# ENERGY TO GROW

## Securing New Zealand's future

BOSTON CONSULTING GROUP

## Basis of preparation

Boston Consulting Group (BCG) was commissioned by the four largest New Zealand gentailers (Contact Energy, Genesis Energy, Mercury and Meridian Energy) to write this independent report for the benefit of the sector. This report reflects the independent views of BCG, and not the commissioning parties.

RSM has provided probity assurance to ensure that the report is held to the highest standard of independence and integrity. This includes attending meetings between BCG and sector participants and confirming that changes made to the draft report are based on facts and not subjective interpretation.

Concept Consulting conducted the quantitative modelling of scenarios used in this report. BCG has drawn on this modelling and other data sources to produce insights, conclusions and recommendations.

## BCG disclaimer

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# Contents

# 1 Purpose and scope

The purpose of this report is to present a holistic view of New Zealand's energy sector and how it can continue to evolve to support the country's economic growth and prosperity by delivering more affordable and secure energy. This holistic perspective is critical to ensuring decisions made across the electricity and gas industries are integrated and well-considered. The report examines underlying fuel sources, energy uses and supporting infrastructure to recommend a whole-of-sector response that maximises the energy sector's contribution to the economy. It was commissioned by the four largest New Zealand gentailers (Contact Energy, Genesis Energy, Mercury and Meridian Energy), but is the independent view of BCG, assured for probity by RSM.

This report builds on the 'The Future is Electric' published by BCG in 2022. The Future is Electric report focused on how the electricity industry could support New Zealand's sustainable energy transition and proposed a bold decarbonisation pathway, 'Smart System Evolution', which deployed technologies including batteries, distributed energy and demand response to complement growth in renewable generation. Analysis and recommendations in this report build on the Smart System Evolution pathway and the recommendations presented in the initial report.

Since the initial report's publication in 2022, the energy sector has demonstrated its commitment to accelerating and enabling New Zealand's decarbonisation ambition. It has built new renewable electricity generation at pace with investments in geothermal, wind, solar and hydropower (hydro). Renewable electricity supply has increased from 82% to approximately 90% today – and with strong momentum in the pipeline, it is expected to exceed 95% by 2027. This is rapid progress.

A number of Future is Electric's Smart System recommendations have also been implemented. The number of Grid Emergencies announced by Transpower, which relate to potential shortfalls in generation supply when margins become tight, have declined substantially reflecting reduced blackout risk. New batteries, demand response and digital solutions have enabled this. Networks have also made significant progress integrating distributed energy resources like solar and electric vehicles. This is maintaining grid stability right down to the street level as new consumer resources connect to the network.

This has supported New Zealand maintaining its position as one of the highest ranked energy systems in the world across the energy trilemma dimensions of affordability, security and sustainability. However, the energy sector has also come up against new challenges and is now at a crossroads. First, a dry winter in 2024 highlighted volatility in electricity prices when low hydro and wind generation is accompanied by a shortage of complementary fuel sources. Second, domestic gas supply continues to fall rapidly, declining by 45% in the last six years and forecast to halve again in the coming five years.

These challenges are threatening the security and affordability of New Zealand's electricity system and the future of large industrial gas users. These two aspects of the energy trilemma, security and affordability, are now sharply in focus for the energy sector and policy makers. Regardless of how stakeholders weigh sustainability, the rapid build of renewables and the transition of gas users to electricity and biomass are a large part of the answer for achieving security and affordability.

The energy sector and policy makers are also thinking about energy in the broader context of New Zealand's current economic situation and setting up the country to realise economic opportunities. While New Zealand's situation is not unique – many developed countries are facing security and affordability challenges in the clean energy transition – New Zealand is distinct in its abundance of hydro and geothermal resources. These resources can underpin a competitive advantage for New Zealand by retaining and attracting energy intensive industries seeking low-carbon, secure and price competitive electricity, including emerging industries such as data centres.

While the Future is Electric report focused on the electricity industry, this report responds to this evolving context with an expanded scope. It explores the challenges faced by the whole energy sector and how it can enable wider economic growth by providing more affordable and reliable energy. Specifically:

- **Section 3** looks at the role New Zealand's energy sector can play in driving economic growth.
- **Section 4** explores the current state of New Zealand's energy sector and how it performs on the energy trilemma.
- **Section 5** identifies priorities to improve energy trilemma outcomes and drive economic growth in the next decade.

- **Section 6** evaluates ways New Zealand could achieve these priorities, by modelling and assessing potential actions against plausible energy scenarios and fundamental questions.
- **Section 7** identifies specific policy, market and regulatory recommendations to achieve these priorities – selecting a combination of actions tested in modelling to identify the best path forward. The recommendations are impartial and reflect whole-of-sector choices; they seek to maximise the energy sector's contribution to New Zealand's prosperity, not what is best for any one market participant.

This report does not seek to model induced economic activity or outcomes, nor does it delve into improbable shifts in the New Zealand market landscape. It explores probable scenarios but does not cover every combination of potential outcomes.

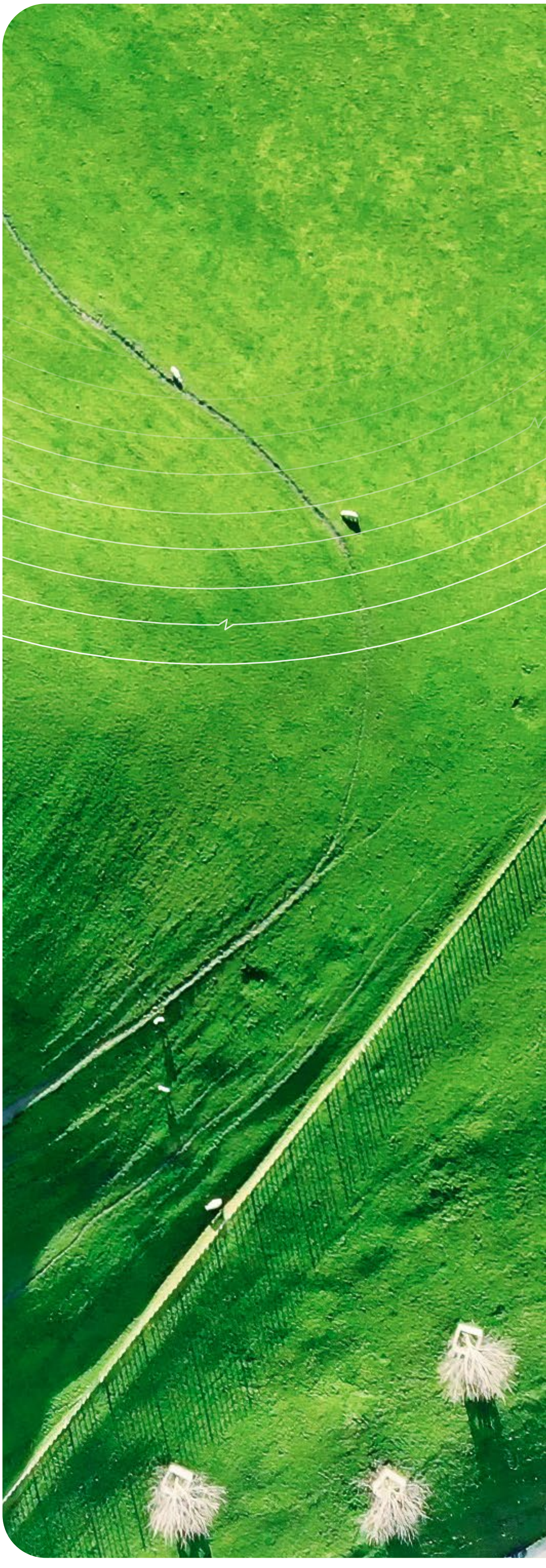
Sector participants have provided and fact-checked data for this report, but BCG has developed the analysis and recommendations independently (see basis of preparation). This report seeks to lay out facts and independent analysis to create a common understanding of the market today and logic for the recommended path.

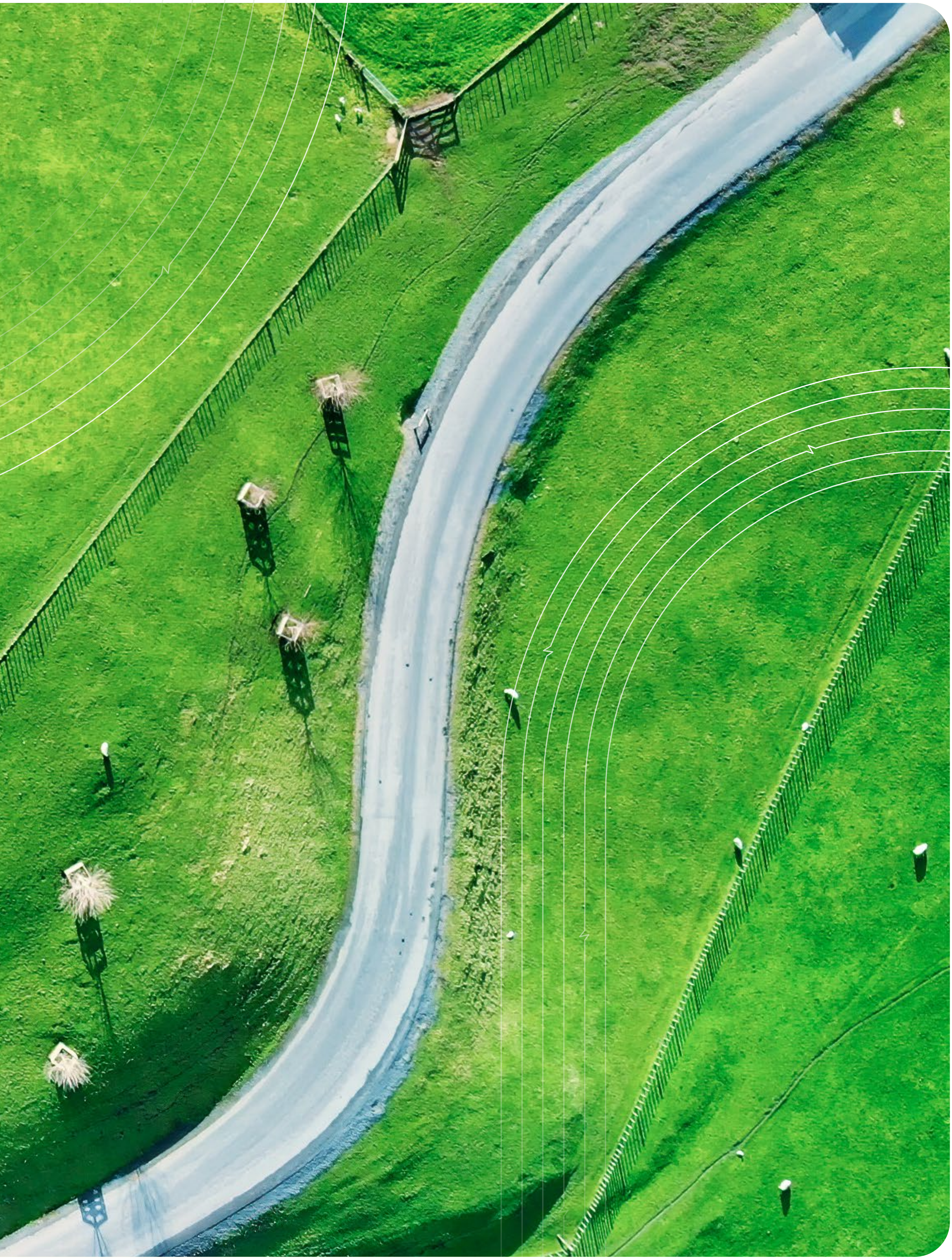
Finally, this report presents over 20 recommendations for New Zealand to strengthen the energy sector and improve outcomes across the energy trilemma. These recommendations have been posed to encourage further discussion and understanding of the possibilities across market participants, end-users, regulators and government, while also stimulating action across the sector.

*Note:*

A list of technical terms and acronyms are provided in the glossary at the end of this report.

All dollar figures are in New Zealand dollars, unless indicated otherwise, and in real terms at 2025 values (i.e. future inflation has not been added to today's costs, and likewise, cost and price estimates for future years have had inflation removed so they are expressed in the New Zealand values of 2025).





# 2 This report at a glance

## 2.1 Context

**Aotearoa New Zealand's energy system remains one of the best in the world, ranked 9th in the world and 1st in Asia by the World Energy Council for its combined equity (affordability), security and sustainability.**[1] New Zealand's high share of renewable electricity (90% and growing rapidly) and domestic gas supply have been a major contributor to this performance, enabling New Zealand to affordably produce energy and be resilient to global energy shocks.

**Despite this, a rapid decline in gas production of 45% over the last six years has exposed weaknesses in the energy sector, impacting affordability and security.** The faster-than-expected drop in domestic production has left New Zealand, which does not have any liquified natural gas (LNG) import capability, fully reliant on its limited domestic supply. This gas supply crunch has continued in 2025 for industrial users, with domestic gas production forecast to halve again in the next five years.

**Affordability and security were especially stretched in 2024 when a dry year reduced hydropower (hydro) generation.** With less hydro generation, New Zealand needed more gas to produce electricity, but gas availability challenges caught the market by surprise and led to both high spot gas and electricity prices. Today, the wholesale electricity price is highly exposed to gas – gas generation is under 10% of total electricity supply yet influences wholesale electricity prices 70–90% of the time.

**New Zealand's situation is not unique; many developed countries are facing security and affordability challenges in the clean energy transition, but New Zealand's hydro and geothermal resources offer a distinct advantage.** The abundance of these resources can underpin a competitive advantage for New Zealand by retaining and attracting energy intensive industries seeking low-carbon, secure and price competitive electricity, including emerging industries such as data centres.

**The country is also developing new renewable generation at an annual rate that is 25% higher than that of the peak of the Think Big hydro programme in the 1970s.** Committed or under-construction projects will lead to 95% renewable generation by 2027 and the broader pipeline should enable 98% renewables by 2030. Having more renewable generation will shorten the periods in which gas sets the electricity price as the marginal producer. It will also reduce the electricity industry's demand for gas by 70% in 2030 (from 30 PJs in 2024 to 9 PJ in 2030).

**However, New Zealand needs more affordable firming to complement these renewables.** While the electricity industry has substantially increased winter fuel stores for firming (storing gas, solid fuel and some diesel), New Zealand remains highly exposed to increasing gas prices. Even with renewables catering to 98% of New Zealand's electricity needs, gas will still set the price of electricity 25–35% of the time.[2] Furthermore, unlike gas, solid fuels are sometimes not able to start fast enough to provide firming for intermittent renewables during demand peaks.

**There is a way through this near-term energy crunch, but it requires bold and decisive action.** New Zealand can fix its domestic gas market, increase the diversity and storage of backup fuel for dry years and demand peaks, and continue to build renewables at the current pace beyond 2027.

**With this action, New Zealand can come out the other side with more affordable and secure renewable energy.** This can be a competitive advantage for the country – leveraging its hydro, geothermal and other renewables to stimulate increased economic growth by retaining and attracting energy intensive industries seeking low-carbon, secure and price competitive electricity, including emerging industries such as data centres.

1 World Energy Council, World Energy Trilemma Index 2024, 2023

2 New Zealand's wholesale market price is set by the last generator needed to meet demand (the marginal unit), and in many peak/low-renewables hours that unit is gas; therefore, gas often sets the price.

## 2.2 Key findings

**By strengthening its gas market, securing backup fuel for electricity and continuing to build renewables at pace, New Zealand can lower wholesale electricity prices.** In our Managed Transition Scenario, wholesale electricity prices decline from $160 per MWh today to $140 per MWh in 2027 (in today's dollars), and $100–120 per MWh in 2030.

~25% drop
in wholesale electricity prices by 2030

**To strengthen the domestic gas market, the government and energy sector can look to actions across supply, demand and storage.** To reduce the imbalance between gas supply and demand, the most effective actions are to accelerate drilling efforts in existing fields and support users to transition an incremental 10 PJ of gas to biomass and electricity by 2030, on top of ongoing and planned conversions.

**In addition, the energy sector should take steps to secure backup thermal fuels to more affordably replace the reduction in hydro during dry periods.** Options include new gas storage, imported LNG and alternative liquid fuels (condensate or diesel). New Zealand has enough solid fuel in storage to mathematically produce enough energy in a dry year, but solid fuel power plant capacity alone cannot meet all demand at peaks – hence gas, and potentially liquid fuels, are also required. While batteries are essential for hours-scale balancing and addressing price spikes, they can't economically cover multi-week dry periods; they complement, rather than replace, seasonal firming.

**It is highly preferable for New Zealand to have a well-functioning domestic gas market, rather than one that relies heavily on imported LNG. Despite this, LNG may still be a prudent backstop if gas supply continues to decline rapidly.** While LNG provides reliable supply of gas, it is more expensive than a combination of new gas storage and liquid fuels for electricity and may take longer to develop. New LNG infrastructure would cost $400–800 million, excluding fuel costs, while infrastructure for gas storage and condensate or diesel would be $150–300 million. The average domestic spot gas price for the last 12 months was $16–18 per GJ (including carbon), while landed LNG would have been $25 per GJ (including carbon). This does not necessarily mean that LNG should not be pursued – it could be a valuable insurance policy against further gas supply decline, mitigating de-industrialisation risk and acting as a backstop to a well-functioning domestic gas market. If LNG is pursued, it is still important to pull all levers to strengthen the domestic gas market, as this will deliver more affordable average gas prices.

**If the electricity industry continues to build renewables at today's pace, it will increase renewable generation to 95% by 2027 and 98% by 2030, and when paired with more reliable firming for dry years, it will support lower wholesale electricity prices.** A higher percentage of renewables decreases the percentage of time that gas sets the wholesale electricity price from 70–90% today, to 50–60% in 2027 with 95% renewables, and 25–35% in 2030 with 98% renewables.

**If these items are delivered (a strengthened domestic gas market, increased backup fuel, and continued pace of renewable development), industrial electricity prices should reduce to 2030, supporting competitiveness and economic growth.** This will be delivered via a reduction in energy costs measured in today's dollars, which represent approximately 80% of industrial consumers' bills.

**Even if these measures are successfully implemented, retail prices for residential consumers are likely to increase through to 2030 due to rising transmission and distribution charges.** Line charges represent 35–45% of final household bills and will increase by 25–35% between now and the start of 2030 in today's dollars, with inflation to come on top. The regulated revenue increments underpinning these higher line charges have already been locked into Commerce Commission price paths. These substantial increases in lines charges will only be offset in part by lower energy costs as wholesale electricity prices fall. Beyond 2030, residential price growth may steady if networks can improve efficiency and if interest rates are lower than in 2024.

**A stronger domestic energy market will lay the foundation to capitalise on an economic opportunity of up to $70 billion in data centres to 2035.** New Zealand's energy resources – particularly geothermal – are perfectly matched to provide 24/7 renewable power, which could underpin the country's next major export industry. To unlock this economic potential, New Zealand would need to adopt an energy abundance mindset – where the conversation shifts from why not, to how the sector collectively delivers an abundance of firmed, renewable energy for the future.

98%

Renewable electricity by 2030

$70b

Economic opportunity

in data centres powered by 24/7 renewable energy

# 2.3 Recommendations to address the findings

The following actions across five priority areas, to be considered alongside other national initiatives, will help New Zealand create a policy, regulatory and market environment that facilitates the delivery of a more affordable and secure domestic energy system. The list presented here is an abridged summary of the more than 20 specific recommendations outlined in detail in Chapter 7. The list below includes what it would take to achieve each recommendation and who would be responsible.

★ **Top priority**

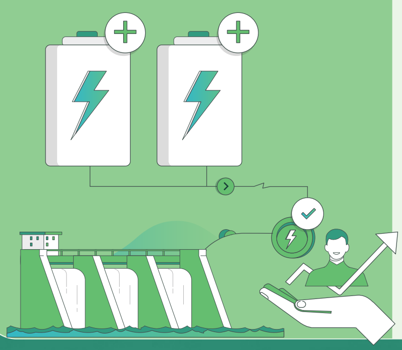
**PRIORITY 1**

## Accelerate renewable electricity generation development

- ★ **Build renewables at pace.** Renewable generation developers would need to reach regular Final Investment Decisions that allow renewables to continue to come online from 2028 to 2030.
- **Deliver faster consenting.** The Environmental Protection Authority and Ministry for the Environment would need to continue to support and improve the fast-track consenting mechanism to ensure it expedites infrastructure delivery.
- **Improve pipeline information.** The Electricity Authority (EA) would need to ensure there is one source of truth that captures all electricity generation and storage work in New Zealand.

**PRIORITY 2**

## Strengthen the electricity market and security mechanisms



- ★ **Investigate firming market designs that provide security for peaks and longer-period events**. The EA could consider a new market, the Sustained Reserve, and / or revisions to existing reserve markets to grow reserve volumes. For example, the Sustained Reserve would provide 2–4 hours of sustained support when the grid is under stress, shoring up security and increasing incentives to invest in new firming (e.g. batteries and other longer duration capacity).
- ★ **Investigate industry, regulatory and market actions to affordably meet dry periods.** Options include the EA strengthening information and regulation, gentailers (or a subset of gentailers) establishing a Gas Strategic Reserve Agreement, or the introduction of new incentives to develop fuel storage and diversify fuels.
- **Get the most out of existing hydro.** If sufficient actions to affordably meet dry periods are taken, Transpower and the EA can enable open access to 300 GWh of contingent hydro. For the new contingent hydro storage level of 532 GWh, Transpower and the EA would need to provide more predictable and earlier access to this storage. Gentailers would work with consenting authorities and key stakeholders to operate existing lakes higher and lower than today.

PRIORITY 3

## Enhance lines infrastructure efficiently

- **Provide a bold vision for grid development to 2050.** Transpower would need to ensure the Te Kanapu Grid Blueprint enables increased generation and electrification for years to come.
- **Commence productivity benchmarking for lines companies.** The Commerce Commission could set up this benchmarking to increase efficiency in spend.
- **Move to a trailing average approach for weighted average cost of capital.** The interest rates used to set revenue for lines companies are based on a 'point in time' approach. By setting a trailing average approach, the Commerce Commission would enable smoother revenues for lines companies and more stable bills for customers, supporting consumer affordability and investment signals.

PRIORITY 4

## Address gas supply decline and introduce domestic gas alternatives

- **Ensure the 'Gas Security Fund' funding model addresses drilling risk and weights focus to near-term gas supply**. This could involve government running a competitive tender process for development well drilling and CO2 scrubbing projects that provide additional gas supply in the near term.
- **Double effective gas storage.** Industry participants (e.g. gentailers) would pursue a combination of more gas storage and potentially condensate or diesel, in line with actions to affordably meet dry periods.
- **Explore alternative thermal fuels.** The sector and government could consider LNG, condensate, diesel or biomass as a replacement for domestic gas when availability is scarce and prices are high. This would involve accelerating early planning and permitting works to enable LNG imports, creating the option to commit to this pathway quickly if required.

PRIORITY 5

## Enable gas users to transition

- **Establish a $100–200 million Industry Resilience Fund.** The fund would need to be spearheaded by the government and the Energy Efficiency and Conservation Authority (EECA) and establish a competitive reverse auction to support users to transition to biomass and electricity at the lowest cost per GJ bid.
- **Increase public awareness.** Government, via EECA could provide information to the public about the energy transition and bring them on the journey, shaping the expectations and speed of commercial and residential electrification. This has been important for other nations navigating the transition.

LNG SPOTLIGHT

## Create optionality for LNG import by accelerating preparations

Modelling demonstrated that imported LNG delivers New Zealand energy security, both for domestic gas users to protect against de-industrialisation and for electricity generation in a dry year, but this security comes at a higher cost than alternative options. It is therefore recommended that LNG is kept in the mix as a future option in the event of ongoing domestic gas supply and demand imbalances. Even if government and the energy sector deliver all recommendations to strengthen the domestic gas market, there is still a chance New Zealand will require LNG in time.

Ensuring New Zealand has the option to pursue LNG in the future would require government and the energy sector to develop an LNG business case, conduct engineering feasibility studies and commence permitting works. These are relatively low-cost activities and can be completed in parallel with other recommendations to strengthen the domestic gas market. With this, government and the sector can make an informed decision based on updated domestic gas supply-demand knowledge and refined estimates of LNG cost, timeline and scale.

If LNG is pursued, key facility and market design choices will minimise costs to energy users and ensure the solution meets the needs of New Zealand's energy system:

- **Minimise times the gas market reaches import price parity.** Deliver a robust domestic gas market so prices only move to LNG price parity in the short periods LNG is required.
- **Implement a single price hub for gas and LNG** to maximise efficiency of price signals – do not split domestic gas and LNG access across users.
- **Set up a full-scale 4 PJ LNG** facility to match standard vessels, provide better access to fuel and hedging and risk products, and better match import volumes with seasonal demand requirements. This would avoid a small-scale and therefore bespoke LNG solution which would require fortnightly imports, increasing duration of import price parity and taking longer to implement.
- **Purchase call options (options to buy) or re-sell unneeded cargoes** where feasible so LNG is only delivered when needed and the cost of risk management is minimised.
- **Amortise LNG capital investment and fixed operations and maintenance (O&M) costs across both gas and electricity users with a broad-based fuel security levy.** Treat LNG as a system-wide insurance policy, with costs socialised rather than borne by individual users. Under a broad-based levy, these costs would be around $0.5 per GJ, compared with $5–22 per GJ if recovered through the marginal fuel price. This approach prevents these costs from being recovered over only a few units of gas, which would increase the marginal fuel cost and significantly raise prices for all consumers, making LNG supply prohibitively expensive.

# 3 The opportunity: How the energy sector can continue to drive economic growth for New Zealand

Around the world, economic growth is underpinned by access to affordable, secure energy that powers industries and communities. Over the past 50 years, New Zealand's affordable, secure and increasingly sustainable energy sector has attracted energy-intensive manufacturing to the country and underpinned a large domestic primary sector. Energy has historically been a competitive advantage for New Zealand due to its abundance of hydropower and low-cost domestic gas, but today, local conditions and global expectations are evolving.

This section explores New Zealand's energy advantages and their role in contributing to economic growth historically and into the future. New Zealand has an opportunity to be one of a few markets where industry can access 24/7 renewable electricity, supported by a strong generation development pipeline to serve electricity demand as it grows.

## 3.1 Looking back: Hydropower and low-cost domestic gas as New Zealand's competitive advantage

**New Zealand developed an abundant and affordable energy sector**

New Zealand's energy demand grew rapidly in the 20th century, as industry expanded and the economy grew. Government responded with major investments in electricity generation, particularly in hydropower along the Waikato River and throughout the South Island, such as the Waitaki and Manapōuri hydro schemes. Construction of the HVDC inter-island cable in 1965 linked the South Island's extensive hydro capacity to the North Island's industrial demand, establishing hydropower as a key source of competitive advantage for New Zealand.

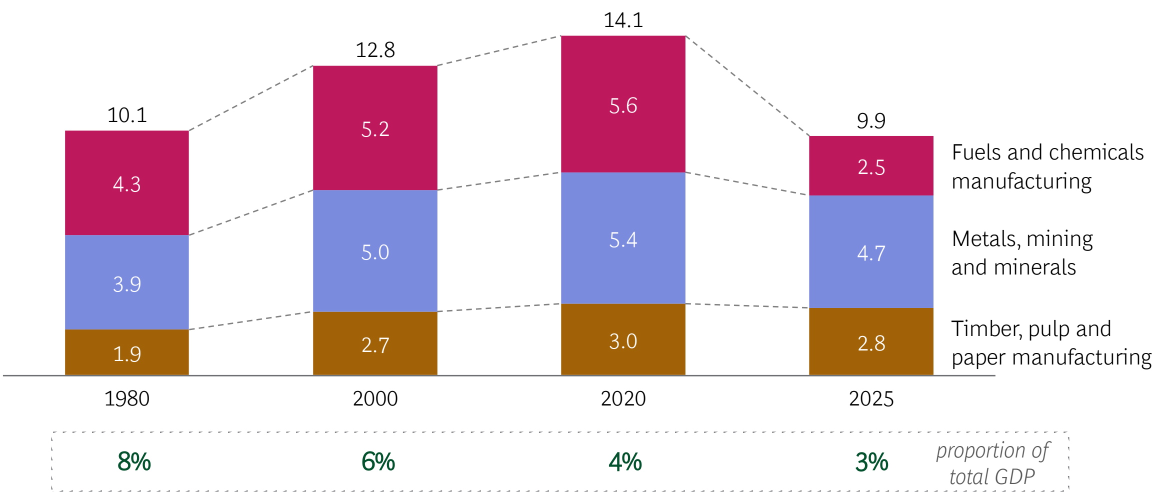
The discovery of the Kapuni (1959) and Maui (1969) gas fields provided the country with an abundant, domestic gas supply and unlocked a new wave of energy investment. The government established the National Gas Corporation to build a piped supply network across the North Island, extending to industrial sites and new gas-fuelled power stations, such as New Plymouth and Huntly. Gas-fired electricity generation complemented hydropower well, helping to manage peak demand and providing a reliable backup in dry years with low rainfall.

domestic gas created a distinct competitive advantage for New Zealand. This attracted a range of energy-intensive industries, including aluminium smelting at Tiwai Point, steelmaking at Glenbrook, methanol and urea production in Taranaki, and pulp and paper processing in the central North Island.

Although New Zealand's economic mix evolved over time – with service industries growing at a faster rate than energy-intensive industries, reducing their relative share of total gross domestic product (GDP) – these industries still consistently grew production and supported regional employment from the late 20th century to 2020, underpinned by reliable, low-cost energy. This trend has only recently reversed – and is discussed in Section 3.2 (see **Exhibit 1**).

## Exhibit 1: Energy-intensive industry contributions to New Zealand's GDP, in real 2025 dollars

**Historic real GDP contribution, by energy-intensive industry**
(2025 $b, year-end March)




Note: GDP = gross domestic product
Source: Stats NZ, BCG analysis

**Since the 2010s, the energy sector has evolved with New Zealand's priorities to focus on decarbonisation**

The energy sector has shifted its focus to decarbonisation, developing new geothermal, wind and solar generation. Existing dispatchable hydro and flexible gas generation complement these developments, helping to manage solar and wind intermittency. These investments are supporting New Zealand to achieve its target of net-zero-emissions by 2050, demonstrating how the energy sector continues to evolve and support national priorities (see **Exhibit 2**).[3]

Exhibit 2: New Zealand's energy advantages in hydropower and abundant domestic gas have underpinned industrial growth over a century


3 Ministry for the Environment, Greenhouse Gas Emissions Targets and Reporting, 2024

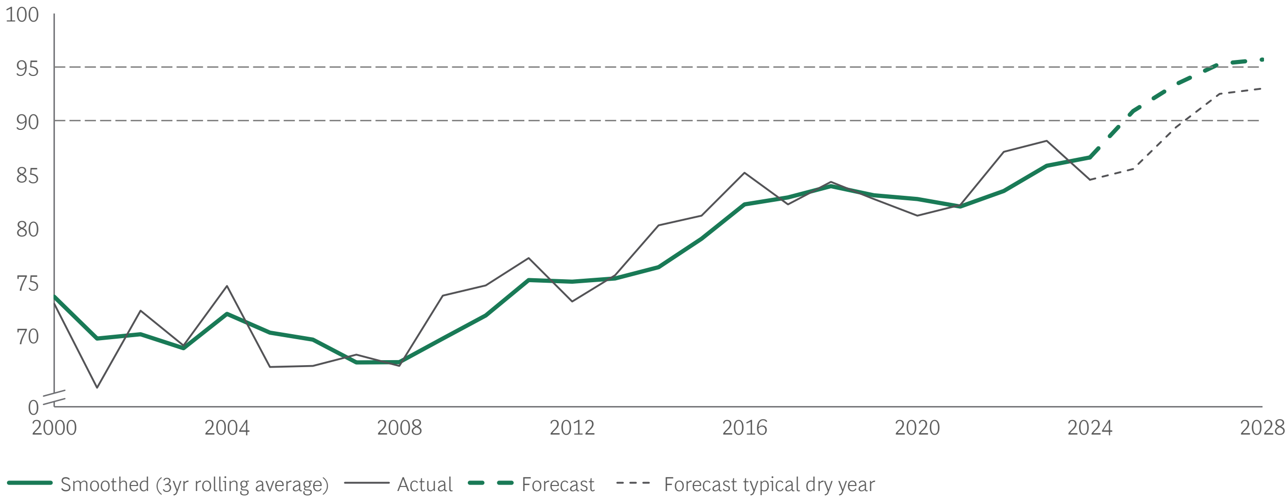
## 3.2 Today: An inflection point for New Zealand's energy sector

### New Zealand is decarbonising its electricity sector at pace

The focus on decarbonisation in recent years has seen the electricity sector move from about 70% renewable generation through the 2000s, to a peak of 88% in 2023. With continued investment in new renewable capacity, New Zealand is on track to deliver more than 95% renewable electricity generation by 2027 (see **Exhibit 3**).

Exhibit 3: Renewables as proportion of total electricity generation, 2000–2028

**Renewable electricity generation**
(% of total electricity supply, 2000–2028F)




Source: MBIE Annual Electricity Statistics, BCG Forecast Analysis

### Despite success in decarbonisation, energy security and affordability challenges are now putting New Zealand's competitive advantage under pressure

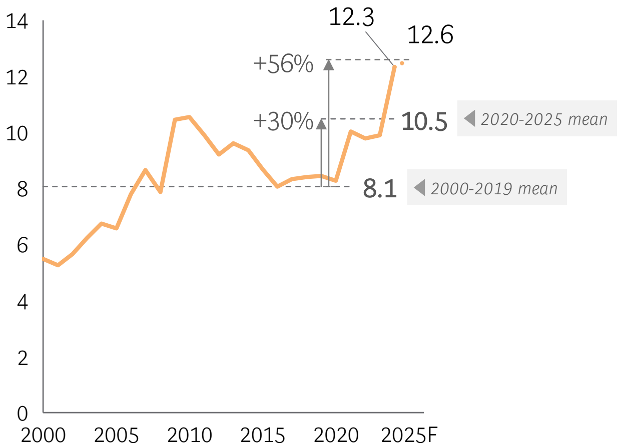
While sustainability is still a priority for the global energy transition, many energy systems are now focusing on energy security and affordability, as supply crunches and rising prices filter through global markets, including New Zealand.[4] Emerging domestic challenges and the evolving needs of industry are putting pressure on New Zealand's historic competitive advantage in reliable, low-cost energy.

In the last five years, average industrial gas and electricity prices in New Zealand have been about 30% higher than the prior 20-year average, with expected 2025 prices for gas and electricity up 56% and 46% respectively (see **Exhibit 4**). These price hikes are challenging New Zealand's cost-competitiveness.

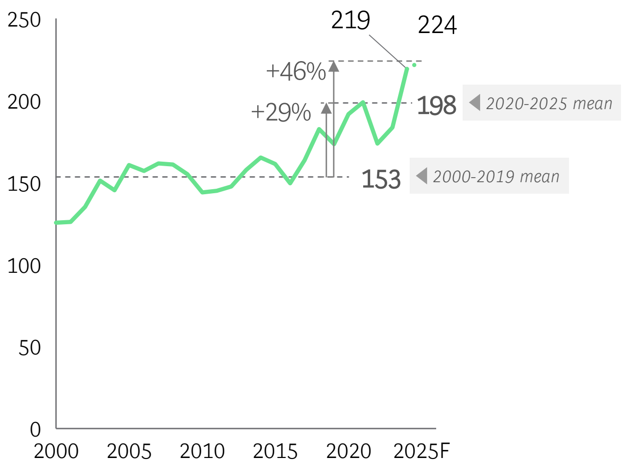
4 BCG, *The Energy Transition's Next Chapter*, 2025

Exhibit 4: Wholesale unit gas prices and industrial unit electricity prices, 2000–2025F

**Wholesale unit gas price**
(2025 $/GJ, calendar year average, excluding carbon)




**Industrial unit electricity price**
(2025 $/MWh, calendar year average)




Source: MBIE, BCG analysis

## Domestic gas supply is declining rapidly and faster than forecast

Total domestic gas production volumes reduced from 195 PJ in 2019 to 107 PJ forecast for 2025 – representing a 45% decline. This has created a tight market and driven unit wholesale prices up to an annual average of about $12 per GJ (excluding carbon).[5] While this price is higher than historic averages, it is still lower than the expected marginal cost of liquefied natural gas (LNG), which is around $21 per GJ (excluding carbon). This highlights the advantages of domestic gas supply, even in a tight market – although forecasts suggest further supply decline over the next five years.

