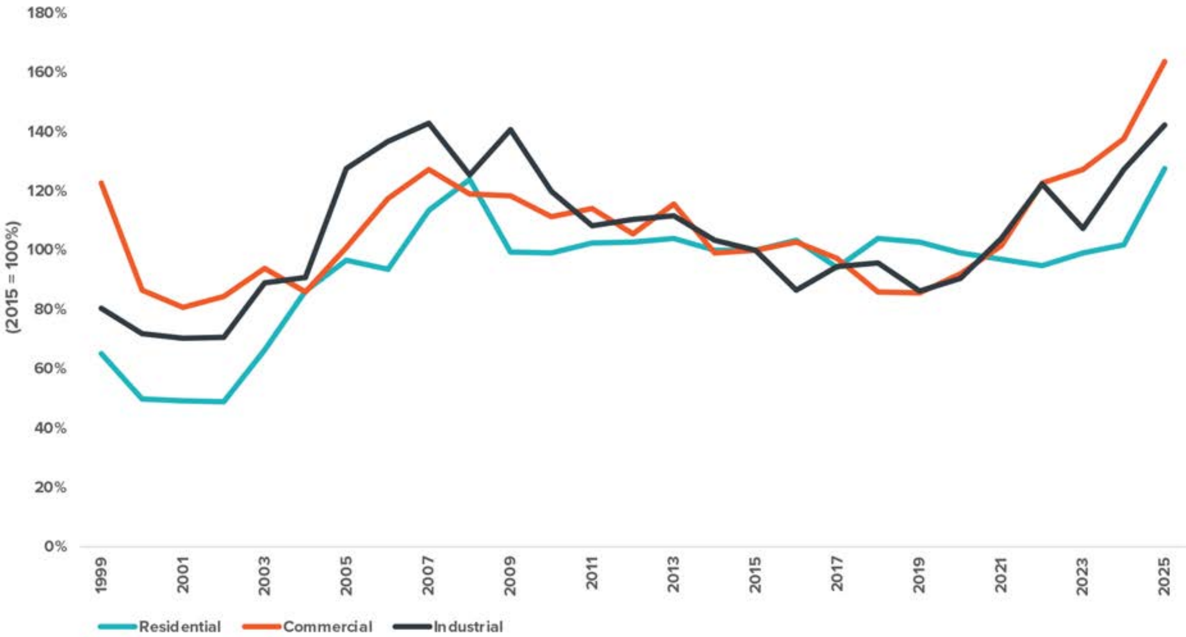
The cost of powering gas firming generation went up significantly

Gas availability and price determine how much gas-fired firming generation can be run and at what cost.

Gas was widely available at low prices until around 2019 (**Figure 30**). However, consumer prices for commercial and industrial customers started rising rapidly after 2019, followed by rising residential consumer prices. Wholesale gas prices, which exclude costs for gas transmission and distribution, have more than doubled since 2015.[63]

[63] Boston Consulting Group, *Energy to Grow: Securing New Zealand's future* (November 2025) at s 4.2; EnergyLink, *The role of gas in electricity and industry* (prepared for Energy Resources Aotearoa, April 2023).

Figure 30: Changes in real average annual gas prices by sector (2015 baseline)



Source: MBIE, Energy price data tables.

Note: Prices are excluding goods and services tax (GST), 2015 was used as the base year.

Gas prices have risen rapidly due to declining domestic gas production, and in particular due to faster-than-expected production declines since the late 2010s.

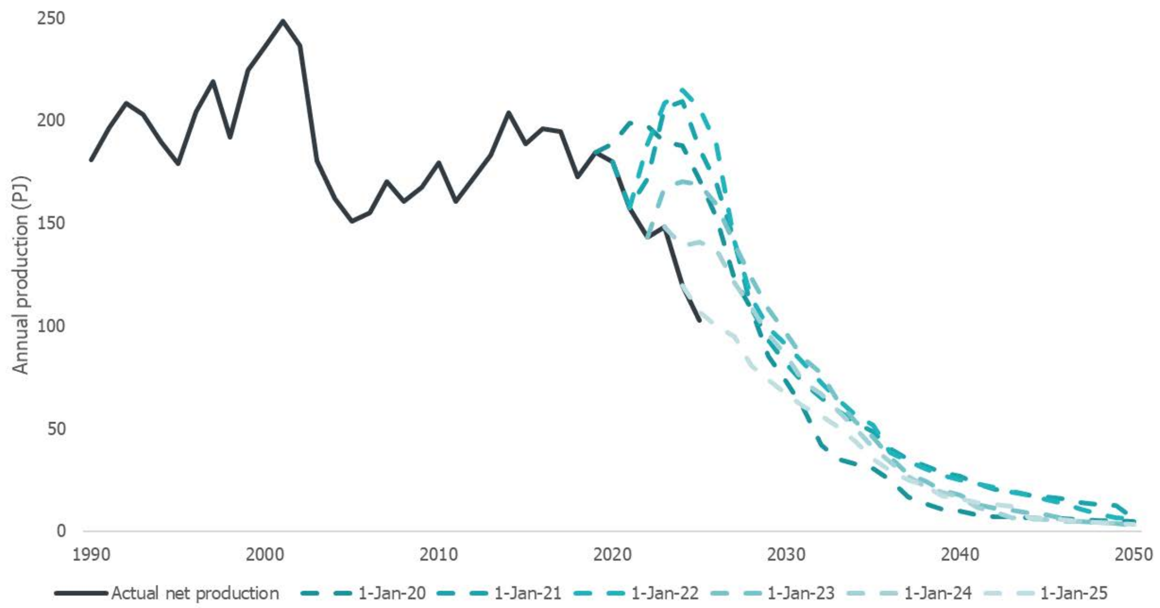
From 2015 to 2025, New Zealand's gas production declined by around 50% (**Figure 31**). No major new gas fields had been discovered since the 2000 discovery of the Pohokura field, despite extensive oil and gas exploration in the 2000s and 2010s. Subsequent policy changes, including a ban on new oil and gas exploration permits from 2018 to mid-2025, also affected the outlook for the sector. Total production from existing fields started declining in 2015.

Gas production projections from the early 2020s suggested that production from existing fields would increase, as higher prices incentivised more investment in formerly marginal reserves. However, production fell significantly below expectations.[64] In 2024, for instance, overall production was 21% lower than in 2023 – significantly lower than production projected and anticipated by the industry.[65]

Domestic gas production is now expected to continue to decline, although the pace remains uncertain.

[64] Concept Consulting, *Various analyses of current electricity and gas market dynamics* (May 2025).
[65] EnergyLink, *The role of gas in electricity and industry* (prepared for Energy Resources Aotearoa, April 2023); MBIE, *Energy in New Zealand 2025: gas*.

Figure 31: Gas production and associated forecasts



Source: MBIE, Gas data tables up to December 2025; MBIE, Petroleum reserves data, 2020–2025.

Falling gas production and higher gas prices have increased the cost of gas-fired firming generation, and this has flowed through to wholesale electricity prices. In dry years, when hydro storage is low and gas-fired generation is called on to firm supply, the higher cost of gas is reflected in wholesale prices. This makes the impact of dry years on electricity prices more severe than it would otherwise be.

Further compounding the challenge is the declining lack of flexibility that will enable gas to be quickly deployed for electricity generation. Gas field production generally does not vary significantly or quickly in response to demand. This means that to quickly deploy additional gas, there are two options: drawing from storage or flexing from large industrial users.

For storage, New Zealand currently has limited gas storage, mainly concentrated at the Ahuroa storage facility. A second gas storage facility at the depleted Tariki gas field is currently being developed.[66] Like electricity infrastructure, it needs to be well-used to make it economic.

Flexing from large industrial users is an option, and in the past Methanex has played this role. Methanex can reduce or stop production on one or more of its production trains at its facility in Taranaki to release gas for electricity generation. However, over the years, Methanex has shuttered most of its production trains for economic reasons, leaving a single operating train to flex up and down or shut down if needed.

Recent developments in gas production, namely the predicted closure of the Māui gas field in 2026, likely signals the closure of Methanex's plants entirely.[67] If this occurs, the options to provide flexibility in gas supply for electricity generation become even tighter.

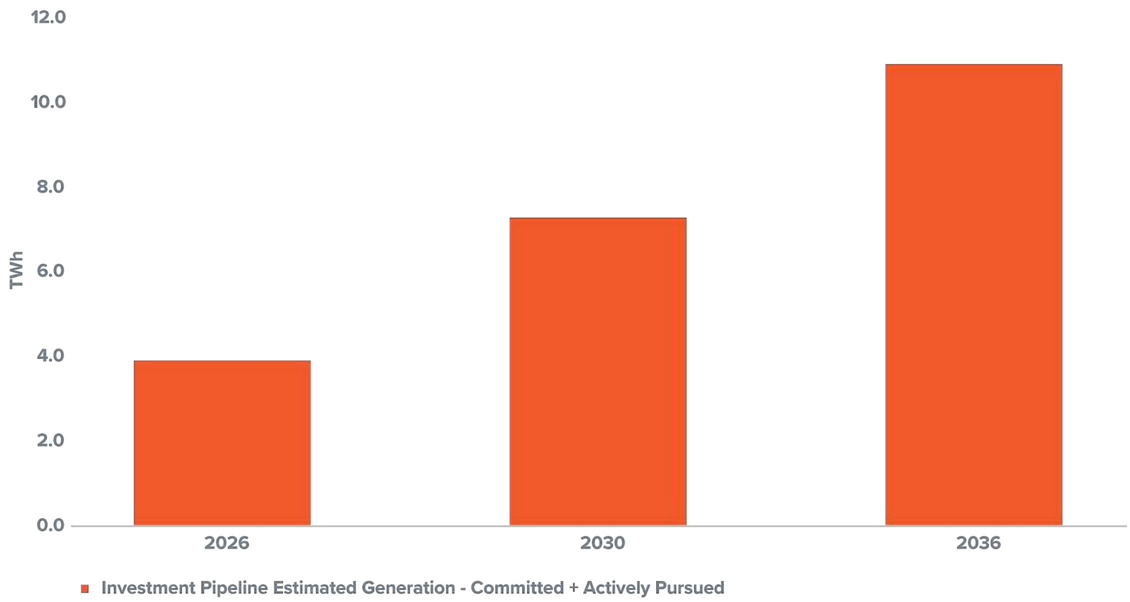
[66] New Zealand Energy Corp., *New Zealand Energy Corp. provides update on Tariki Gas Storage Project* (26 November 2025).
[67] Energy News, *Maui closure likely by year-end – OMV* (23 April 2026); BusinessDesk, *OMV notifies government of end-of-2026 deadline on Māui gas field closure* (24 April 2026).

4.2. The path back to lower prices

We have established that, starting 2019, electricity prices began rising well in excess of estimated costs of adding new supply and persisted this way for the next few years. In a functioning market, we would expect additional supply to be commissioned and prices to be coming down. Therefore, the solution to the current turbulence in energy prices is most likely increasing supply.

This is what appears to be occurring. According to the Electricity Authority's Investment Pipeline, an additional 3.6 TWh worth of electricity generation is currently committed and actively pursued for construction by 2026, and a further 2 TWh by 2030.

Figure 32: New cumulative electricity generation supply committed and actively pursued, 2026, 2030, 2036



Source: Electricity Authority, Generation investment pipeline, (March 2026)

Note: If a final investment decision hasn't been made but other significant milestones have been reached (a location being secured in addition to a consent application being submitted or contracts to finance the project executed) then the project is "actively pursued".

Forward prices seem to be responding to this investment. As of May 2026, forward prices are approaching LCOE estimates. A recent analysis by Concept Consulting estimated that prices will align with LRMC by 2030.[68] It has taken several years, but the predicted result appears to be happening, as shown in **Figure 27** above.

Notwithstanding recent price trends, it is worth considering whether there are any barriers to enable new electricity generation to be developed faster and with less friction. By doing so, we might be able to identify improvements to the system so that it can more easily respond to unexpected events that require generation to scale up to bring prices down.

[68] Concept Consulting, *Various analyses of current electricity and gas market dynamics* (May 2025).

Reducing investment uncertainty

Developers commit to generation projects based on expectations of future revenue. Making forecasts of future revenues are difficult if there is significant uncertainty around prices and demand.

Uncertainty around future demand

On the demand side, one reason why new supply may not have been commissioned earlier is due to uncertainty around the New Zealand Aluminium Smelter (NZAS). NZAS is responsible for around 12% of New Zealand's total electricity consumption, but for years its financial viability has been in question. Closure of NZAS, or agreements to turn it off during periods of high demand or low supply, would provide the market with additional flexible capacity. Had the NZAS closed, it would have led to a significant amount of available supply to hit the market, lowering prices, and reducing viability of new energy build.