The tight gas market is impacting large industrial gas consumers and the broader industrial sector. Higher gas prices have caused wholesale electricity prices to rise, due to the strong link between gas and electricity over the last ten years (an 80% correlation), with periods of significant spot price volatility.

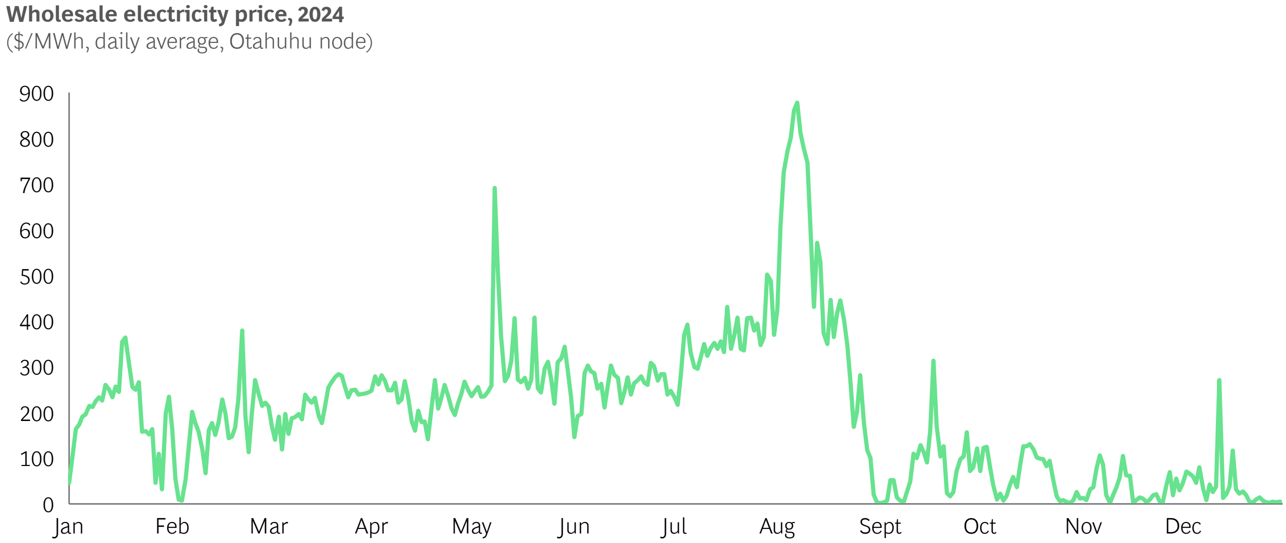
5 Ministry of Business, Innovation and Employment, Gas Statistics, 2025

**The dry period in winter 2024 exposed weaknesses in energy security**

In winter 2024, New Zealand experienced a dry and low-wind period that reduced hydro and wind electricity generation. Demand for gas-fired electricity generation increased to maintain electricity supply security, driving already constrained gas prices higher. To direct gas supply to the electricity system during this period of tight supply, major industrials such as Methanex had to reduce their energy demand and gas consumption.

The supply pressure and increased demand for gas pushed wholesale electricity prices to daily averages of over $800 per MWh in early August (see **Exhibit 5**) – about 4.5x higher than the typical winter average over the previous five years.[6]

Exhibit 5: Daily average wholesale electricity price, 2024




Source: Electricity Authority

6 Electricity Authority, Review of Winter 2024, 2025

### High energy prices have impacted energy-intensive industries

Since 2020, economic growth across energy-intensive industries has declined, with reduced production volumes and several plant closures (see **Exhibit 6**).

Although multiple factors such as inflation, increasing labour costs, shifting consumer preferences and geopolitical uncertainty have influenced production economics, higher energy costs are also frequently cited as a contributing factor.

### Exhibit 6: Reduced GDP across energy-intensive industries, 2020–2025

**GDP reductions, by energy-intensive industry, 2020–2025**
(2025 $b, year-end March)

| Industry | GDP reduction, 2020–2025 | Detail and examples |
|---|---|---|
| Fuels and chemicals | -57% | Marsden Point refinery closed in 2022<br>• High electricity and natural gas costs cited as key driver<br>Methanex, Ballance, other small players<br>• Reduced production due to gas supply constraints |
| Timber, pulp and paper | -6% | 41% reduction in pulp and paper export volumes<br>Plant closures:<br>• Norske Skog–Tasman – closed printing mill<br>• Winstone Pulp – closed pulp mill<br>• Oji Fibre Solutions – closed paper mills |
| Metals, mining and minerals | -14% | Lower aluminum volumes in 2025<br>• Tiwai smelter provided electricity demand response in Jun-Sep 2024, reduced production reflected in March-2025 GDP<br>30% reduction in mining's contribution to GDP in 2025 versus 2020 |

Note: GDP = gross domestic product
Source: Stats NZ, Refining NZ, Gas Industry Co., Methanex, Norske Skog, Winstone Pulp International, Radio New Zealand,

Marsden Point stopped its fuel refining operations in 2022 and converted to an import-only terminal due to sustained low margins.[7] It faced competition from larger regional refineries with scale and production cost advantages and also cited rising energy costs and limited access to affordable gas at the required volumes as contributing factors.[8]

Methanex, New Zealand's largest gas consumer, reduced its gas consumption by around 50% between 2023 and 2024, from 55 PJ to 27 PJ.[9] Due to the constrained gas market, it idled production in 2024 so the electricity market would have enough gas to support grid firming during the dry year.[10] Methanex is now operating at reduced capacity due to gas supply uncertainty, with some production trains idled indefinitely.

7 Refining NZ, Refining NZ Board Confirms Transition to Import Terminal, 2021

8 Refining NZ, The Marsden Point Conversion Proposal, 2021

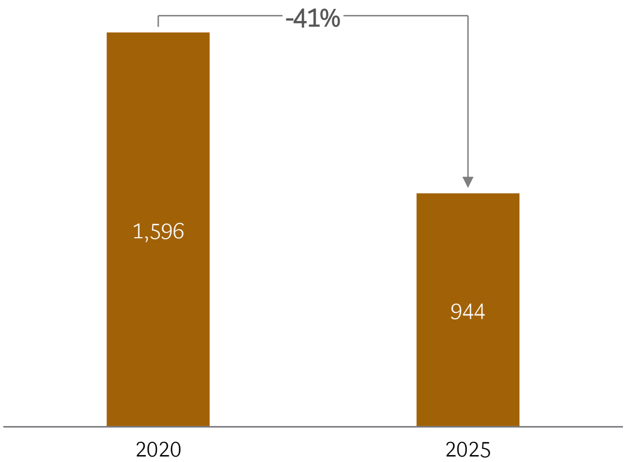
9 Gas Industry Co., Quarterly Report, 2025

10 Methanex, Annual Report 2024, 2024

In the timber manufacturing sector, there have been significant reductions in pulp and paper production in recent years (see **Exhibit 7**). Mill closures include the Tasman newsprint, Karioi pulp, Penrose recycled paper and Kinleith paper mills. Structural demand decline and high domestic production costs have compressed margins.[11] In many cases, higher energy costs contributed to higher production costs – for example, Winstone Pulp International's forward electricity costs doubled between 2019 and 2021, and Pan Pac Pulp in Hawkes Bay curtailed operations during the 2024 spot price hikes to avoid high electricity costs.[12,13]

## Exhibit 7: Pulp and paper industry export volumes, 2020–2025

**Pulp and paper industry export volumes, 2020–2025**
('000 tonnes, year-end June)

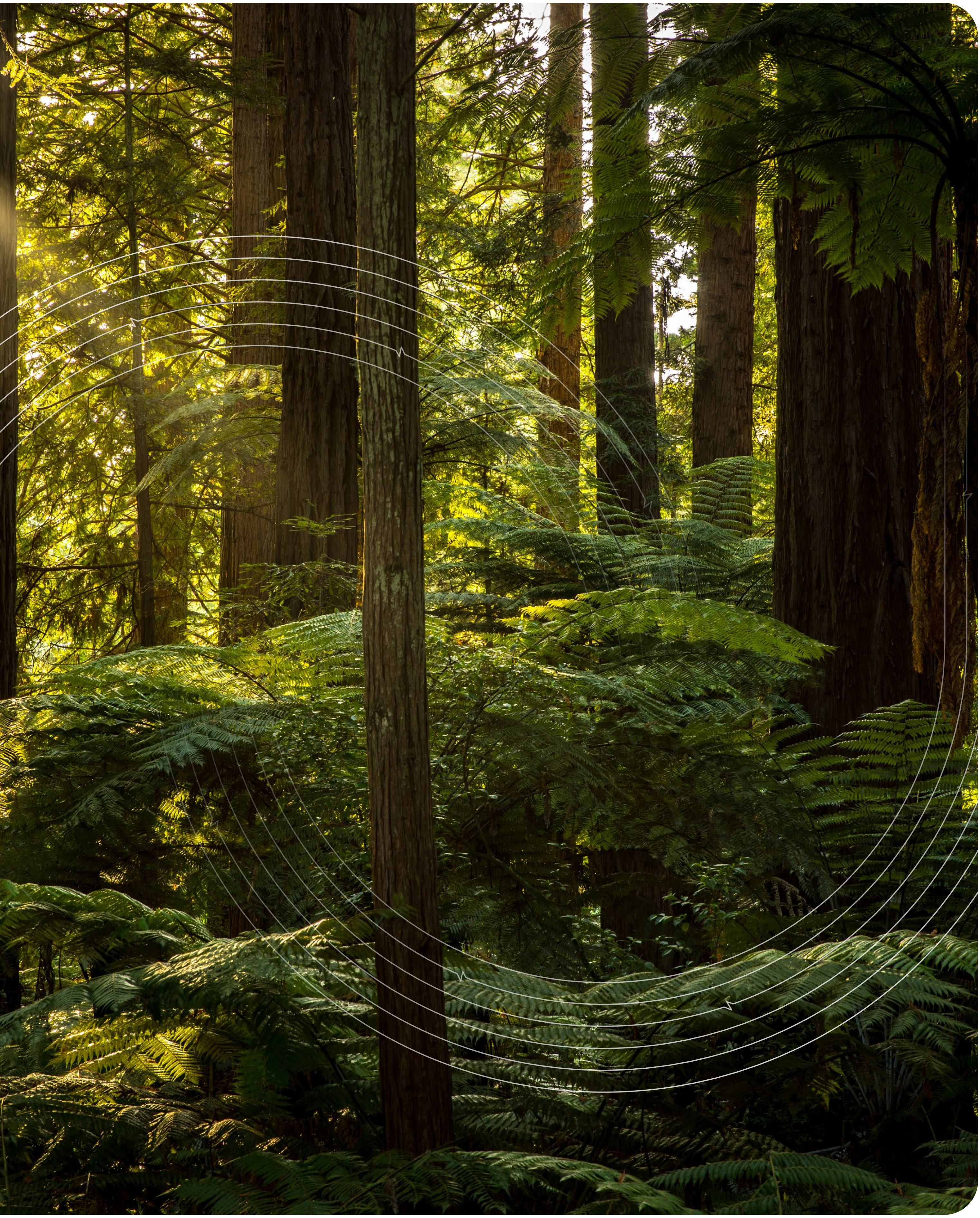



Source: Stats NZ, MPI, BCG analysis

11 Norske Skog, Norske Skog to Close the Tasman Mill in New Zealand, 2021

12 Winstone Pulp International, Submission to Electricity Authority Consultation Paper, 2021

13 Radio New Zealand, Pressure on Power Companies to Act as Energy Woes Mount, 2024



### Structural shifts in electricity demand are underway globally

As the global energy sector faces mounting supply challenges, structural shifts in demand are accelerating. After years of effectively flat electricity demand across developed economies including New Zealand, demand is now expected to grow substantially.

Industries and transport are electrifying to decarbonise, while large-scale technological shifts – such as the development of data centres to support artificial intelligence – are driving electricity demand higher. Energy-intensive industrial players are increasingly seeking low-cost, secure and sustainable energy to underpin their growth.

### New Zealand's energy sector is at an inflection point

Against this backdrop, New Zealand's energy sector is at an inflection point. With the right action, the sector can secure the country's energy future with a well-managed transition. By leveraging its significant resource potential, New Zealand has the opportunity to renew its global competitive advantage in abundant, firmed renewable electricity to underpin a new era of sustainable economic prosperity.

## 3.3 Looking forward: Abundant, firmed renewable energy as a renewed competitive advantage for New Zealand

### To renew New Zealand's energy advantage, the sector must meet the needs of energy-intensive industries

As New Zealand plans the path forward, the energy sector must consider what energy-intensive industrial users prioritise in an energy offering, including:

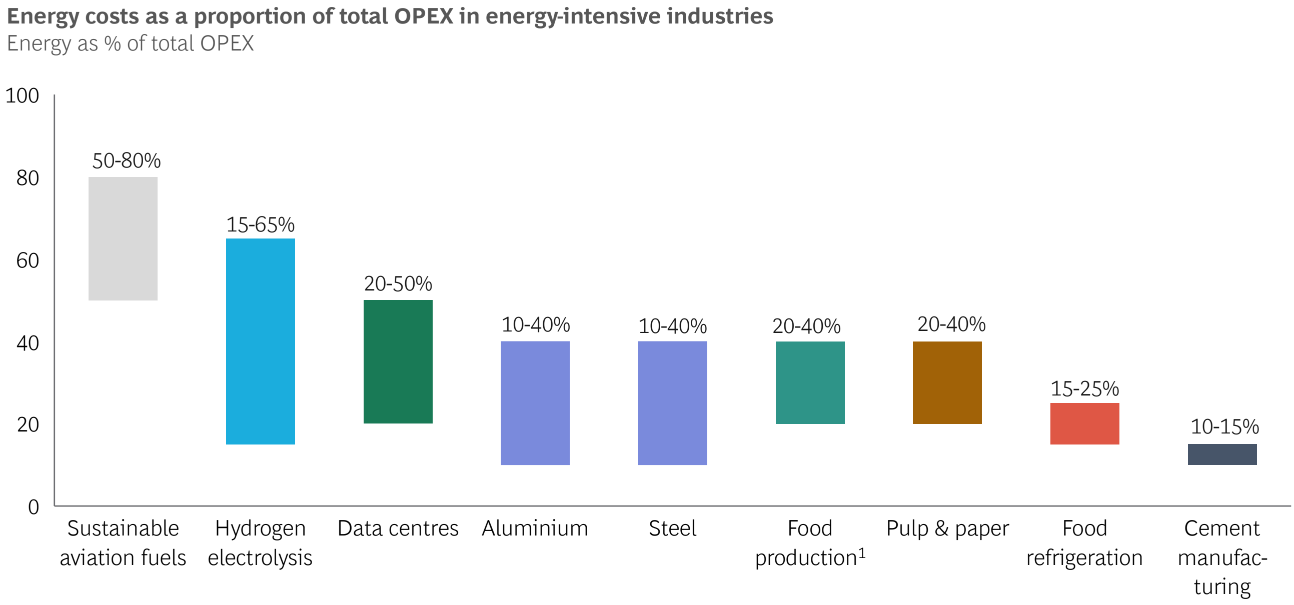
- Cost
- Carbon intensity
- Alignment of generation to load profiles
- System scalability

Addressing each of these is essential to positioning the energy sector competitively for the future.

***Cost: Global cost-competitiveness is essential to maintaining comparative advantage***

In energy-intensive industries, energy constitutes a disproportionately large share of operating costs. Even small shifts in unit energy price can significantly impact production economics and hence site selection (see **Exhibit 8**).

Exhibit 8: Energy costs as proportion of operating costs in energy-intensive industries



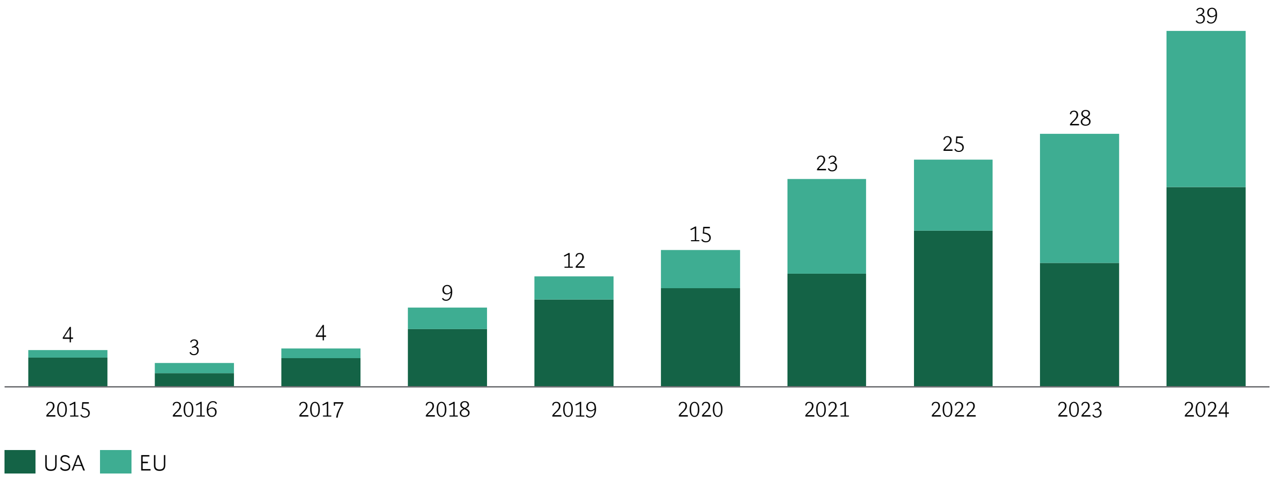

1. Includes food and dairy processing, glasshouse crop production
Source: Publicly available corporate reports, expert interviews, BCG desk research and analysis

***Carbon intensity: Low-carbon energy is increasingly a demand driver as the global economy decarbonises***

Energy-intensive industries are increasingly facing pressure from investors, regulators and consumers to reduce emissions, making access to low-carbon energy central to ESG and decarbonisation targets. As a result, companies are increasingly entering power purchase agreements (PPAs) to secure low-carbon renewable energy certificates (see **Exhibit 9**). Global initiatives such as the 24/7 Carbon-free Energy Compact (CFE) which brings together more than 170 corporations, governments, NGOs and energy providers, are accelerating this trend across the energy sector.

Exhibit 9: Renewable PPAs uptake, USA and EU, 2015–2024

**New clean power purchase agreements, USA and EU**
(GW added per year)




Note: Includes publicly announced agreements
Source: Clean Energy Buyers Association, BloombergNEF

***Alignment of generation to load profiles: Energy-intensive industries need access to energy that meets their varying load requirements***

Aluminium smelters and data centres need consistent, 24/7 energy supply and have limited flexibility to adjust consumption at short notice. In contrast, electrolysis operators and electric-arc furnace steelmakers can operate in batches and schedule energy use. Therefore, for large energy users, an energy system's ability to match generation to load profiles is a critical decision-driver in choosing where to set up or expand operations.

***System scalability: Energy systems must be able to support future demand growth***

The scalability of an energy system to meet demand growth underpins an industry's ability to grow production. System scalability depends on both the availability of energy resources and the ability to deploy them effectively to ensure new demand does not lead to escalating prices or reliance on thermal fuels. Limited renewable resources, or regulatory barriers to developing renewables can stifle growth and undermine future cost-competitiveness, carbon performance and supply reliability.

For example, the Pennsylvania-New Jersey-Maryland (PJM) interconnection region in the United States is one of the world's largest data centre hubs. Driven in part by surging demand for data centres, end-user electricity prices are rising. Capacity prices have increased nearly ten-fold, from an average of about $29 per MW-day in 2024/25 to roughly $270 per MW-day in 2025/26, as the system attempts to scale rapidly to meet demand.[14] Eroding public sentiment caused the regulator to introduce a price cap in 2025 to protect consumers from rapidly rising electricity bills.[15]

14 IEEFA, Projected Data Center Growth Spurs PJM Capacity Prices by Factor of 10, 2025

15 Congressional Research Service, PJM's Electric Capacity Market, 2025

**New Zealand is well positioned globally to support energy-intensive industry**

New Zealand's abundant natural resources – lakes and rivers, geothermal activity, wind and sunshine – underpin its existing renewable energy base. As a result, the country sits among a small group of markets offering relatively low-cost, low-carbon electricity (see **Exhibit 10**).

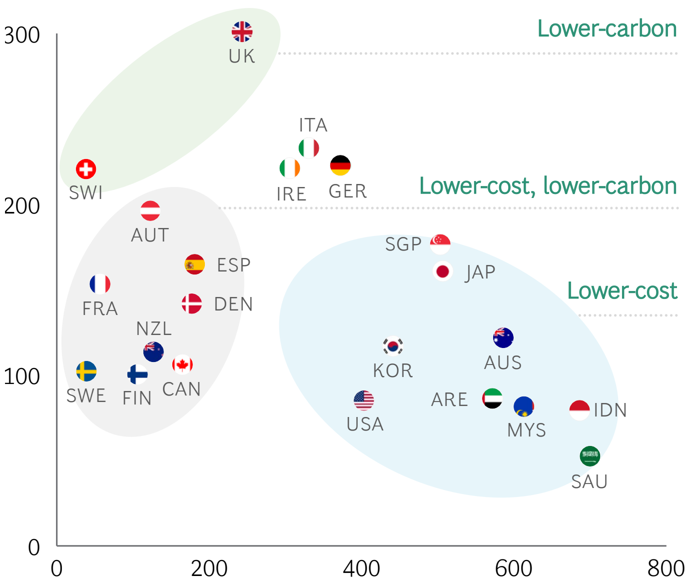
Many peer countries fund new generation and storage through government budgets or tax credits, not electricity bills. For example, the United States finances large production and tax incentives under the Inflation Reduction Act, Canada similarly offers a refundable Clean Technology Investment Tax Credit and Australia underwrites projects through its Capacity Investment Scheme and many states offer solar rebates. Because these subsidies are off-bill, electricity prices understate true costs. Adjusting for fiscal support would lift peers' effective prices and strengthen New Zealand's relative position.

Furthermore, New Zealand's limited reliance on thermal fuel imports for electricity shields the system from global price shocks, while high renewable penetration delivers low-carbon electricity.

Exhibit 10: Average industrial electricity price and carbon intensity, by market

**Average industrial electricity price and carbon intensity, 2020–2024, by market** (2025 US $)

Average industrial price ($/MWh)



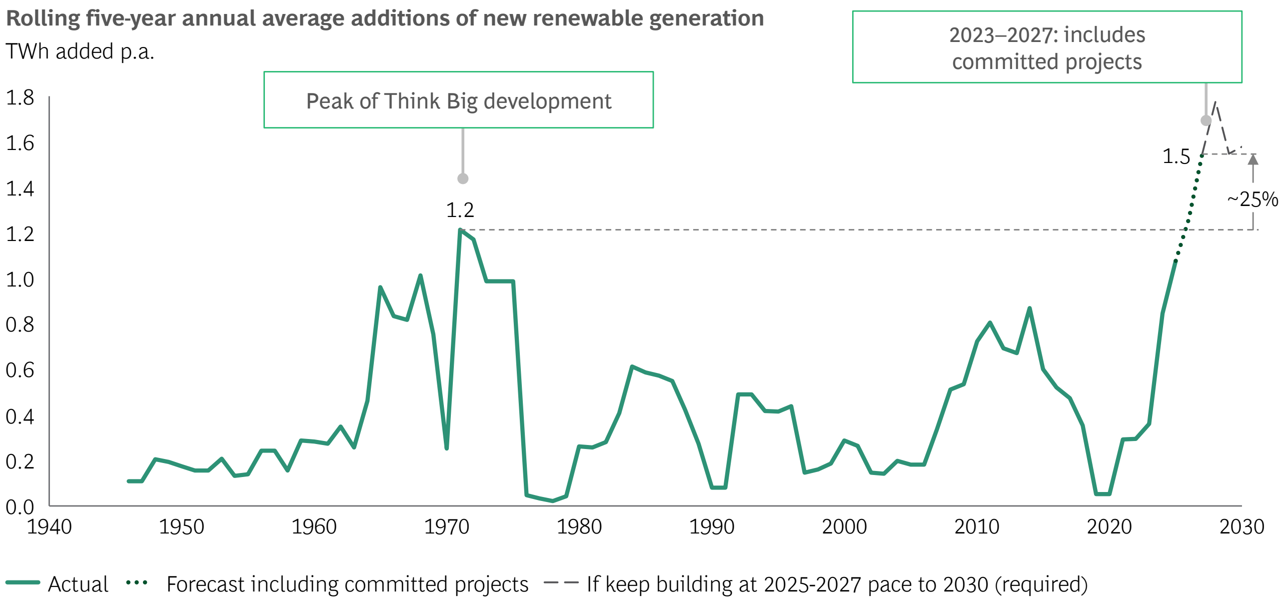

Carbon intensity (kg-$CO_2$/MWh)

Source: Enerdata, Our World in Data, Ember, Energy Institute, Australian Competition and Consumer Commission

The country is well positioned to continue delivering low-cost, low-carbon energy into the future. Investments in geothermal, wind and solar generation are displacing thermal generation, reducing long-run marginal costs and carbon intensity. A strong pipeline of renewables is set to continue this trend, with a further 4.1 TWh of generation either consented or under construction and expected to come online by 2027.[16]

As a result, renewables are being developed at their fastest ever rate – 25% faster than during New Zealand's 'Think Big' era of large-scale hydro developments in the 1970s (see **Exhibit 11**).

## Exhibit 11: Rolling five-year average of annual renewable generation commissioned




16 Concept Consulting generation pipeline

**New Zealand's energy system has abundant, untapped renewable resources to scale its energy system and meet the needs of industry in the future**

New Zealand has significant untapped renewable energy potential. This means the system can scale to meet industrial demand growth, without reverting to thermal energy and compromising its strength in low-cost, low-carbon supply.

**Geothermal:** Beyond existing geothermal generation, New Zealand's untapped conventional resources are estimated to hold 21 TWh of annual generation potential – equivalent to 50% of total current national supply.[17,18] In addition, supercritical resources could generate another 30 TWh of annual supply.[19,20]

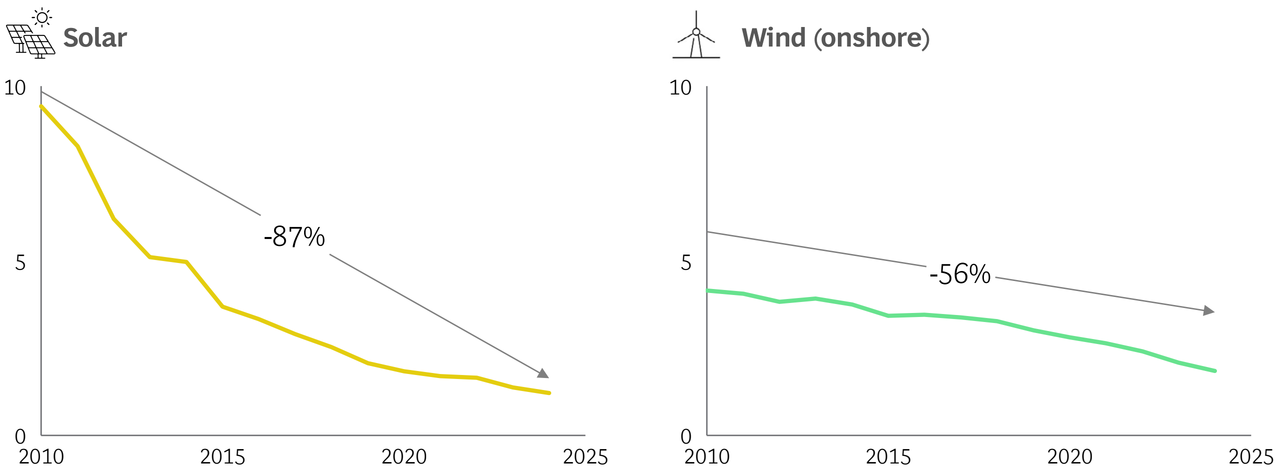
**Wind:** New Zealand has 6.3 GW of onshore generation in the pipeline at varying development stages – translating to 22 TWh of annual generation.[21,22] The government is also establishing a regulatory framework for offshore wind development, with 6.5 GW of capacity under investigation by multiple developers.[23]

**Solar:** There is 14.8 TWh of untapped rooftop generation, and another 24 TWh of utilityscale solar in the pipeline at various development stages. [24,25]

Delivering renewable generation has become increasingly cost-efficient over the last 15 years. Globally, the average CAPEX spend for solar farms has fallen by 87%, and onshore wind by 56% (see **Exhibit 12**). Now that the technology needed to harness New Zealand's untapped renewable resources exists and is becoming increasingly economical, the challenge has shifted from technological feasibility to speed of delivery.

Exhibit 12: Average CAPEX spend for wind and solar developments, 2010–2025

**Global average CAPEX for solar and wind generation development**
(2025 $m/MW)




Source: IRENA

17 IEA Geothermal, New Zealand, 2024

18 Conventional: <3.5km depth, <350°C; Geothermal, The Next Generation, 2025

19 Castralia, Supercritical Geothermal in New Zealand, 2023

20 Supercritical: >3.5km depth, >400°C; Geothermal, The Next Generation, 2025

21 NZ Wind Energy Association, Onshore Windfarm Pipeline, 2025

22 Assumes 40% capacity factor

23 NZ Wind Energy Association, Offshore Windfarms, 2025

24 Transpower, The Sun Rises on a Solar Energy Future, 2019; assumes 16% capacity factor

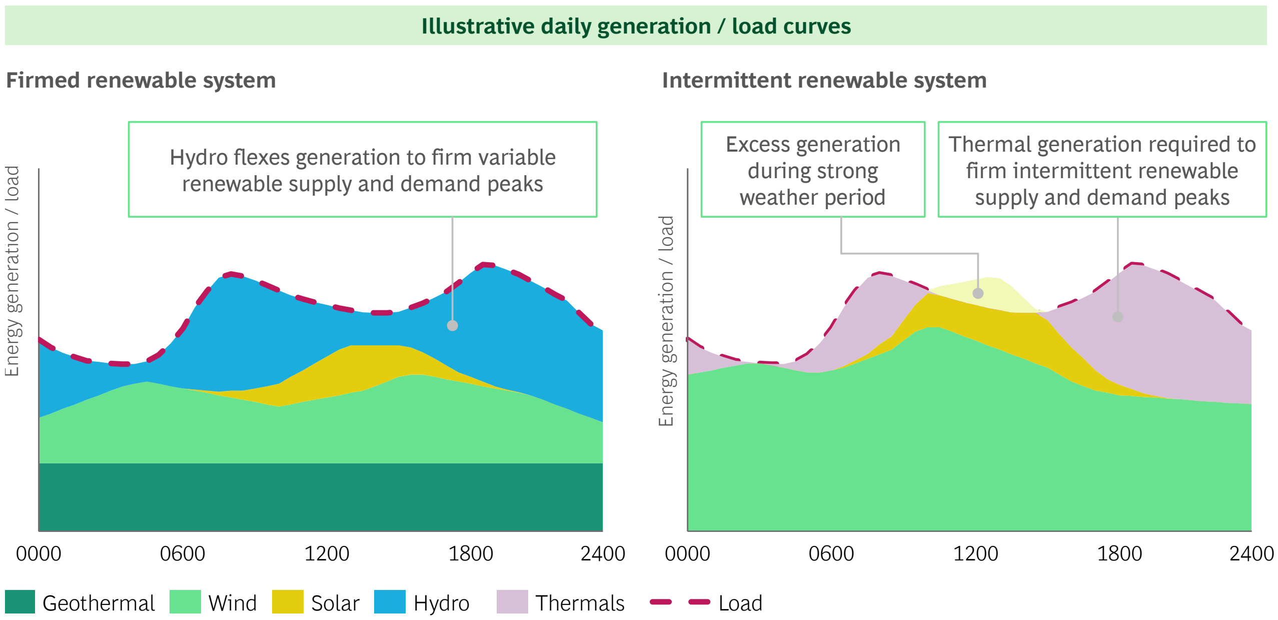
25 Transpower, Whakamana i Te Mauri Hiko, Monitoring Report, 2024; assumes 16% capacity factor

**Backed by existing hydropower, New Zealand's untapped renewables can provide industry with consistent, firmed renewable energy**

As New Zealand builds renewable generation, it will continue to displace thermal generation, with geothermal providing reliable, inherently firmed baseload generation. However, the expansion of wind and solar increases supply variability, as these intermittent technologies need additional firming capacity in times of low wind and sun.

New Zealand's extensive existing hydropower system provides a unique advantage: it is inherently dispatchable, meaning water can be held back during periods of excess renewable generation and released during demand peaks and low-generation periods (see **Exhibit 13**). As the system evolves, hydro can shift from a predominantly baseload role, to providing renewable firming, replacing the function traditionally performed by thermal fuels.

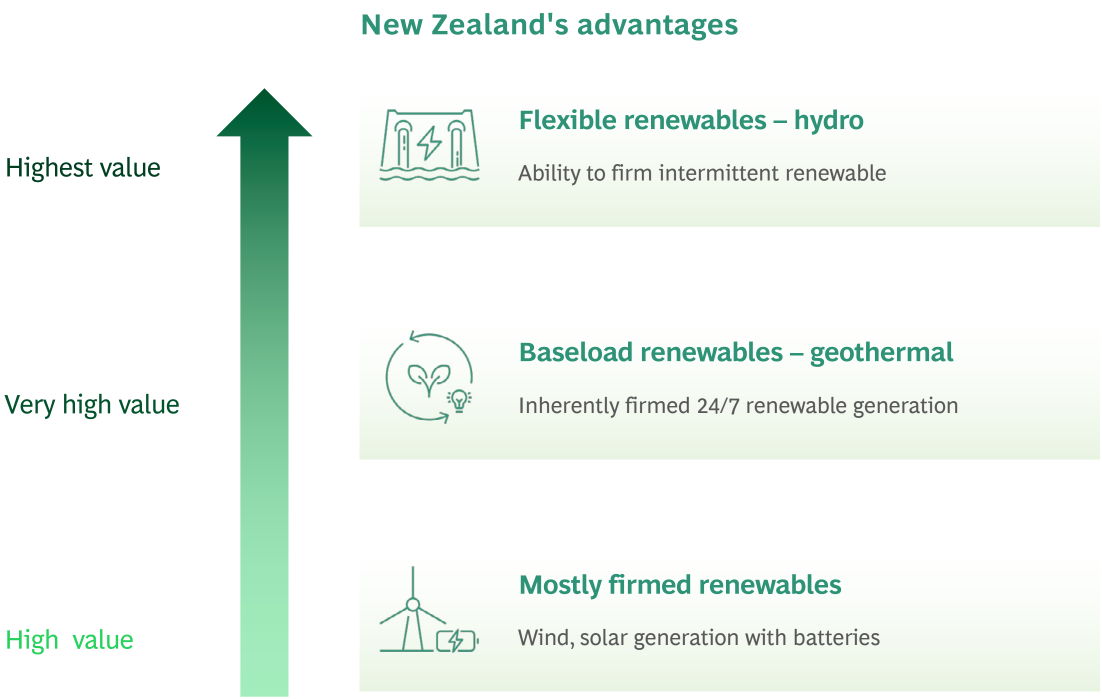
Exhibit 13: Illustrative view of how hydro generation can flex to firm highly renewable systems




Note: For illustrative purposes only

Geothermal generation can then sustain and expand baseload supply, while hydro delivers flexibility to firm variable renewables. Together, they enable a consistent, firmed, low-carbon system – unlocking a distinct advantage for New Zealand in 24/7 renewable energy – albeit with some thermal fuels required in dry periods.