This uncertainty was lifted in 2024 when NZAS signed a supply agreement with Meridian for 20 years. However, during the period of 2019 to 2024 when prices were above LRMC, this uncertainty was likely keeping new investment on the sidelines.

Uncertainty concerning future gas production

For gas, no major new fields have been found since 2000, drilling results have generally been worse than expected, existing wells have declined at a faster rate than forecast,[69] and indications are that the Māui field may close at the end of 2026. Barring a low-probability discovery of a major new oil field, the direction is clear: downwards.

It could be argued that continued optimistic projections of gas production in 2019, 2020 and 2021 dampened construction of new electricity supply and have prolonged the period where prices have exceeded costs of new supply. Those considering building cheap supply in those years might have held back if they were reading optimistic projections of gas production and expecting prices to come back down.

Recognition of the need for a more managed approach to the gas transition is growing. The final recommendations of the Energy Transitions Frameworks' Gas Working Group, released in November 2025, identified a range of transition issues and called for a framework to address them.[70]

Questions remain about how gas exits the system: at what pace, with what support for affected users and infrastructure, and how the electricity system's firming needs will be met as gas-fired generation declines. The issue is not whether gas production continues to fall but whether that decline is managed in a way that limits disruption, or reactive in a way that compounds it.

A challenge in the regulatory framework has been the timeliness and quality of disclosures on gas availability, including, for example, the potential downside outcomes from various drilling campaigns, which may have blurred wholesale price signals and delayed investment in

[69] Concept Consulting, *Various analyses of current electricity and gas market dynamics* (May 2025).
[70] Gas Working Group, *Final recommendations*, Energy Transitions Framework (November 2025).

alternative generation, storage, and fuel switching options for businesses and industry. In a direct response to this gap, MBIE and the Gas Industry Company are committed to improving the transparency and timeliness of gas reserve, production, and security-of-supply data.[71]

What a managed pathway looks like and who is responsible for delivering it is appropriately a question for government, the gas industry, and the relevant regulators. This connects to the fourth of the Commission's National Infrastructure Plan implementation pathways: *supporting the gas transition by ensuring markets and consumers have adequate information and incentives to manage risks, as well as giving urgent attention to assisting the market with transition issues.*

Uncertainty around government supply interventions

Managing dry year risk has been a perennial policy issue for New Zealand. Several significant policy solutions have been implemented or proposed by the Government over time. These interventions are often discussed as addressing security of supply challenges, but in practice they appear to be intended to address concern about high prices.[72]

One consequence of the New Zealand's energy-only market design is that interventions which cap or reduce prices during scarcity periods will also reduce the revenue available to generation plant that operates through those periods. This point applies to all generation, but firming plants that require sufficient periods of high prices to cover their fixed capital costs are particularly affected. Reduced revenue in those periods weakens the investment case for generation, potentially reducing investment.

This was borne out by the strategic reserves and Whirinaki diesel peaker schemes from 2004 to 2010. The Electricity Commission operated a reserve energy scheme between 2004 and 2010 due to low hydro lake levels and the Government commissioned Contact Energy to build and operate a diesel peaking plant on the Whirinaki site to be run if triggered by a set reserve generation capacity level, to help preserve hydro storage.

The reserve scheme was phased out from 2009 and the Whirinaki plant sold to Contact Energy. A subsequent review found the scheme reduced security of supply by encouraging market participants to rely on the Electricity Commission to ensure security, and discouraged investment by electricity generators in peaker plants.[73]

More recently, the New Zealand Battery Project (2020-2023) proposed a pumped hydro scheme at Lake Onslow.[74] Like the Whirinaki diesel peaker, this proposed government-supported electricity generation that would run during dry years. By contrast, a current (2025) proposal for LNG import terminal would involve government support for fuel supply that could be used by existing gas generation plants that would operate on a commercial basis.[75]

[71] See Workstream 2, Action 2.4: MBIE, *At a glance: New Zealand's Energy Package* (October 2025).
[72] See Appendix B for a fuller discussion of winter 2024 dry year challenges.
[73] Electricity Authority, *Security of supply*.
[74] The NZ Battery Project was set up in 2020 to explore possible renewable energy storage solutions for when our hydro lakes run low for long periods. A pumped hydro scheme at Lake Onslow was one of the options being explored. The Government stopped the Lake Onslow investigations in late 2023. MBIE, *NZ Battery Project*.
[75] MBIE, *At a glance: New Zealand's Energy Package* (October 2025); Hon Simon Watts (Minister of Energy), *Delivering LNG to support energy security* (9 February 2026).

The size of the effects of these proposals depends on the specific design of the intervention and the alternatives available, but it illustrates why changes to one part of an energy-only market can produce unintended consequences, such as reduced investment in other generation options. This risk can be mitigated through a well-developed business case that thoroughly considers a long list of options, closely examines how the investment will be funded, and analyses the impacts on investment elsewhere in the sector.

Market competition and new entry

In a workably competitive market with no barriers to entry, periods where electricity prices are consistently higher than LRMC are expected to lead to increased generation investment that drives prices back to LRMC. However, this might not occur if incumbent generators enjoy market power that enables them to limit their own investment and sustain prices above LRMC, without attracting new entry.

Internationally, competition issues regarding energy systems can arise because generation and network assets are capital-intensive, access to network infrastructure is essential, consumer demand is often insensitive to price changes, and individual electricity generators can be pivotal to system outcomes at times.[76] As previously highlighted, New Zealand's electricity market is relatively concentrated with Genesis, Meridian, Mercury, and Contact accounting for around 83% of generation and a similar share of the retail market.

The OECD and New Zealand's regulatory bodies have identified concentration and barriers to new entry as potential concerns for the electricity sector. The OECD's 2026 Economic Survey of New Zealand notes that concentration could result in slower investment and higher prices and identifies limited access to firming capacity as a potential barrier for independent generators and retailers.[77] It observes that market power is episodic in character, with hydro-dominant portfolios holding more influence in wet years and thermal-dominant portfolios in dry years.

The Electricity Authority has expressed concern that "the combination of gentailer vertical integration and their control of flexible generation is hindering competition in generation and retail, and investment in new electricity generation."[78] The Commerce Commission has similarly raised concerns about the state of competition in the electricity sector, including in its consideration of the 2025 Huntly Firming Deal to secure long-term purchase agreements for coal supply to Genesis' thermal power station.[79]

It is difficult to measure how the state of competition is affecting electricity generation investment, and there is no conclusive evidence of harm. However, competition remains a focus for international commentators and local regulatory bodies, and various regulatory initiatives are underway. These include work by the Electricity Authority, Commerce

[76] OECD, Competition in Energy Markets, OECD Competition Policy Roundtable Background Note (2022).
[77] OECD, *OECD Economic Surveys: New Zealand 2026* (2026).
[78] Electricity Authority, *Level playing field measures: consultation paper* (October 2025); Electricity Authority, Reviewing risk management options for electricity retailers: issues paper (7 November 2024).
[79] Commerce Commission, *Authorisation of the Strategic Energy Reserve Huntly Firming Option ('Huntly Deal')* (5 November 2025) at 16, 35–37.

Commission, MBIE, and the Government through its Energy Package to strengthen market transparency, improve access to firming capacity, and support new entry.[80,81]

Reviews of the electricity system and the OECD have also noted that the transition towards more renewables may increase the ability of firming generation to exercise market power, suggesting that competition dynamics will require ongoing monitoring as the market evolves.[82] The need for ongoing monitoring is reflected in the Commission's second National Infrastructure Plan implementation pathway: *strengthening coordination, monitoring, reporting and regulation of electricity and gas sectors to keep markets competitive, enable new generation, improve market transparency, and improve energy affordability*.

Regulatory costs and delays

Even if competition is working well, electricity prices could remain persistently higher than LRMC if there are large unforeseen regulatory barriers impacting the certainty and pace of investment in new generation. This could slow down the pace of investment and potentially increase costs, leading prices to be higher than they need to be for longer.

Electricity infrastructure typically requires significant land and physical resources, as well as a range of planning, design, building, and commissioning phases. Regulatory approvals (for instance, consents for land use, environmental management, building and safety) can stretch out planning timeframes or create uncertainty about how long these processes will take.

The Electricity Authority's 2025 Generation Investment Survey finds that solar and wind farm developers consider resource consent processes a significant constraint on the pace of development.[83] In contrast, transmission grid connection approvals are perceived to have a more modest effect on timeframes, and Overseas Investment Act requirements are perceived as a smaller issue following changes to streamline approvals.[84]

The financial costs of resource consent processes, including mitigations imposed through these processes, appear to be small relative to total project costs, and unlikely to explain a large and sustained gap between electricity prices and LRMC. Based on a review of projects consented in the late 2010s, Commission research found that consenting costs[85] averaged around 5.5% of total project costs for all categories of infrastructure, and around 2.6% for energy infrastructure projects.[86]

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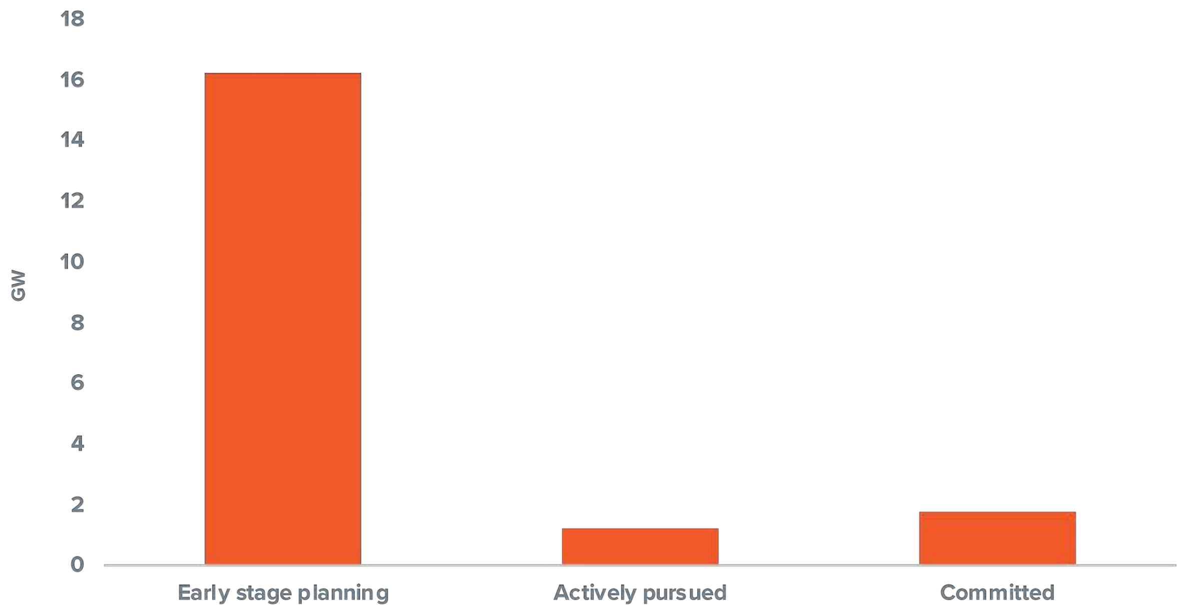
[80] Market Development Advisory Group, *Price discovery in a renewables-based electricity system: final recommendations paper* (2023) at p 35; Electricity Authority, *Level playing field measures: options paper* (27 February 2025).
[81] For example, Workstream 2, Building Stronger Markets: MBIE, *At a glance: New Zealand's Energy Package* (October 2025).
[82] Bushnell et al., *Review of the NZ Electricity Market Performance: peer review evaluation* (8 June 2025) at p 33; Frontier Economics, *Review of Electricity Market Performance* (23 May 2025); OECD, *Economic Surveys: New Zealand 2024* (May 2024). These sources also suggest caution in addressing competitive influences on markets.
[83] Electricity Authority, *Barriers to developing new electricity generation* (2025).
[84] Costs associated with obtaining land use and environmental consents from a local authority.
[85] As defined as those costs with meeting the obligations of the Resource Management Act 1991.
[86] Sapere Research Group, *The cost of consenting infrastructure projects in New Zealand* (prepared for New Zealand Infrastructure Commission, July 2021).

However, resource consent timeframes can be long: it takes an average of 214 days to obtain a resource consent for a medium complexity infrastructure project like a wind farm.[87] This is on top of other approvals such as building consents, other council approvals, and safety and accreditation steps.

Electricity generators appear to respond to regulatory approval timeframes, and other project-related uncertainties, by planning well in advance and maintaining a pipeline projects at various stages. The Electricity Authority's Investment Pipeline shows that there are many projects in early-stage planning, as well as some that are being actively pursued (for example, through site acquisition or consent applications) but not yet committed (**Figure 33**).

The Government's reforms to the resource management system, which include providing a fast-track consenting pathway that is open to electricity projects and developing new resource management legislation, are aimed at addressing regulatory delays and barriers to new investment. Infrastructure Plan Recommendation 11 highlights the need to "*commit to maintaining a stable legislative framework for resource management that enables infrastructure development while managing environmental impacts*".

Figure 33: New cumulative electricity generation in early planning, actively pursued, or committed, year 2028, in gigawatts



Source: Electricity Authority, Generation investment pipeline, (March 2026)

Note: If a final investment decision hasn't been made but other significant milestones have been reached (a location being secured in addition to a consent application being submitted or contracts to finance the project executed) then the project is "actively pursued".

[87] Sapere Research Group, *Infrastructure consenting for climate targets: Estimating the ability of New Zealand's consenting system to deliver on climate-critical infrastructure needs* (prepared for New Zealand Infrastructure Commission, January 2023).

5. The long-run transition to net zero

The previous section highlighted that the period since 2019 has been a challenging one for our goals of low prices and stable supply of electricity. However, as we noted, so long as frictions to adding new supply are minimised, we would expect prices to normalise, and they appear to be doing so.

In the long run, however, in addition to low prices and stable supply, our energy system needs to be low emissions to meet our climate objectives. The National Infrastructure Plan highlighted that investment in new electricity generation to meet our net zero commitment is one of the largest infrastructure priorities we face as a country over the next 30 years.

This section lays out that challenge, highlights the infrastructure implications, and discusses pathways for a smooth transition.

5.1. A pathway to decarbonisation

The decarbonisation pathway for energy

The New Zealand Climate Change Response Act 2002 requires the country to achieve net zero emissions for all greenhouse gases (except biogenic methane) by 2050. To achieve this goal, the types of energy we use for generating electricity, heating our homes, fuelling our cars, and getting around are all going to have to change. At the same time, it is important that this transition be as smooth and low-cost as possible to minimise affordability concerns for households and businesses.

To advise the government on the best approaches to this transition, the Climate Change Response (Zero Carbon) Amendment Act 2019 created the Climate Change Commission (CCC). The Act also set into law the process for achieving emissions targets. The Act requires five yearly emissions budgets to be set; these enable a step-down pathway towards the 2050 target. Each budget is set at least 10 years in advance, giving businesses and government time to plan.

One of the key functions of the CCC is to produce a range of scenarios and pathways for reaching New Zealand's 2050 emissions targets, varying in the degree of technological change and societal shift assumed.[88] The most recent set of advice the CCC provided to government on the emissions pathway was for the fourth emissions budget (EB4).

The CCC describes its EB4 demonstration pathway as “the Commission’s judgement of what would be ambitious and achievable, provide flexibility for the future, and offer lasting economic, societal and environmental benefits that will likely exceed overall costs”.[89] The

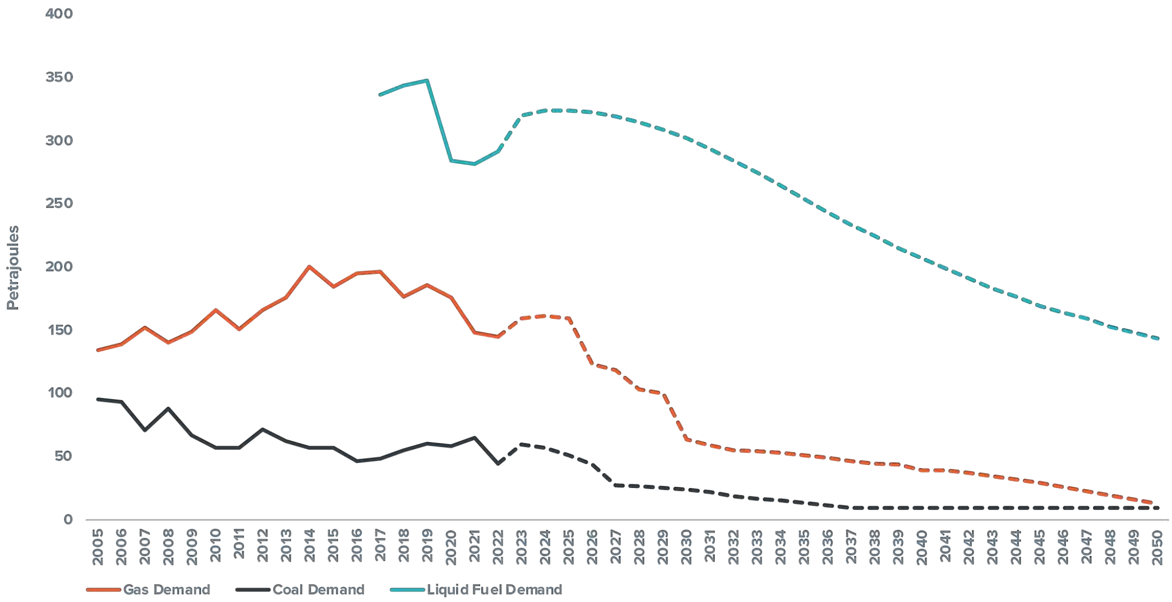
[88] He Pou a Rangi Climate Change Commission, *Advice on Aotearoa New Zealand's fourth emissions budget* (November 2024).
[89] He Pou a Rangi Climate Change Commission, *Advice on Aotearoa New Zealand's fourth emissions budget* (November 2024) at p 101.

Government has not made decisions on the fourth emissions budget, and is due to make these decisions by the end of 2027.[90]

The CCC uses the Emissions New Zealand (ENZ) model to analyse scenarios for the fourth emissions budget.[91] The modelling makes various assumptions about future trends relevant to achieving emissions goals, such as trends in the cost and availability of different electricity generation sources, the cost and availability of other energy-related technologies like electric vehicles, and other sources of energy demand growth like data centres.[92]

Electricity is expected to be the infrastructure system component that is most heavily affected by decarbonisation.[93] Electricity is expected to replace, in large part, the burning of fossil fuels and coal for energy (**Figure 34**). In the EB4 demonstration path, energy emissions reduce by 56% by 2040 compared to 2022, through the conversion of the vehicle fleet and industrial processes from fossil fuels to electricity.[94]

Figure 34: Forecast demand for fossil fuels and coal for energy in CCC EB4 pathway, 2005 to 2050, in petajoules

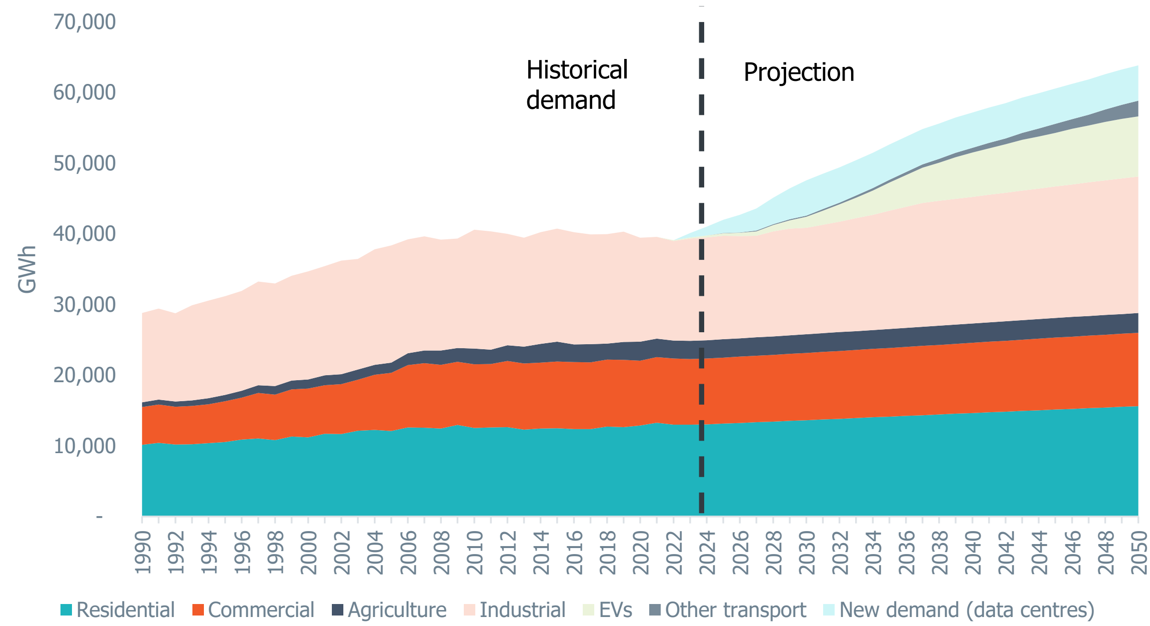


Source: He Pou a Rangi Climate Change Commission, Modelling and data: Final reports on the fourth emissions budget and 2050 target review (November 2024).

[90] Ministry for the Environment, *Government resets 2050 biogenic methane target* (2025).
[91] He Pou a Rangi Climate Change Commission, *Emissions in New Zealand (ENZ) Model Technical Manual* (2021).
[92] Key assumptions relevant to electricity and gas infrastructure demand include the following: Coal use in electricity generation is fully converted to biomass by 2032; 600 MW of data centres will be incrementally built from 2023 through to 2030; and capital costs of renewable electricity generation will decrease each year at a slower rate than in the recent past, in real terms (0.3% cost reduction per year for onshore wind; 1.1% per year for offshore wind; 1% per year for utility solar; and 0.07% per year for geothermal). Some assumptions are now modestly out of date, for instance, given the "Huntly Deal" agreed to by the four largest gentailers involves coal being retained until at least 2035, timeframes for biomass conversion are likely to be later.
[93] He Pou a Rangi Climate Change Commission, *Advice on Aotearoa New Zealand's fourth emissions budget* (November 2024) at p 13.
[94] He Pou a Rangi Climate Change Commission, *Advice on Aotearoa New Zealand's fourth emissions budget* (November 2024) at p 20.

The CCC expects growth in electricity use out to 2050 to be primarily driven by an uptake in electric vehicles, data centres, and other transportation (**Figure 35**).

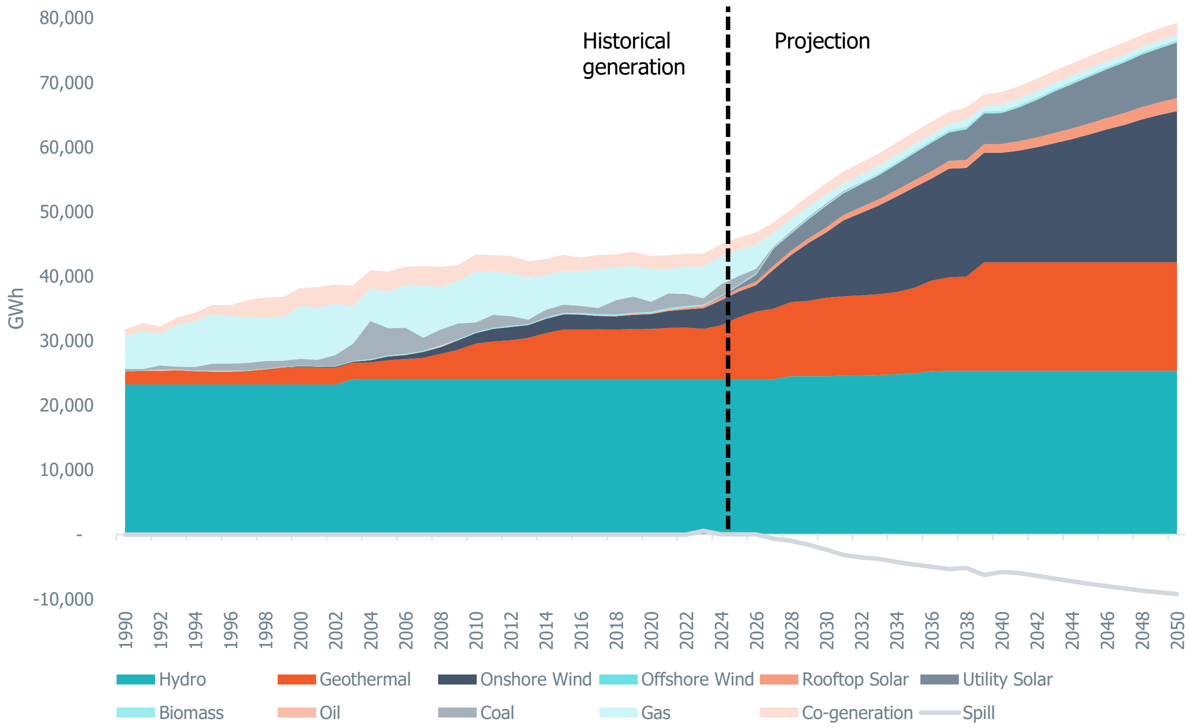
Figure 35: Forecasted electricity use by sector in the EB4 pathway, 1990 to 2050



Source: He Pou a Rangi Climate Change Commission, Modelling and data: Final reports on the fourth emissions budget and 2050 target review (November 2024).