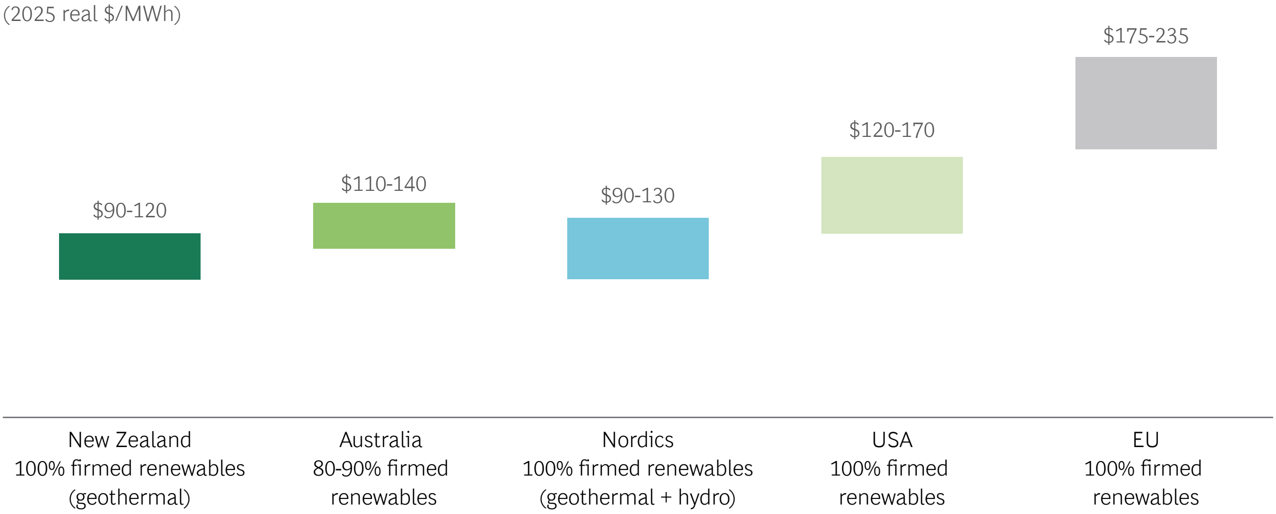
Exhibit 14: New Zealand’s highly valuable combination of renewable resources




In contrast, Australia is building intermittent renewable generation without a significant existing hydropower base. It is having to invest heavily in megaprojects such as the Snowy 2.0 hydro scheme to meaningfully displace thermal generation and provide firming capacity for intermittent renewables.

Exhibit 15: Industrial firmed renewable PPA price ranges

**Industrial firmed PPA price ranges**[1]
(2025 real $/MWh)




1. Prices reflect energy-only costs for 10–12-year firm PPAs starting 2026–2028, exclusive of retail/wires. Methodologies benchmark against long-run baseload prices, geothermal LRMCs and shaping premiums from reliable sources (KYOS, CSIRO, OPIS, ATB, Lazard). ±10–20% caveats apply for basis risk, contract structure, hourly matching scope, and local attribute rules
Note: Currency conversions (US, EU, AU) made 13/08/2025
Source: CSIRO, KYOS, OPIS, ASX Announcements, Lazard LCoE, Data Center Dynamics, Reuters, ATB/NREL, Eurelectric

### New Zealand's industrial PPAs are globally competitive and support the building of renewables

New Zealand's abundant untapped renewable resources translate to globally competitive industrial PPA pricing (see **Exhibit 15**). These agreements also support the build-out of renewables by underwriting new developments with revenue guarantees.

Globally, 100% firmed renewable PPAs are becoming increasingly common. These PPAs pair particularly well with New Zealand's advantages in geothermal generation or a portfolio of intermittent renewables firmed by dispatchable hydro.

### Consistent renewable energy is well-suited to support industries with various load profiles

New Zealand's ability to deliver consistent renewable energy supply is an advantage in meeting diverse industrial demand profiles. Both industries with batch load requirements and those requiring continuous supply can be served by firmed renewable systems. Continuous users are particularly well-suited, as they pair naturally with renewable baseload generation, such as geothermal and hydro. By contrast, energy systems dominated by intermittent renewables often depend on industrial demand response – suiting flexible users but limiting their ability to support those that need consistent energy.

**New Zealand's renewed competitive advantage will position it to grow existing and attract emerging energy-intensive industries to drive economic growth**

New Zealand has historically supported energy-intensive industries well. With a renewed competitive advantage in 24/7 renewable energy, it can support existing industries to grow and attract emerging industries like data centres to drive economic growth for the future.

While New Zealand's energy offering can effectively serve all industries with significant energy requirements, its niche market is those seeking consistent, renewable supply with future scalability – with only a few markets in the world offering such a combination. These industries are sizeable globally and have strong future trajectories (see **Exhibit 16**). Aluminum smelting at Tiwai Point is a strong example of an energy intensive industry which can competitively operate in New Zealand, with Tiwai's PPA to 2044 an indicator of the operator's long-term interest in New Zealand. Growth could come through the reopening of potline 4 which was shut down in 2020. The line would add 9% to annual production, 25 full time jobs and $100m in annual exports, while requiring 50MW of additional power.[26]

Exhibit 16: Examples of fast-growing, existing and potential future energy-intensive industries

| | Energy-intensive industry | Consistent energy needs[1] | 2025 global market ($b) | CAGR to 2030 | Industry trends |
|---|---|---|---|---|---|
| Growing industries | Data centres | ✓ | 575 | 12% | • Rapidly growing industry to support digital services and AI<br>• $8t global investment expected to 2030<br>• Developers, particularly hyperscalers, seeking consistent renewable energy |
| Existing industries | Steel | | 3,250 | 4% | • Mills converting from coal-fueled to electric-arc furnaces to decarbonise, shifting energy demands to renewable electricity<br>• New Zealand's Glenbrook Steel Mill commissioning electric-arc furnaces in 2026 |
| | Aluminium | ✓ | 400 | 5% | • Global demand increasing for green aluminium, powered by renewable electricity<br>• Tiwai smelter secured renewable PPA to 2044 |
| | Dairy (powder) | | 60 | 3% | • Global demand is forecast to grow modestly<br>• Electrifying dehydration heat processes are underpinning the sector's future energy security and cost-competitiveness |
| Potential future industries | Sustainable aviation fuels | ✓ | 2.5 | 60% | • E-kerosene emerging as long-term, scalable solution<br>• Production process is highly energy intensive<br>• Renewable energy essential for emissions-reduction |
| | Green hydrogen | | - | - | • Increasing demand for green hydrogen as feedstock for chemicals, e-fuels, etc. to support decarbonisation<br>• Electrolysis production process, highly energy intensive<br>• Renewables essential for emissions reduction<br>• Emerging market potential in short/medium term |
| | Direct air capture | ✓ | - | - | • Process to extract $CO_2$ directly from air; feedstock for e-fuels, chemicals<br>• Energy intensive; renewables essential for emissions reduction<br>• Emerging market potential in the medium term |

1. Refers to industries with 24/7 energy needs, with low-ability to flex demand intra-daily to support grid balancing via demand response
Source: Market reports, desktop research, BCG analysis

26 Newsroom, Tiwai Smelter Testing Gentailers' Appetite for a New Renewable Project, 2025

Such industries could also help New Zealand build economic ecosystems, as highlighted in the BCG report, 'The Future of NZ Inc: What will New Zealand be known for in 2050?'.[27] A Green Tech ecosystem is particularly well-positioned to leverage New Zealand's energy sector, with strong potential in energy-intensive industries such as data centres and sustainable fuels.

**Beyond energy, New Zealand has complementary advantages to attract investment**

In addition to energy, New Zealand has a series of complementary advantages that increase the country's right to win. New Zealand is a stable, democratic nation with strong private property rights and rule-of-law. The business environment is underpinned by open, free-markets, and strong international relations, including CPTPP membership and free-trade agreements with the EU and China. These factors, when coupled with affordable and secure energy, give New Zealand a compelling value proposition for energy-intensive industry investment to drive future economic growth.

**To truly unlock a renewed competitive advantage in abundant, firmed renewable energy, the sector must adopt an energy abundance mindset for the future**

New Zealand's energy resources position it to deliver low-cost, low-carbon and scalable energy, with the ability to meet a range of energy-intensive industrial needs. This presents a significant opportunity to attract emerging industries to the country and grow existing industries – underpinning a new wave of sustainable economic growth.

But this opportunity is not guaranteed. Realising it will require the sector to adopt and embrace an **energy abundance mindset** to overcome the imminent challenges outlined in this report. Without abundance as the driving force, New Zealand risks a deficit-driven transition, with constrained supply limiting industrial growth and future economic opportunities. The sector could lose its public license to expand energy-intensive industries if they were perceived to come at the expense of affordable energy for the consumer.

Embracing an abundance mindset will require the whole sector to align – including generators, transmission and distribution operators, retailers, innovators, policymakers, regulators, financiers, consenting authorities, and central and local government. With proactive planning and investment in new generation and infrastructure to attract and stimulate demand, New Zealand's energy abundance can become a foundation for long-term economic growth.

27 BCG, Future of NZ Inc: What Will New Zealand Be Known for in 2050?, 2025

## Featured economic opportunity: Data centres

*up to*

**$70b**

*economic opportunity for New Zealand to 2035*

**Energy unlocks the data centre opportunity**

*New Zealand's firmed renewables, particularly geothermal, are well-suited to data centre energy needs*

**$1** *of direct energy generation investment* → *unlocks* → **$16** *of economic impact over ten years*

*up to*

**3.5TWh**

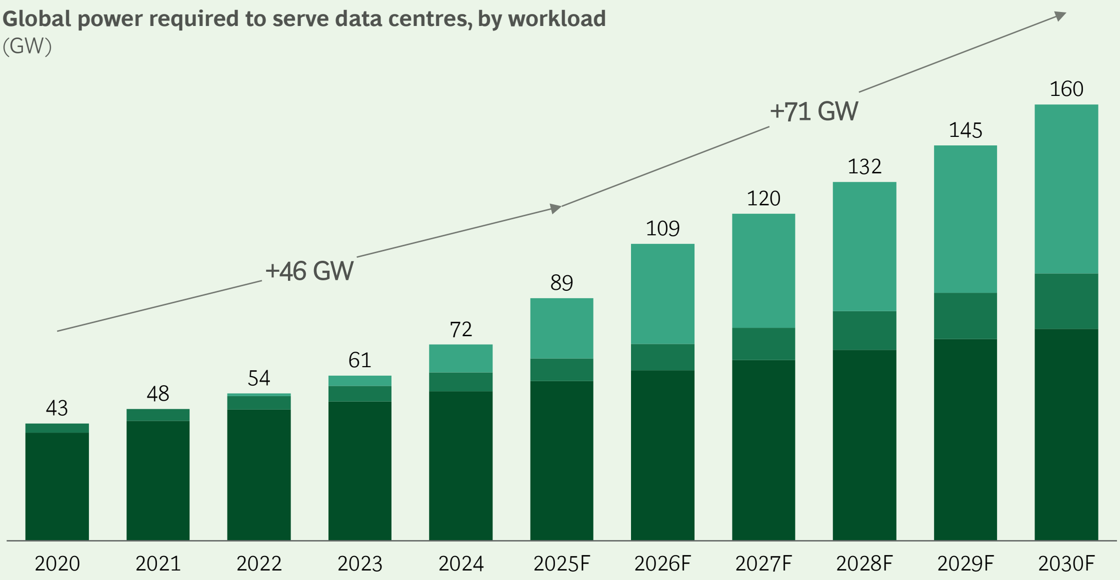
*electricity demand increase to 2035*

### The global data centre market has exploded and is expected to grow rapidly

Data centres are the core infrastructure that underpin the technologically-driven world we live in. As people and businesses increase their reliance on technology and GenAI, demand for data centres is growing rapidly. The global market doubled in size from 2020 to 2025 and is expected to nearly double again to 2030. GenAI workloads are driving the majority of demand growth for computing power and significant energy requirements (see **Exhibit 17**).

### Exhibit 17: Global data centre market power demand estimate and forecast

**Global power required to serve data centres, by workload**
(GW)




| Workload segment | CAGR (%) (2020–2025) | CAGR (%) (2025–2030) |
| --- | --- | --- |
| Overall market | 15 | 12 |
| GenAI | - | 35 |
| Other AI + HPC | 19 | 20 |
| Traditional enterprise | 8 | 6 |

Note: CAGR = compound annual growth rate
Source: BCG Global Data Centre model, BCG analysis

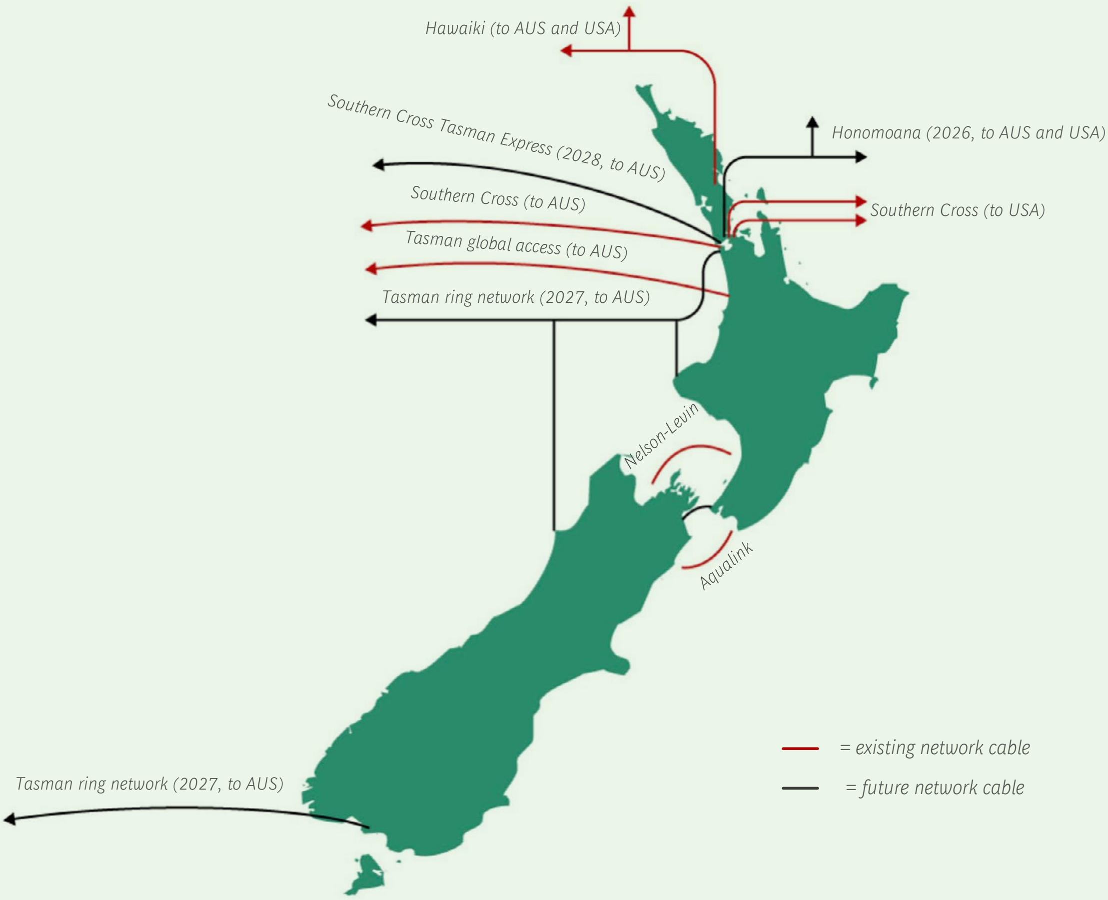
### New Zealand's data centre market is small but growing and can accelerate its growth by winning global workloads

New Zealand's data centre market is small, with approximately 125 MW of existing data centre capacity primarily serving local enterprise needs.[28] The market has roughly doubled in size since 2020, primarily driven by regional co-location data centre developers such as CDC and cloud providers such as Microsoft launching New Zealand 'availability zones.' This growth focused on serving domestic workloads, and is set to continue, with 125–175 MW of further capacity expected by 2030.[29]

Traditionally, latency sensitivity has made the proximity of a data centre to its users critical, meaning New Zealand's data centres have primarily served domestic workloads.[30] However, a growing proportion of new workloads globally are not latency-sensitive, particularly in training large AI models – opening a significant new global market, accessible to New Zealand.

New Zealand is well-connected to global network infrastructure to support these international workloads, with ongoing investments in sub-sea cables further enhancing international connectivity (see **Exhibit 18**). Sub-sea cables connect directly to the USA and Australia, and then continue to south-east Asia and the wider global network.

## Exhibit 18: Sub-sea international fibre-optic network infrastructure in New Zealand




Note: Destinations listed are the first main location the cable connects to, before connecting into wider global network. Some cables also connect to small island states before listed destinations
Source: Submarine Cable Map

28 NZTech, Empowering Aotearoa New Zealand's Digital Future, 2025; UBS, Spark New Zealand Analyst Report, 2025

29 NZTech, Empowering Aotearoa New Zealand's Digital Future, 2025; UBS, Spark New Zealand Analyst Report, 2025; BCG

30 Latency – the time it takes to receive a response to a request. This depends on how well-connected the system network is and how far the signal has to travel (e.g. from user to data centre, and back).

**With its energy advantages, New Zealand is well positioned to serve data centres**

Low-cost, reliable, low-carbon and scalable electricity supply aligns well to data centre requirements. New Zealand's geothermal and dispatchable hydropower generation are particularly well suited, as data centre operators are increasingly seeking renewables to meet emissions reduction targets while running their centres 24/7. Hyperscalers such as Google, Microsoft and AWS, all have 100% renewable energy targets for their data centres by 2030.[31] And regional co-location developers such as CDC are already 100% renewable-energy certified.[32]

Beyond energy, data security and sovereignty also drive locality decisions, as data centres often house highly sensitive information. As a stable democracy with strong data sovereignty laws and an abundance of renewable energy potential, New Zealand is well positioned to serve these trends and capture global market share.

**Capturing just 2% of APAC workloads would be a step change for New Zealand's data centre and electricity industries**

Demand for data centre power for GenAI workloads without strict latency requirements is expected to grow by 39 GW globally to 2030, with 6 GW across the Asia-Pacific (APAC) region, excluding China.[33] Countries are already seeking data centre capacity beyond their borders: Singapore's data centre growth is constrained by land and energy supply, which led to a moratorium on development between 2019–2022.[34] Now it has a competitive bid process in place to manage scarce land, water and energy, which limits possible domestic development.[35] Similarly, Australian developers are seeking cost-competitive renewable energy to offset local reliance on thermal generation.[36]

If New Zealand were to capture just 2% of this APAC growth, its data centre market could expand IT power demand by 120 MW to 2030, and 300 MW to 2035. When underlying domestic market growth is added, total new capacity to 2035 will be 600MW. This would translate to total incremental electricity demand increases of up to 1.5 TWh to 2030, and up to 3.5 TWh to 2035, including both domestic and export demand. This could be supported by 15–20% of New Zealand's untapped conventional geothermal generation potential.[37]

**Developing renewable energy generation to serve a local data centre industry could drive significant wider economic activity**

Energy supply is the constraining factor on growing a local data centre industry. It is essential that New Zealand adopts an energy abundance approach – investing in energy supply and infrastructure to unlock wider economic impact.

Every $1 invested in new renewable energy generation to support data centres unlocks around $13-18 of economic impact over ten years (see **Exhibit 19**). This includes direct investment in new generation, data centre construction and IT fit-out, ongoing maintenance, management and operations, energy expenditure, and the indirect effects flowing through the upstream supply chain resulting from direct spending.

31 Microsoft, Sustainability, 2025; Google, Sustainability, 2025; AWS, Sustainability, 2025

32 CDC, Stable Planet, 2025

33 BCG global data centre model

34 Economic Development Board, Singapore Pilots Sustainable Way To Grow Data Centre Capacity, 2022

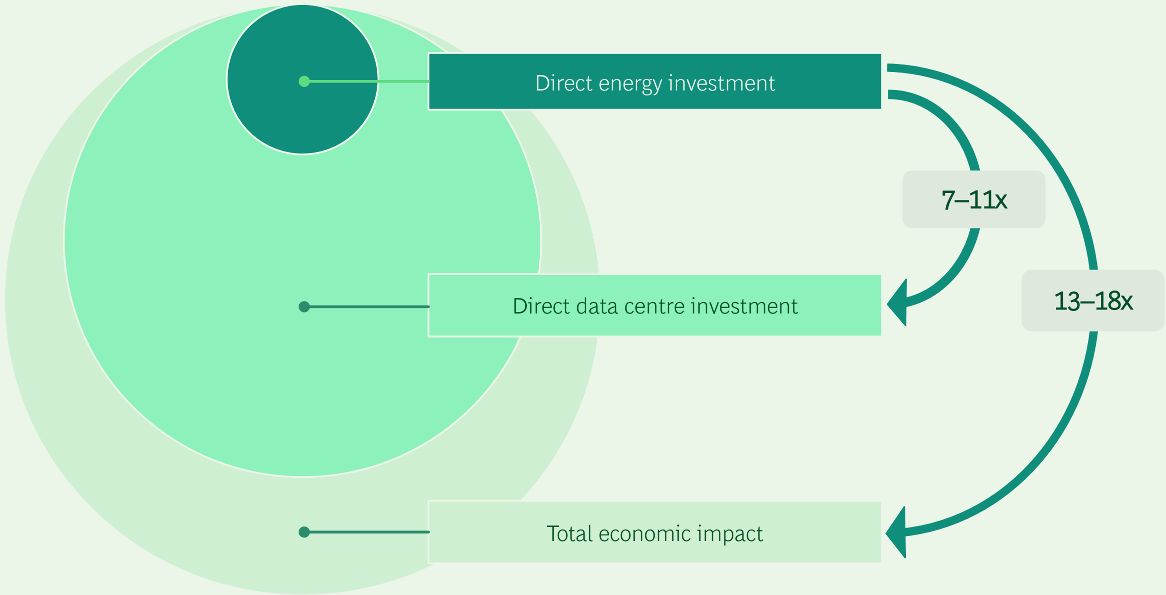
35 Economic Development Board, EDB & IMDA Launch Pilot DC-CFA Exercise, 2022

36 Data Center Dynamics, DCI Completes First Data Center in Auckland, 2023; Rider Levitt Bucknall, Two Hyperscale CDC Data Centres, 2022; NextDC, AK1 New Zealand Data Centre, 2025

37 IEA Geothermal, New Zealand, 2024

Exhibit 19: Economic impact of energy investment to support data centres

**Economic impact of investment in energy generation to support a data centre**
(10-year period)




If New Zealand attracted 2% of the APAC market, in addition to underlying domestic market growth, this would translate to 600 MW of data centre capacity build and present an **economic opportunity of up to $70 billion to 2035** including direct and upstream impacts (see **Exhibit 20**).

## Exhibit 20: Ten-year economic impact resulting from 600 MW of data centre development

**Illustrating the economic impact of direct energy investment to support 600 MW of data centre development, to 2035**

| | |
|---|---|
| **Energy investment** | |
| 3.5 TWh system generation uplift[3] | |
| **CAPEX** | |
| Construction | $4.3–5.3b [1] |
| Indirect upstream supply chain impact (additional supply chain activity triggered by direct project spending, including materials, manufacturing, professional services, logistics etc.) | $6.7–8.2b [2] |
| Total direct investment | $4.3–5.3b |
| Total indirect economic impact | $6.7–8.2b |

| | |
|---|---|
| **Data centre investment** | |
| 600MW of data centre capacity *requiring 3.5TWh of energy per year*[3] | |
| **CAPEX** | |
| Construction | $8.6–11.4b [4] |
| Indirect upstream supply chain impact (additional supply chain activity triggered by direct project spending, including materials, manufacturing, professional services, logistics etc.) | $5.9–7.9b [2] |
| IT equipment (typically replaced every 6 years) | $8.2–13.6b [5] |
| **OPEX** | |
| General maintenance (general facility and mechanical maintenance) | $6.0–7.6b [6] |
| Indirect upstream supply chain impact (additional supply chain activity triggered by direct maintenance spending, including materials, manufacturing, professional services, logistics etc.) | $4.4–5.6b [2] |
| IT equipment maintenance (maintenance and repairs of servers and network infrastructure) | $2.4–4.1b [7] |
| Indirect upstream supply chain impact (additional supply chain activity triggered by direct maintenance spending, including contractors, professional services, logistics etc.) | $1.2–1.9b [2] |
| Energy | $1.7–2.4b [8] |
| Indirect upstream supply chain impact (additional supply chain activity triggered by energy opex spending, including transmission, maintenance, professional services, logistics etc.) | $1.2–1.8b [2] |
| Total direct investment | $26.9–39.1b |
| Total indirect economic impact | $12.7–17.2b |

| | |
|---|---|
| **Total 10-year economic impact** | $50.6–69.8b |

1. Average $/MW CAPEX spend for NZ 2020–2025 generation developments; 2. Indirect impact multipliers derived from Statistics NZ I-O tables, weighted to domestic-only spend; 3. Assumes average IT uptime load factor = 0.62, PUE = 1.2, occupancy factor = 0.9; 4. Benchmarked $/MW CAPEX spend for NZ developments (Cushman and Wakefield, Turner and Townsend); 5. Assumes CAPEX benchmark of $15m–26m/MW, six-year replacement cycle, CAPEX amortised over replacement period; 6. Assumes annual maintenance and management OPEX benchmark of $1.9m-2.4m/MW/yr; 7. Assumes annual maintenance OPEX at 5% of IT CAPEX p.a.; 8. Assumes $90-120/MWh PPA energy cost

Note: Assumes all IT equipment imported and excluded from domestic indirect impacts. Assumes data centre capacity incrementally built to 2035 aligning to BCG forecasts. Assumes two-year construction period + remaining to 2035 operational. Induced economic impacts are not considered.

Source: Gartner, The Datacenter as a Computer: Designing Warehouse-Scale Machines, Cushman and Wakefield, Statistics NZ, desktop research, expert interviews, BCG Global Data Centre model, BCG analysis

Beyond the direct and upstream supply chain impacts of investment, data centres have significant downstream economic value in supporting the growth of New Zealand businesses. Digital services now act as the backbone to many different industries – data centres are central infrastructure for these services.

Data centres have the potential to support emerging economic ecosystems, as outlined in the BCG report, 'NZ Inc: What will New Zealand be known for in 2050?'.[38] **Table 1** outlines some sample use cases for data centres across proposed ecosystems.

Table 1: Data centres can provide the infrastructure digital services to support New Zealand economic ecosystems

| Ecosystem | Description | Example data centre use cases |
|---|---|---|
| Agriculture 4.0 | Supporting more sustainable and efficient food production | • Geospatial analytics<br>• Autonomous machinery<br>• Livestock and carbon monitoring |
| Space and satellites | Designing and manufacturing componentry, launch vehicles and satellites | • Space imaging<br>• Satellite fleet operations<br>• Orbit monitoring |
| Green tech | Developing new technologies and expertise to support the global energy transition | • Energy grid optimisation<br>• Asset management and maintenance prediction<br>• Climate modelling |
| Future of medicine | Improving medical outcomes with new practices, pharmaceutical discoveries, health IT advances and novel medical devices | • AI and machine learning for imagery and diagnoses<br>• Software development supporting novel medical devices<br>• Virtual and AI-supported care models |
| Creative industries | Leveraging New Zealand's unique talents and expertise to produce new content, products and experiences for the world | • Film processing<br>• Animation and CGI<br>• Game development and hosting |

38 BCG, Future of NZ Inc: What Will New Zealand Be Known for in 2050?, 2025

# 4 New Zealand energy sector overview and outlook

This section provides an overview of the electricity and gas industries today, and assesses the performance of New Zealand's energy sector across the energy trilemma – affordability, security and sustainability. It provides a set of facts and frames the challenges across the energy sector to inform future energy pathways and recommendations in later sections.

## 4.1 Electricity industry overview and outlook

New Zealand's electricity industry is growing to meet increasing demand and maintain and improve energy outcomes. Electricity is the primary source of energy for most households and businesses and is critical for enabling economic activity across the country.

The industry is designed to deliver affordable, reliable and sustainable electricity, but is now at an inflection point. After 15 years of flat total demand, the system is entering a period of growth driven by industry and transport electrification, and an emerging energy-intensive data centre industry.

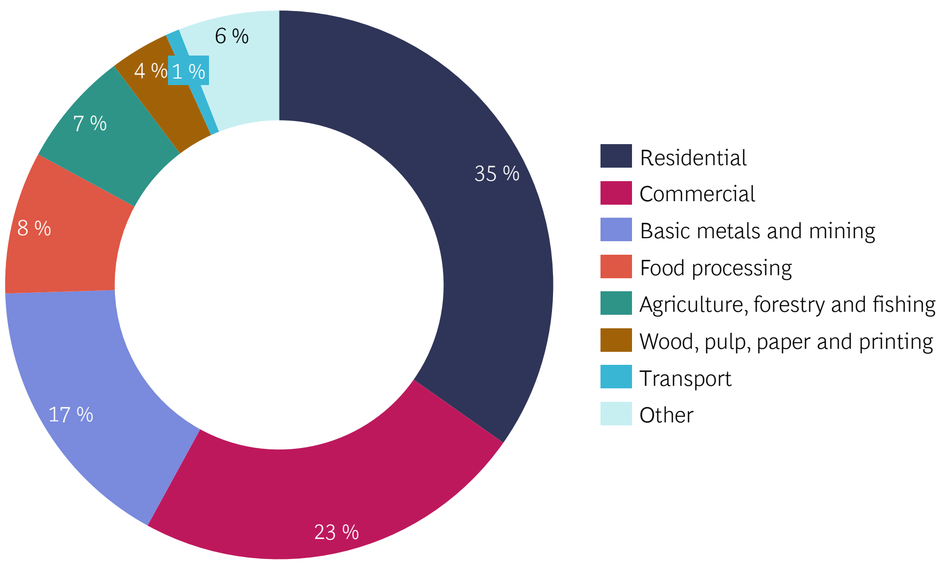
There is momentum in renewable generation development, with over 4 TWh of net generation added in recent years – equivalent to 10% of 2024 total demand. These developments have supported displacing ageing thermal plants through a period of flat demand. Development momentum will need to be maintained to meet increasing demand, and to ensure and improve energy outcomes.

### 4.1.1 Electricity usage and generation mix today

In 2024, New Zealand consumed 40.3 TWh of electricity across all major user groups.[39] Households used 35%, offices and commercial premises used 23%, energy-intensive industries used 36%, and the balance was used across transport and others (see **Exhibit 21**).

Exhibit 21: Electricity demand by major users, 2024

**Share of electricity demand, by major users**
(% of total demand, 2024)




Note: 2024 Basic Metals and Mining net demand and total demand uplifted by 0.3TWh to offset atypical Tiwai demand response
Source: MBIE, BCG Analysis

39 Note: Actual demand = 40.0 TWh; 0.3 TWh added to offset atypical Tiwai aluminium smelter demand response in 2024

### Total electricity demand was effectively flat over the past 15 years, despite significant economic and population growth

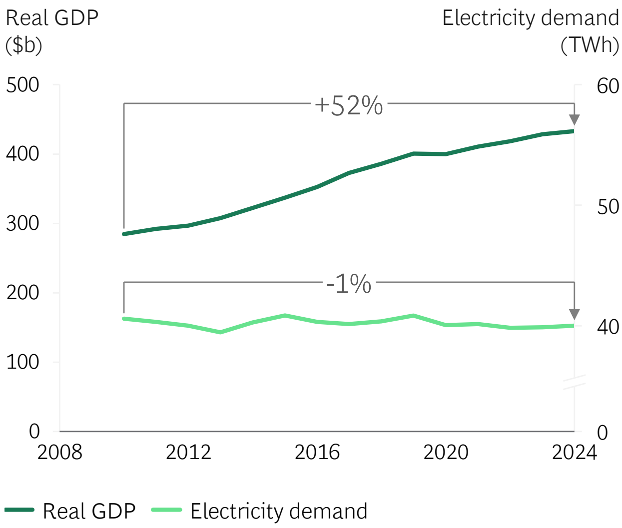
Despite national electricity demand remaining effectively flat over 15 years, the economy grew by 52% (see **Exhibit 22**), and New Zealand's population grew by 23%.[40] This reflects two trends:

- **A shifting economic mix:** Service industries with relatively low energy demands grew significantly, while a small number of energy-intensive industries reduced or closed operations.
- **Increasing energy efficiency:** Households and businesses adopted more efficient heating, lighting and appliances, with the average household reducing their annual electricity consumption by 8–10% over 15 years.[41]

Analysis of the internal dynamics of electricity demand over the last 15 years reveals a changing economic mix. Residential consumption increased with population growth, partly offset by modest efficiency gains. The electrification of industrial process heat applications, particularly in the food processing and agriculture industries, and the uptake of electric vehicles, caused upticks in electricity consumption. However, these were largely offset by industrial decline in the pulp and paper industry, and modest reductions in metals production (see **Exhibit 23**).