To meet electricity demand growth, electricity generation output is forecast to increase significantly. The increase in generation is projected to primarily come from wind, utility and rooftop solar, and geothermal generation (**Figure 36**). Geothermal generation is expected to account for a larger proportion of baseload generation. Generation from coal and gas is assumed to decrease over time. In an increasingly renewable system, generation "spill" is also expected to increase as wind and solar generation will exceed electricity use at some times.

Figure 36: Forecast electricity generation by source in the EB4 pathway, 1990 to 2050



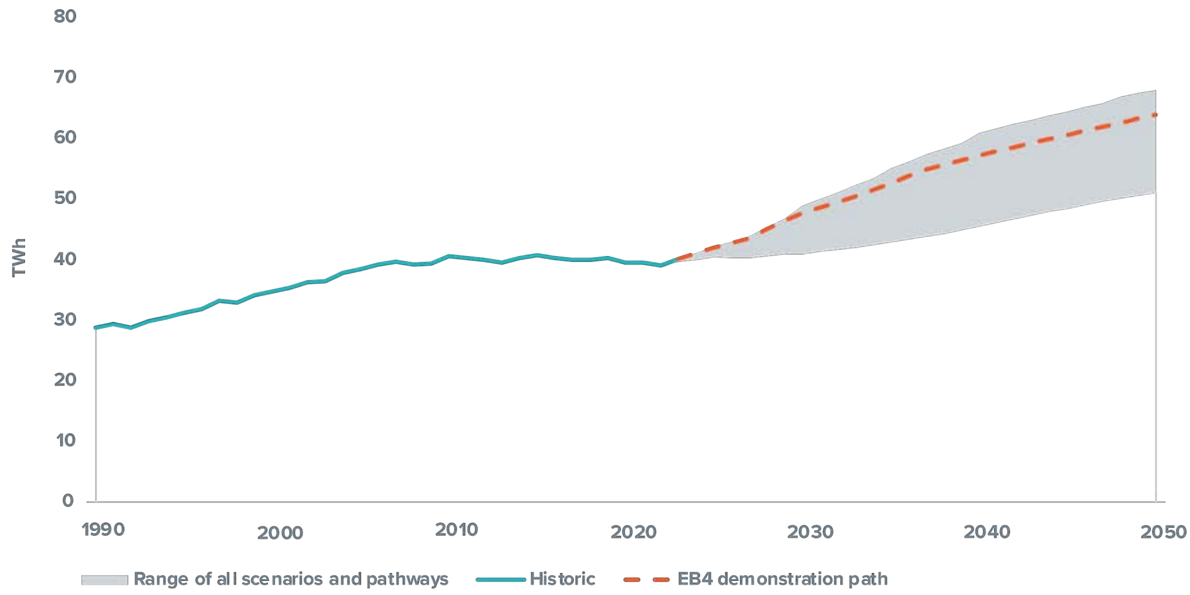
Source: He Pou a Rangi Climate Change Commission, Modelling and data: Final reports on the fourth emissions budget and 2050 target review (November 2024).

Note: Spill is an oversupply of electricity from renewable generation at a time when there is no need for this power.

There is uncertainty about how much electricity demand will grow, partly driven by policy choices

The CCC also produces a range of other scenarios and pathways, which provide a sense of the degree of uncertainty facing electricity infrastructure due to different climate policy choices. It expects electricity use to increase across all scenarios and pathways, but there is a wide range for how much it might need to increase (**Figure 37**).

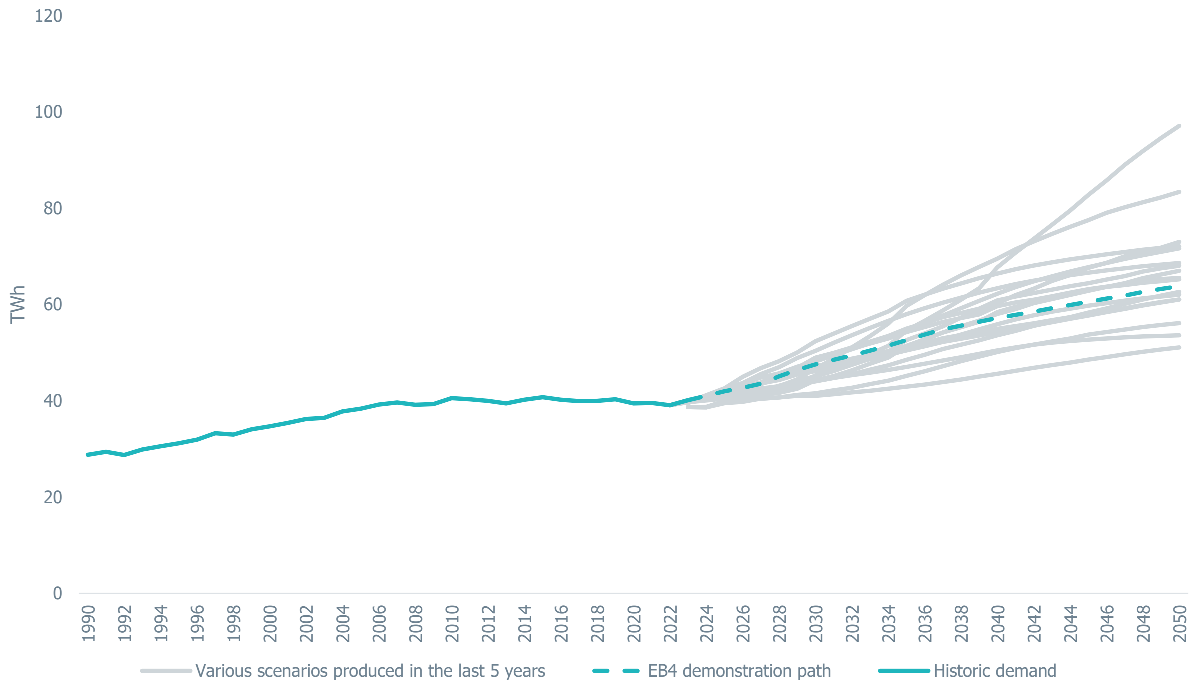
Figure 37: Demand for electricity in New Zealand, 1990 through 2050, in TWh



Source: He Pou a Rangi Climate Change Commission, Modelling and data: Final reports on the fourth emissions budget and 2050 target review (November 2024).

The CCC's EB4 electricity demand projection sits in the middle of the range of scenarios produced by electricity sector participants, including MBIE and Transpower. Other projections agree that electricity generation and use will rise, while the projection range highlights that the speed of growth is uncertain (**Figure 38**).

Figure 38: Range of electricity demand forecasts produced in the last five years



Source: He Pou a Rangi Climate Change Commission, Modelling and data: Final reports on the fourth emissions budget and 2050 target review (November 2024); MBIE, Electricity Demand and Generation Scenarios: Results summary (July 2024); and Transpower, Te Kanapu Future Grid Blueprint – Consultation 3: Future Direction – Our Energy Scenarios (March 2026).

The energy infrastructure needs for decarbonisation: the Commission's Forward Guidance

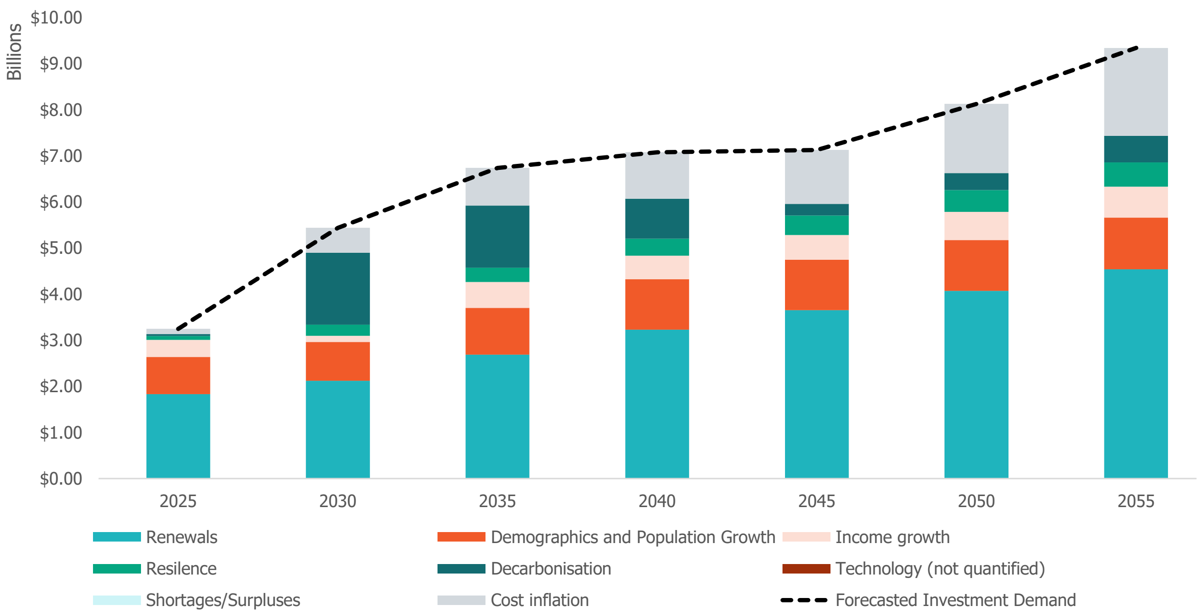
Chapter 3 of the National Infrastructure Plan lays out what the Commission views are the investment requirements required for the country over the next 30 years, also called our Forward Guidance for investment.

This is a forecast of a range of macro-level drivers of infrastructure demand, which capture the factors that the Commission considers are likely to affect the need for investment in infrastructure.

The demand drivers used include renewal of existing infrastructure; demographic change; economic and income growth; construction price inflation; resilience to natural hazards; decarbonisation; technology change; and shortage of existing infrastructure.[95] The Commission provides forecasts for each sector, summing their requirements to get an overall investment need for the country.

Our Forward Guidance projects that meeting future demand for electricity and gas will require a significant, but not insurmountable, amount of investment over the next 30 years. Capital investment is expected to grow from about 0.8% of GDP to 1.3% in 2055 (**Figure 39**).

Figure 39: Forward Guidance investment forecast for electricity and gas, 2025 to 2055, in 2025 NZD



Source: New Zealand Infrastructure Commission modelling and analysis.

While much of this will be renewing the existing stock of electricity infrastructure we already have, a significant uplift will be required to meet decarbonisation goals. The Commission's Forward Guidance uses the CCC EB4 demonstration pathway as the basis for assessing infrastructure investment requirements. The additional decarbonisation investment required is calculated as the difference between the EB4 demonstration pathway and the CCC's reference

[95] New Zealand Infrastructure Commission, *Forward Guidance: Results and Modelling Technical Report* (2026).

scenario which describes the current trajectory of New Zealand's emissions based on existing policies and measures.

Investment needed to decarbonise adds an estimated $26 billion above base-level demand over the 30-year period, or an average of just over $835 million per year. Most of this additional investment will be needed in the next 10 to 15 years. A significant portion of this investment (~90%) will need to be in new electricity generation and associated network asset upgrades, with the rest being in transmission and distribution. Delivery of this investment will require sufficient workforce skill and capacity, as well as unconstrained access to materials.

Excluding modelled decarbonisation investment demands, energy infrastructure capital investment demands would be much lower. Non-decarbonisation-related demand for renewal and growth of electricity investment total between $2-4 billion per year.[96]

[96] New Zealand Infrastructure Commission, *Forward Guidance for Infrastructure: Summary of results and findings* (February 2026).