Exhibit 22: Electricity demand and real GDP, 2010–2024

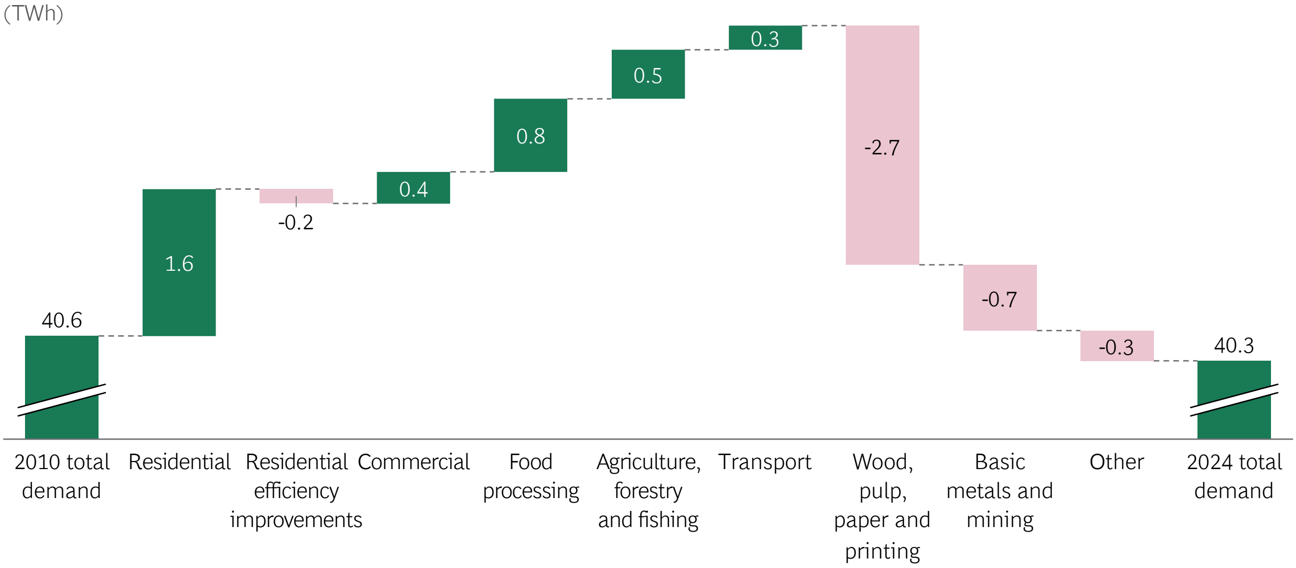
**Real GDP and total electricity demand, 2010–2024**




Source: Statistics NZ, RBNZ, MBIE

Exhibit 23: Electricity demand changes by major users, 2010–2024

**Change in electricity demand profile, 2010–2024**
(TWh)




Note: 2024 basic metals net demand and total demand uplifted by 0.3TWh to offset atypical Tiwai demand response
Source: MBIE, Electricity Authority, BCG Analysis

40 Statistics New Zealand, Population, 2025

41 Statistics New Zealand, MBIE, BCG analysis

**The electricity generation mix has evolved as new renewables have been commissioned**

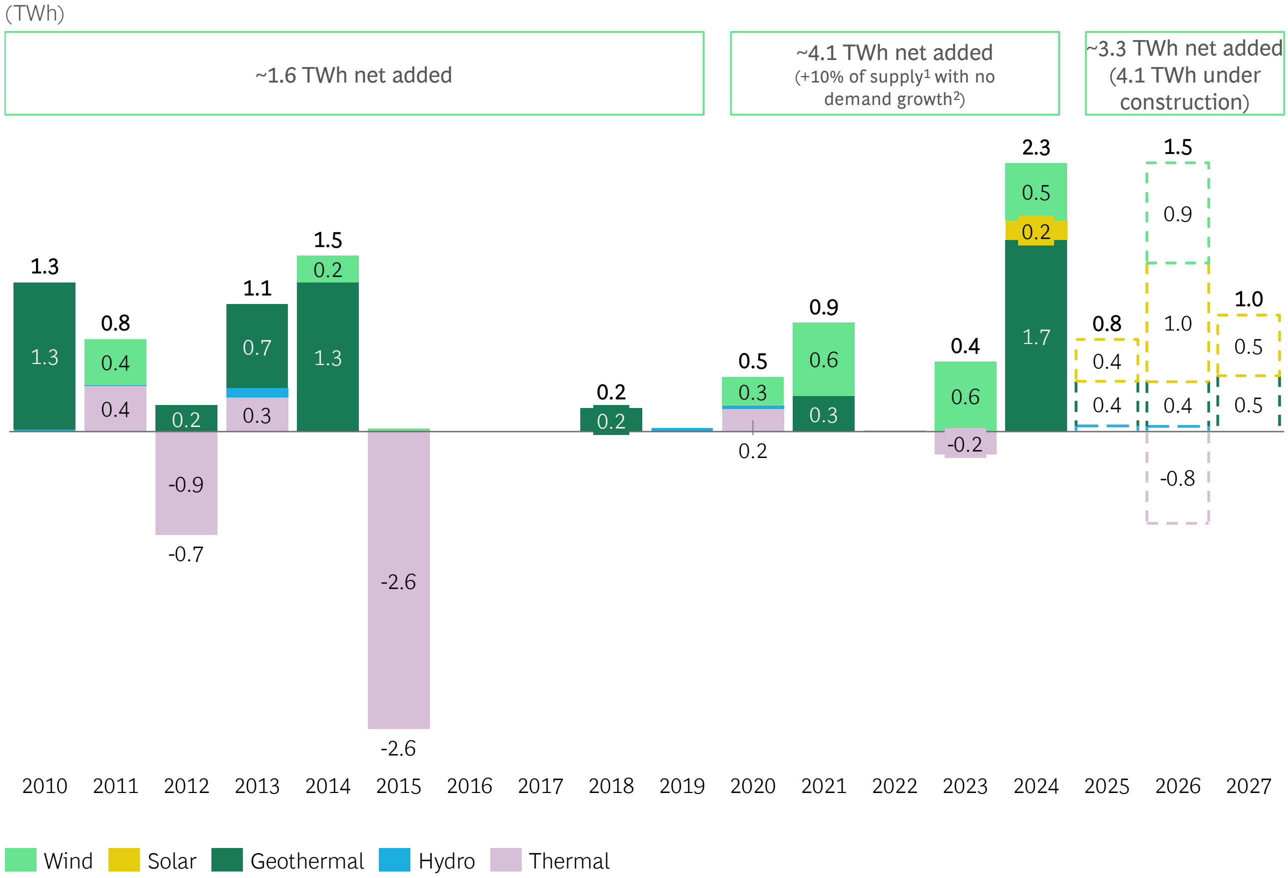
While demand has been relatively flat over the past 15 years, New Zealand's electricity supply mix has changed. Several new renewable generation plants have been commissioned over the last five years, adding a net 4.1 TWh of generation or equivalent to 10% of annual supply. Major projects included Kaiwera Downs Stage 1 (0.1 TWh) and Turitea (0.4 TWh) wind farms commissioned in 2023, and Harapaki wind farm (0.5 TWh), Tauhara geothermal (1.4 TWh), and Te Huka Stage 3 geothermal (0.4 TWh) commissioned in 2024. From 2010 to 2019, 4.9 TWh of new, primarily renewable generation was commissioned.

Given flat demand over this 15-year period, new renewables have replaced thermal generation, with the decommissioning of ageing thermal units including the Otahuhu and Southdown gas-fuelled plants.

The renewable build-out is set to continue, with a further 4.1 TWh of generation either consented or under construction and expected to come online by 2027 (see **Exhibit 24**). Renewables are being developed 25% faster than during New Zealand's 'Think Big' era of large-scale hydroelectric developments in the 1970s.

Exhibit 24: Generation commissioned and decommissioned between 2010 and 2025, and forecast to 2027

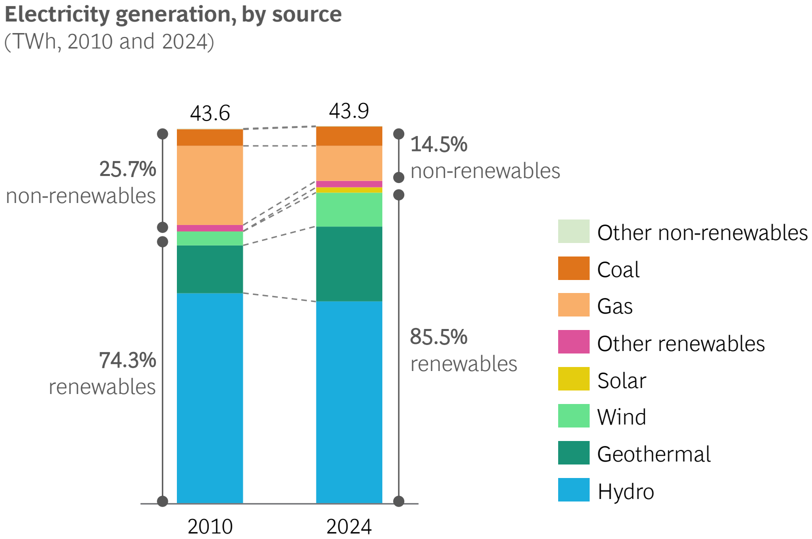
**Generation commissioned and decommissioned 2010–2027**
(TWh)




1. 10% of the total electricity supply of 44.0 TWh in 2024 2. Demand was 39.6 TWh in 2024 down 0.9 TWh from 2015 when it was 40.3 TWh
Note: Figures may not add due to rounding; Assumes Taranaki Combined Cycle (TCC) closure in 2026
Source: Concept Consulting; Transpower; BCG Analysis

New Zealand's total generation mix is becoming increasingly renewable. Total renewable generation increased from 74.3% in 2010 to 85.5% in 2024 (see **Exhibit 25**), down from a peak of 88.1% in 2023 due to the dry year in 2024.

Exhibit 25: New Zealand total electricity generation by source, 2010 and 2024




Note: Hydro generation in 2024 was lower than in a typical hydrological year
Source: MBIE

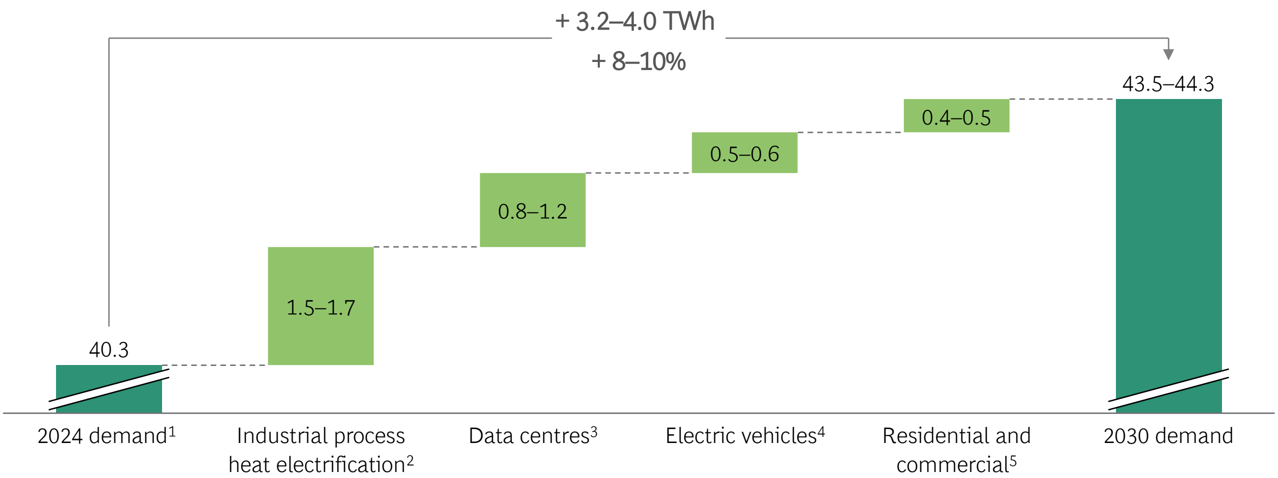
### 4.1.2 Electricity use in the future

**Electricity demand is expected to increase, driven by the electrification of industry and transport, the expansion of data centres and residential and commercial growth**

Total national annual electricity demand is expected to increase by 3.2–4.0 TWh, or 8–10% to 2030. This is a significant shift after 15 years of flat national demand. Drivers of growth include: i. the electrification of industrial process heat; ii. build-out of new data centres; iii. continued uptake of new electric vehicles; and iv. baseline residential and commercial growth (see **Exhibit 26**).

Exhibit 26: Key drivers of electricity demand growth, 2025–2030

**Electricity demand growth drivers**
(TWh, 2025–2030)




**2024 demand**
- 40.3TWh total electricity demand at in 2024
- Demand effectively flat since 2010

**Industrial process heat electrification**
- Electrification of gas/coal-fueled heat processes
- Key industries include dairy, meat, food, horticulture, metals

**Data centres**
- Existing base of data centres to ramp up capacity
- Several large sites under construction or in pipeline

**Electric vehicles**
- Growth over next five years from 2.8% to 8.4% of light vehicle fleet, including PHEV
- Initial wave of heavy transport electrification

**Residential and commercial**
- Core demand growth among households and commercial users
- Household and commercial fuel switching

**2030 demand**
- Total electricity demand growth expected at 3.2–4.0TWh by 2030
- 8–10% increase on 2024 demand

1. Uplifted by 0.3TWh to offset atypical Tiwai demand response; 2. Driven by process heat fuel switching opportunities identified from RHDD and company announcements, includes cogen switching; 3. Growth based on scaled UBS NZ market forecast and assumed export market from 2028; 4. Concept Consulting forecast; 5. Concept Consulting forecast, including base demand growth and fuel switching
Source: MBIE, Transpower, Climate Change Commission, Ministry of Transport, UBS NZ, EECA RETA and Regional Heat Demand Dashboard, Concept Consulting, BCG analysis

## Industrial process heat electrification

Industrial users of process heat are significant energy users in New Zealand. Such processes range from heating for drying products (e.g. dairy dehydration), chemical processes (e.g. steelmaking) and timber processing (e.g. pulp and paper production).

The heat for these processes have been from gas and coal historically, but users are increasingly electrifying their process heat operations to reduce emissions and reduce reliance on thermal fuel supply and price volatility. These conversions are expected to increase annual demand for electricity by 1.5–1.7 TWh to 2030 assuming current policy settings (i.e. no support for switching and limited de-industrialisation).

Exhibit 27: Sample of users electrifying process heat operations

| User | Industry | Process | Electrification to 2030 (PJ) | Electrification to 2030 (TWh) |
|---|---|---|---|---|
| Fonterra | Dairy | Dehydrators[1] | 4.8 | 0.8 |
| New Zealand Steel | Steel | High-temperature furnace | 0.9 | 0.3 |
| Other smaller users | Food processing; pulp and paper | Electrode boilers, dryers | 0.7 | 0.1 |

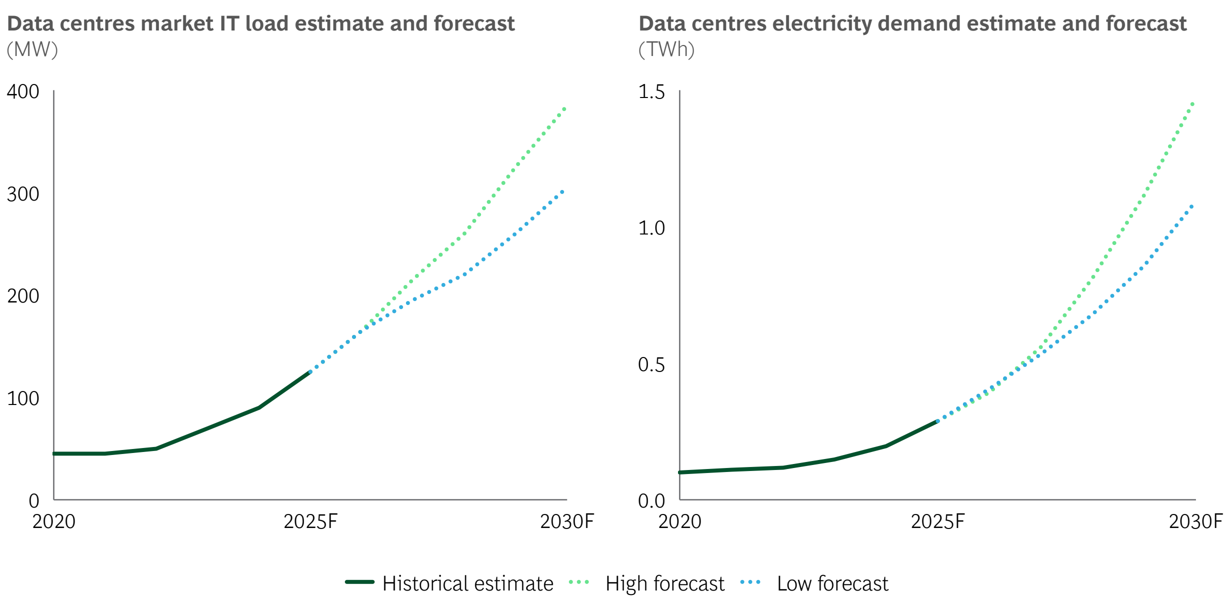
1. Assumes 40% heat pumps and 60% electrode boilers for heat
Source: EECA RETA dashboard, company announcements

## New data centres

Data centres are the core infrastructure behind the digital economy. Demand for their computing power is rapidly increasing, particularly with the uptake of GenAI. New Zealand's data centre market is small but growing, having roughly doubled in size over the last five years – largely driven by regional co-location developers such as CDC and cloud providers such as Microsoft establishing a local presence.

Data centres require significant electricity offtake. As the market continues to expand, annual electricity demand is expected to rise by 0.8–1.2 TWh to 2030 (see **Exhibit 28**).

Exhibit 28: Data centre market IT load and electricity demand estimate and forecast




Assumes pre-2025 OF = 0.8, PUE = 1.4 and LF = 0.25; post-2025 domestic workloads OF = 0.9, PUE = 1.3 and LF = 0.5; and export workloads OF = 0.9, PUE = 1.2 and LF = 0.7
Note: LF = IT load factor, accounting for average uptime; OF = occupancy factor; PUE = power usage effectiveness factor
Source: UBS NZ, NZTech, MBIE, expert interviews, desktop research, BCG analysis

## Uptake of new electric vehicles

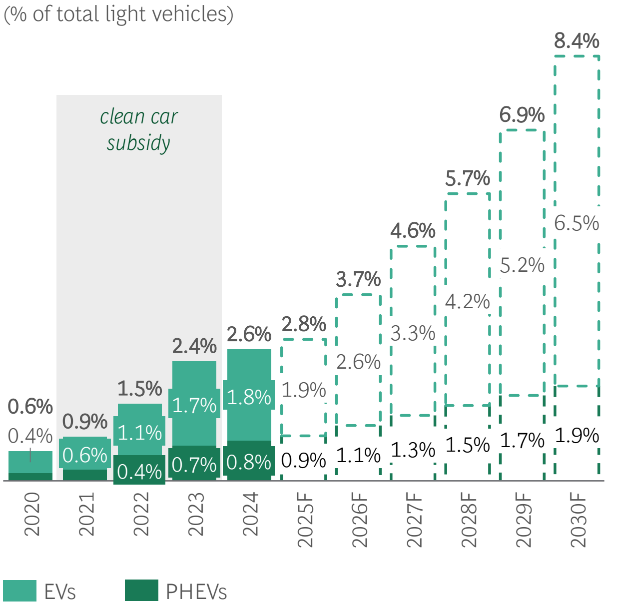
The uptake of electric vehicles has increased rapidly over the last five years, from a small baseline, to now make up 2.8% of the light vehicle fleet (1.9% Battery Electric Vehicles, 0.9% Plug-in Hybrid Electric Vehicles).[42] While the annual sales of electric vehicles have slowed in 2024 since the removal of the clean-car discount in 2023, total annual electricity demand for electric vehicles is expected to increase by 0.5–0.6 TWh to 2030 (see **Exhibit 29**). This includes plug-in hybrid vehicles, which are growing as a share of the fleet, and other electric transport, including heavy vehicles, ferries and trains. Growth rates are assumed to align with similar international markets.

## Base residential and commercial growth

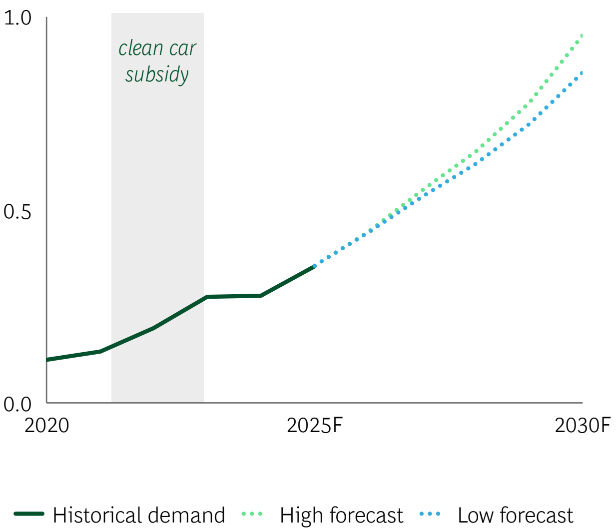
Underlying annual electricity demand from baseline economic activity is expected to increase by 0.4–0.5 TWh to 2030. This reflects increased household demand driven by population growth, and higher commercial demand from the expansion of the non-energy-intensive industries. In addition, some residential and commercial users are expected to switch from thermal-fuelled to electric-powered space and water heating appliances.

### Exhibit 29: Electric vehicles electricity demand forecast

**Proportion of electric vehicles in light vehicle fleet**
(% of total light vehicles)




**Electric vehicles electricity demand forecast**
(TWh)




Note: Forward growth approximated using MBIE Growth scenario, rebased to 2024 fleet statistics
Source: Ministry of Transport, EV Database, MBIE, Concept Consulting, BCG analysis

42 EVBD NZ, EV Dashboard NZ, October 2025

## 4.2 Gas industry overview and outlook

Gas is foundational to New Zealand's energy mix and economy. For decades, ample domestic supply, anchored by large discoveries such as Maui in the late 1960s, supported competitively priced energy and enabled economic growth. Gas underpins a significant amount of industrial activity (process heat and feedstock), and a large installed base means many residential and commercial customers still rely on gas.

In New Zealand's energy sector, gas is the shock absorber that underwrites security of supply for the electricity industry. It provides long-duration, flexible energy for peaks and dry-year cover. Gas-fired generation is the grid's flexible backstop as it quickly meets New Zealand's peaks in demand, compensates for shortfalls in hydropower generation and covers intermittent renewables when they cannot fully meet demand. As New Zealand adds more intermittent renewables, the firming value of gas will rise.

However, the role of gas is now at risk. Since 2015, prices have more than doubled and domestic supply has declined by 50% despite development efforts. Gas supply is expected to halve again in the next five years despite further development to the Tūrangi and Mangahewa fields. This structural gas supply decline is expected to continue, driven by ageing offshore fields such as Maui, Kupe and Pohokura and the transition to a market of limited flexibility, due to the Ahuroa gas storage downgrade and potential exit of Methanex. These factors put pressure on affordability and security of gas, and indirectly the affordability and security of electricity.

**New Zealand's domestic gas supply has declined ~50%** since 2015 despite recent development efforts, with largest field decline in Pohokura

**Gas supply could halve again in the next 5 years** without immediate interventions, increasing both the price of gas and risk of demand destruction for industrial players

**The transition to a market of limited flexibility**, due to the Ahuroa gas storage downgrade and potential Methanex exit, **puts pressure on energy security**

### 4.2.1 Gas supply and market challenges today

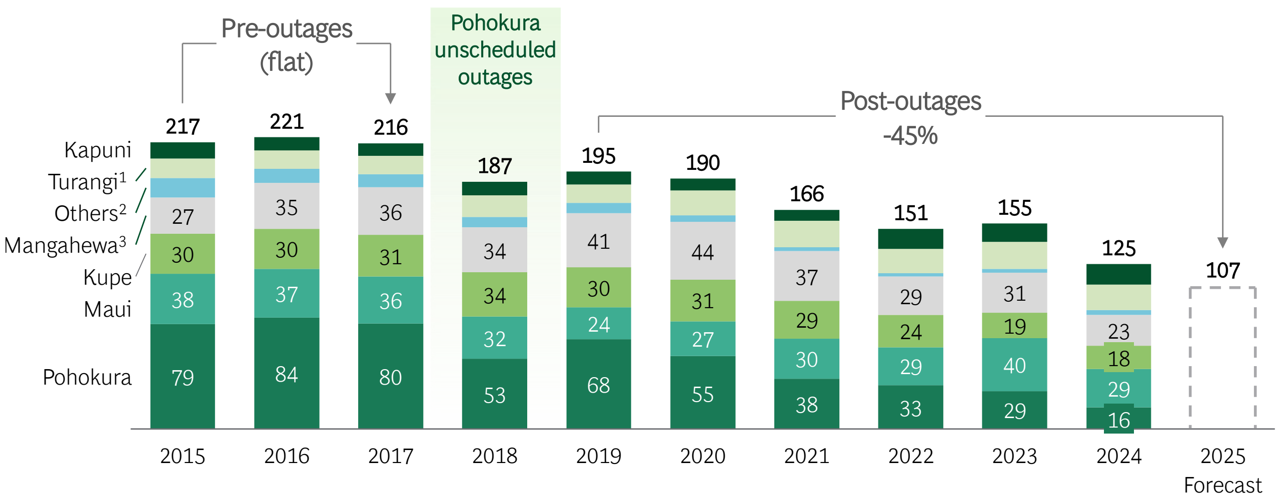
**New Zealand's gas supply is declining**

New Zealand's upstream gas outlook is now defined by ageing and declining reserves. In the last decade, upstream gas supply has declined 50% from 217 PJ in 2015 to a forecast of 107 PJ in 2025 (see **Exhibit 30**). Maui, Pohokura and Kupe together supplied 70% of national gas in 2015 (147 PJ), but today their total production has declined by 65% to a forecast of 50 PJ in 2025 – just 47% of total supply based on the Ministry of Business, Innovation and Employment (MBIE) Producer Forecast. The decline in production of these three fields drove the majority of the 90 PJ under delivery in total gas supply in 2024 versus expectation based on 2022 MBIE Producer Forecast.

The year 2019 marked a turning point, highlighting the effects of ageing reservoirs nearing end of life despite moderate investment. From 2019 to 2024, Pohokura's annual delivery alone fell 75%. Now, most supply comes from a small set of late-life Taranaki fields, increasing system-wide risk.

Exhibit 30: Gas production by field 2015–2024, and 2025 production forecast

**Gross gas production by site and recent production forecast**
(Gross PJ, calendar year)



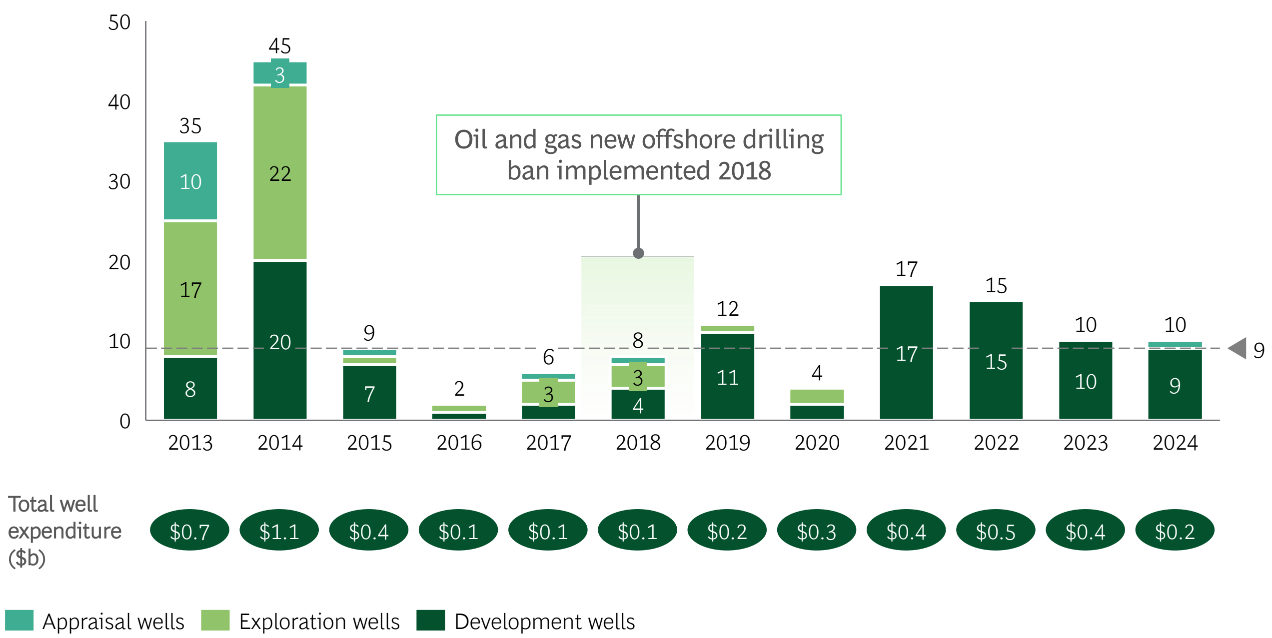

1. Includes Kowhai; 2. 'Others' defined as any site that produced < 10 PJ in 2024; 3. Includes McKee
Source: MBIE Annual Gas Production and Consumption 2025 Q1, MBIE Gas Production Profile (Forecast)

### Efforts to mitigate declining supply are not working and are eroding supply confidence

Operators have spent $1.5 billion drilling over 50 development wells since 2020, which has slowed the decline but not restored deliverability to prior levels or reached the expected uplift (see **Exhibit 31**).

Exhibit 31: Total wells drilled by type, 2015–2024

**Total wells drilled by type (2015–2024)**
(# wells drilled)




Note: Disaggregated data on well drilling not available prior to 2013; thus, showing total aggregate prior to 2013
Source: MBIE Activity Statistics

Most of the gas industry's drilling efforts have been development wells. Development well activity since 2021 has been consistently above the average drilling activity (nine wells per year). However, these development efforts haven't delivered expected results. For example, Kupe's 2024 development campaign was unsuccessful: the KS-9 intervention failed to deliver sustainable flow, capping field output and causing both financial losses and underperformance against target flows.[43]

New Zealand's ban on new offshore exploration permits was introduced in 2018, with only a few existing exploration permits proceeding to drilling in subsequent years. Most of these campaigns, including OMV's 2019–2020 wells, were unsuccessful and subsequently abandoned, with only one minor discovery that was not developed.[44] The reversal of New Zealand's ban on offshore exploration in July 2025 removed a policy constraint, but the investment case for exploration is impacted by demand uncertainty and rising costs. Knowing this, significant focus is needed on disciplined, value-driven development of existing wells. Incremental gas supply is a function of drilling intensity and drilling success; New Zealand needs to concentrate capital on the most productive existing assets and sequence development efforts based on demonstrated results.

***Well type definitions***

***Exploration wells*** *are first penetrations into undrilled prospects and carry the highest geological risk.*

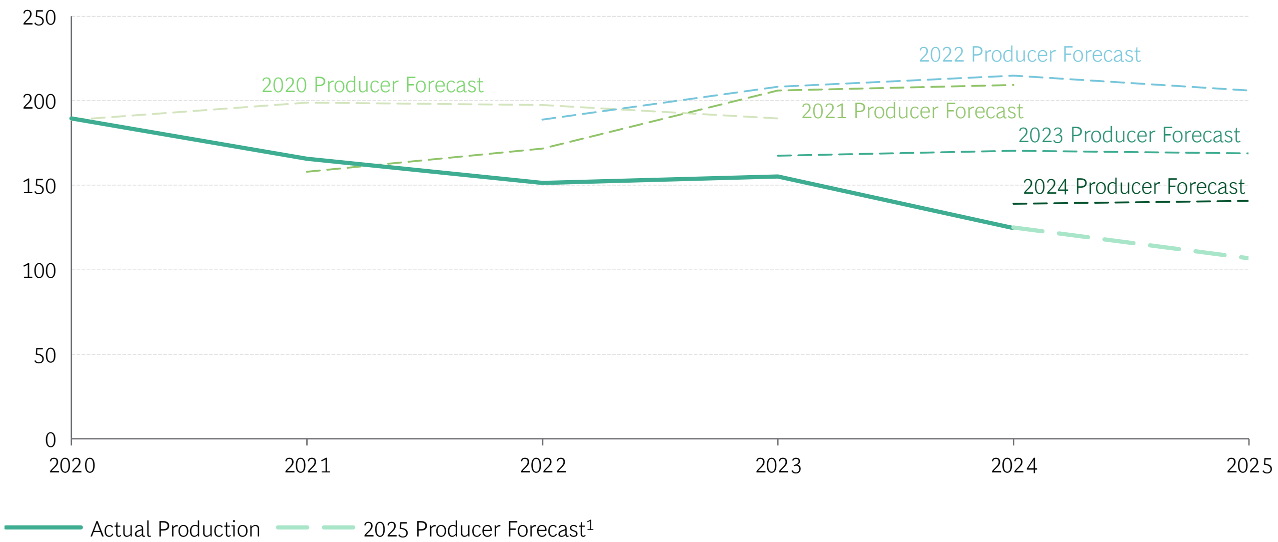
***Appraisal wells*** *identify the size and extent of a gas deposit to guide decisions on whether to establish a development well.*

***Development wells*** *are drilled within approved fields to deliver volumes at scale and manage reservoir performance.*

Drilling efforts have resulted in disappointing outcomes as ageing reservoirs experience reduced well productivity and pressure. As a result, gas production has repeatedly underperformed MBIE Producer Forecasts by 10–20% each year since 2022, eroding confidence and increasing uncertainty across the sector (see **Exhibit 32**).

Exhibit 32: MBIE producer supply forecasts, 2020–2025

**Gas production forecasts**
(Gross PJ, calendar year)




1. MBIE Producer Forecast from 2025 MBIE Gas Production Forecast (as of 1 January 2025)
Source: MBIE Annual Gas Production and Consumption; MBIE Gas Production Profile (Forecast)

43 NZX, Kupe Production Update, 2024

44 New Zealand Petroleum and Minerals, Annual Reports, 2025

### Gas supply has continued to decline into 2025

Performance of H1 2025 confirms the same dynamics: the decline in gas supply is structural and persistent, not a one-off. New Zealand's reliance on a small set of maturing Taranaki fields leaves limited options as over 70% of production came from the top three fields in 2019, and those same fields now account for less than 50% in 2025 (see **Exhibit 33**).

## Exhibit 33: Gas production by big-6 field, H1 2019 versus H1 2025

**Gross gas production delta H1 2019 versus H1 2025**
(Gross PJ)

| | H1 2019 | | H1 2025 | | |
|---|---|---|---|---|---|
| **Site** | **PJ** | **%** | **PJ** | **%** | **PJ delta** |
| A Tūrangi[1] | 7 | 9% | 11 | 23% | 4 |
| Mangahewa[2] | 11 | 15% | 9 | 18% | -3 |
| Kapuni | 4 | 5% | 5 | 11% | 2 |
| B Pohokura | 31 | 41% | 8 | 16% | -23 |
| Maui | 10 | 13% | 9 | 18% | -1 |
| Kupe | 13 | 17% | 7 | 15% | -6 |
| **Total** | **77** | **100%** | **49** | **100%** | **-27** |

A **Onshore sites grew 16%** in production between 2019 and 2025

B **Offshore sites declined 56%** in production between 2019 and 2025

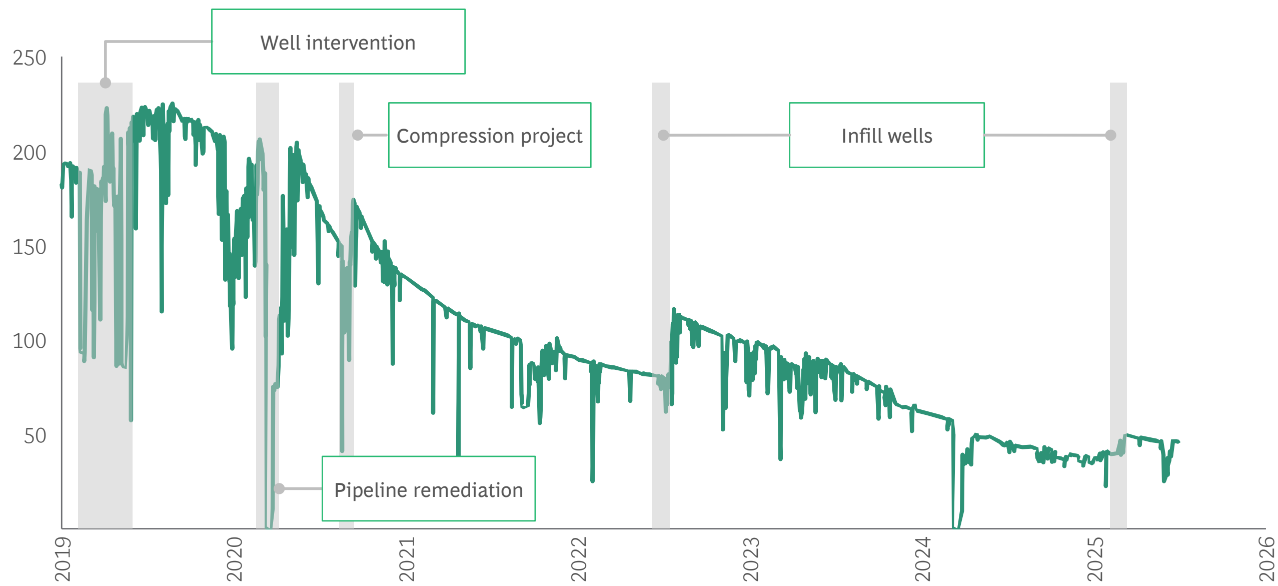
Note: Pohokura categorised as offshore despite having both offshore and onshore operations. Numbers may not add due to rounding
1. Includes Kowhai; 2. Includes McKee
Source: Enerlytica

Much of the legacy base was anchored offshore (Maui, Kupe and Pohokura), where weather, subsea maintenance and platform outages amplify volatility. Pohokura remains the dominant driver of the decline: its share has fallen from 40% of national output in 2019 to 16% in 2025, and of the 27 PJ production drop between H1 2019 and H1 2025, 23 PJ (85%) is attributable to Pohokura alone.

Pohokura interventions have bought time, not growth. Targeted compression, workovers and infill drilling have cushioned the decline but haven't restored deliverability to prior levels. Each project has provided a slight uplift, flattening the decline curve temporarily; however, then performance reverts to similar rate of decline, with no step-change in underlying reservoir productivity. Structural decline is entrenched as daily output has fallen from a 225 TJ peak (2019) to a low 25 TJ in June 2025, a 90% drop as the reservoir matures (see **Exhibit 34**).

Exhibit 34: Daily gas production at Pohokura, Jan 2019–Jun 2025

**Daily Pohokura gas production (Jan 2019 to Jun 2025)**
(TJ)

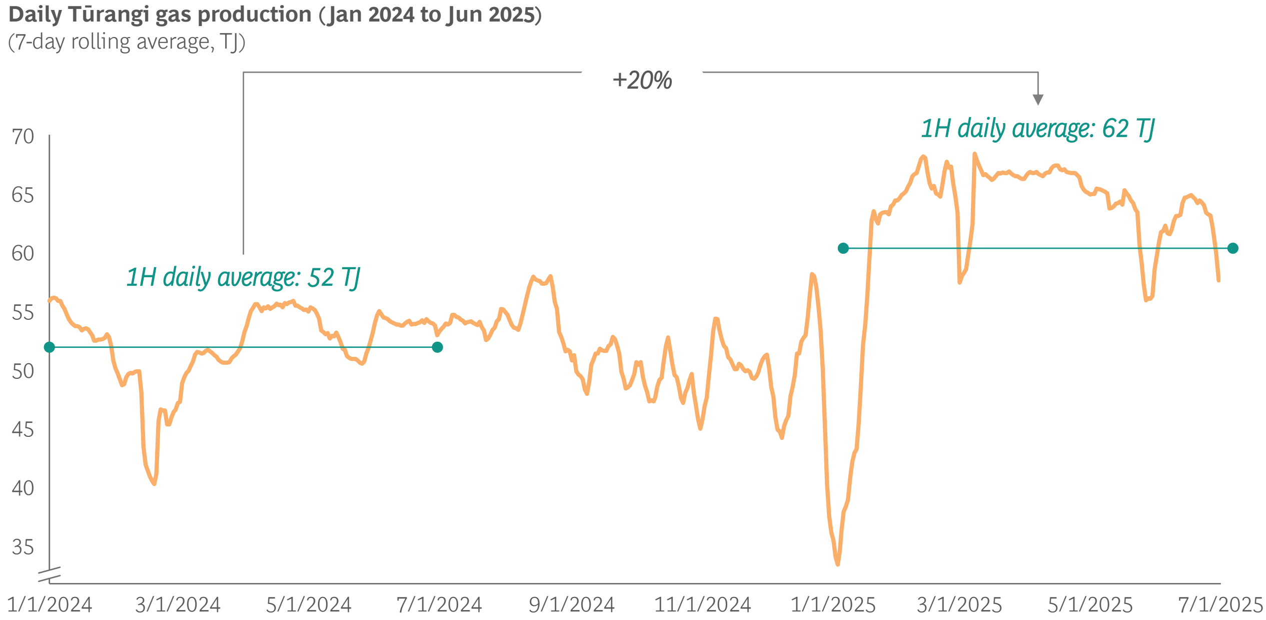



Source: Enerlytica

Despite offshore decline, a handful of onshore developments are providing some encouraging signs with modest but real uplift. Tūrangi is a bright spot, with five wells drilled since 2024, increasing daily delivery by 20% 1H YoY (see **Exhibit 35**).[45] Development drilling across four wells at Mangahewa has met pre-drill expectations and started to show promise as the wells come online in the second half of 2025. The average production for Mangahewa in September 2025 was 62 TJ per day, 7% greater than production in September 2024 (58 TJ per day).[46,47]

While these onshore developments are promising, they don't change the aggregate gas supply outlook as they do not fully backfill losses from larger offshore developments. Despite pockets of optimism, New Zealand's gas market remains in a tough position, with concentration and maturity continuing to shape outcomes.

Exhibit 35: Daily gas production across Tūrangi, January 2024 to June 2025




Source: Enerlytica

45 Enerlytica, NZ Gas Quarterly Forecasts 3Q 2025, 2025

46 Enerlytica, NZ Gas Quarterly Forecasts 3Q 2025, 2025

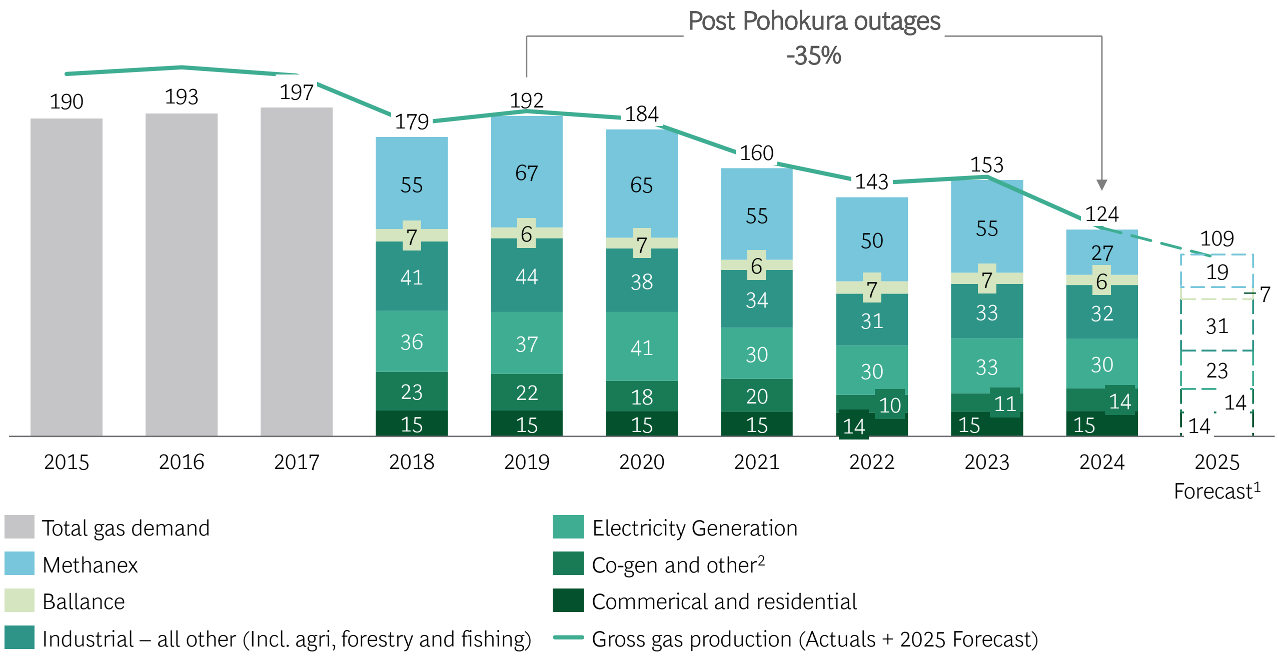
47 GIC, Daily Gas Production by Major Fields, 2025

**Along with tightening gas supply, demand has also declined**

With supply tightening, the risk of undersupply grows. New Zealand's forecast gas supply in 2025 is trending below expected demand by 2 PJ. This growing security risk impacts the investment and operating decisions of gas users, depending on their use profile and flexibility, contracted volumes and the share of gas in their cost base. As a result, demand has declined by 35% from 2019 to 2024 as industry has exited New Zealand or converted their energy (see **Exhibit 36**).

Exhibit 36: Gas demand by user group, 2015–2024

**Total gas demand across major users**
(Gross PJ, calendar year)




Note: Demand breakdown by major users only available 2018 onwards
1. 2025 forecast based on Q1 actuals and extrapolated YoY volume decline, while Methanex and Ballance estimates assume existing day rate remains flat for remainder of 2025 and Ballance temporarily closes for 4 months; 2. 'Other' includes energy transformation (excluding electricity generation), non-energy use (minus Methanex and Ballance feedstock), and stock change
Source: MBIE Annual Gas Production and Consumption 2025 Q1, Gas Industry Co. Consumption

Gas demand is concentrated in industry, with 53% of 2024 consumption in industrial uses (including methanol and urea feedstock), 35% in electricity generation/co-gen/other, and 12% across commercial and residential loads. Commercial and residential demand is stable given the relatively small individual volumes and high willingness to pay for gas as a heating and cooking source. Declining demand has come from industrial curtailment or fuel transition, alongside reduced use of gas by the power sector.

A number of trends are driving declining demand among industry and energy sector users:

- **Methanex:** Methanex is an international methanol producer with a key presence in New Zealand. It is the largest single gas user (primarily for feedstock) and accounted for roughly 36% of gas use in 2023. Methanex has provided key gas flexibility in New Zealand, altering its demand to accommodate the needs of the broader market. The growing decline in domestic supply has caused Methanex to stop operations at its Waitara Valley location in 2021.[48] It now only runs its Motunui location at one train capacity and accounts for only 22% of gas demand in 2024.

48 RNZ, Methanex to Mothball Waitara Valley Plant in Taranaki, 2021

- **Ballance:** Ballance is a key producer of fertiliser in New Zealand, historically operating at a steady baseload using gas mostly for feedstock. However, gas supply uncertainty has forced it into a more variable position. Ballance only recently secured short-term contracts to keep its Kapuni plant running during 2025, highlighting ongoing curtailment risk and exposure to a tight gas market.[49]

- **Industrial process heat:** Industrial players span food, pulp and paper, wood products, chemicals, cement, glass and metals processors that use gas for steam, dryers, kilns and direct-fired heat. Industrial demand has declined over time as players proactively transition to other fuels with the risk of tightening gas supply and subsequent price volatility.

- **Electricity generation:** Gas plays a dual role for electricity generation – historically providing baseload at Huntly and today acting mainly as a fast-start peaking fuel. As renewables scale, baseload demand has fallen, with gas now concentrated on firming during dry years and peak periods. In 2025, electricity-generation gas use is expected to continue declining, with Huntly's dual-fuel rankine units increasingly turning to solid fuels as gas tightens.

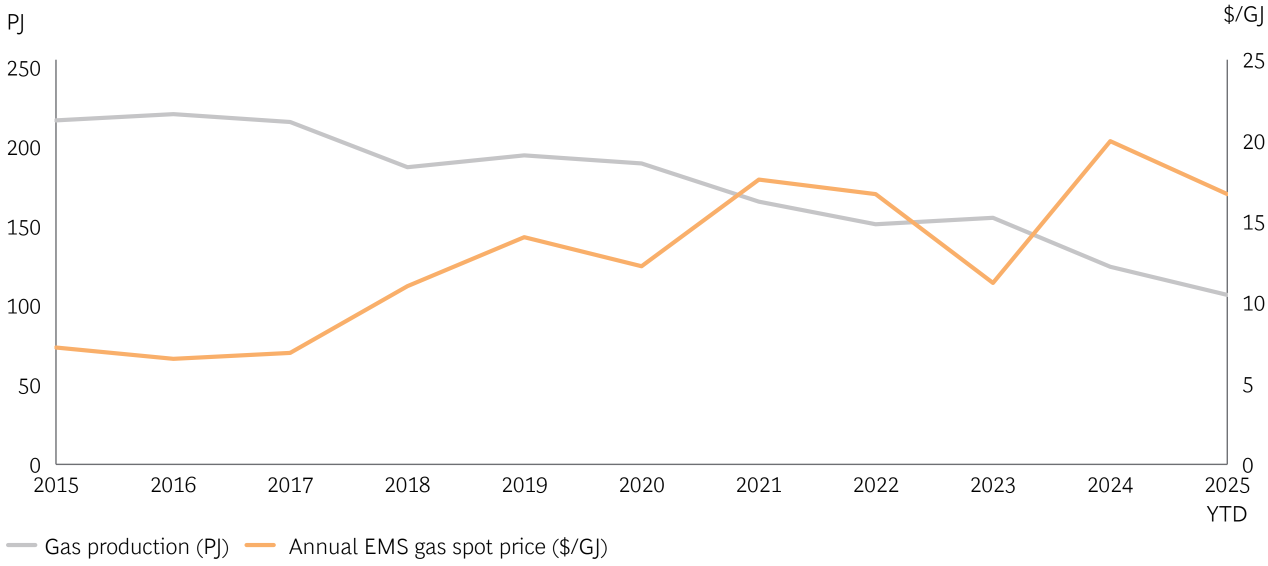
- **Co-generation and other:** Gas traditionally fueled on-site steam and heat via co-generation at large industrial sites. While demand has fluctuated, the transition to electric boilers, heat pumps and biomass is driving a decline going forward. Fonterra is emblematic as it works to shift its onsite co-generation of 5PJ out of gas by 2026.[50]

### Tightening supply elevates gas prices, increases pressure on industrial players and challenges international competitiveness

A structurally tightening market with supply declining faster than expected (dropped 50% since 2015) and limited system flexibility are pushing gas spot prices higher (more than double since 2015) and increasing volatility (i.e. 2024 dry winter impact, knowing pricing increases during dry years are a function of the market) (**Exhibit 37**).

Exhibit 37: Gas production versus average annual gas spot price (including carbon), 2015–2025

**2015 to 2025 YTD gas production versus annual gas spot price**




Note: Gas spot prices inclusive of carbon price and all $ figures in NZ; 2025 gas production set as MBIE producer forecast
Source: MBIE Annual Gas Production and Consumption 2025 Q1, Concept Consulting EMS Gas Spot Prices

49 Farmers Weekly, Ballance Secures Kapuni Gas – For Now, 2025

50 Fonterra, Fonterra Announces Electrification Plans to Future-Proof Operations, 2025

This shift to a scarce gas economy erodes New Zealand's historical competitive advantage and places increasing pressure on key gas transformation players. New Zealand's gas price has rapidly climbed from $7 per GJ in the 2000s to $16–18 per GJ (including carbon) and is on an upwards trajectory.

New Zealand's gas-intensive transformation industries, like methanol and urea production, are losing cost competitiveness as gas supply tightens and prices rise. At those price levels, exported Methanex methanol from New Zealand would struggle to compete with lower-cost producers offshore, and urea produced in New Zealand would no longer be able to compete with the cost of imports. Global methanol players experience gas price ranges between $4–10 per GJ in North America, Caribbean, North Africa and Middle East regions. Meanwhile, global urea commodity players produce with gas prices typically ranging $3–7 per GJ from the Middle East, China, India and North Africa. Additionally, top urea exporters typically charge a price of $800–900 per tonne FOB (free on board) versus $900–970 per tonne from Ballance.[51] In an economy with tight gas supply, any molecule-heavy conversion business (especially methanol and fertiliser) sits on the wrong side of the global cost curve.

These pressures are already visible. Ballance has warned of curtailing its operations in response to feedstock constraints and, on a like-for-like basis, will find it increasingly difficult to compete with global urea suppliers, pointing toward a pragmatic shift to imports. Methanex, while contracted to use New Zealand gas to 2029, faces tightening supply, a 2028 turnaround, potential Maui exit by 2027, elevated price volatility, and benchmark economics that make sustained operation beyond 2028 challenging without a structural change in supply and the cost base.[52],[53],[54]

**Historically Methanex has provided valuable demand flexibility; if it exits New Zealand, the gas market will need that flexibility even more as supply tightens**

For years, New Zealand's energy system has relied on Methanex's demand flexibility to manage winter peaks in national energy demand. During market tightness, Methanex reduces methanol production when gas prices reach $30–40 per GJ, releasing critical gas to the market. With declining domestic gas supply and Methanex's future in New Zealand uncertain, this flexibility is now at risk.

At its peak, Methanex operated three methanol production trains, consuming 245 TJ per day (see **Exhibit 38**). Today it runs only a single train at 60 TJ per day, which is about a 75% reduction in gas consumption compared to its peak. This last train is already operating close to its minimum rate (45–50 TJ per day) – anything below this level and Methanex cannot run or adapt its gas demand, materially reducing the flexibility it once provided.

If Methanex exits, it would remove 60 TJ per day of national gas demand (22 PJ per year, 20% of national demand). This might create a short-lived surplus of gas but would permanently strip the energy system of its primary flexibility.

The system implications of Methanex's exit would be material. The gas system would need to lean on storage, and it does not have enough. Ahuroa, the country's only underground gas store, has shifted from an expected 18 PJ of working capacity to 6–8 PJ after water ingress was identified in 2022. That amounts to a 55–65% loss of gas flexibility, materially shrinking New Zealand's seasonal and dry-year buffer. By global standards 6–8 PJ is not enough capacity, and limits the ability to absorb the surplus gas supply associated with a Methanex exit (60 TJ per day or 22 PJ per year) and cover any unplanned outages.

51 Ballance, Ballance Product Price List, 2025

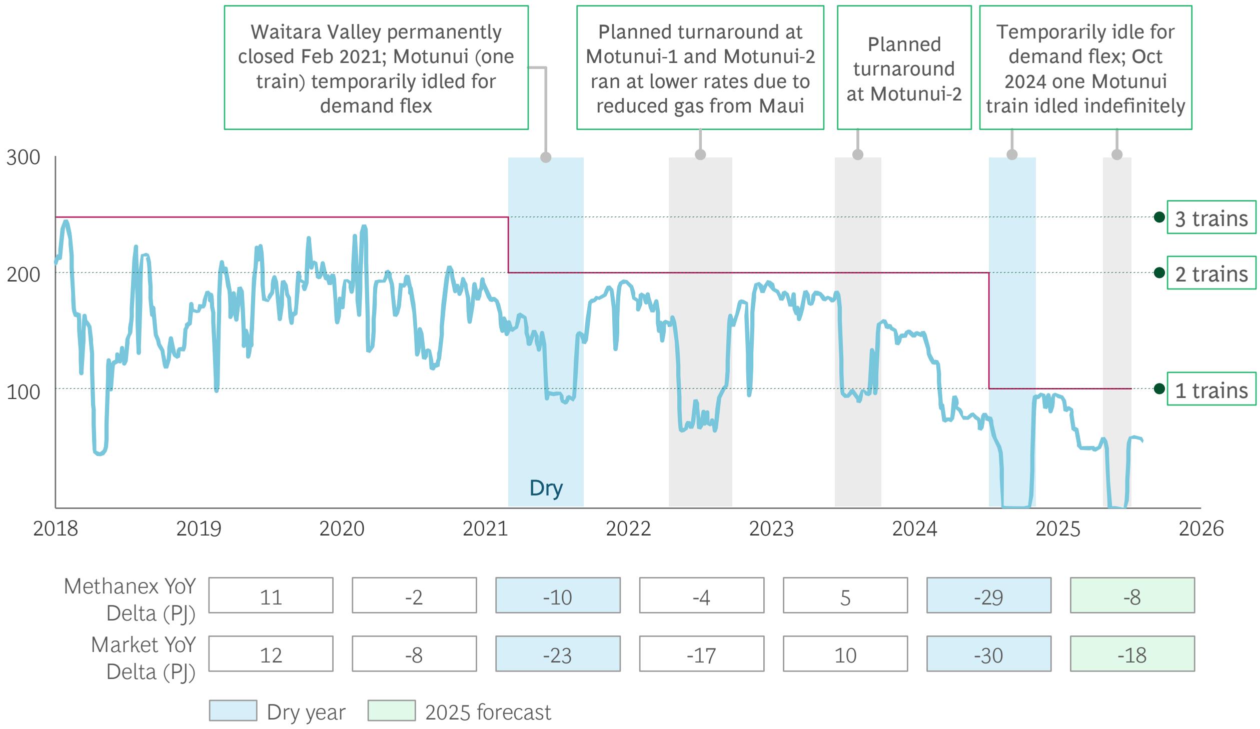
52 Methanex, Methanex Reaches Long Term Agreement for Natural Gas Supply 2018, 2018

53 Enerlytica, Maui Thesis 2025, 2025

54 Turnaround – A planned, scheduled outage of a processing unit or site (e.g. methanol train) to perform statutory inspections, major maintenance, repairs and upgrades. Typically occurs every few years and requires the unit to be shut down, temporarily reducing or stopping production.

Exhibit 38: Daily Methanex gas consumption, January 2018 to August 2025

**Daily Methanex gas consumption (Jan 2018 to Aug 2025)**
(TJ, trailing average – last 7 days)




Source: Gas Industry Co. Consumption, Methanex Annual Report

## 4.2.2 Gas supply and market challenges in future

This section looks at New Zealand's rapidly declining gas supply referencing a number of forecasts:

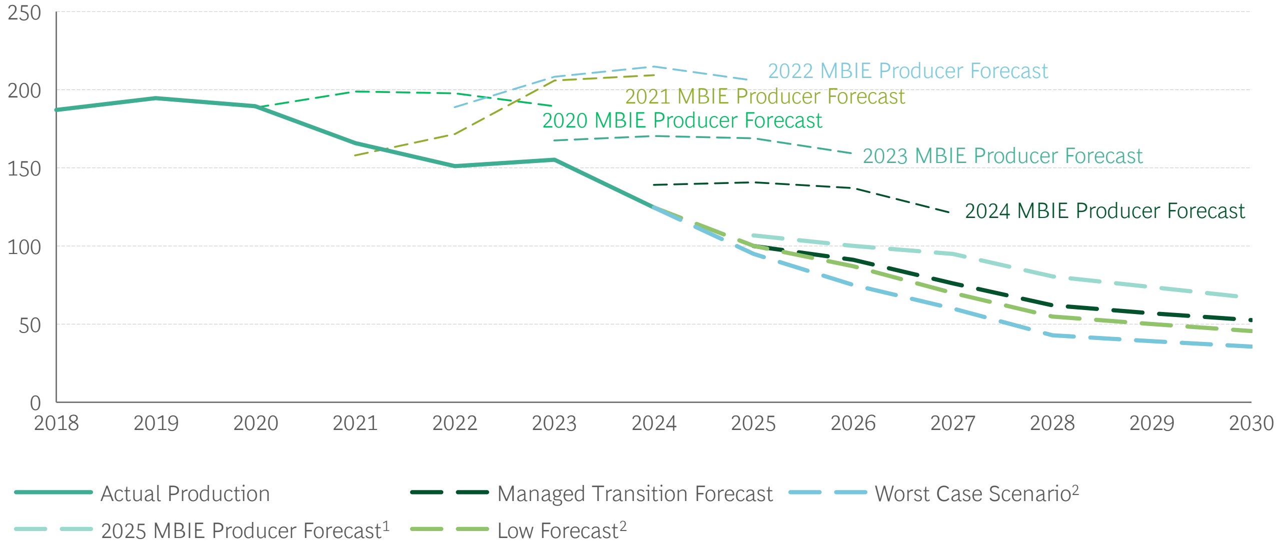
- **2025 MBIE Producer Forecast:** The MBIE's supply outlook as of 1 January 2025, and assuming Maui exits in 2027.
- **Managed Transition Forecast:** BCG's supply outlook which assumes there is further development of existing fields, positive development in Tūrangi and Mangahewa, and that Maui exits the gas system in 2027.
- **Low Forecast:** An adjusted Enerlytica supply outlook which assumes positive development in Tūrangi and Mangahewa, no further activity in the other existing fields, and that Maui exits the gas system in 2027.
- **Worst-case Scenario:** An adjusted Enerlytica supply outlook which assumes no further action towards future reinvestment work (baseline case) and that Maui exits the gas system in 2027.

**The outlook for gas supply is increasingly bleak**

New Zealand's gas market has moved from abundant to constrained. The 2025 MBIE Producer Forecast expects supply to reach 107PJ by 2025 down 15% on 2024, and gas is being traded at around $16–18 per GJ, with many people in the industry considering this a new normal versus the $7 per GJ cost in the 2000s. In the coming years, supply is forecast to continue to decline 8–18% each year based on the Managed Transition Forecast with mature fields ageing out faster than earlier models anticipated, and revisions pulling the trajectory lower. This worsens the risk of gas under-supply and a bumpy transition.

Exhibit 39: Gas production forecasts to 2030

**Gas production forecasts**
(Gross PJ, calendar year)




1. 2025 MBIE Producer Forecast from the 2025 MBIE Gas Production Forecast (as of 1 January 2025); 2. Low Forecast and Worst Case Scenario based on adjusted Enerlytica scenarios
Source: MBIE Annual Gas Production and Consumption, MBIE Gas Production Profile (Forecast), Enerlytica

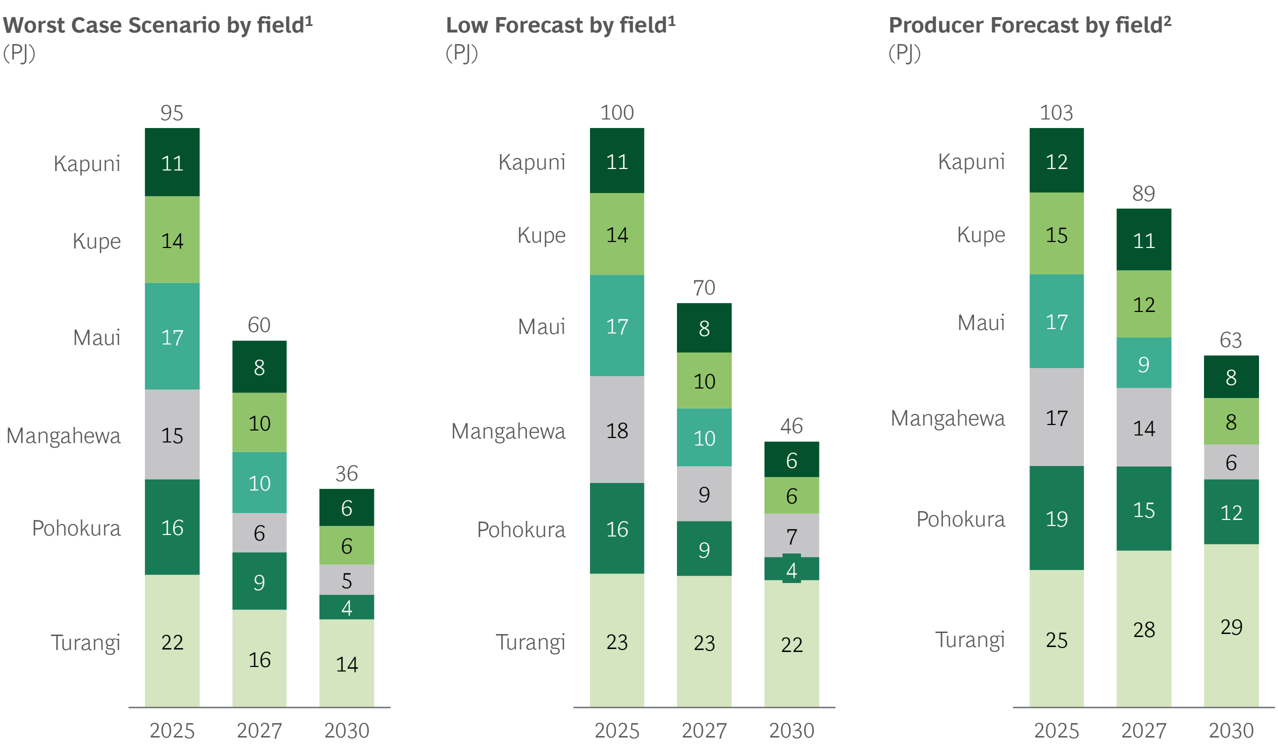
New Zealand's production trajectory is now in line with the Low Forecast and Managed Transition Forecast. The near-term picture is acute: output in 2024 under-delivered producer expectations by 10%, and the 0–3-year window shows a stark step-down in supply as forecasts continue to be reset downwards. The market now expects 107 PJ in 2025, versus 141 PJ in last year's outlook and 169 PJ the year before. Production is then expected to slip further, to 100 PJ in 2026 and 67 PJ by 2030 based on MBIE Producer Forecast. However, the gap between expectation and reality is widening, reinforcing that the Low Forecast and Managed Transition Forecast are the right anchors for planning.

The Managed Transition Forecast assumes continued positive development programmes at Mangahewa and Tūrangi and a delivery uplift at one other existing field to slow the decline and smooth the profile. This forecast expects output to increase by 7 PJ versus the Low Forecast in following years, driven by 2–3 additional development wells increasing daily delivery; however, both paths sit on a downward slope as reservoirs mature. Without a step-change in development effectiveness, persistent downside risk remains.

**There are some bright spots in field delivery, but overall forecasts and declining reserves point to a fragile outlook and short-term urgency**

Field-by-field analysis points to a concentrated and fragile supply stack that remains highly dependent on the success of Tūrangi as its reserves are the least depleted.

Exhibit 40: Production forecasts by big-6 fields, 2025 versus 2030




1. Worst case scenario and low gas supply forecast based on adjusted Enerlytica scenarios; 2. 2025 MBIE Gas Production Forecast (as of 1 January 2025)
Note: Mangahewa includes McKee and Tūrangi includes Kowhai
Source: MBIE Annual Gas Production and Consumption 2025 Q1, Enerlytica

## Exhibit 41: Gas fields reaching end of life

| *Ranked by gas production in H1 2025* | Location | Owner | H1 2025 Gas Production (PJ) | 2P Remaining Reserves (PJ)[3] | Reserve Depletion[4] | Estimated End of Life[5] |
|---|---|---|---|---|---|---|
| Tūrangi[1] | Onshore | Greymouth | 11 | 414 | 38% | 2035+ |
| Mangahewa[2] | Onshore | Todd | 9 | 83 | 89% | 2030 |
| Maui | Offshore | OMV | 9 | 40 | 99% | 2027 |
| Kupe | Offshore | Beach/Genesis /Echelon | 7 | 87 | 79% | 2030+ |
| Pohokura | Offshore and Onshore | OMV/Todd | 8 | 181 | 86% | 2035+ |
| Kapuni | Onshore | Todd | 5 | 93 | 92% | 2035+ |

1. Includes Kowhai; 2. Includes McKee; 3. 2P remaining reserves are proven and probable reserves. These reserves have a 50% certainty of being produced.; 4. Based on MBIE 2P reserves as of January 1st, 2025; 5. Based on 2025 H1 actuals compared to remaining 2P reserves assuming same production rate going forwards
Source: MBIE Natural Gas Reserves, Enerlytica Historical Production Data

- **Tūrangi:** Tūrangi drives the upside in the MBIE Producer Forecast and Low Forecast versus the Worst-Case Scenario. Tūrangi's reserve is 38% depleted versus other fields that are 79%+ depleted. In addition to the development wells drilled since 2024, the Low Forecast assumes three additional development wells at Tūrangi per year from 2026, driving an expected delivery increase in 2027. The MBIE Producer Forecast is similarly dependent on Tūrangi, expecting greater growth in delivery from 2025 to 2027.
- **Mangahewa:** Mangahewa delivers some optimism based on the initial performance of its recent 2025 development wells. The Low Forecast assumes three more development wells in 2027 which will help to minimise the delivery decline, compared to doing nothing in the Worst-Case Scenario. The MBIE Producer Forecast predicts a similar rate of decline in Mangahewa as the Low Forecast.
- **Kapuni:** The Low Forecast does not expect any improvement in Kapuni, meaning no difference with the Worst-Case Scenario. The MBIE Producer Forecast is more optimistic, predicting less of a decline from 2025 to 2027, before an accelerating decline leading up to 2030.

In contrast, the 3 offshore fields Kupe, Pohokura and Maui face decline, reliability and deliverability uncertainties. Both the Low Forecast and Worst-Case Scenario expect no further action in these fields, while key differences under the MBIE Producer Forecast vary by site:

- **Kupe:** The MBIE Producer Forecast expects a lesser rate of decline versus other forecasts. Similar to Mangahewa, Kupe has remaining reserves (2P) sitting at around 80PJ and will potentially near end of life in the next five years.
- **Pohokura:** In the past, Pohokura has accounted for a significant portion of domestic gas production volume, but its contribution is expected to decrease rapidly without further activity. The MBIE Producer Forecast expects further development at Pohokura to minimise its decline. OMV also disclosed plans to begin fracking at Pohokura next year to attempt to sustain current delivery.[55]

55 Energy News, OMV Plans First Pohokura Fracking Next Year, 2025

- **Maui:** Across all forecasts, Maui declines at a similar rate and is expected to exit by 2027, if not earlier. If Maui steps back materially or closes, incremental drilling and redevelopment at Pohokura and Kapuni become increasingly valuable to the sector to keep molecules flowing. Strategically, OMV faces choices at Maui (and Pohokura) as it nears end-of-life: balancing market reliance on Maui volumes against a potential decommissioning liability of more than $1 billion.[56] Other fields would most likely remain online following Maui's closure, supported by higher prices and independent infrastructure; however, without mitigation, decline could accelerate and pull forward end-of-life for marginal assets.

In all forecasts, reliance on a handful of fields is rising and the penalty for delay in development compounds quickly – as reservoirs deplete, pressure falls and water handling increases, which makes gas harder and costlier to produce. Owners must weigh incremental investment against remaining recoverable volumes, price outlook and decommissioning liabilities to maximise end-of-life value.

### The gap between gas supply and underlying demand is expected to widen

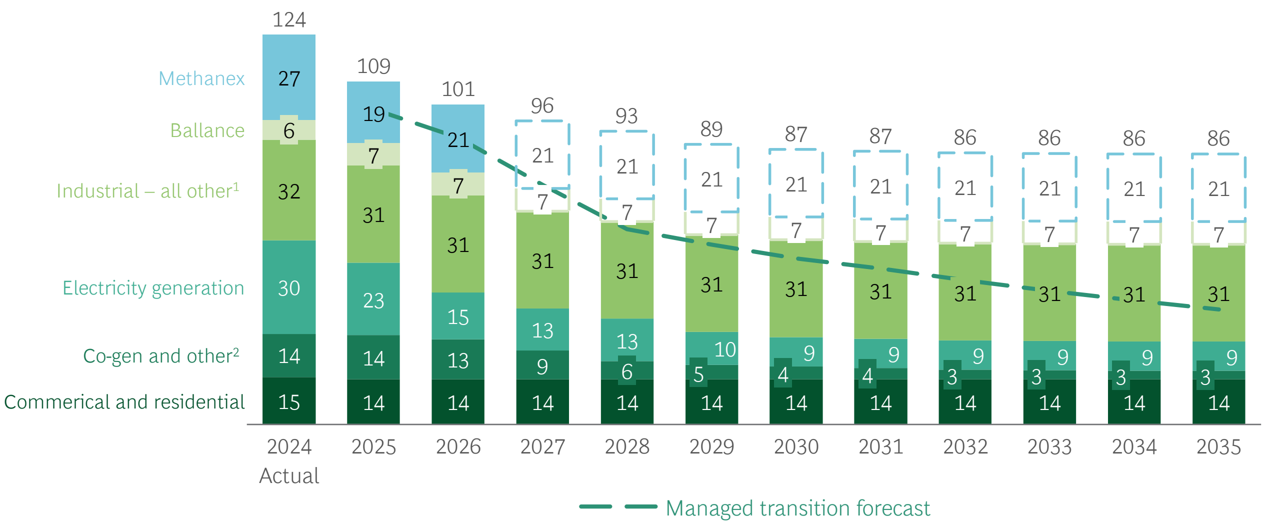
Domestic supply now sits below underlying demand, and the gap is set to widen over the next five years, resulting in a pinch point between 2026 to 2030. Assuming a normal hydrological year, underlying demand exceeds available gas by roughly 10 PJ in 2026 and then doubles in 2027 based on the Managed Transition Forecast.