5.2. Progress towards long-term needs is slower than required

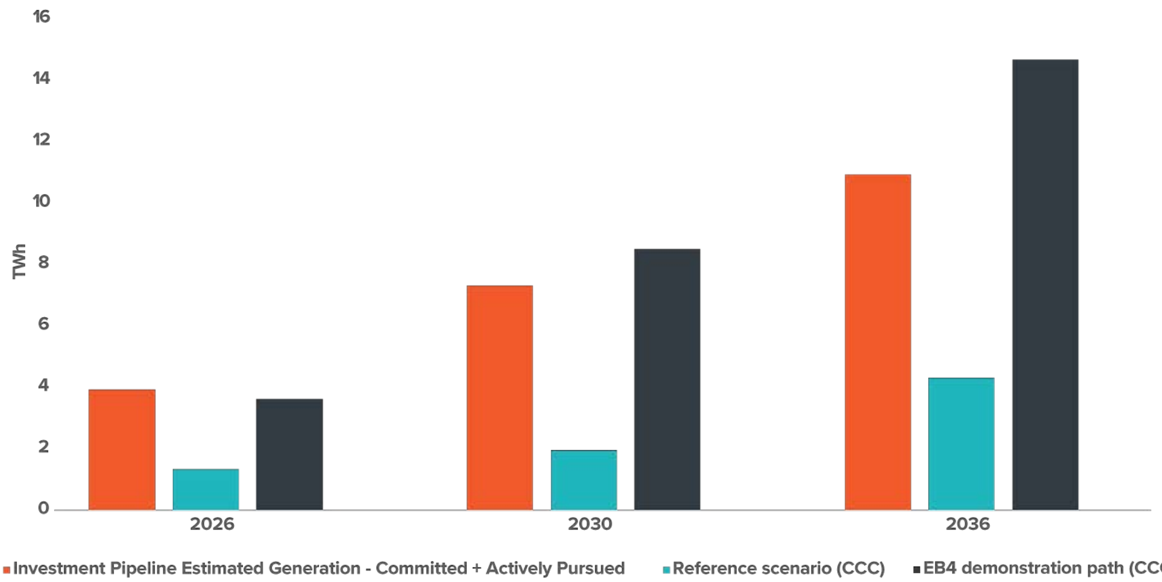
Developers are planning to invest a lot, but appear less confident about long-term demand

In recent years, there has been a notable increase in the amount of new electricity generation capacity that has been committed or actively pursued by developers. This reflects both a response to high prices, as discussed above, and expectations of future demand growth.

The Electricity Authority's generation investment pipeline shows that investment intentions are higher than the CCC's reference scenario for electricity demand growth. This scenario reflects what would happen if climate policies are not sufficient to meet decarbonisation goals, leading to lower electricity use.

However, medium- and longer-term investment intentions are not yet sufficient to meet the electricity demand required for full decarbonisation of the economy in line with the EB4 demonstration path.

Figure 40: Electricity generation investment intentions versus requirements to achieve CCC scenarios for demand, as at 2026, 2030 and 2036.



Source: Electricity Authority, Generation investment pipeline, (March 2026), He Pou a Rangi Climate Change Commission, Modelling and data: Final reports on the fourth emissions budget and 2050 target review (November 2024), Infrastructure Commission Analysis.

Note: If a final investment decision hasn't been made but other significant milestones have been reached (a location being secured in addition to a consent application being submitted or contracts to finance the project executed) then the project is "actively pursued". Generation was estimated from the capacity values in the generation investment pipeline. It was estimated using the following formula: generation (MWh) = capacity (MW) * hours in a year * capacity factor. The assumption for capacity factors can be found in Table A1 in Appendix A. The additional demand to achieve the CCC scenarios is calculated by taking the demand at the relevant year (2026, 2030, and 2026) minus the base year 2022.

This likely reflects how investment decisions work in New Zealand's energy-only market: developers will only commit to building generation if they expect prices sufficient to recover their costs. While developers anticipate demand growth above baseline, they appear uncertain whether demand will materialise at the level required by the EB4 path.

Unlike the period from 2019 to today, where new *supply* has been slow to force prices back towards long-run marginal costs, the challenge for the long-term transition to net zero is that *demand* uncertainty could constrain investment in new electricity infrastructure. Without confidence in future demand growth, full commitment to the required investment remains unlikely.

The following sections cover some of the key challenges and their implications for policy and infrastructure.

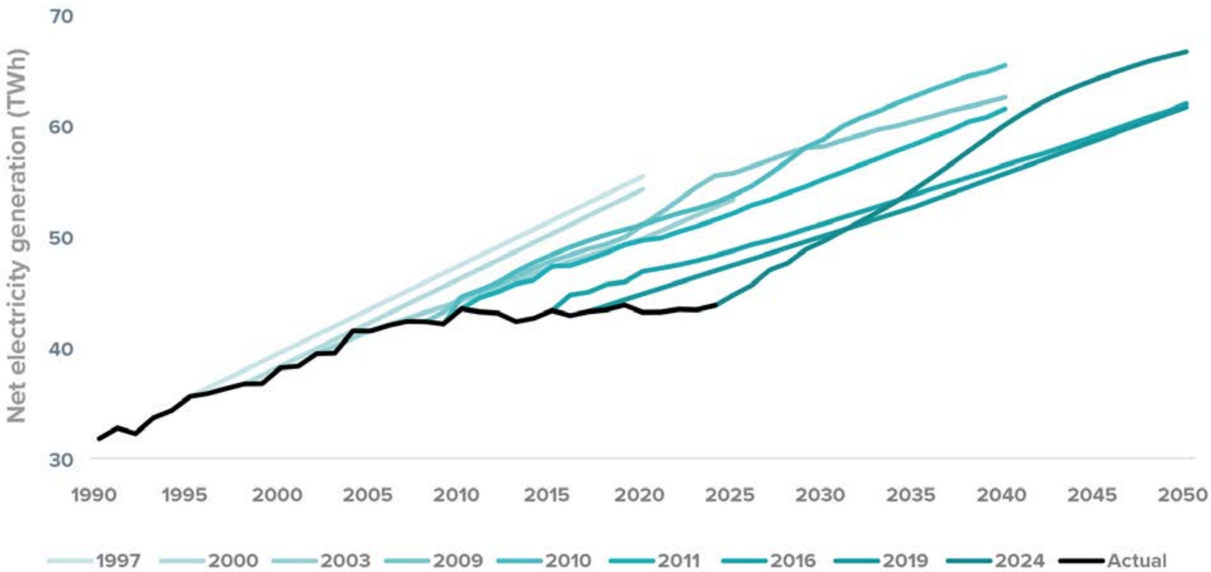
5.3. The challenges to achieving investment required for net zero

Policy change can create uncertainty and affect investment confidence

Investment in new electricity generation is long term and capital intensive. Developers commit to projects years before they generate revenue, and the financial case depends heavily on expectations about future electricity demand, prices, and policy settings. Uncertainty about any of these factors raises the cost of capital and can delay or prevent investment that would otherwise proceed.

Projecting demand is not easy. Anticipating structural changes in the economy and the uptake of new technologies is even harder. Demand projections for electricity have a long track record of being wrong, especially from the late 2000s to early 2020s (**Figure 41**).

Figure 41: New Zealand official electricity generation projection, 1964-2024



Source: New Zealand Infrastructure Commission, [Probabilities, Not Predictions: Practical tools for modelling uncertainty and supporting better decisions]() (2026) at p 13. New Zealand Infrastructure Commission analysis of various Ministry of Commerce Energy Outlook publications, Ministry of Economic Development Energy Outlook publications, MBIE's electricity demand projections and electricity generation statistics.

What distinguishes the outlook over the next 30 years is not just uncertainty about the pace of technological change, but uncertainty about policy direction. Current policy signals do not appear strong enough to drive the structural shift needed to meet long-term emissions goals. Without clearer signals, the investment required to build out electricity capacity at the necessary scale remains uncertain.

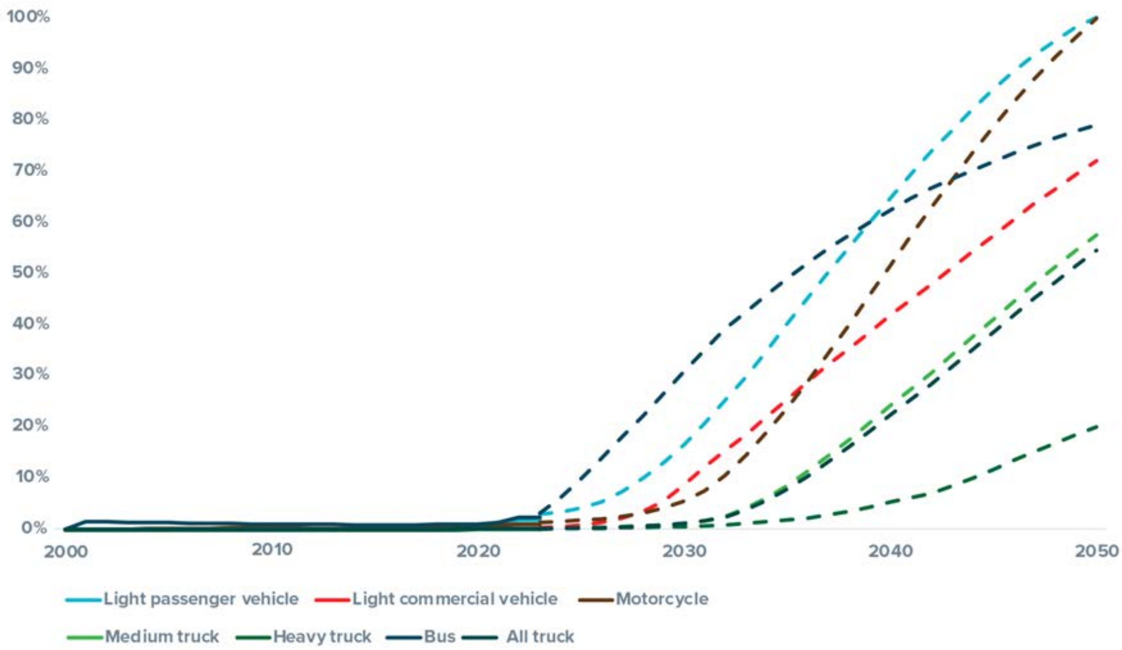
Technology and policy uncertainty: the electric vehicle example

The take-up of electric vehicles (EVs) comprises a significant portion of expected electricity demand growth. CCC projections suggest that the electrification of the vehicle fleet will drive more than a third of total growth in electricity demand to 2050.

The pace of EV uptake depends both on technological factors, such as the speed at which battery prices reduce relative to the cost of operating petrol and diesel vehicles, and policy choices, such as how to incentivise or enable consumers adoption of EVs. The latter is a matter of policy choice; the former is much less so.

The Climate Change Commission's fourth emissions budget pathway assumes rapid growth in the electric vehicle fleet – with 62% of new light vehicle registrations electric by 2030, and 100% by 2035. To date, uptake has been slow. For instance, in 2024, just over 2.5% of the light vehicle fleet was electric, slightly below the 4% assumed in that scenario.[97]

Figure 42: Projected EV proportion of vehicle fleet in EB4 pathway, by vehicle category, 2000-2050



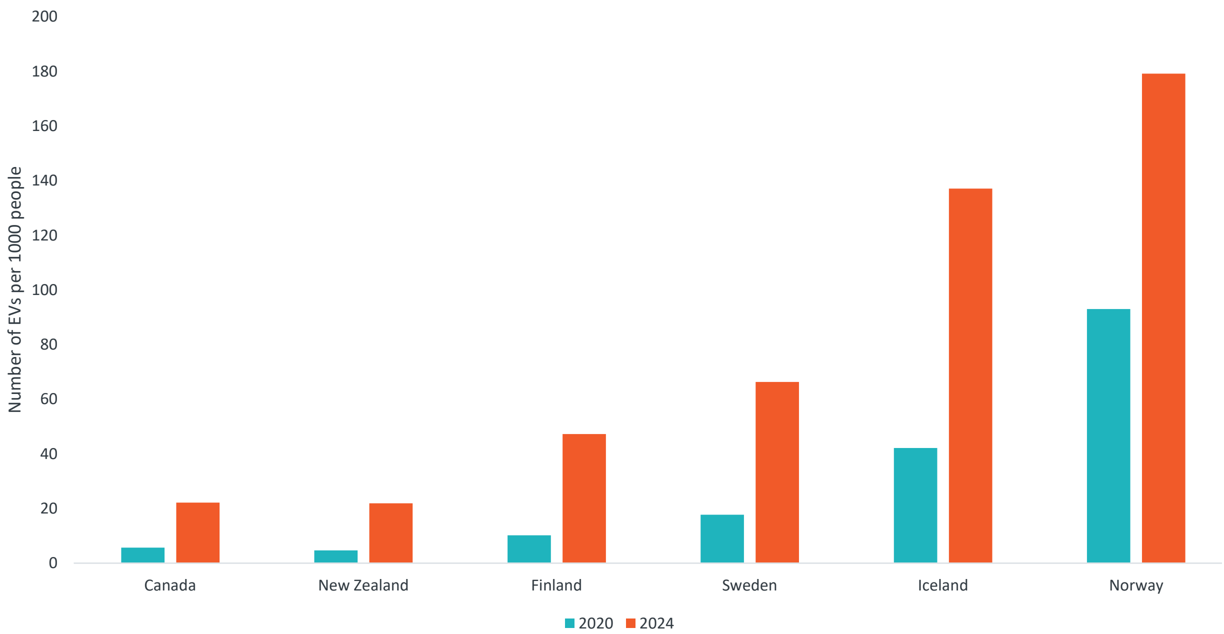
Source: He Pou a Rangi Climate Change Commission, Modelling and data: Final reports on the fourth emissions budget and 2050 target review (November 2024)

International comparisons suggest that policy choices can have a material impact on EV uptake. Uptake is growing in most countries as EVs become comparatively more affordable and accessible. However, some countries have much higher adoption rates and faster growth in part due to policy incentives. For instance, in 2024, New Zealand had around 22 EVs per 1,000 people, compared with 179 in Norway and 66 in Sweden (**Figure 43**).