56 OMV, Combined Annual Report 2024, 2024



## Exhibit 42: Underlying gas demand forecast across major users versus Managed Transition Forecast

**Underlying gas demand forecast across major users versus Managed Transition Forecast**
(Gross PJ, calendar year)




1. Includes Agriculture, Forestry and Fishing; 2. 'Other' includes energy transformation (excluding electricity generation), non-energy use (minus Methanex and Ballance feed stock), and stock change
Source: MBIE Annual Gas Production and Consumption 2025 Q1, MBIE Electricity Report 2025 Q1, Gas Industry Co. Consumption, Enerlytica

'Underlying demand' is defined as what the market would use without constraints in a normal hydrological year:

- **Methanex:** Continuing to run at one train capacity at its Motunui location
- **Ballance:** Securing gas contracts and continuing to operate with 7 PJ at its Kapuni plant
- **Industrial users:** Retaining operations with limited industrial closures (for reasons other than gas availability and pricing) and only modest fuel switching
- **Electricity generation users:** Transitioning to renewable generation as it is built, seeing demand trend from 23 PJ in 2025 to 9 PJ by 2030 as thermals are displaced; gas will retain a smaller, but critical peaking and firming role in normal hydrological years
- **Co-gen and other users:** Transitioning co-generation units to alternatives (e.g. electricity and biomass), causing demand to decline
- **Residential and commercial users:** Gradually electrifying uses of energy, causing demand to stay relatively flat

Given the significant gap between supply and demand, Methanex and Ballance could curtail operations or exit by 2027. Any unused contracted volumes would then be traded at high prices. While these exits represent 28 PJ, they will not rebalance the system over the following years. The Managed Transition Forecast expects supply will still be 6 PJ below underlying demand, excluding Methanex and Ballance in 2030. This implies temporal shortages across the year, potentially leading to permanent demand destruction as industrial gas users close.

Additionally, **Exhibit 42** reflects a normal hydrological year. In a dry year, gas demand from electricity generation would rise, drawing on storage and absorbing any surplus molecules. As a result, generation demand could be materially higher than shown. In periods where supply is even tighter, gas prices would be pushed higher and gas could be reallocated from industry to generation, potentially accelerating industrial closures.

**New Zealand will need to consider the economics of key gas users to minimise value destruction**

Gas undersupply is likely from 2027 and unmanaged industrial demand destruction would have significant impact on New Zealand's economy. Each gas-using industry contributes to New Zealand's economy very differently, so fuel substitution and any curtailment will need to consider the value these industries bring.

At import-parity gas prices, feedstock users such as Methanex and Ballance will struggle to compete with offshore supply, delivering relatively low value per GJ to New Zealand compared with many process-heat users. Methanex and Ballance provide demand flexibility, while other industrial users often underpin higher local output, employment and critical supply chains.

## Exhibit 43: Value generated by major gas users

| | *Ranked by ability to transition out of gas* | 2024 Gas Consumed (PJ) | Est. Gas % of Operating Costs | GDP[1] / PJ Gas ($m) | Exports[2] / PJ Gas ($m) | Jobs / PJ Gas | International Alternative | Potential Alternatives |
|---|---|---|---|---|---|---|---|---|
| Easiest | Electricity Generation | 30 | *Not applicable* | *Not applicable* | *Not applicable* | *Not applicable* | No | Yes, renewables or coal/diesel |
| | Industrial – Food Processing | 22 | 3–5% | $45–75 | $70–100 | 300–500 | Yes | Yes, biomass/electric boilers, VHTHP, HTHP |
| | Industrial – Wood | 2 | 1–2% | $15–30 | $10–20 | 150–300 | Yes | Yes, biomass/electric boilers, VHTHP, HTHP |
| | Commercial and Residential | 15 | *Not applicable* | *Not applicable* | *Not applicable* | *Not applicable* | *Not applicable* | Yes, but sticky preferences |
| | Industrial – Other | 3 | 1–2% | $30–60 | $20–40 | 200–400 | Yes | Yes, heat pumps |
| | Industrial – Chemicals | 2 | 1–2% | $20–40 | $15–30 | 150–300 | Yes | Partial, biomass/electric boilers |
| | Industrial – Basic Metals | 2 | 1–2% | $15–30 | $15–30 | 150–300 | Yes | Partial, majority high process heat |
| | Methanex | 27 | 75–85% | $6–8 | $6–8 | 6–7 | Yes | No, limited economic viability as highly dependent on gas |
| Most difficult | Ballance (Kapuni plant)[3] | 6 | 75–85% | $3–4 | *No exports* | 14–16 | Yes | No, limited economic viability as highly dependent on gas |

Note: Only first order of GDP shown; Industrial players account for gas used for feedstock and process heat; Co-generation is not included as it will be fully transitioned out of gas by 2030

1. Gross domestic product measures the value created domestically or contributed to the NZ economy (sales revenue minus the value of imported inputs); 2. Exports measure the total sales revenue from goods and services sold overseas, including the value of imported inputs; 3. Performance for Ballance's Kapuni plant only to isolate for urea production

Source: MBIE Annual Gas Production and Consumption 2025 Q1, Gas Industry Co. Consumption, Infometrics, Methanex and Ballance Annual Reports 2024, IBISworld Ballance Report, RNZ, IEA – Renewables for Industry, IRENA – Renewable Energy in Manufacturing, Renewable Thermal Collaborative

New Zealand needs to urgently preserve high-value industrial activity, accelerate orderly fuel switching, and prioritise targeted support for electrification (such as electric boilers and heat pumps) and biomass where feasible. The system can protect the sectors that create the most value for New Zealand, treat lower-value feedstock demand as flexible, and manage the transition to avoid an irreversible loss of productive capacity.

**Both the gas market's supply and demand sides must be addressed to alter the bleak outlook**

Gas supply is declining and mitigation efforts have failed to stop the trend. The decline is forecast to accelerate, with the gap between supply and demand widening. While there is optimism in some gas fields, the sharp reduction in reserves underscores near-term urgency. Tightening supply has already lifted prices, suppressed demand and heightened the risk of permanent demand destruction. A potential Methanex exit would further underline the need to add new sources of flexibility in the gas system.

Sections 5.2 and 5.3 outline the priorities to reshape New Zealand's outlook and deliver an orderly transition. On the supply side, the priority is to slow decline through targeted field redevelopment and potential carbon scrubbing to unlock high $CO_2$ gas, add new sources of system flexibility and secure alternative thermal fuel sources to complement domestic gas. On the demand side, the market must be balanced – affordability must be preserved by accelerating fuel-switching to electricity and biomass, while ensuring industrials have access to timely and transparent market information.

## 4.3 Energy system performance across the energy trilemma

By global standards, New Zealand's energy sector continues to perform well across all three dimensions of the energy trilemma – energy equity, environmental sustainability and energy security. In the latest international rankings, published by the World Energy Council (WEC) in 2024, New Zealand retained first place in Asia Pacific and ninth place globally **(see Exhibit 44)**, one of only nine countries to achieve an A-rating in all three dimensions. Its rankings for environmental sustainability and energy security improved from 2022.[57]

Exhibit 44: New Zealand remains 9th out of 127 countries in the World Energy Council's Trilemma Index


Note: Movement versus 2019 ranking as presented in BCG's the Future is Electric report, 2022
Source: World Energy Council 2023 Ranking

57 World Energy Council, World Energy Trilemma Index, 2023

**What is the energy trilemma?**

The energy trilemma, as defined by the World Energy Council, demonstrates the need for well-functioning energy systems to balance outcomes across three dimensions:

- ***Energy equity:*** Ability to provide universal access to reliable, affordable energy for domestic and commercial use
- ***Energy security:*** Ability to meet current and future energy demand and the ability to withstand and respond to system shocks
- ***Environmental sustainability:*** Ability to mitigate and avoid environmental degradation and climate change impacts

Maintaining a balance across these dimensions is a key challenge as New Zealand progresses to more decentralised, decarbonised and digital energy systems. Each dimension of the trilemma has core and secondary considerations. While a holistic view of the trilemma has been taken throughout this report, the core considerations (energy affordability, energy security, and environmental sustainability) are the focus of the six scenarios modelled (Section 6).

### 4.3.1 Performance on energy affordability

New Zealand performs well with regard to affordability, ranking 18th globally on energy equity measures.

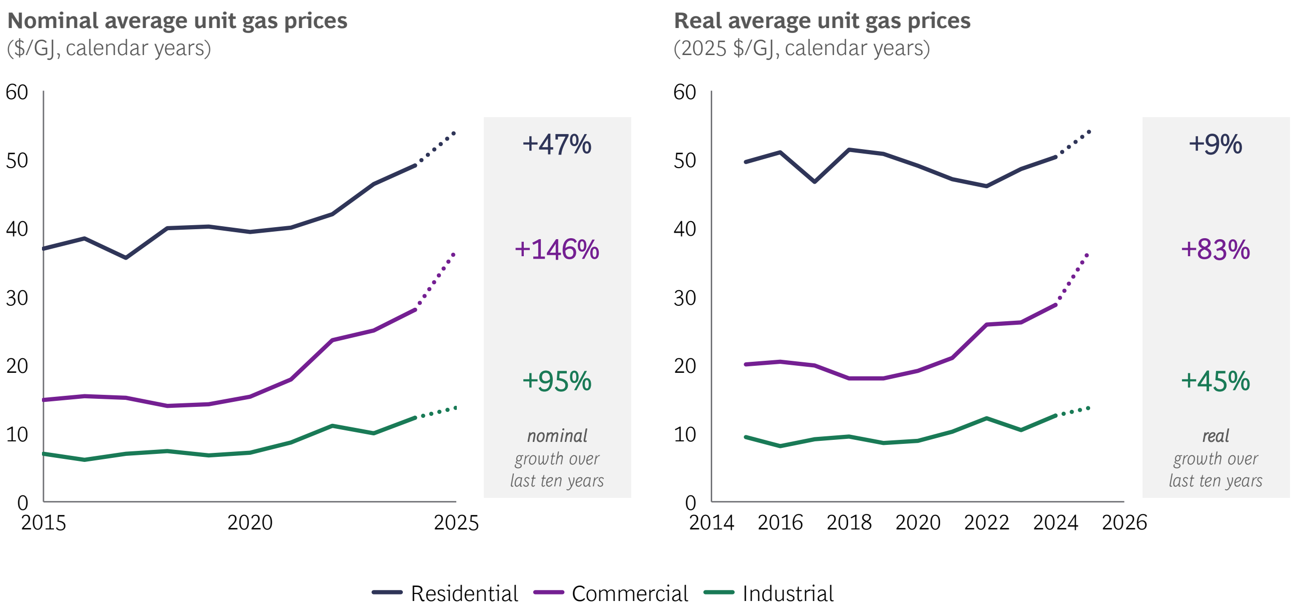
Despite strong global performance, rising energy prices in New Zealand have been widely felt by households and businesses during a period of high inflation.

**Domestic gas prices have risen for all user groups over the last decade**

Over the past decade, nominal residential gas prices have risen 47%, while commercial and industrial gas prices have risen 146% and 95% respectively.

In real terms, residential prices have risen a modest 9%. However, commercial prices have risen 83% and industrial prices have risen 45%. The majority of price increases have occurred within the last five years, as the gas market has tightened under constrained supply (see **Exhibit 45**).

Exhibit 45: Nominal and real unit gas prices, 2015–2025




Note: Residential prices include GST, commercial and industrial prices exclude GST. 2025 figures are forecasts, based on actual Q1/Q2 figures.
Source: MBIE Energy Prices, BCG analysis

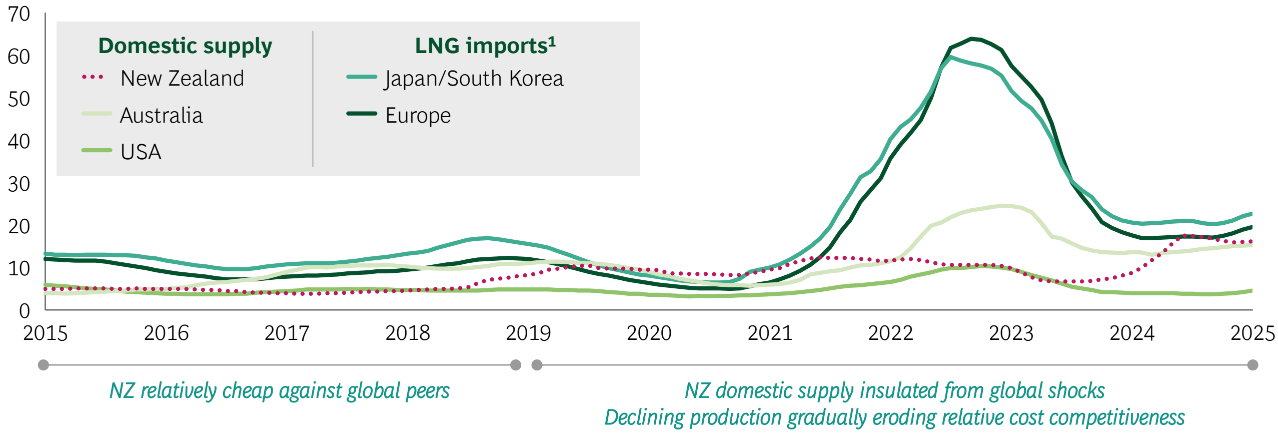
### Domestic gas prices have still remained competitive relative to global peers – until recently

New Zealand's domestic gas market has maintained globally competitive wholesale prices, due to its ringfenced domestic supply and lack of imports or exports. The market is insulated from global shocks – such as the European gas crisis triggered predominantly by Russia's invasion of Ukraine – allowing New Zealand to maintain low-cost gas relative to global peers (see **Exhibit 46**) for electricity generation and industrial uses.

The recent decline in production volumes is gradually eroding New Zealand's cost-competitiveness relative to global peers. New Zealand has maintained cost-competitiveness relative to markets reliant on liquefied natural gas (LNG) imports, such as Japan, South Korea and Europe, which continue to see elevated prices following global supply shocks. However, the United States has diverged from this trend, maintaining a clear relative cost advantage in 2025.

Exhibit 46: International wholesale gas spot prices comparison

**Nominal wholesale gas spot price, global peer liberalised markets**
($/GJ, 12-month rolling average, year-end March)



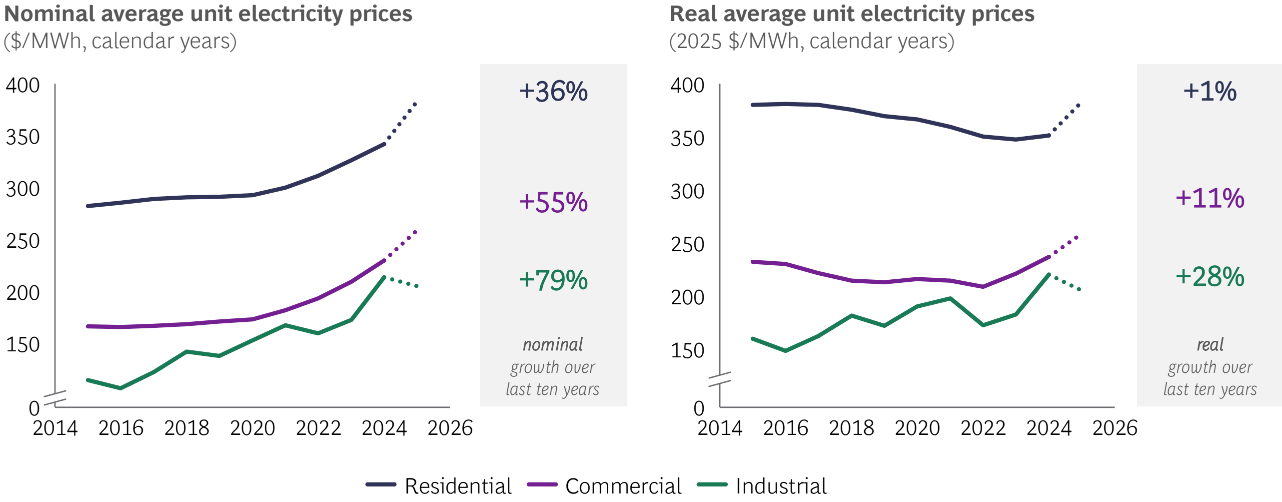

1. Japan/South Korea prices solely represent LNG imports. Europe prices heavily weighted to LNG imports.
Note: Prices exclude carbon. Pricing data sourced from representative regional hubs/spot market indices: New Zealand = emsTradepoint (domestic gas only); Australia = AEMO STTM, Sydney (domestic gas only); Japan/South Korea = Japan/Korea Marker (LNG imports only); USA = Henry Hub (vast majority domestic gas only); Europe = Title Transfer Facility (TTF), Netherlands (strongly influenced by LNG imports)
Source: IEA, AEMO, emsTradepoint, Concept Consulting, Bloomberg, BCG analysis

**Electricity prices have held steady in real terms for residential and commercial users, but increased for industrial users**

All consumers have felt electricity unit prices rise over the last decade, particularly during a period of high inflation. Nominal household prices are up 36%, commercial prices have risen 55% and industrial prices have risen 79%.

Yet in real terms, household prices increased only 1%, while real commercial prices have risen 11%. However, industrial users have felt real price increases of 28% on average, with unhedged users exposed to higher increases and volatility (see **Exhibit 47**).

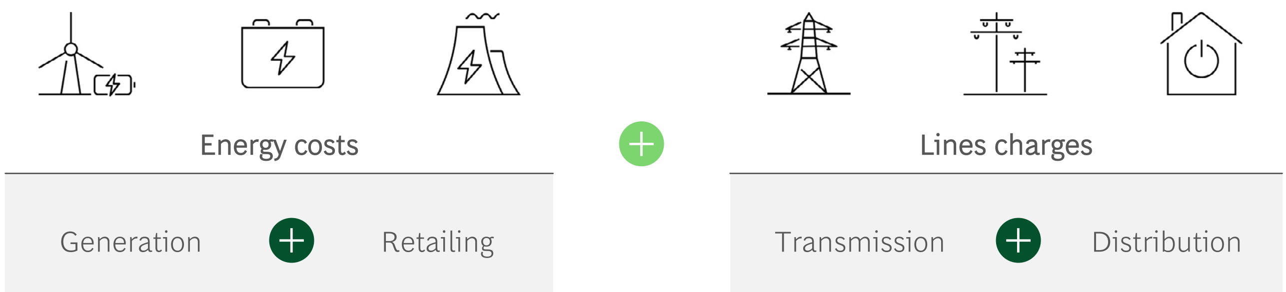
Exhibit 47: Electricity unit prices – nominal and real




Note: Residential prices include GST, commercial and industrial prices exclude GST. 2025 figures are forecasts, based on actual Q1/Q2 figures
Source: MBIE Energy Prices, BCG analysis

Electricity prices paid by end-users are a function of two primary components: energy costs and lines charges (see **Exhibit 48**).

Exhibit 48: Components of end-user electricity prices

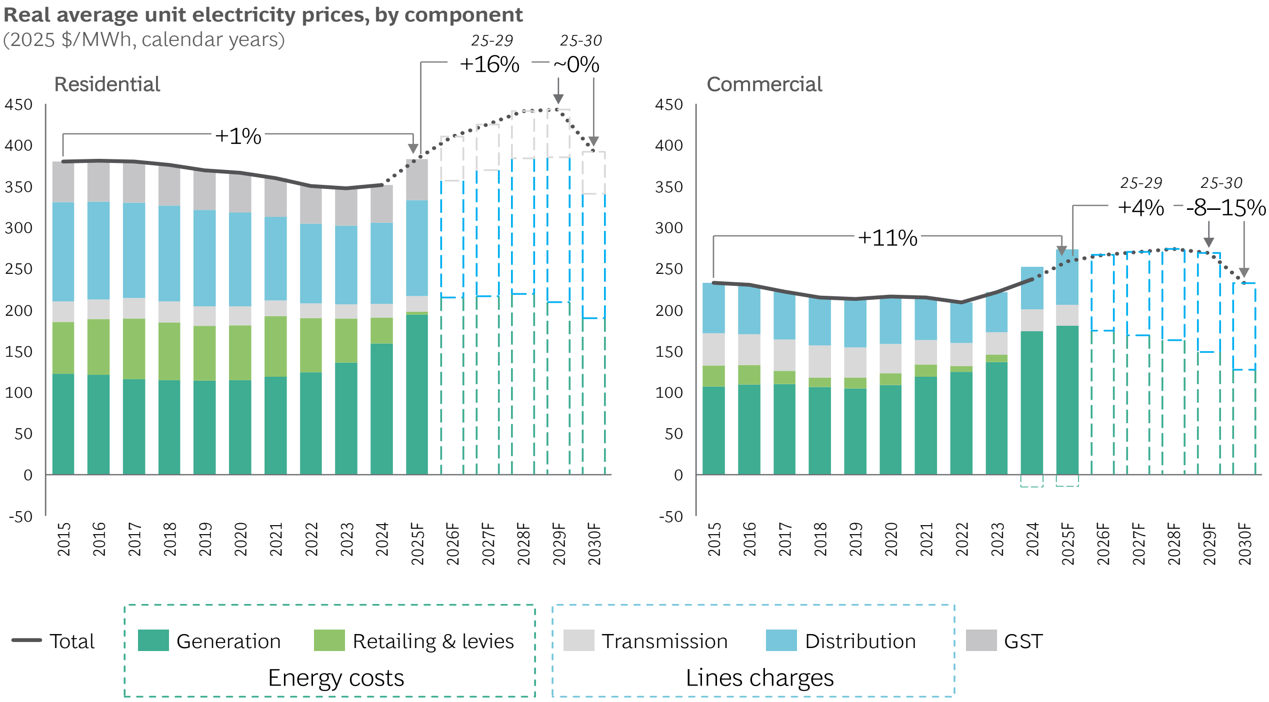


Changes in the prices paid by end users over the last 10 years and in the years ahead can be better understood by splitting unit prices into these components and their sub-components:

- Energy cost sub-components: generation costs, retailing costs/margins and other levies
- Lines charges sub-components: transmission and distribution costs

**Exhibit 49** shows estimated energy costs and lines charges, broken out into their sub-components.[58]

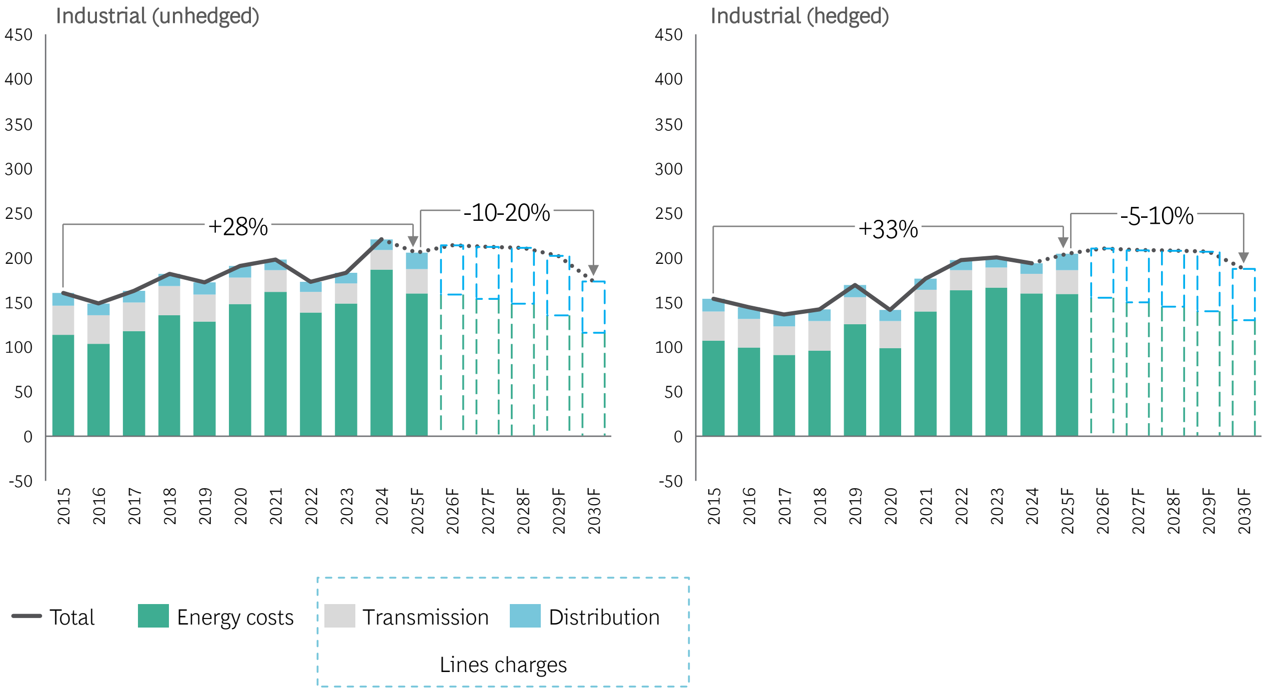
## Exhibit 49: Break down of electricity unit prices by component and sub-component




Note: Transmission and distribution costs estimated based on proportional allocation of total revenue to each user group, Commerce Commission information and realised charges data. Generation component estimated based on trailing average wholesale prices (residential = 4-year trailing avg.; commercial = 2-year trailing avg.), with DWAP/TWAP factors applied to each user group. Retailing and levies back-calculated as residual from total average price less transmission, distribution and generation components. Accounts for ETS, levies, metering, and average retail margin across market. Unhedged historical energy cost back-calculated as residual from total industrial average price less lines charges, forecast based on ASX futures and Concept Consulting forecasts with nominal retail margin included. Hedged historical energy cost based on Energy Link Electricity Contract Index, forecast based on two-year trailing average of ASX futures and Concept Consulting forecasts with nominal retail margin included. Sub-components for energy costs (generation and retailing) have not been estimated for industrial prices. All figures are market average estimates; actual figures will vary between market participants. Commercial excludes GST.
Source: MBIE, Commerce Commission, Concept Consulting, EnergyLink, BCG analysis

58 Modelling is intended to illustrate how cost components drive price changes. These are presented as estimated market averages. Costs presented do not represent actual costs of any one market participant.

**Real average unit electricity prices, by component**
(2025 $/MWh, calendar years)




| | | % of bill today | % change 2015–2020 | % change 2020–2025 | forecast % change 2025–2030 |
|---|---|---|---|---|---|
| Residential | *Energy costs* | 59% | -2% | +9% | 0-5% |
| | *Lines charges* | 41% | -5% | -2% | +10–15% |
| | *Total price* | | -4% | +5% | 0-5% |
| Commercial | *Energy costs* | 64% | -7% | +36% | -20–25% |
| | *Lines charges* | 36% | -7% | -1% | +10–15% |
| | *Total price* | | -7% | +20% | -8–15% |
| Industrial (unhedged) | *Energy costs* | 83% | +30% | +8% | -25–30% |
| | *Lines charges* | 17% | -9% | +6% | +25–30% |
| | *Total price* | | +19% | +8% | -10–20% |
| Industrial (hedged) | *Energy costs* | 80% | -8% | +61% | -15–20% |
| | *Lines charges* | 20% | -9% | 6% | +25–30% |
| | *Total price* | | -8% | +40% | -5–10% |

= >5% reduction  = ±5% minimal change  = >5% increase

### Energy cost sub-components – generation and retailing

Energy costs can be broken down into two sub-components: generation and retailing, which include margins and levies.

Over the last decade, generation costs have risen, primarily driven by increasing gas prices (see *At a glance: Factors influencing wholesale prices*). The extent to which these increases affect total prices varies by user group, as the retailing component can provide price hedging for end-users.

For **industrial users,** rising energy costs have been the primary driver of total price increases. This is because generation costs are largely passed through to the end-user – also leading to greater price volatility. Hedged users are generally able to soften the impact of volatility more than unhedged users. Energy costs are expected to moderate to 2030, putting downward pressure on total prices.

**For commercial users,** energy costs have also increased, but to a lesser extent, and are expected to moderate to 2030. Greater retail price hedging and tightening retail margins have dampened the impact of rising generation costs on end-user prices in recent years.

For **residential users,** exposure to rising generation costs has been even more limited. Retail hedging and compressed margins have absorbed most of the generation costs increases (see **Exhibit 49**). As a result, total energy costs have remained relatively stable – this trend is expected to continue in coming years.

Despite moderating energy costs, increasing lines charges are set to influence prices in the coming years.

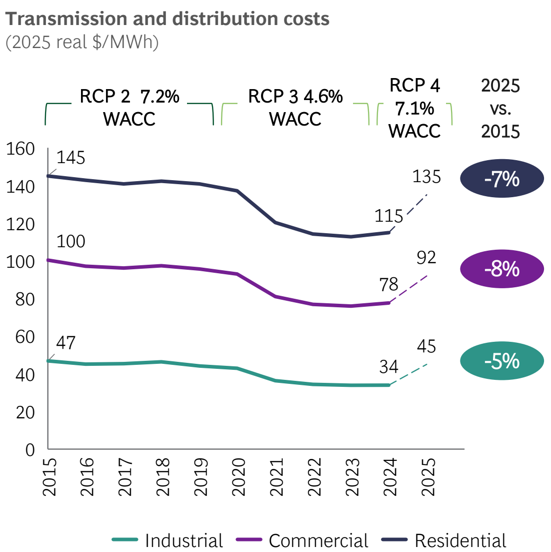
### Lines charges sub-components – transmission and distribution

Lines charges are the costs associated with the transmission and distribution of electricity, from generation to end-users. These comprise two sub-components: national grid transmission, administered by Transpower; and local lines distribution, administered by local network companies (e.g. Vector, Orion).

Transmission and distribution revenues are regulated by the Commerce Commission through five-year price-quality paths, which are partially informed by the allowed rate of return on capital for five-year regulatory periods. Transmission and distribution companies then apply pricing methodologies established by the Electricity Authority to recover this revenue via lines charges. Low interest rates in the late 2010s lowered the regulated rate of return from 7.2% to 4.6% in April 2020, reducing lines charges to April 2025. However, from April 2025, the rate increased to 7.1%, reflecting the lagged effect of higher interest rates during the post-COVID inflationary period (see **Exhibit 50**). This will increase lines charges over the next five years.

Increased lines charges will put upward pressure on total electricity prices, with the effect varying by user group, depending on the share of total costs attributable to lines charges.

Exhibit 50: Unit lines charges for residential, commercial and industrial users




Note: Estimated 2025 residential price reflects up to $120–250 annual increase in transmission and distribution charges, based on average household consumption of 8 MWh ($15–30/MWh cost increase)
Source: MBIE, Concept Consulting Line Charge Estimates, Commerce Commission

For **residential users,** changes in lines charges have been the primary driver of total price movements over the last ten years. Residential users pay higher lines charges per unit of electricity than industrial users (see **Exhibit 50**) because they are more geographically dispersed, requiring a wider and denser distribution network. Residential users benefitted from lower lines charges in the early 2020s, putting downward pressure on total prices. However, regulated increases from April 2025 are expected to put upward pressure on total prices – with these changes locked in by regulation and independent of market effects.

The Commerce Commission estimates the rise in lines charges in 2025 will increase household electricity bills by $10–25 per month (excluding GST) in 2025, and $5–15 per month in each subsequent year to March 2030.[59]

For **commercial users,** lower lines charges in recent years helped to offset rising energy cost, moderating total price increases. Regulated uplifts in the coming years will reverse this trend, placing upward pressure on total prices.

For **industrial users,** the impact of higher lines charges will be felt, but to a lesser extent. They pay lower lines charges relative to total prices because many connect straight into the national grid, bypassing local distribution requirements.

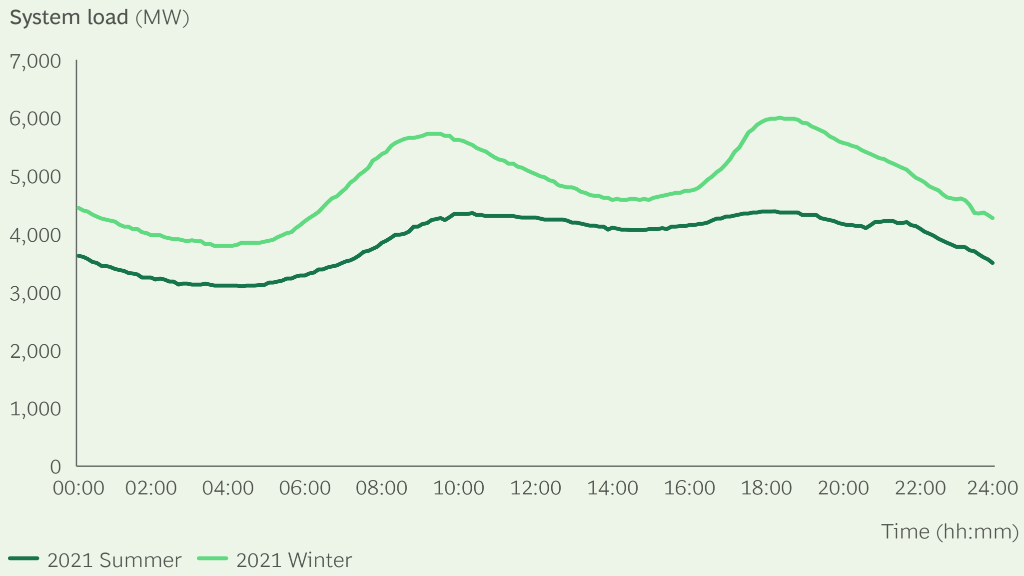
## At a glance: Factors influencing wholesale prices

### Electricity generation comprises renewable generation and firming

Renewable generation makes up the majority of electricity supply in New Zealand, with thermal fuels (gas and coal) used to firm the system through demand peaks and dry periods with lower hydro generation.

Electricity supply is traded on the wholesale market based on real-time supply and demand dynamics. Generators offer capacity at their marginal cost. The mix of capacity offered varies by source, depending on weather (e.g. sunshine and wind), hydro storage levels, thermal fuel availability and other generation factors. Electricity demand varies throughout the day, with peaks in the mornings and evenings, and across a year, with higher overall demand in winter (see **Exhibit 51**).

Exhibit 51: Typical summer and winter daily load profiles



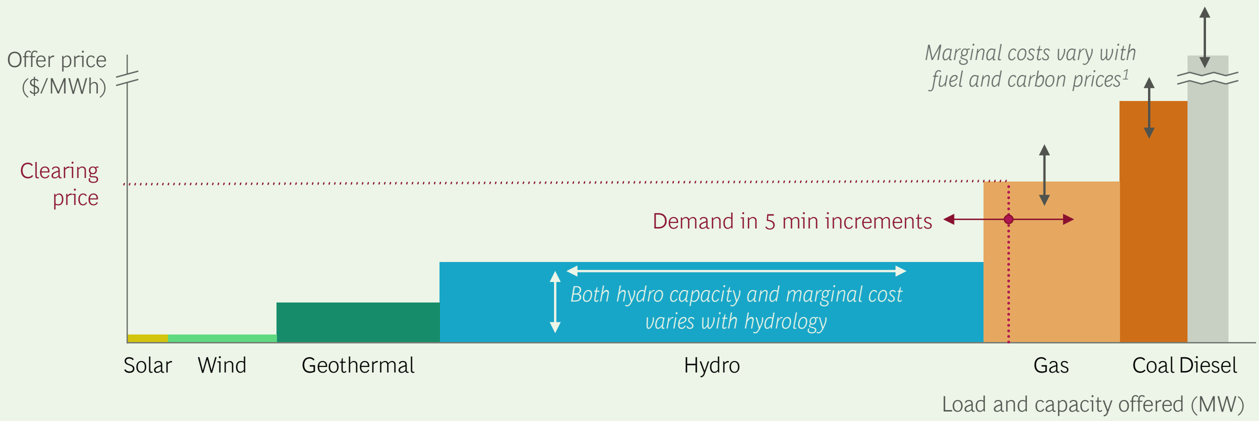

Source: Transpower, BCG analysis

59 Commerce Commission, Understanding How Changes to Lines Charges May Impact your Electricity Bill, 2025

Supply and demand are balanced at each time increment, with the marginal generator clearing the market and setting the wholesale price (see **Exhibit 52**).

### Exhibit 52: Illustrative wholesale market dynamics

**Illustrative wholesale electricity market dynamics**




1. Current carbon prices is material at $55–75 which translates to $20–30/MWh for gas and $50–70/MWh for coal
Source: EMS Gas Prices, HBA Coal Price Index, WSP Thermal Generation Stack, NZU unit prices, DCCEEW Emissions Factors

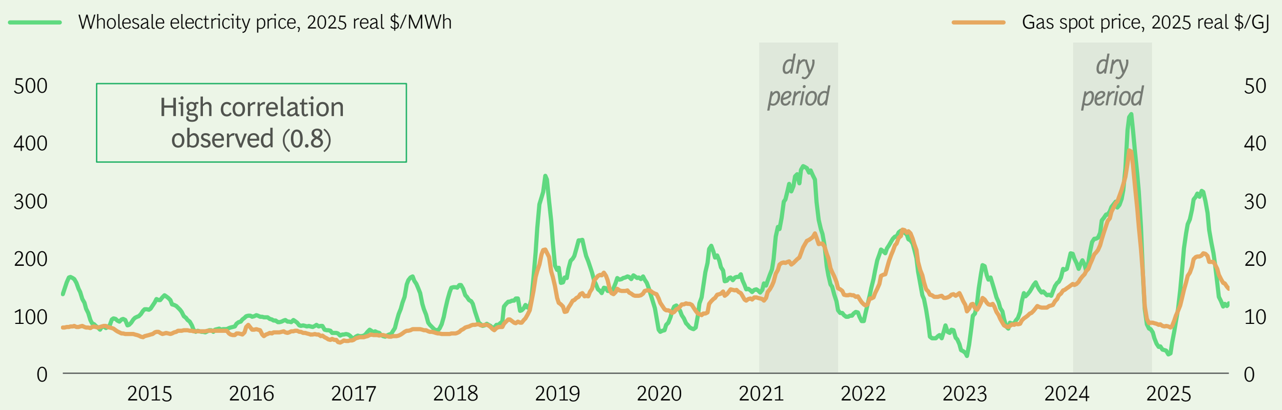
**Increasing gas prices have caused wholesale electricity prices to rise in recent years**

While the significant build out of renewables has displaced thermal generation during a period of flat demand, wholesale electricity prices have risen. This rise is the result of increasing gas prices, as gas generation is used to firm the system to meet demand peaks and manage variability from intermittent renewables and dry years. Due to its firming role, gas frequently clears the market and sets wholesale electricity price.

Over the last decade, gas generation produced in 95% of hours, on average, which had a high influence on marginal pricing. As such, there is a high correlation between gas pricing and electricity wholesale pricing (see **Exhibit 53**).

### Exhibit 53: Gas prices have heavily influenced electricity prices over the last decade

**Wholesale electricity and gas spot price relationship**
(Trailing 8-week average)




Source: EMI Electricity (Otahuhu node), EMS Gas Spot Prices (including carbon)

Given the increasingly tight gas market and frequency at which gas generation sets the wholesale electricity price, rising gas prices have caused wholesale electricity prices to rise in recent years.

During dry periods, such as in 2024, the electricity market requires higher gas volumes for firming to compensate for lower hydropower generation. This increased demand from the electricity market subsequently pushes up wholesale gas prices.

As a result, the gas and electricity markets are strongly interlinked, with price causality running in both directions.

The additional reliance on imported coal for firming, particularly in dry years, exposes the electricity market to global thermal fuel price volatility. These effects flow through to wholesale electricity prices, which can lead to spot price movements.

**Increasing the proportion of renewable generation weakens the influence of gas prices on wholesale electricity prices**

As the proportion of renewable generation increases, the frequency with which gas generation clears the wholesale electricity market reduces (see **Exhibit 54**). Therefore, the influence of gas pricing on electricity pricing weakens.

Exhibit 54: As renewable penetration increases, gas clears the market less frequently

| % renewable generation | % of time gas produces in an hour |
|---|---|
| 85% | 90% |
| 90% | 80% |
| 92% | 70% |
| 94% | 60% |
| 95% | 50–60% |
| 96% | 40–50% |
| 97% | 35–40% |
| 98% | 25–35% |
| 99% | 20–25% |

**In addition to more renewable generation, affordable fuel for firming is essential to maintain electricity affordability**

Building additional renewable generation alone will not ensure long-run electricity affordability – while it is helpful, more affordable gas for system firming is also essential.

A simple method for calculating wholesale electricity pricing is shown in **Exhibit 55.**

Exhibit 55: Simple heuristic to estimate wholesale electricity prices

wholesale electricity price ($/MWh) ≈ ( % of time gas clears in an hour × SRMC[1] of OCGT[2] ($/MWh) ) + ( % of time gas doesn't clear in an hour × balancing item price ($/MWh) )

1. Short-run marginal cost 2. Open-cycle gas turbine
Note: Balancing item consists of water price risk, returns to recover capital costs, and operations and maintenance costs. The balancing item used in this 'rule of thumb' calculation is $60/MWh based on observed levels over the last 4 years

To lower wholesale electricity pricing in the future to at or below the long-run marginal cost of renewables plus firming $110130 per MWh (from $160 per MWh in the past 12 months), the optimal level of renewable build is dependent on the price of gas (see **Exhibit 56**).

At today's gas price of $15–17.50 per GJ, a rate of 95–97% renewable generation is required to return and maintain long-run electricity prices at the marginal cost of renewables. However, if the cost of gas was to increase to $25 per GJ, which is the liquefied natural gas (LNG) import parity price, 98–99% renewable generation would be required to maintain electricity pricing at the long-run marginal cost of renewables plus firming. At a level of renewable generation where meaningful spill will occur, especially during sunny and windy periods, it can challenge the economics for any further renewable investment.

The below heuristic illustrates that two items are essential to achieving affordable wholesale electricity prices:

- A high % of renewable generation – likely to be 96%+ in future
- The domestic gas market needs to be fixed to ensure average prices of $15–20 per GJ for electricity (or better), including carbon

## Exhibit 56: Wholesale electricity price estimates, based on proportion of renewable generation and unit gas price

**Wholesale electricity price heuristic estimate**
($/MWh)

| Renewable % of electricity generation | % of time gas clears in an hour | Gas price including carbon ($/GJ) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | $10 | $15 | $17.5 | $20 | $22.5 | $25 | $30 |
| 85% | 90% | $114 | $164 | $188 | $213 | $238 | $263 | $312 |
| 90% | 80% | $108 | $152 | $174 | $196 | $218 | $240 | $284 |
| 92% | 70% | $102 | $141 | $160 | $179 | $198 | $218 | $256 |
| 94% | 60% | $96 | $129 | $146 | $162 | $179 | $195 | $228 |
| 95% | 50–60% | $93 | $123 | $138 | $153 | $168 | $183 | $213 |
| 96% | 40–50% | $88 | $113 | $126 | $138 | $151 | $164 | $189 |
| 97% | 35–40% | $82 | $103 | $113 | $123 | $134 | $144 | $164 |
| 98% | 25–35% | $78 | $94 | $102 | $110 | $118 | $126 | $142 |
| 99% | 20–25% | $73 | $84 | $90 | $96 | $102 | $108 | $119 |

Below LRMC of renewable generation plus firming

At LRMC of renewable generation plus firming

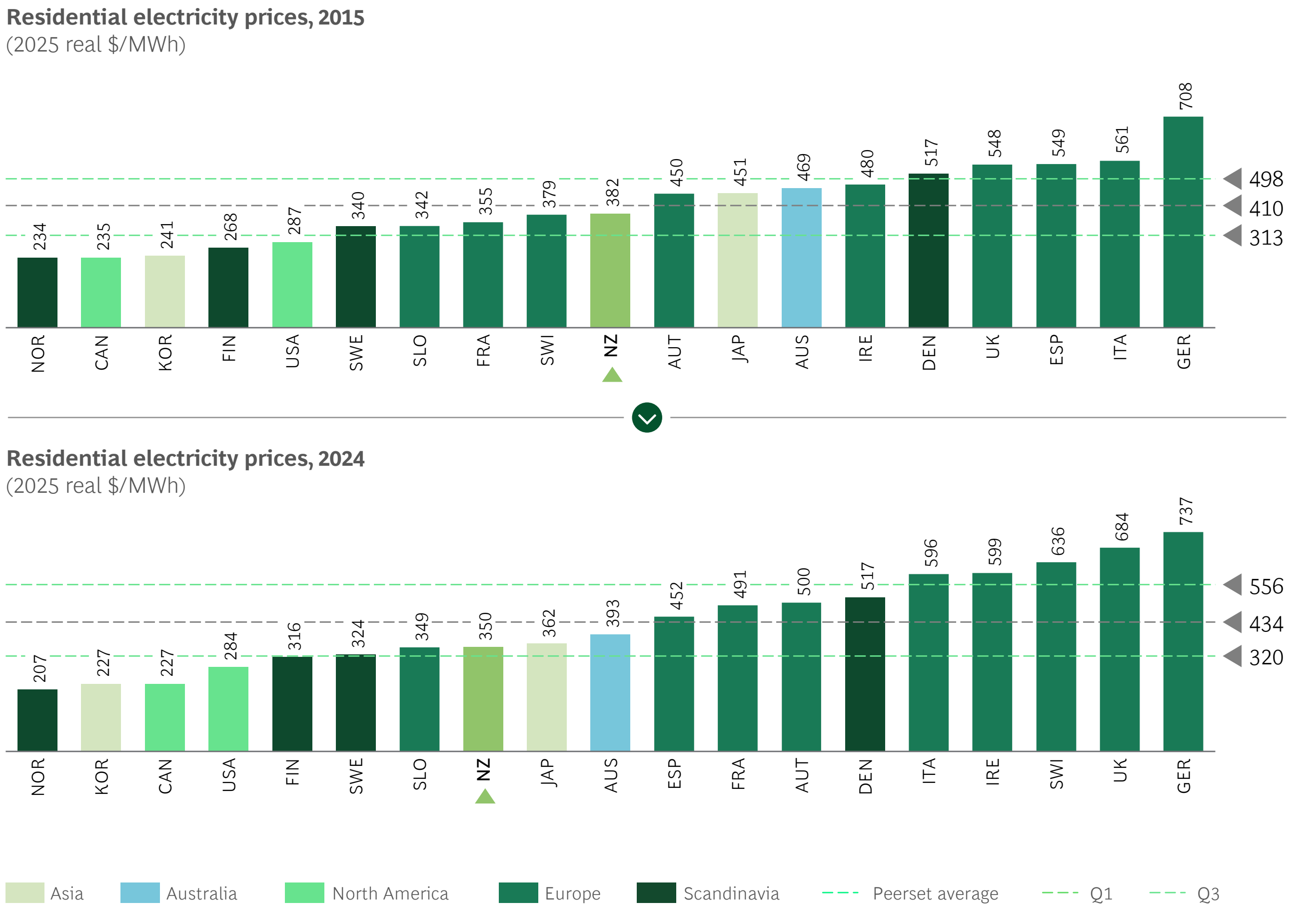
Above LRMC of renewable generation plus firming

Note: LRMC = Long-run marginal cost

**New Zealand electricity prices perform well compared to global peers**

New Zealand residential unit electricity prices are competitive among global peers. Prices have improved from 2015 to 2024, both in absolute and relative terms, moving towards the lower quartile of peer markets (see **Exhibit 57**).

Exhibit 57: New Zealand residential electricity prices compared to global peers

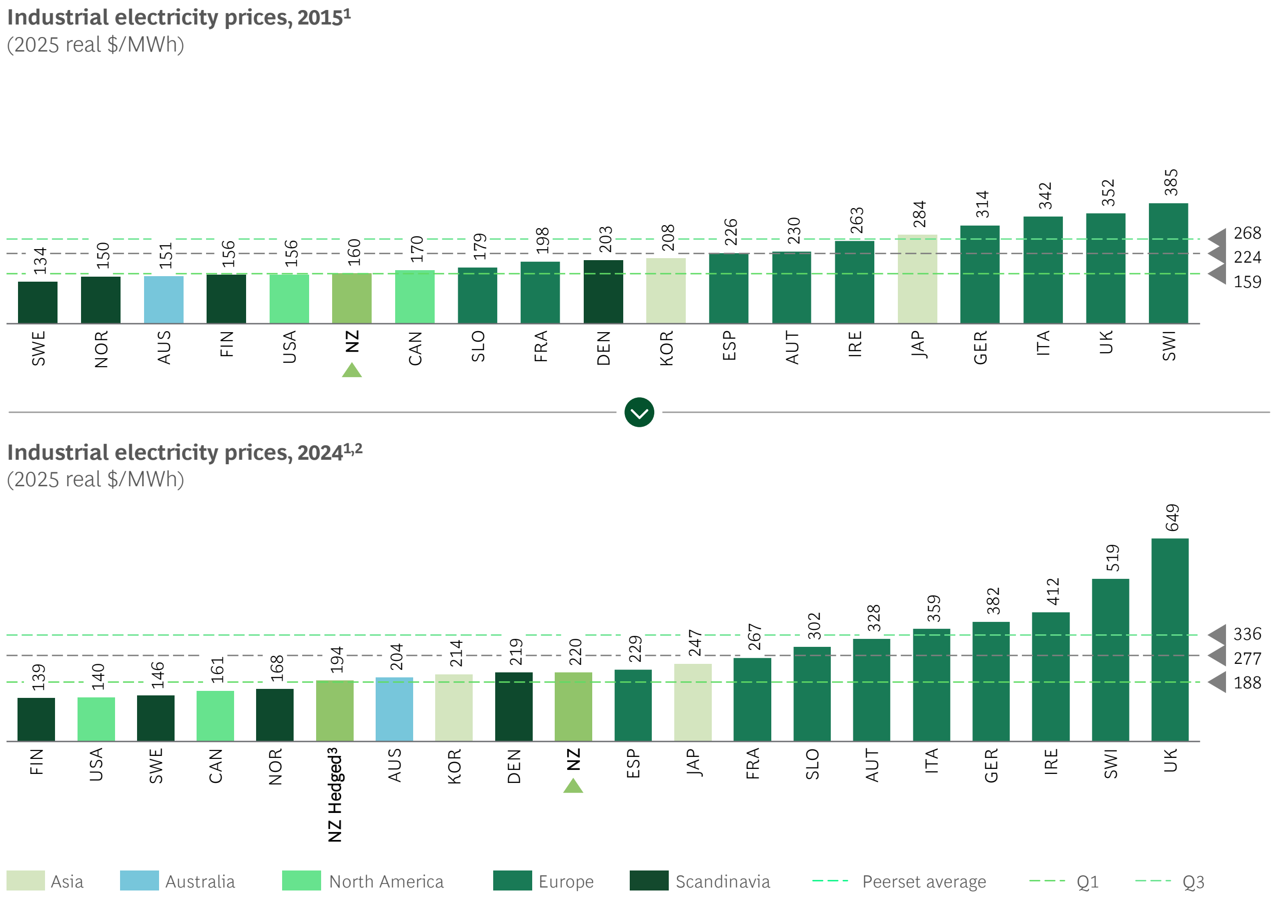



Note: Peers include Australia, Austria, Canada, Switzerland, Germany, Denmark, Slovenia, Sweden, Spain, Finland, France, UK, Ireland, Italy, New Zealand, Norway and United States; Expressed in 2025 real NZ $; 2024 figures converted to 2025 real prices using 2% Stats NZ inflation benchmark
Source: MBIE, Stats NZ, Enerdata

On industrial pricing, New Zealand sat between the lower quartile and average when compared to peers in 2024, slightly worsening in relative position on 2015 pricing.

Both the tight gas market and dry year effects influenced 2024 prices. Despite this, the country's relatively low reliance on thermal fuel imports has insulated it from global price shocks – protecting it from much larger price increases, such as those felt in European markets following Russia's invasion of Ukraine.

### Exhibit 58: New Zealand industrial electricity prices compared to global peers




1. New Zealand hedged price excluded from quartile calculations, average; 2. No data available from Australia, Sweden and Switzerland. Prices derived from recent business kWh data (US $ to NZ $), with historic adjustment for 2015; 3. Energy Link NZ ELL index monthly contract price and transmission charges
Note: Expressed in 2025 Real NZ $; 2024 figures converted to 2025 real prices using 2% Stats NZ inflation benchmark
Source: MBIE, Stats NZ, Enerdata, IEA, RH Nuttall, RBNZ

As discussed in Section 3.2, New Zealand's abundant untapped renewable resources also translate to globally competitive industrial PPA pricing, which support the build-out of renewable generation.

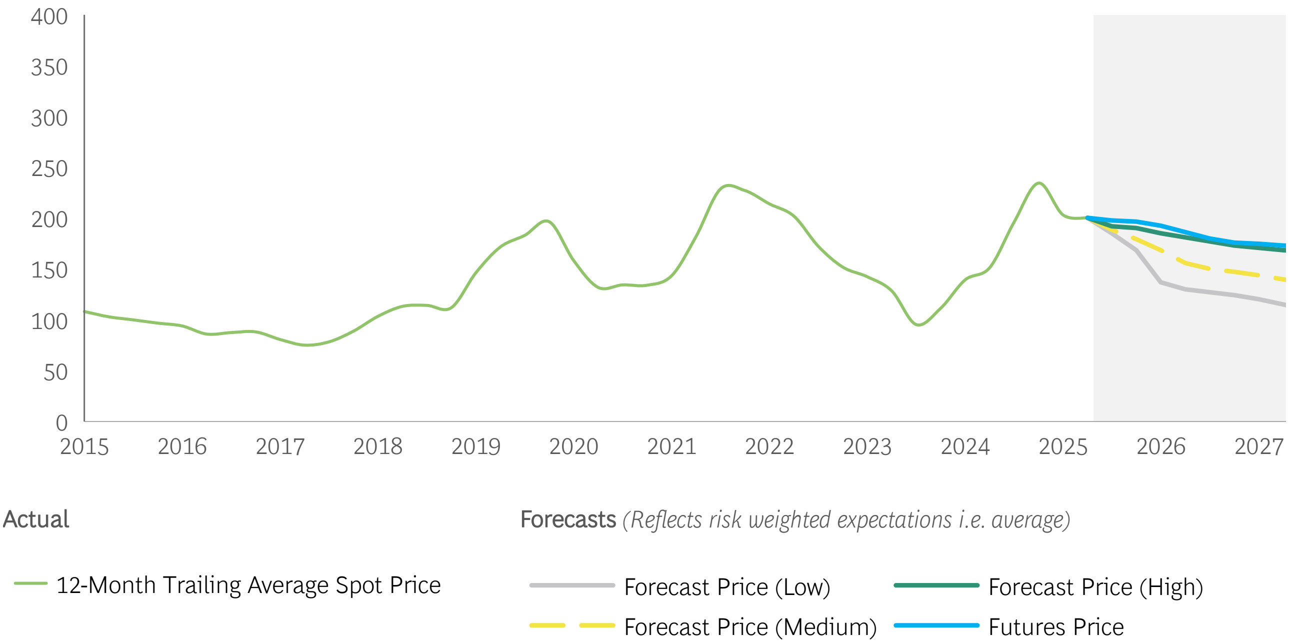
### Wholesale prices are forecast to decline in coming years, despite the futures curve remaining high

With the build-out of renewable generation set to continue to displace thermal generation and reduce the frequency at which gas generation clears the market, wholesale electricity prices are forecast to decline in coming years. Despite this, futures prices currently remain elevated, reflecting market perceptions of dry-year risk, declining domestic gas supply and lower storage volumes, and other risks relating to the development pipeline, consenting and construction (see **Exhibit 59**).[60]

60 Futures are traded contracts used to hedge against future wholesale electricity price volatility and signal market expectations of future spot prices through their traded prices.

Exhibit 59: Electricity wholesale spot prices (actual and forecast)

**New Zealand electricity wholesale spot prices (actual and forecast)**
(Quarterly average, 2025 real $/MWh, 2015–2028)




Note: Spot price and forecasts reflect Otahuhu. Future prices derived by applying spot volume-weighted trading average (Benmore, Ota 1:1.35) to listed electricity futures. Forecasts based on Concept Consulting analysis
Source: EMI, Concept Consulting Forward Electricity Price Forecast, ASX

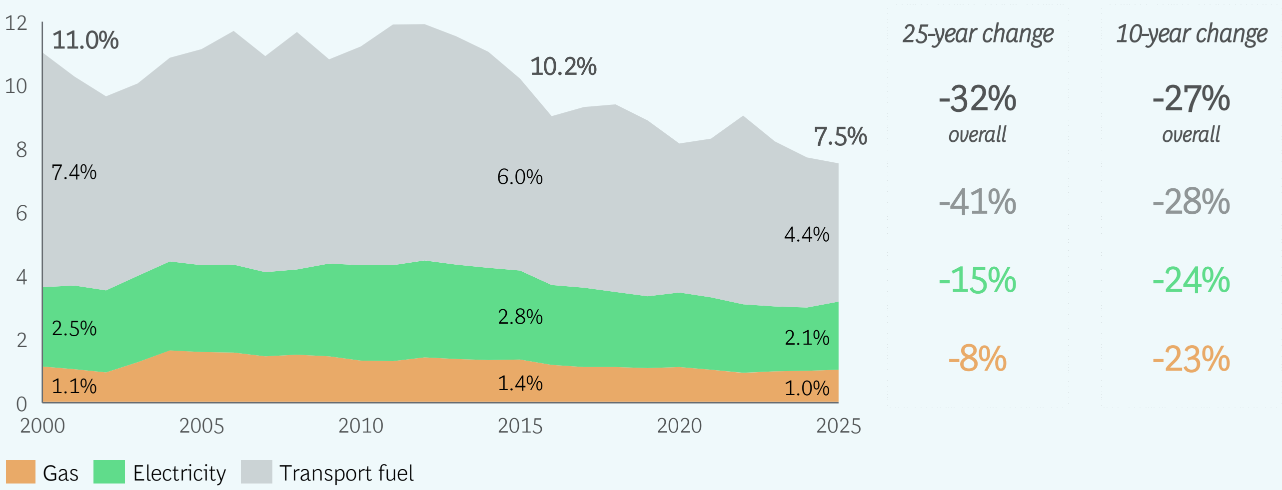
## Households are spending less of their income on energy than 25 years ago

Over the past 25 years, the proportion of income an average household spends on energy has fallen by 32% – from 11% in 2000 to 7.5% in 2025 – including a 27% reduction over the last decade (see **Exhibit 60**). The proportion of income an average household spends on electricity and gas has fallen by 13% – from 3.6% in 2000 to 3.1% in 2025 – including a 24% reduction over the last decade (see **Exhibit 60**).

Energy bills comprise electricity, gas and fuel for vehicles for an average typical household, and are a function of energy unit pricing and energy consumption. Trends in both these drivers across the three energy categories – together with rising real incomes – have all simultaneously contributed to the net reduction of real household energy spending against income over 25 years.

Exhibit 60: Average household energy spend as a proportion of real income

**Household energy spend as proportion of real income**
(% of real household income)



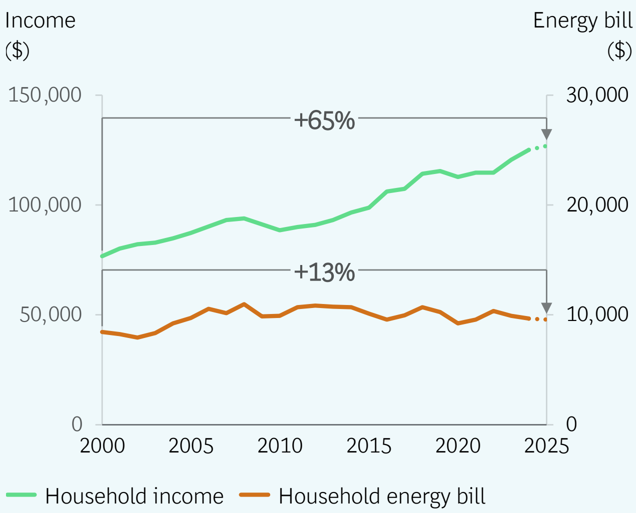

Note: All spend figures are aggregated averages across households to illustrate underlying trends; energy consumption varies by individual household. Study assumes household is connected to North Island reticulated gas network as a typical gas user. Median household income.
Source: Statistics NZ, Oxford Economics, MBIE, Ministry of Transport, Consumer NZ, Australian Govt. Dept. of Infrastructure and Regional Development, EV Dashboard NZ, BCG analysis

## Total household energy bills have risen 13% in real terms over 25 years, offset by a 65% rise in real incomes

Real household incomes have risen 65% over the past 25 years – including 28% in the last decade – significantly outpacing real growth of 13% in total household energy bills (see **Exhibit 61**). On average, households are now in their strongest position of the last 25 years, spending 7.5% of their income on energy, as opposed to 11% in 2000.

Exhibit 61: Median real household income and real household energy bills

**Median real household income and real household energy bills**
(2025 $)




Source: MBIE, Ministry of Transport, NZ Treasury, RBNZ, Oxford Economics, Consumer NZ, Desktop Research, BCG analysis

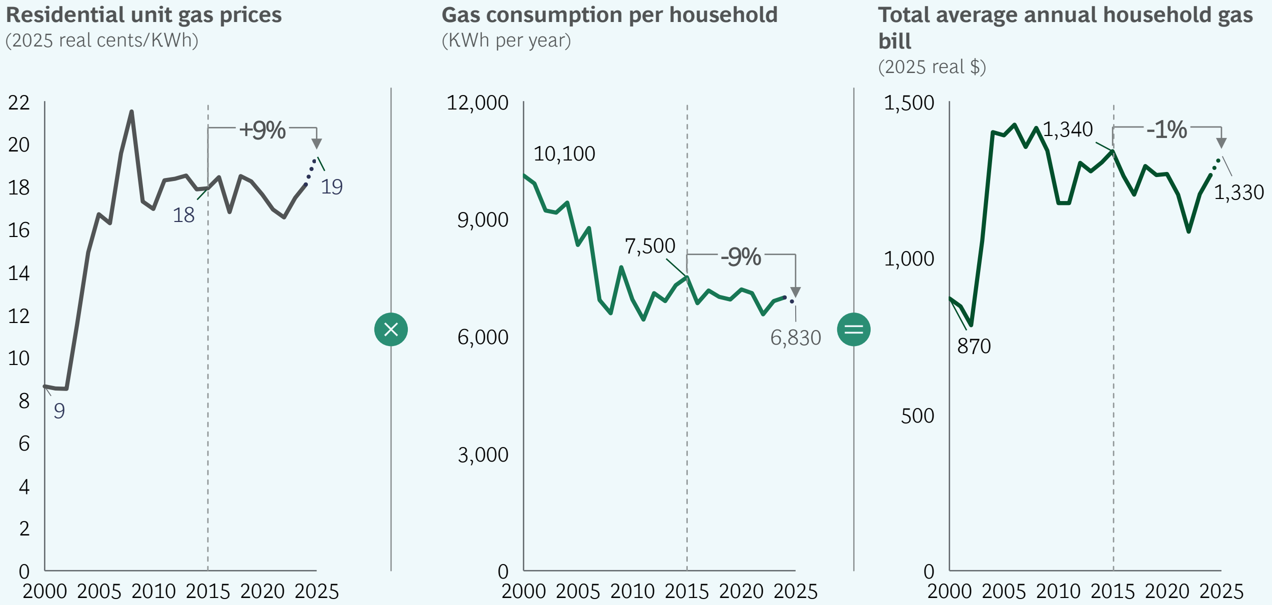
**Households are spending more on gas than 25 years ago, and roughly the same as a decade ago**

Many households use natural gas for water heating, cooking and space heating. The number of houses connected to the reticulated North Island gas network has steadily increased over the last 25 years.[61]

Residential unit gas prices rose sharply in the early 2000s, following significantly lower-than-forecast production from the Maui gas field – historically New Zealand's largest field.[62] Consequently, average household gas consumption declined in response to higher prices. The first production from the Pohokura gas field in the mid-2000s offset the reduction in supply from Maui and helped to stabilise prices going forward.[63]

As a result, household gas bills rose sharply in the early 2000s, and have seen modest declines on average since then (see **Exhibit 62**).

Exhibit 62: Residential gas prices, consumption and annual gas bills




Note: 2025 figures are forecasts
Source: MBIE, Stats NZ, Gas Industry Co., BCG analysis

61 Gas Industry Co, Switching, 2025

62 MBIE, Gas Statistics, 2025

63 MBIE, Gas Statistics, 2025

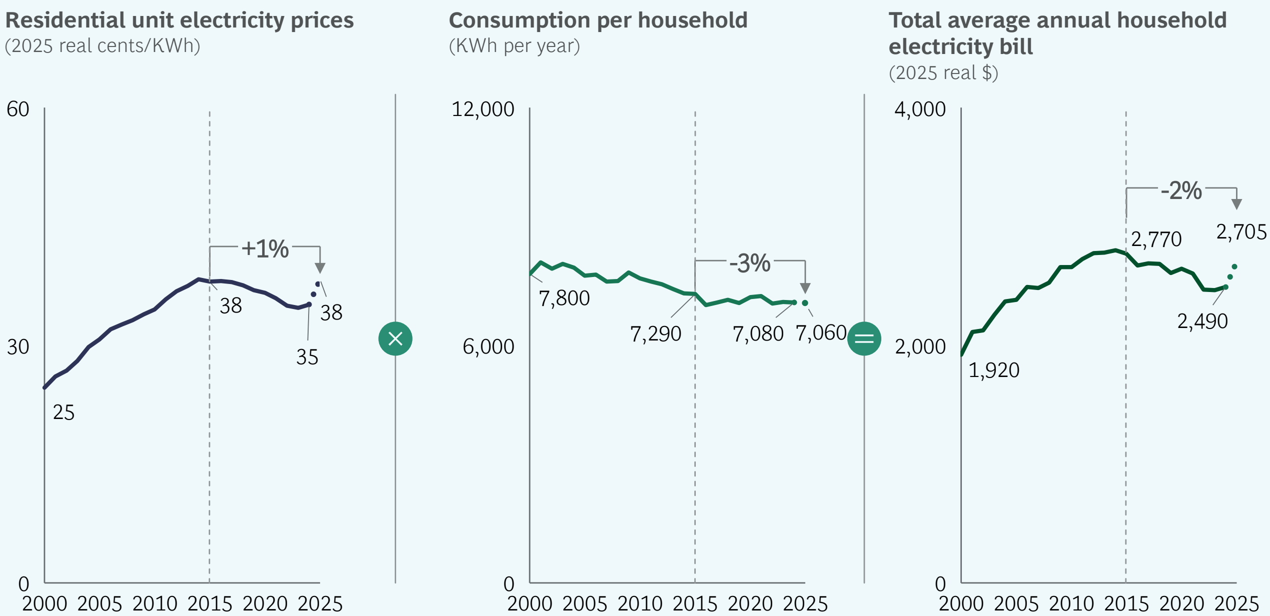
**Households are spending more on electricity than 25 years ago, but less than a decade ago**

Residential electricity prices rose steadily from 2000 to 2015, also driven by rising network costs and a series of dry years.[64] From 2015, unit prices fell in real terms – primarily due to lower lines charges, and pinched retail margins absorbing wholesale price increases. In 2025, lines charges are increasing which will flow through to household prices, as reflected in the forecast 2025 unit price.

Consumption per household has steadily decreased over 25 years, reflecting improvements in energy efficiency. These gains are largely attributable to more efficient appliances and better home insulation, enabling more efficient space heating.

As a result, household electricity bills increased through the first 15 years of the century, then decreased by 2% on average over the last ten years (see **Exhibit 63**).

Exhibit 63: Residential electricity prices, consumption and annual electricity bills




Note: Unit price 2025 forecast includes 2025 lines charge uplift; consumption 2025 forecast assumes ten-year trend continues
Source: MBIE Sales-Based Electricity Costs, Commerce Commission, BCG analysis

64 Commerce Commission, North Island Grid Upgrade, 2015

**Households are spending roughly the same amount on vehicle fuels as 25 years ago**

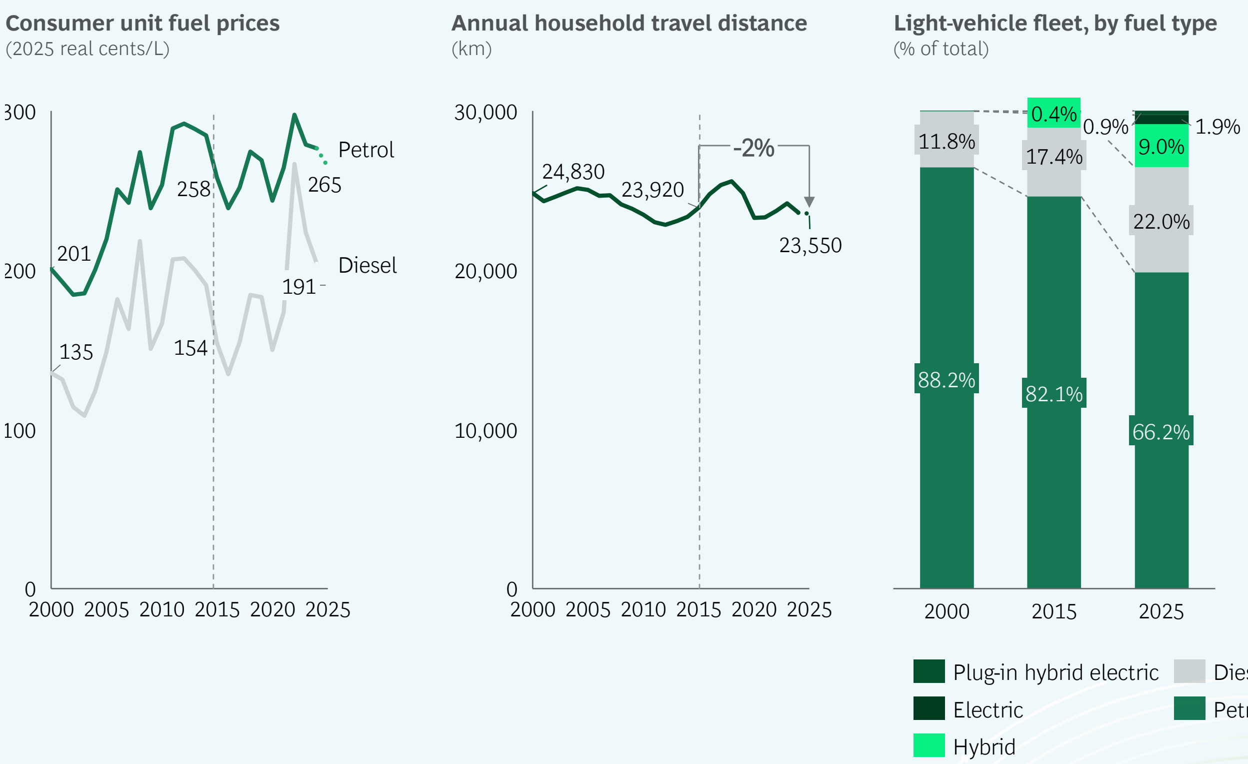
Private vehicles are the primary mode of transport for many households, meaning transport-related energy costs contribute substantially to household energy bills. Roughly 60% of average household energy bills relate to transport fuels.[65]

Over the past 25 years, fuel costs have increased overall, with significant volatility. Petrol unit prices have risen 30%, and diesel by 40%. Given New Zealand's reliance on fuel imports for transport, its domestic fuel prices are exposed to global volatility, which flow through to household energy bills.