This suggests that policy choices about how to enable EV uptake will help to determine the pace of electricity demand growth, and, in turn, the pace of new electricity generation investment.

[97] Ministry of Transport, *Annual fleet statistics*.

Figure 43: Electric vehicle stock per 1000 people in selected OECD countries



Source: New Zealand Infrastructure Commissions analysis of IEA, Global Electric Vehicle Outlook 2025, (2025) and OECD, Historical population data (2025).

Policy uncertainty affecting demand: the Emissions Trading Scheme

The New Zealand Emissions Trading Scheme (NZ ETS) is the Government's main tool for reducing net carbon emissions.[98] It is a "cap and trade" emissions trading scheme that requires emitters to surrender New Zealand Units (NZUs) equal to the number of tonnes of carbon dioxide they emit. It incentivises the electricity sector to shift to more efficient forms of generation by making it more expensive to operate thermal generation relative to renewable generation. Most importantly though, the ETS is important for electricity demand growth, because it is designed to incentivise businesses and households to convert carbon-emitting appliances, like coal boilers or petrol cars, to electric alternatives.

As shown in **Figure 44,** NZU prices have been volatile over the past five years. This reflects many factors, but a significant one is changes to ETS policy settings. Multiple Governments have changed these settings, depending on their current preference for balancing long-term decarbonisation goals with short-term cost of living concerns.[99]

The Treasury publishes estimates of ETS prices that would be required to meet long-term decarbonisation targets. This is presented as a range, reflecting different assumptions about low-emission technologies and the cost of adoption for businesses and households. Current ETS prices are below this range, suggesting the ETS does not currently provide a sufficient price signal for decarbonisation.

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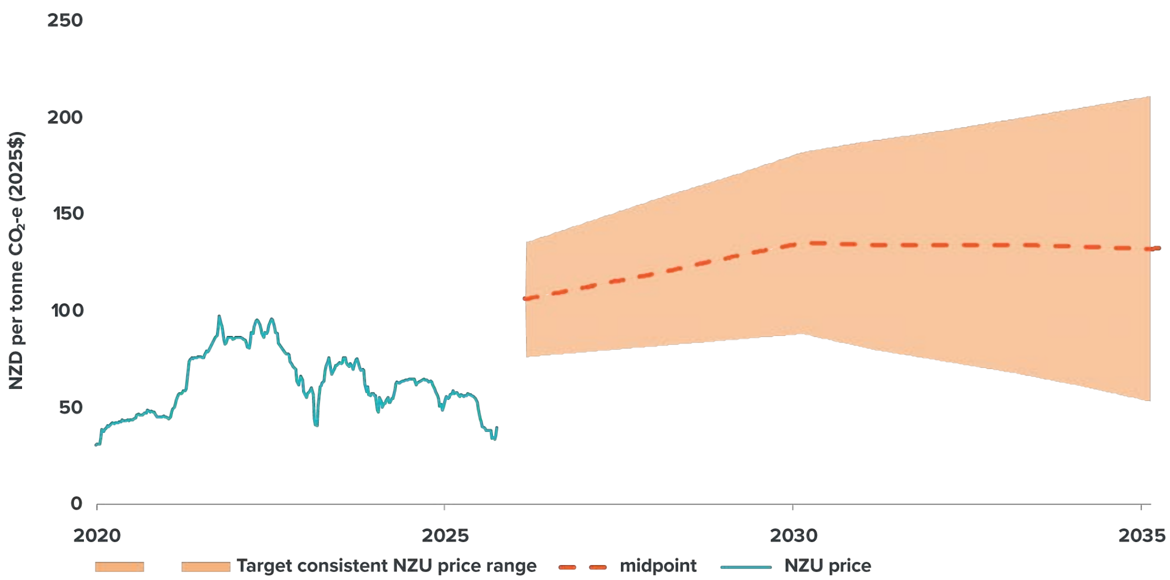
[98] Ministry for the Environment, *New Zealand's second emissions reduction plan 2026–30: Amended January 2026* (January 2026).
[99] He Pou a Rangi Climate Change Commission, *Advice on Aotearoa New Zealand's fourth emissions budget* (November 2024) at p 55.

Market commentary and the CCC's engagement with market participants suggest that lower prices may reflect waning confidence in the long-term stability of the scheme.[100] Around the late 2030s, the net emissions cap within the NZ ETS is expected to reach zero, limiting the scheme's effectiveness without further policy changes.[101]

ETS price volatility and perceived uncertainty about the future price path could affect the speed at which households and businesses electrify. Future policy choices that reduce this uncertainty – or increase it further – may in turn influence the pace of electricity demand growth, and, in turn, new generation investment.

Figure 44: Historical NZU prices and future prices required to meet decarbonisation targets, 2020-2035



Source: Theecanmole, New Zealand Emission Unit Prices in the NZ Emissions Trading Scheme 2010 to date; New Zealand Treasury, Assessing climate change and environmental impacts in the CBAx tool (October 2025).

The transition will require multiple approaches to dry year or peak demand situations

As the energy system transitions more to renewable electricity generation, it is likely that the profile of wholesale electricity prices will change in two ways.

First, because generation plant from wind, solar, and geothermal generally have lower LRMC to build and operate, as more electricity comes from these sources, over the long term, we should expect downward pressure on average electricity prices.

Second, demand peaks and the sources for firming generation will look different than they do today.

[100] Marex, January 2026 NZU Update (January 2026); He Pou a Rangi Climate Change Commission, NZ ETS unit limits and price control settings for 2027–2031 (April 2026).
[101] He Pou a Rangi Climate Change Commission, *Advice on Aotearoa New Zealand's fourth emissions budget* (November 2024).

This implies a changing role for hydroelectricity in our system. Wind and geothermal generation will take on a larger role in meeting our base electricity demand. As more renewable generation is built, and fossil fuel generation is phased down, less hydro-electric power will be required on a day-to-day basis, which will free up hydro-storage to be used to "fill in the gaps", take a more prominent role in providing firming and allow more thermal generation to retire.[102] This may help to smooth long-run volatility.

To balance the electricity system, wholesale electricity prices may need to swing more widely – spending more time either very low or very high, rather than centring around a mid-point price. Prices will be very low much of the time, as low-cost renewable generation is sufficient to meet demand. However, they will also need to be very high at other times, when high-cost firming generation or demand response are needed to cover shortfalls of renewable generation relative to demand.

We have begun to see this occur over the last five years (**Figure 45**). In recent years, there have been more trading periods where wholesale prices are very low and, in some cases, even close to zero. This represents a change relative to past trends, where very low and very high wholesale prices were less common.

In this context, electricity users will need to take steps to manage their exposure to varying wholesale electricity prices.

Figure 45: Distribution of inflation adjusted demand-weighted wholesale prices

Source: New Zealand Infrastructure Commission analysis of the Electricity Authority, Wholesale price trends and Stats NZ, Consumers Price Index (CPI).

Note: The graph displays how many days each year wholesale prices fell within each price range (percentile). For example, in 2025, wholesale prices were in the highest range, the 95^{th} to 100^{th} percentile, for 50 of the days. P0-P5 represents the lowest price range, while P95-P100 represents the highest.

[102] Electricity Authority, *Hydro storage limits and why rain matters for electricity* (17 April 2025).

The importance of demand flexibility

Demand flexibility, which involves shifting electricity use away from high-price periods or reducing electricity use in periods with high prices, can help electricity users manage their exposure to volatile wholesale prices. Increased demand flexibility can also reduce how much high-cost firming capacity the system needs to build to cover periods of low renewable output. The Market Development Advisory Group noted that as the system transitions toward higher shares of intermittent renewables, the value of demand-side flexibility will rise.[103]

Demand flexibility is a longstanding feature of New Zealand's electricity system. For instance, technologies like "ripple control" for appliances like commercial hot water heating have been used by distributors and retailers since the 1950s.[104] It is common for major industrial energy users, and some smaller residential and commercial users, to adjust their consumption in response to wholesale prices.

The electricity sector continues to actively pursue innovations in this area. Demand flexibility is increasingly feasible for smaller residential and commercial customers as a result of new digital technologies. There are potentially further untapped gains.[105] For instance, EECA estimates that approximately 1,350 GWh of energy per year could be shifted from peak periods using demand flexibility measures at a procurement price of less than $500 per MWh.[106]

Lifting uptake requires consumers to have both the ability and incentive to shift their use. At present, most consumers pay fixed retail tariffs regardless of when they use electricity. This protects them from price volatility but removes any financial incentive to save by shifting consumption away from high-price periods. To address this, the Electricity Authority now requires retailers with more than 5% market share to offer time-of-use pricing plans.[107]

The role of the hedging market

The importance of hedging will increase for both generators and electricity users as the electricity system transitions toward higher shares of intermittent renewables. Major electricity users, such as large industrial customers and electricity retailers, will need to be more active in financial markets.

For generators, access to long-term hedging arrangements provides revenue certainty that supports investment decisions. For electricity retailers and large users, hedging provides protection against price spikes that would otherwise flow through to operating costs or consumer bills. Both depend on hedge markets being sufficiently deep and liquid to meet their needs.

The Electricity Authority's role in monitoring and developing hedge markets will become more important. This includes supporting market liquidity, developing disclosure requirements for over-the-counter contracts, and ensuring that both generators and users can access the products they need to manage risk effectively.

[103] Market Development Advisory Group, *Price discovery in a renewables-based electricity system: final recommendations paper* (2023) at p 22.
[104] EECA, *Ripple Control of Hot Water in New Zealand* (September 2020).
[105] Boston Consulting Group, *Climate Change in New Zealand: The Future Is Electric* (2022).
[106] EECA, *The full potential of flexible electricity use in New Zealand: Summary and Insights Report* (February 2026).
[107] Electricity Authority, *Improving pricing plan options for consumers: Time-varying retail pricing for electricity consumption and supply* (16 July 2025).

6. Conclusion

6.1. The path to affordable prices, stable supply, and low emissions

Our analysis points to four key lessons for how New Zealand can navigate the challenges ahead.

Building low-cost electricity infrastructure will keep prices low in the long term

The shift toward renewables is fundamentally changing the economics of electricity generation. Wind and solar have become much cheaper to build and have low operating costs, while thermal generation has become more expensive to run.

As cheaper renewable generation continues to displace more expensive thermal capacity, this should put sustained downward pressure on prices in normal periods. The challenge is ensuring that the commercial case for firming generation, which is needed when renewables fall short, remains viable, so the system can handle demand peaks and dry years without severe price spikes.

Policy certainty and coherence are critical

Infrastructure providers need confidence that demand will be there before committing to large, long-lived investments. In the short term, clearer policy signals, for instance around the gas transition and the role of government supply interventions, could have reduced price volatility and improved investment conditions.

Over the long term, certainty about New Zealand's path to net zero is essential: without it, the investment needed to meet decarbonisation-consistent electricity demand is unlikely to materialise at the pace required.

An adaptable and flexible system will keep costs down and supply reliable

As the energy mix shifts toward renewables, wholesale prices will increasingly be either very low or very high, making the ability to shift demand away from peaks more valuable. Demand flexibility, competitive generation markets with low barriers to new entry, and well-functioning financial hedging markets will all play a greater role in keeping the system affordable and resilient.

Infrastructure is only part of the answer; the system needs to become more sophisticated in how it responds to supply and demand pressures.

Players in the energy system will need to adapt and coordinate

The energy system involves many players – asset owners, regulators, investors, and consumers – and change in one part of the system can have consequences elsewhere. More active coordination will be needed to track these interactions and ensure that interventions in one area do not inadvertently create problems in another. But coordination alone is not sufficient: the governance arrangements overseeing the system will also need to evolve as the transition progresses.

The gas transition is a cautionary example. Limited visibility over production risks caused disruption that better institutional arrangements could have reduced. As the energy transition gathers momentum, the ability to monitor progress, anticipate emerging risks, and provide clear signals to all players will become increasingly important.

6.2. The New Zealand Infrastructure Commission's role

This paper has examined the key challenges and frictions in New Zealand's short- and long-term energy system and sets out the Commission's assessment of where coordination is most needed. It supports the Commission's overarching recommendation in the National Infrastructure Plan:

> ***Accelerated electricity investment:*** *Establish clear, consistent, and coordinated Government policies to accelerate electricity infrastructure investment that supports economic growth and emissions reduction.*

The themes and findings outlined in this paper reflect our current understanding of how electricity infrastructure is tracking towards this goal, and where further action may be beneficial.

New Zealand's energy transition is underway, and the direction of travel is clear. What remains less certain is the pace, the cost, and whether the frictions identified in this paper are addressed before they become harder to resolve.

The Commission's existing functions include periodically providing Government with long-term strategic advice on infrastructure needs and priorities, as reflected in the recent National Infrastructure Plan. We also provide ongoing advice and information through our Forward Guidance on future infrastructure investment demands, through the National Infrastructure Pipeline, which coordinates information on investment plans, and our policy advice on infrastructure issues. These work programmes provide a standing basis for monitoring progress and offering independent, sector-wide analysis as the transition unfolds. This paper is a contribution to that ongoing work.

Appendix A: Methodology for short-run and levelised cost of electricity by fuel type

This technical appendix describes the methodology, inputs, and assumptions for calculating levelised cost of electricity (LCOE) and the short run marginal costs (SRMC) in this report.

Short run marginal cost calculation

The short-run marginal cost was calculated using a formula from the Electricity Authority.[108]

$$SRMC = VOM + HR(fuel\ delivery\ costs + fuel\ price + \frac{emissions\ factor}{1000} carbon\ price)$$

Where:

- SRMC is expressed in \$/MWh
- VOM is the variable operating and maintenance costs expressed in \$/ MWh
- HR is the heat rate expressed in GJ/MWh. It's a measure of how efficiently a fuel energy is converted into electricity.[109]
- Fuel delivery cost is the costs of delivery fuel to a generation plant expressed in \$/GJ
- Fuel price is the price for each fuel type expressed in \$/net GJ. This reflects the price for the fuel used to generate electricity. For example, for a hydro plant, this is water. For a diesel plant, this is diesel fuel.
- Carbon price is the price applied to carbon emissions in \$/tonnes of CO_2. This was only added for coal as the gas spot price includes the carbon price
- Emissions factors is expressed in tonnes of CO_2/TJ.

The variable operating and maintenance costs (VOM), heat rate and fuel delivery costs were sourced from the MBIE electricity demand and generation scenarios (EDGS) generation stack. For each plant type (solar, wind, etc) a representative set of plants were selected from the generation stack. The VOM, heat rate and fuel delivery cost values for those plants were each averaged to produce representative estimates for each variable.

The carbon price and fuel price estimates were sourced from MBIE EDGS commodity prices assumptions. The reference scenario prices were used with the relevant year of 2015, 2025, or 2035.

The spot price for gas includes the carbon price in the cost of gas and therefore no emission factor is required.

The prices and costs in MBIE's generation stack and commodity prices were assumed to be in 2023 NZD. The prices were converted into 2025 Q1 prices, using the Stats NZ all groups CPI

[108] Electricity Authority, *Appendix C: Calculating thermal short-run marginal cost*
[109] WSP, *2020 Thermal generation stack update report*, (prepared for MBIE, October 2022)

figure for 2023 Q4. 2025 Q1 was chosen to align with 2025 generation stack report[110] capital costs used in the levelized cost of electricity estimations.

Additional information on sources and accompanying notes can be found towards the end of this appendix.

Levelised cost of electricity (LCOE)

The LCOE was calculated using Electricity Authority's formula as the base of the calculations.[111]

$$LCOE = \frac{levelised\ capex\ (\$)}{annual\ output\ (MWh)} + FOM(\frac{\$}{MWh}) + SRMC(\frac{\$}{MWh})$$

Levelised capex calculation

The formula used is shown below:

$$levelised\ capex = \frac{capex * interest\ rate}{(1 - (1 + interest\ rate)^{(-asset\ lifetime)}}$$

Where:

- Capex is total capital cost in NZD/MW
- Asset life is the number of years that the plant is expected to operate
- Interest rate or discount rate

The capex figures were sourced from 2025 generation stack report values for current costs estimates.[112] The capital cost value for 2025 were taken directly from the report.

For estimating the capital costs for 2015 and 2035, we used a capital cost multiplier to adjust the capital cost estimate to current capital cost estimates. The multiplier was created by dividing capital cost estimates for 2015 and 2035 by current capital cost estimates. The multiplier was then multiplied by the 2025 capital cost estimate to give capital costs for 2015 and 2035. The multiplier values and sources are outlined in **Table A1**.

Assumptions for the asset lifetimes sources are also outlined in Key assumptions, inputs, and parameters **Table A1**.

Annual output calculation

The annual output for each plant was calculated as shown below:

$$Annual\ output\ (MWh) = hours\ in\ a\ year * \ capacity\ factor$$

Where:

- Hours in a year are 8760

[110] Beca Limited and Concept Consulting Group Limited, *2025 generation stack report* (prepared for Transpower New Zealand Ltd, September 2025)
[111] Electricity Authority, *Electricity hedge prices compared to new estimate of the LCOE* (September 2025).
[112] These are overnight capital costs, the cost of building if it was finished "overnight". Beca Limited and Concept Consulting Group Limited, *2025 generation stack report* (prepared for Transpower New Zealand Ltd, September 2025) – p9

- Capacity factor is a measure of how often a plant generates electricity over a year.[113] Capacity factors are different for different plant types. The assumptions for each plant type are outlined in **Table A1**.

Fixed operating cost calculation

The fixed operating costs were sourced from the MBIE electricity demand and generation scenarios (EDGS) generation stack. For each plant type (solar, wind, etc) a representative set of plants were selected from the generation stack. The fixed operating costs for those plants were each averaged to produce a representative estimate.

Key assumptions, inputs, and parameters

Table A1 below lays out the various inputs and assumptions used in the calculations of SRMC and LRMC for different types of generation.

Table A1: **Inputs, assumptions, and parameters for SRMC and LCOE calculations**

	Solar	Wind	Geothermal (Binary)	Geothermal (Flash)	Gas (OCGT)	Gas (CCGT)	Coal (Rankine cycle plant)
Capacity factor	0.16	0.39	0.925	0.925	0.15	0.23	0.5
Asset life	25	25	30	30	25	30	25
Emissions factor (tonnes of CO_2/TJ)	NA	NA	19.2	19.2	Emissions cost is included in the gas spot price.	Emissions cost is included in the gas spot price.	92.8
Discount rate	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Heat rate (GJ/GWh)	NA	NA	12000	12000	10406.4	7550	10900
Capital costs multiplier for 2015	3.17	2.23	1.08	1.08	0.61	0.80	0.95
Capital costs multiplier for 2035	0.64	0.76	0.97	0.97	0.52	0.74	0.94
Plants used in averages	Foxton solar farm, Lauriston solar farm, Lodestone Kohira solar farm, Lodestone Rangitaiki solar farm, Lodestone Te Herenga o Te Rā solar farm, Pukenui solar farm	Harapaki wind farm, Kaiwera Downs wind (Stage 1), Mahinerangi 1, Mill Creek, Tararua Stage 1 & 2, Tararua Stage 3, Te Āpiti, Te Rere Hau, Te Uku, Turitea North, Turitea South, Waipipi, West Wind, White Hill	Te Ahi O Maui (KA22), Kawerau, Mōkai, Ngā Awa Pūrua, Ngātamariki, Ngāwhā Stage 1 & 2, Ngāwhā Stage 3 (OEC4), Ōhaaki, Poihipi Road, Rotokawa, Kawerau (TOPP1), Kawerau (TOPP2), Tauhara Stage 1, Te Huka (Binary), Te Huka Unit 3, Te Mihi, Wairākei Binary, Wairākei A & B.	Same as geothermal (binary)	Huntly Unit 6, Junction Road, Mangahewa Power Station, Stratford Peaker and McKee power plant	Huntly Unit 5 and Taranaki Combined Cycle (TCC).	Huntly Unit 1 and Huntly Unit 2.

[113] MBIE, Energy in New Zealand 2023, (August 2023).

Changes in LCOE and SRMC between years were only modelled with changing capital costs, carbon prices and fuel prices. All other variables were held constant.[114]

The discount rate of 5% was chosen as Commonwealth Scientific and Industrial Research Organisation (CSIRO), MBIE's EDGS and other sources had used rates between 5% to 7%. We tested the sensitivity of our results with an 8% discount rate, which predictably increased the absolute LCOEs for all generation plant types by between 9% and 27% (coal and solar respectively). It subsequently made thermal generation modestly less expensive relative to renewables, primarily because renewables are relatively more capital intensive as opposed to operationally intensive.

Sources

The following is a list of sources and technical notes for the various parameters used in the calculation

Capacity factors

- Solar, wind, and geothermal (binary and flash)
  - Beca Limited and Concept Consulting Group Limited, *Generation Stack 2025 – a snapshot*, (prepared for Transpower New Zealand Ltd, 2025).
  - Capacity factors were given as a range; our analysis uses the midpoint.
- Offshore wind
  - Ishwar, C., Mason, I., *Offshore wind potential for New Zealand*, Department of Civil and Natural Resources Engineering, University of Canterbury, (June 2019).
  - The capacity factor for offshore wind was used for calculating the estimated electricity generation of offshore wind capacity listed in the Electricity Authority generation investment pipeline.
- Gas (OCGT)
  - Concept Consulting Group Limited, *Generation Investment Survey – 2023 updates*, (2023).
- Gas (CCGT)
  - Estimated from the average capacity factor for Contact's Taranaki combined cycle (TCC) for FY17–FY25. Contact Energy, *ESG Reporting - Taranaki combined cycle* (accessed 6 May 2026).
- Coal
  - Estimated from Mathias Hofmann, George Tsatsaronis, *Comparative exergoeconomic assessment of coal-fired power plants – Binary Rankine cycle versus conventional steam cycle*, (January 2018).
  - The source gave a range of capacity factor from 40%–80%, 50% was taken as an estimate.

[114] Except for solar, wind, geothermal (binary) and geothermal (flash) for 2025. The capital cost multiplier was calculated using LCOE estimates which would account for changes in capacity factors, asset lifetimes and other variables.

Asset lives

- Solar
  - Millar, A., *Economics of Utility-Scale Solar in Aotearoa New Zealand*, (prepared for MBIE, May 2020).
- Wind
  - Energy Efficiency & Conservation Authority, *National Policy Statement for Renewable Electricity Generation Technical Guide*, (February 2013).
- Geothermal
  - Lawless Geo-Consulting, *Future Geothermal Generation Stack*, (March 2020).
- Gas (OCGT, CCGT) and coal (Rakine cycle plant)
  - WSP, *2020 Thermal generation stack update report*, (prepared for MBIE, October 2022).

Emissions factors

- Geothermal (flash and binary)
  - New Zealand Geothermal Association, *2020 Annual NZGA Geothermal Review*, (May 2021).
  - The MW-weighted average emissions intensity was 69 gCO_2e/KWh (net), this was converted into tonnes per TJ with conversion factor of 0.27778.
- Gas (OCGT and CCGT)
  - Electricity Authority, *Appendix C: Calculating thermal short-run marginal cost*.
  - This source notes that the spot price for gas includes carbon costs.
- Coal
  - Ministry for the Environment, *New Zealand's Greenhouse Gas Inventory 1990-2023*, (April 2025).
  - It was the 2023 emissions factor for consumption-weighted average emission factors used for New Zealand's sub-bituminous coal-fired electricity generation for 1990 to 2023.

Heat rates

The heat rates were generally sourced from MBIE, *Electricity demand and generation scenarios*, (July 2024) in EDGS 2024 – Assumptions.

Additional notes:

- All geothermal plants in MBIE's generation stack had a heat rate of 12,000 (GJ/GWh), this value was used as the estimate for geothermal plants.
- The heat rate for gas (OCGT) was estimated by averaging the corresponding values for Huntly Unit 6, Junction Road, Mangahewa Power Station, Stratford Peaker and McKee power plant. Huntly units 1 & 2 were excluded as these are Rankine units which can use both coal and gas, they are not typical OCGT.

- The heat rate for gas (CCGT) was estimated by averaging the corresponding values for Huntly Unit 5 and Taranaki Combined Cycle (TCC).
- The heat rate for coal (Rankine cycle plant) was estimated by averaging the corresponding values for Huntly Unit 1 and Huntly Unit 2.
- Heat rate adjusted into GJ/MWh by dividing values by 1000.

Capital costs and LCOE

- Capital costs for gas (OCGT and CCGT)
    - To generate 2015 figures:
        - Commonwealth Scientific and Industrial Research Organisation, *GenCost 2025-26: Consultation draft*, (December 2025).
        - The 2018 capital cost was divided by the 2025 capital cost to give an estimated 2015 capital cost multiplier.
    - To generate 2035 figures:
        - Beca Limited and Concept Consulting Group Limited, *2025 generation stack report* (prepared for Transpower New Zealand Ltd, September 2025).
        - The 2035 capital cost estimates were divided by the 2025 capital cost estimate to give the 2035 capital cost multiplier.
- Capital costs for coal (Rankine Cycle)
    - To generate the 2015 figures:
        - Beca Limited and Concept Consulting Group Limited, *2025 generation stack report* (prepared for Transpower New Zealand Ltd, September 2025).
        - The 2026 capital cost was divided by the 2025 capital cost estimate to give a proxy for the 2015 capital cost multiplier.
    - To generate the 2035 figures:
        - Beca Limited and Concept Consulting Group Limited, *2025 generation stack report* (prepared for Transpower New Zealand Ltd, September 2025).
        - The 2035 capital cost estimates were divided by the 2025 capital cost estimate to give the 2035 capital cost multiplier.
- Capital costs for solar, wind and geothermal (flash and binary)
    - To generate the 2015 figures:
        - Weighted average LCOE estimates were sourced from the International Renewable Energy Agency, *Renewable Power Generation Costs in 2024*, (July 2025).
        - The 2015 weighted average LCOE was divided by the 2024 weighted average LCOE to give the 2015 capital cost multiplier. These figures are LCOE, not just capital cost, so they do consider improvements in the

technology over time. These values will include changes in the capacity factors, asset life, emissions factors and other improvements.

- To generate the 2035 figures:
  - Beca Limited and Concept Consulting Group Limited, *2025 generation stack report* (prepared for Transpower New Zealand Ltd, September 2025).
  - The 2035 capital cost estimates were divided by the 2025 capital cost estimate to give the 2035 capital cost multiplier.

Other sources

Variable	Source
Fuel price	MBIE, *Electricity demand and generation scenarios*, (July 2024) in EDGS 2024 – Assumptions
Fixed operating cost	MBIE, *Electricity demand and generation scenarios*, (July 2024) in EDGS 2024 – Assumptions
Variable operating cost	MBIE, *Electricity demand and generation scenarios*, (July 2024) in EDGS 2024 – Assumptions
Carbon price	MBIE, *Electricity demand and generation scenarios*, (July 2024) in EDGS 2024 – Assumptions
Fuel delivery costs	MBIE, *Electricity demand and generation scenarios*, (July 2024) in EDGS 2024 – Assumptions
CPI all groups	Stats NZ, *Consumer Price Index: All Groups for New Zealand (Quarterly series)*, Infoshare
Discount rates	MBIE, *Electricity demand and generation scenarios: results summary* (July 2024)

Appendix B: Security of supply monitoring

How security of supply is defined

Security of supply refers to the ability of the electricity system to meet demand over time. It is primarily a question of physical availability – whether there is enough generation and transmission capacity to meet peak demand on any given day, and enough fuel to sustain generation over longer periods – rather than the price at which energy is available.[115]

When supply becomes tight, rising wholesale prices are a key mechanism for signalling scarcity and incentivising demand reduction or additional generation. In extreme situations where hydro storage is critically low and thermal generation is insufficient, additional contingent hydro storage can be activated to provide a buffer.

Transpower's role in monitoring security of supply

Transpower, in its role as system operator, monitors security of supply on an ongoing basis based on parameters set by the Electricity Authority.[116] Security of supply reporting is designed to ensure that market participants have the information they need to manage risks and respond to emerging supply pressures, including through new investment.

Transpower publishes an annual Security of Supply Assessment that evaluates the adequacy of generation resources to meet demand over the next decade. This accounts for growth in electricity demand, new generation investment, and expected hydro inflows and thermal fuel stocks.

It also provides more regular monitoring, including quarterly security of supply outlook reports that provide 12-month forecasts and weekly market outlook reports that provide up-to-date estimates of the risk of energy shortfalls.

How security of supply indicators evolved through the 2024 dry year period

Winter 2024 brought two overlapping supply pressures together at the same time – low hydro lake levels and shortages of thermal fuel. Nonetheless, Transpower's security of supply monitoring shows that although wholesale prices rose to very high levels, the risk of physically running out of energy remained below critical security of supply thresholds.

Hydro inflows were poor: storage dropped to 51% of the seasonal average between April and August meaning the system had to draw heavily on thermal generation to maintain supply.

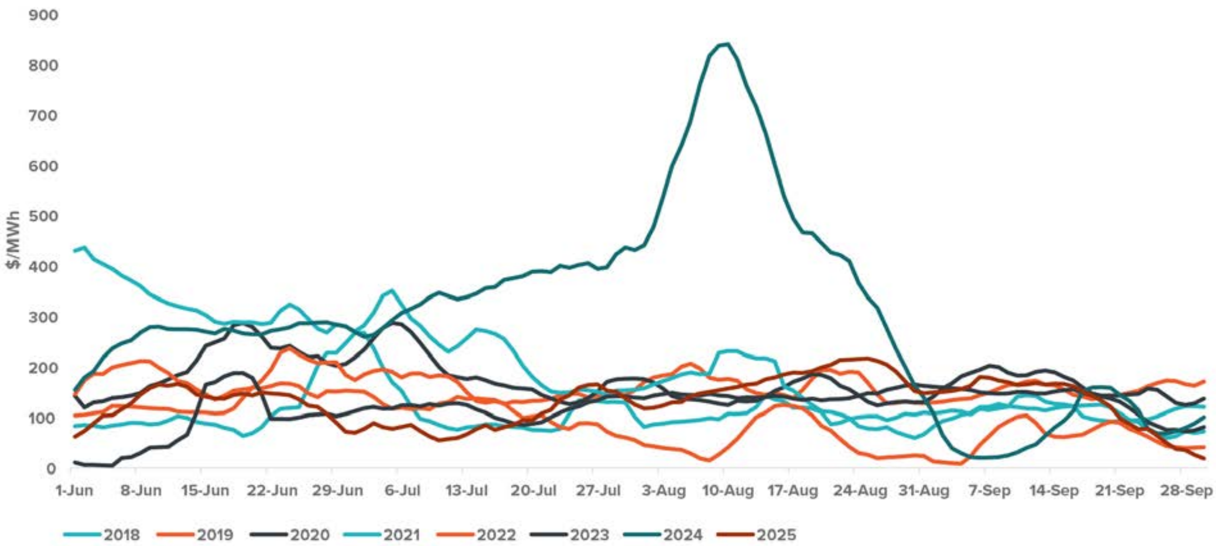
Layered on top was the structural decline of domestic gas supply, which was driving high wholesale electricity prices. As discussed above, uncertainty around the New Zealand

[115] Electricity Authority, *Security of supply*.
[116] Transpower, *Security of supply*.

Aluminium Smelter and the future of gas may have previously discouraged additional investment in supply to bring prices back in line with LRMC.

Prices rose significantly as a result. For the first part of August 2024, daily average wholesale prices were $820/MWh,[117] compared with the 2018–2023 average winter wholesale price around $180/MWh **(Figure B1)**.

Figure B1: Inflation-adjusted 7-day rolling average wholesale prices from June to September, 2018-2025



Source: Electricity Authority, EMI wholesale prices; Stats NZ, Consumers Price Index (CPI).

Note: Prices are in 2024 Q3 dollars.

However, the electricity system never approached a physical shortage. Hydro storage, while low, did not drop to alert levels (the threshold at which Transpower would assess a 1% chance of running out of energy). **Figure B2** shows the trajectory of lake storage levels across the preceding four months to August 2024. By mid-August, hydro storage had fallen far below average, although it was still above critical thresholds.

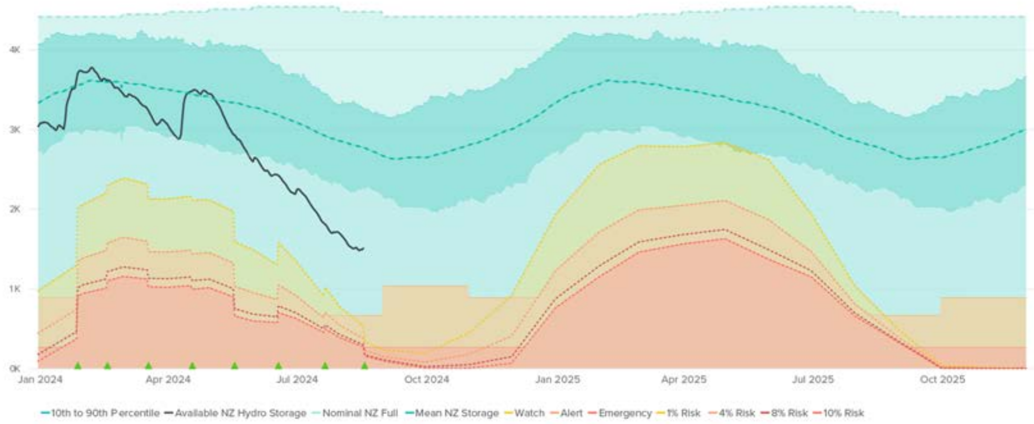
However, increased rainfall in September and October bolstered hydro storage, which was above the long-term average by the end of October. **Figure B3** shows the situation as of December 2024. Due to increased hydro inflows, wholesale electricity prices declined significantly after winter, falling to extremely low prices at times.

High winter prices incentivised generators to purchase additional thermal fuels and issue demand response notices to large industrial consumers, keeping the system in balance without conservation orders being issued.[118] [119]

[117] Electricity Authority, *Review of Winter 2024* (April 2025).
[118] For example, Meridian issued a demand response notice to New Zealand Aluminium Smelter in May 2024 to reduce load which was extended in July 2024 to 24 September 2024. Contact secured purchase of ~3.5PJ of gas from Methanex to be supplied from August through to October 2024 to run its Taranaki Combined Cycle gas-fired power station for the remainder of 2024.
[119] Bushnell et al., *Review of the NZ Electricity Market Performance: peer review evaluation* (8 June 2025) at p 6; Hansen, C., Oceania Summit 2025 – Review of NZEM (September 2025).

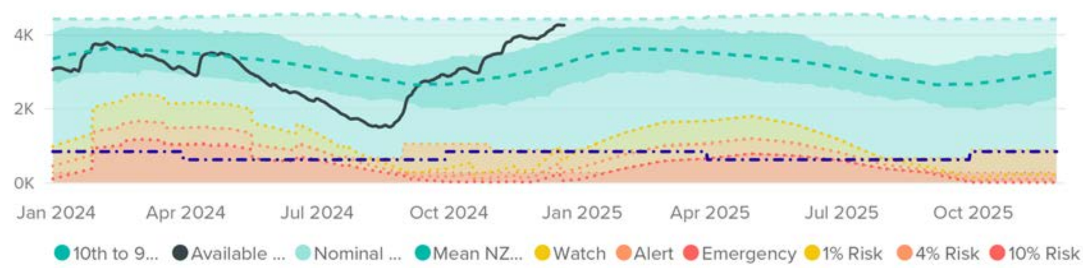
Transpower did temporarily adjust the alert boundary in August 2024 to allow generators earlier access to contingent storage at Lakes Tekapo, Pukaki and Hāwea. This was a precautionary measure that was not actually triggered in practice.[120]

Figure B2: Electricity Risk Status Curves as at 19 August 2024



Source: Transpower, *Electricity Risk Curve update – August 2024* (August 2024).

Figure B3: Electricity Risk Status Curves as at 22 December 2024



Source: Transpower, *Market Operations – Weekly Report – 22 December 2024* (December 2024).

[120] Transpower, *Security of Supply Review – Winter 2024* (November 2024). See also Meridian Energy, *Letter to Transpower on contingent storage* (27 November 2024).