Over this same period, household travel distances have remained relatively flat, with interim declines following shock events such as the COVID-19 pandemic (see **Exhibit 64**).

The impact of higher fuel prices has been offset by improvements in vehicle efficiency, as households gradually transition to more efficient alternatives such as diesel vehicles, hybrids and electric vehicles.

Exhibit 64: Consumer unit fuel prices, annual household travel distance, light vehicle fleet composition, 2000–2025



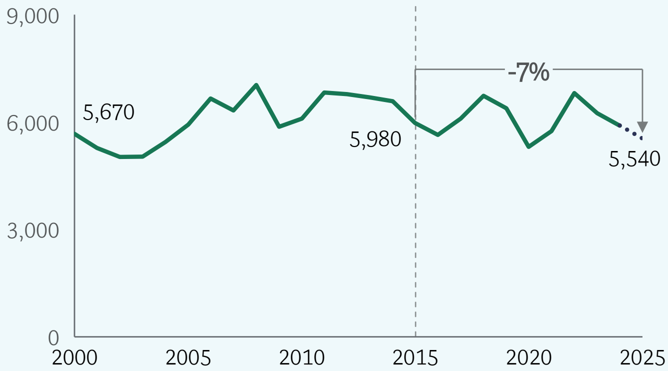

Note: Light-vehicle fleet 2025 figures are forecasts based on growth trajectories
Source: MBIE, Ministry of Transport, BCG analysis

65 World Population Review, Cars by Country, 2025

As a result, household transport energy bills over 25 years have remained relatively flat overall, with high inter-year volatility flowing through from global fuel price movements (see **Exhibit 65**).

Exhibit 65: Energy bills for transport have been volatile, but remained relatively flat overall

**Total average annual household transport fuel bill**
(Real 2025 $)




Source: MBIE, Ministry of Transport, Oxford Economics, Consumer NZ, Desktop Research, BCG Analysis

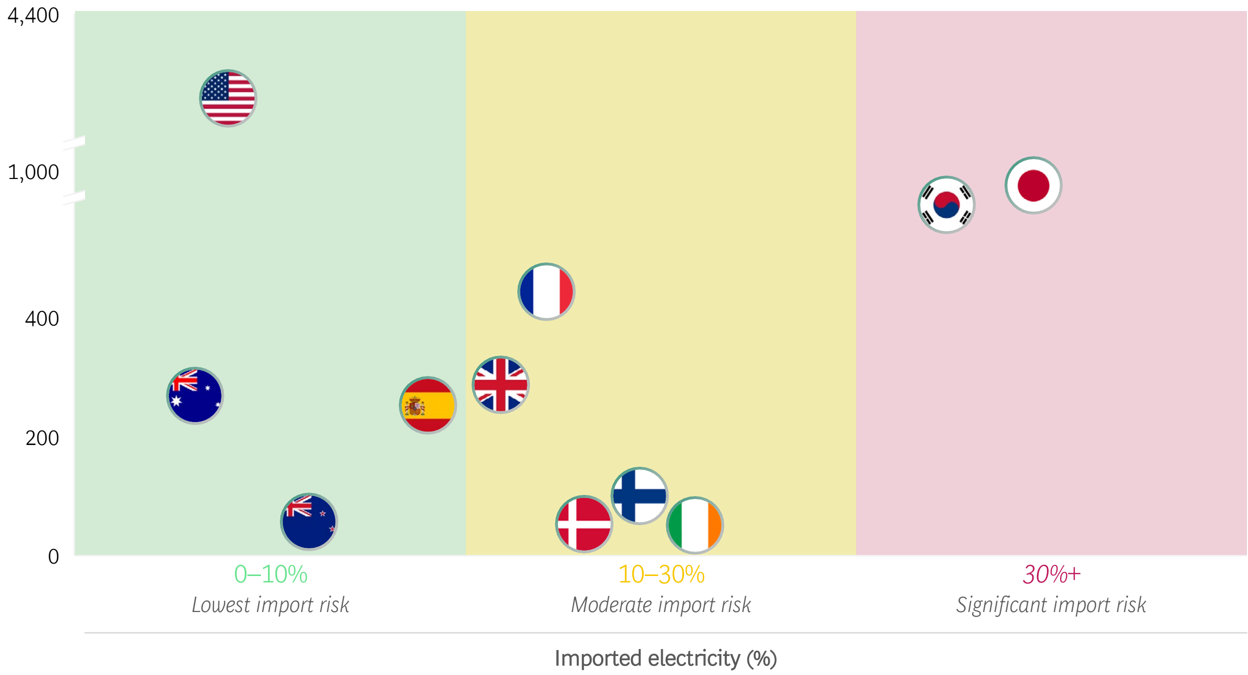
## 4.3.2 Performance on energy security

**New Zealand's energy system is relatively reliable and secure**

New Zealand's energy market is secure by international standards, supported by a largely self-sufficient system with fuel imports. A balanced generation portfolio, anchored with strong hydro resources, intermittent renewables and complemented by flexible thermal and stable baseload capacity, supports resilience and buffers the country from global energy shocks. While extreme weather events and earthquakes pose risks to infrastructure, widespread blackouts are rare and the domestic market reliably meets demand.

Exhibit 66: Total energy consumption and import reliance

**Total electricity consumption**
(TWh, 2023)




Source: IEA, Statistic Review of World Energy

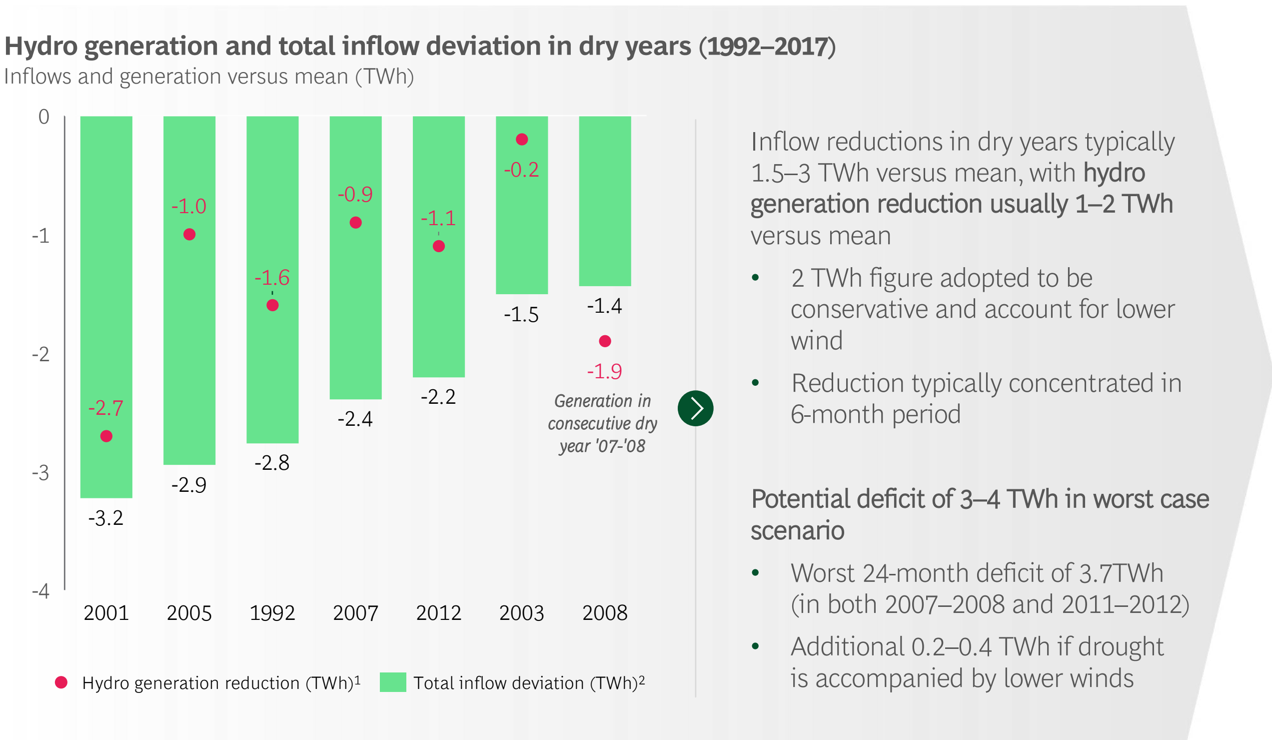
**Dry, windless periods present the biggest risk to energy security and have previously been managed with increased gas generation**

The key risk to energy security in New Zealand is dry and windless periods, due to its high share of hydro generation and growing share of wind generation. At present, hydropower provides 55–60% of New Zealand's electricity, exposing the system to hydrological risk; in historical 'dry years' New Zealand typically experiences an inflow deficit of 1–3 TWh, but disciplined water management has limited the drop in hydro generation to 1–2 TWh. In extreme cases, there can be 'effective' inflow deficits of 3–4 TWh, as seen in 2001 when inflows fell by 3.2 TWh in a single year, and in 2007–2008 when consecutive low-inflow years produced a 24-month deficit of 3.7 TWh versus typical inflows, further depressing hydro generation.[66] As wind capacity grows there is additional risk if the drought is accompanied by lower winds. The worst-case scenario is therefore a 4 TWh deficit in generation across consecutive dry and windless periods.

Historically, dry periods were managed by reducing demand and increasing thermal generation. As more flexible thermal capacity came online in the late 1990s and early 2000s, conservation campaigns waned and dry years were met primarily by thermal generation, with low-cost domestic gas and combined-cycle gas turbine (CCGT) facilities providing most of the flexibility.[67]

**However, in 2024 the energy market was presented with a different challenge: gas market tightness and low hydro inflows required a different method to ensure supply**

Exhibit 67: Hydro generation and total inflow deviation in dry years (1992 – 2017)

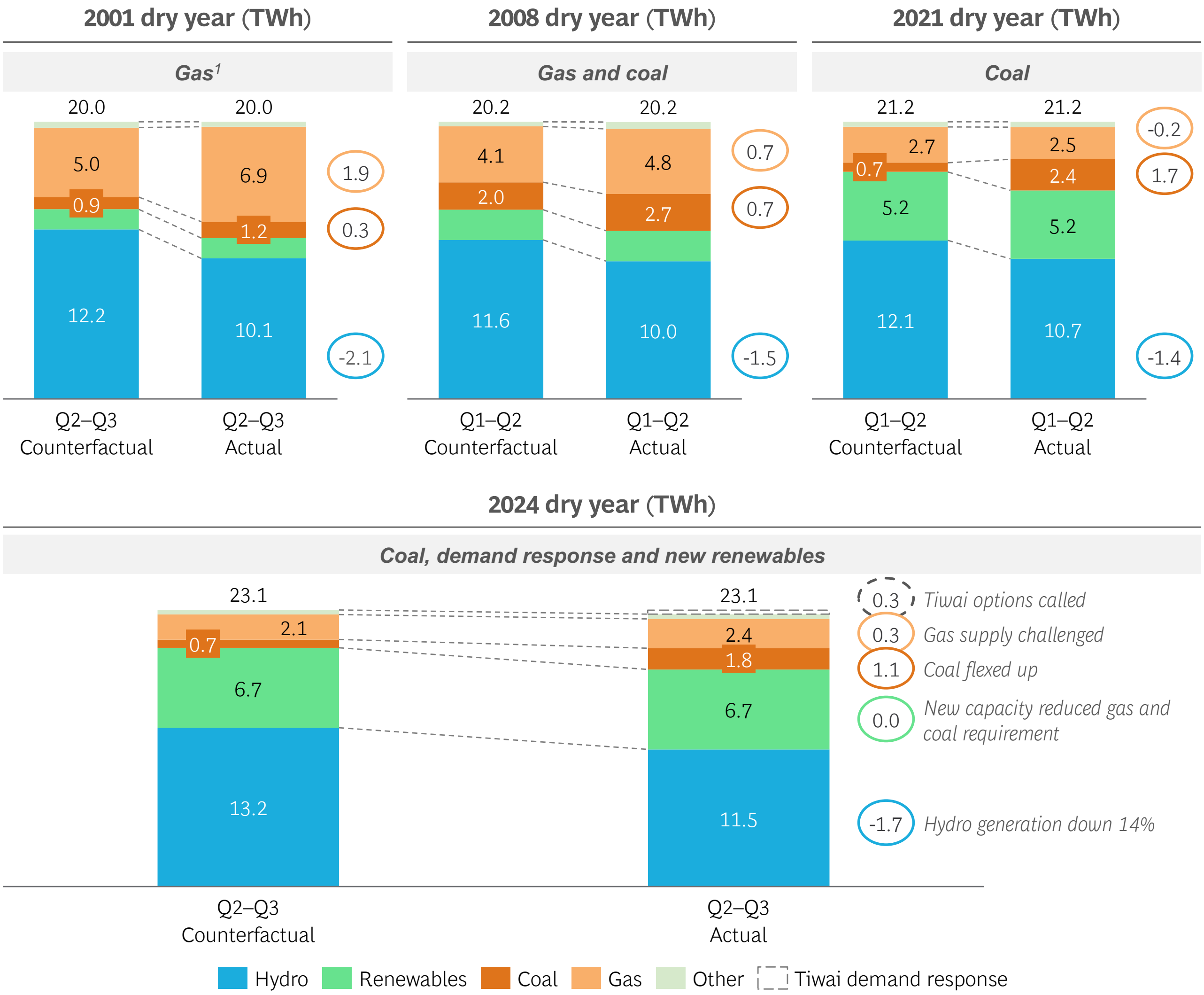



1. Reduction calculated against average generation in 5 previous years; 2. Inflow deviation calculated as delta between annual inflow and median of seasonal inflows (1992–2017)
Source: Hydro Inflow data from MBIE Estimated Gross Benefits of NZ Battery options (2021), MBIE Annual Electricity Generation

66 MBIE, Estimating the Gross Benefit of NZ Battery Options, 2022

67 MBIE, New Zealand Generation Stack Updates, 2020

## Exhibit 68: Management of dry periods, 2000–2024




1. Gas supply was more flexible due to Maui's swing production capabilities. These are no longer feasible due to depleted field reserves
Note: Counterfactual reflects average hydrological generation of 5 previous, hydrologically typical years, actual renewable and 'other' generation, and assumes thermal fills remaining gap to demand. Reflects 6-month generation profiles
Source: MBIE Quarterly Generation and Demand, Electricity Authority Eye on Electricity - Tiwai Demand Response 2024

In the first half of 2024, New Zealand experienced one of the driest periods on record, with hydro generation falling by 1.7 TWh. This coincided with challenges in the domestic gas market, with gas production declining faster than the Producer Forecast and market expectations, leaving the gas market tight and unable to ramp up and down to make up for the deficit in hydro generation.

The electricity sector responded with a combination of levers:

- Genesis drew on a 730kt solid fuel stockpile and restarted imports from Indonesia, delivering 350–400kt between July and September 2024.[68]
- Contact and Genesis signed a gas offtake agreement with Methanex, securing 6.7PJ of gas for electricity generation at the peak of electricity prices.[69]
- Meridian and Contact activated their Tiwai options, reducing demand by 0.3 TWh between August and September.[70]

68 Genesis Energy, Genesis Commits to Solid Fuel Stockpile for Security, 2024

69 Contact Energy NZX Announcement, Contact secures Gas from Methanex, 2024

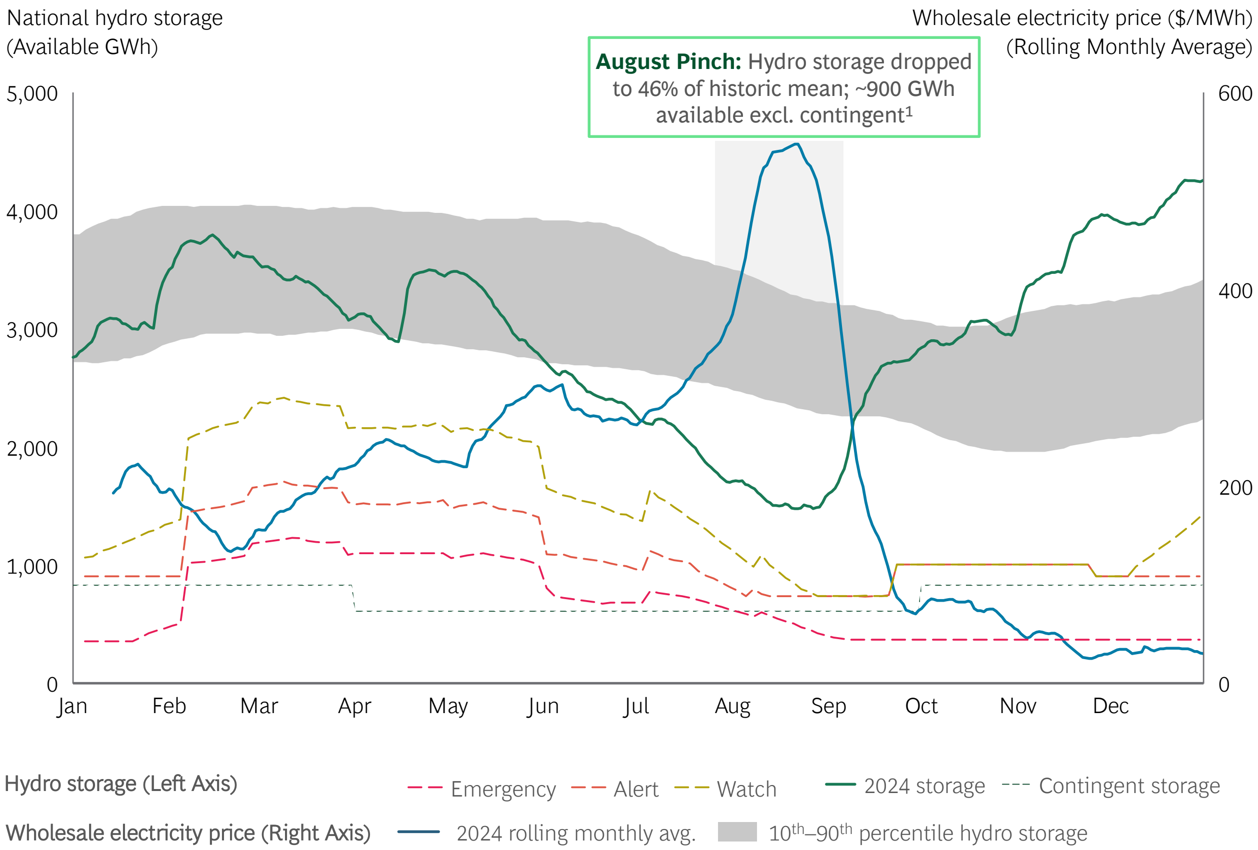
70 Meridian Energy, Demand Response Agreement, 2024

- Transpower lifted the contingent storage access trigger, making an additional 0.6 TWh of hydro storage accessible for generation (remained unused as rain arrived shortly after).[71]

Although thermal flexibility was required to manage hydro levels, demand was served with record low thermal fuel use for a dry, windless period, due to the 1.5 TWh of renewable generation that was added to the system from 2021 to 2023.

However, as hydro storage declined, wholesale electricity prices rose, spiking further when gas supply constraints drove up fuel costs, reaching $800 per MWh in August before easing as the Methanex offtake deal reduced fuel uncertainty and rain arrived. Importantly, the vast majority of volumes were hedged, meaning most users did not feel the impact of elevated spot prices. Exposure was limited due to appropriate hedging by large industrial consumers and gentailers on behalf of residential and commercial.

## Exhibit 69: Hydro storage and electricity prices, 2024




1. Additional 612 GWh in contingent storage, noting Transpower lifted the access trigger in late August – later rainfall meant this was not met and contingent storage was unused
Source: Electricity Authority NZ Wholesale Prices, Transpower Monitoring Report

While 2024 confirmed that dry periods pose material risk, the maturing energy ecosystem and market responses place New Zealand in a stronger position to manage these events. While historically dry periods threatened security and affordability, today the market can meet demand and do so more sustainably, albeit at higher costs.

71 Transpower, Transpower Gives Industry Additional Flexibility to Manage Emerging Electricity Supply Risks, 2024

## Exhibit 70: Affordability, security and sustainability outcomes of dry periods

| *Energy Trilemma* | 1992 Q2–3 | 2001 Q2–3 | 2005 Q3–4 | 2008 Q1–2 | 2012 Q1–2 | 2021 Q1–2 | 2024 Q2–3 | 7 dry years in last ~30 years; 2 in last 4 years |
|---|---|---|---|---|---|---|---|---|
| Security | Conserva-tion Call on all users for voluntary saving of 10% of demand | Conserva-tion 10-week campaign to reduce public demand 10% (15% in govt. sector) | Demand met | Demand met (noting voluntary public awareness campaign run encouraging prudent use) | Demand met | Demand met (noting Tiwai demand response) | Demand met (noting Tiwai and Methanex demand response) | Market now reliably solves to meet demand |
| Affordability (Real $/MWh) | Not available | $3,100 in Q3 5x prior 8 qrt. avg. Gas: $8.7/GJ Coal: $230/t | $177 in Q3 1.8x prior 8 qrt. avg. Gas: $10.6/GJ Coal: $190/t | $366 in Q2 3x prior 8 qrt. avg. Gas: $7.6/GJ Coal: $225/t | $169 in Q2 1.8x prior 8 qrt. avg. Gas: $10.5/GJ Coal: $180/t[1] | $334 in Q2 2.2x prior 8 qrt. avg. Gas: $12.1/GJ Coal: $240/t[1] | $317 in Q3 2.2x prior 8 qrt. avg. Gas: $17.0/GJ Coal: $225/t | 2024 prices in line with past, despite higher gas costs |
| Sustainability (% renewable electricity) | 69% | 57% | 63% | 58% | 65% | 75% | 81% | Dry years now met with lower emissions |

*Fossil fuel costs incl carbon costs after 2012* →

1. Adjusted prices based on the trailing average coal price ratios of from 1 to 1.8 for 5000kCal ICI 3 coal compared to HBA standard grade
Source: MBIE Annual Electricity Generation, MBIE Real Quarterly Average Fuel Prices, MBIE Coal Prices in New Zealand Markets, RBNZ Inflation Figures, Bloomberg Indonesian Coal Reference Prices HBA Standard Market, EPA Historical NZU Prices, JWC Indonesia Coal Price Index

**The sector has taken considerable action to ensure security and mitigate affordability challenges that emerged in 2024**

In 2025, gentailers have taken further action individually and as a sector to better prepare for and manage dry, windless periods:

- Gentailers entered a solid fuel contract, Huntly Strategic Energy Reserve Agreement, which has strengthened system resilience, lifting total solid fuel supply to 1,100kt (600kt under the 2025 agreement) and ensuring Rankine unit operations at Huntly Power Station to 2035.[72]
- Contact and Genesis entered gas offtake agreements with Methanex and Ballance (Autumn 2025), providing more confidence around gas supply and mitigating the risk of extreme electricity prices.[73]
- Between 2024 and 2025, 3.5 TWh of new generation is expected to come online, including 320MW of geothermal baseload, and complemented by 200MW of new battery capacity, bringing total BESS capacity to 330MW.[74],[75]

72 Commerce Commission, Commission Authorises Gentailers' Application for Strategic Energy Reserve, 2025

73 Contact Energy, Contact Secures Gas from Methanex, 2025

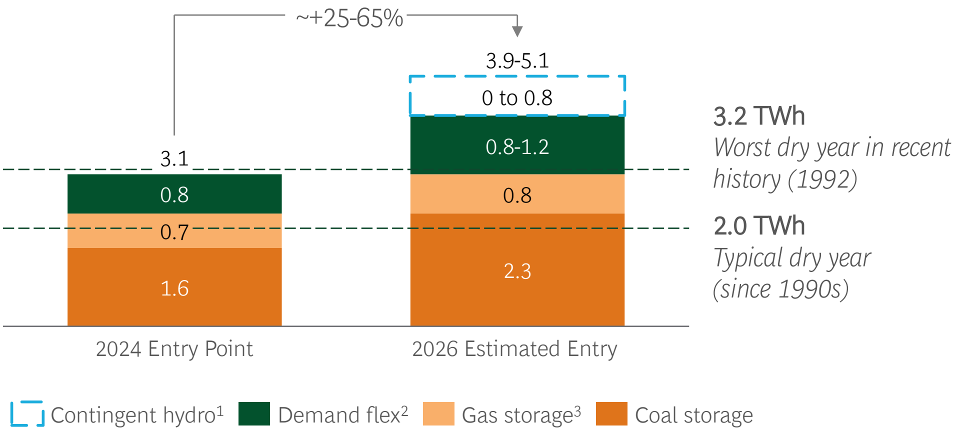
74 EA, Generation Investment Pipeline, 2025

75 Concept Consulting, Development Pipeline

Going into 2026, the electricity industry will be in a better position (see **Exhibit 71**).

### Exhibit 71: Industry action to lift winter energy fuel storage and demand flexibility for 2026 versus 2024

**Electricity storage and flex**
(TWh)




1. Existing 832 GWh of contingent hydro storage across Tekapo, Pukaki and Hawea; 2. Tiwai up to 0.8TWh and Methanex gas flex agreements (assumes similar volumes as seen in 2025 of 2.8 PJ); 3. Assumes 6 PJ of gas in Ahuroa storage
Source: Company Announcements, BCG Analysis, Electricity Authority

Additionally, new gas storage investigations are underway for 2026 and beyond, and Transpower is undertaking a full review of its contingent hydro storage access.

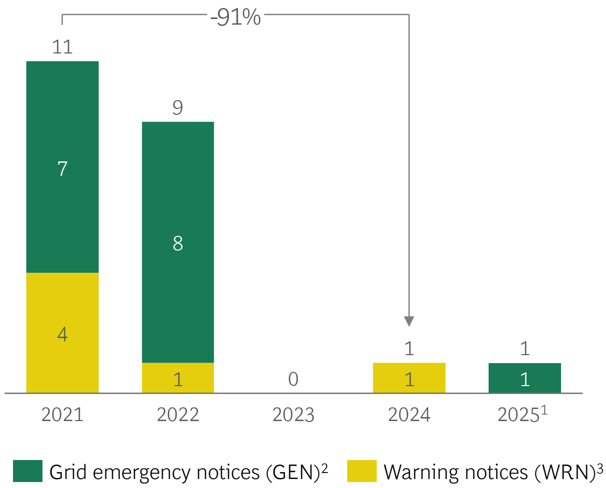
In the years ahead, thermal generation in New Zealand will continue to be challenged by the ongoing decline of the gas market, which tightens dry period flexibility. The energy system will need to carefully manage gas demand, maintain fuel flexibility and sufficient thermal capacity, and develop more storage to handle seasonal and year-to-year swings.

While these challenges remain, overall resilience has improved as the combined impact of market mechanisms, storage and new generation reduce exposure to dry period conditions. In this context, the challenge will be ensuring the system can address dry-year risk affordably.

In terms of meeting peak demand the sector has made significant improvements towards a smart system with increased levels of batteries and demand response. As a result the frequency of Transpower formal notices for potentially insufficient generation or reserves has declined significantly since 2021, the year in which the 9 August blackout was experienced.

### Exhibit 72: The frequency of 'Formal Notices' issued by Transpower

**Transpower formal notices for potentially insufficient generation or reserves**
(2021–2025)




1. Through October 2025; 2. Early signals that the electricity system is under stress, potential risk to supply demand balance; 3. Formal notification that power system is no longer secure, and urgent action is required
Note: 2021 and 2024 reflect dry, windless conditions; 2023 reflects market shocks following the Hawke's Bay hurricane; 2022 and 2025 reflect typical hydrological conditions
Source: Transpower

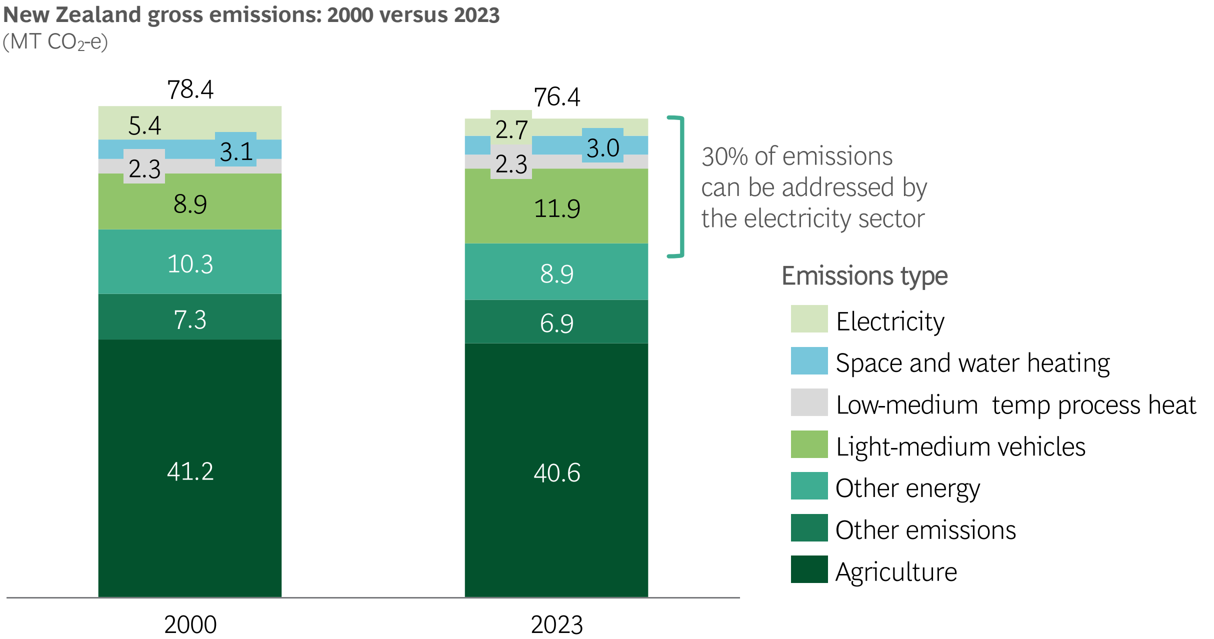
### 4.3.3 Performance on energy sustainability

**Energy emissions have declined by 18% since 2005**

New Zealand has made significant progress in sustainability, developing renewable capacity to support the decarbonisation of the electricity network, transport and industry, alongside improvements in industrial efficiency and carbon-reduction methods.

On a total emissions basis, New Zealand's emissions have only declined slightly (see **Exhibit 73**). However, electricity emissions declined 66% between 2005 and 2023 (see **Exhibit 75**) while overall energy sector emissions declined 18% in the same period. This is because transport emissions have increased slightly since 2005 and other energy emissions (e.g. industry) have remained flat.

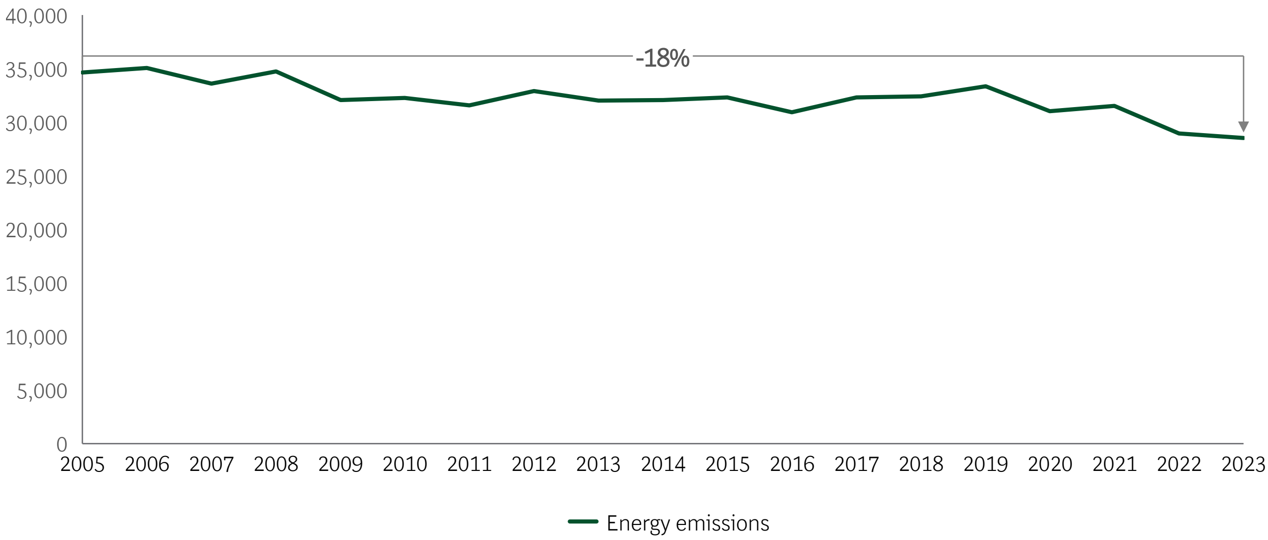
Exhibit 73: New Zealand's gross emissions 2000 versus 2023




Source: Climate Change Commission, MBIE, Ministry of Transport, Ministry of the Environment

### Exhibit 74: Energy sector emissions 2005 to 2023

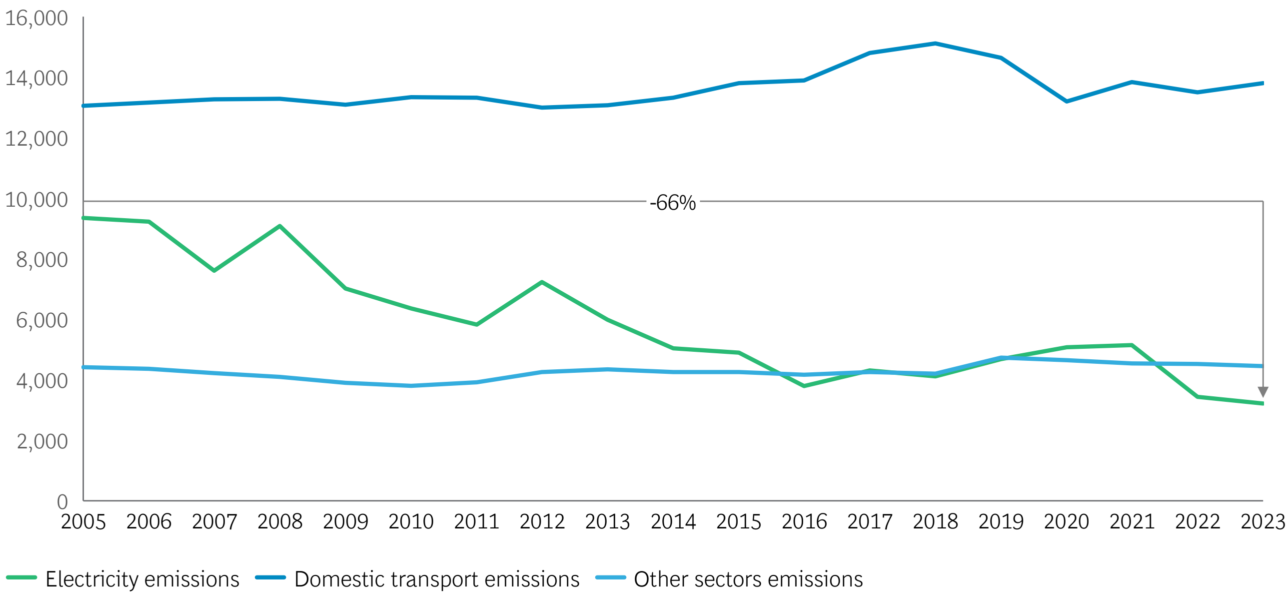
**Energy sector emissions over time (2005 to 2023)**
Kilotonnes carbon dioxide equivalent (kt $CO_2$-e)




Source: MBIE Energy Sector Greenhouse Gas Emissions

### Exhibit 75: Emissions 2005 to 2023 – electricity, domestic transport and other sectors

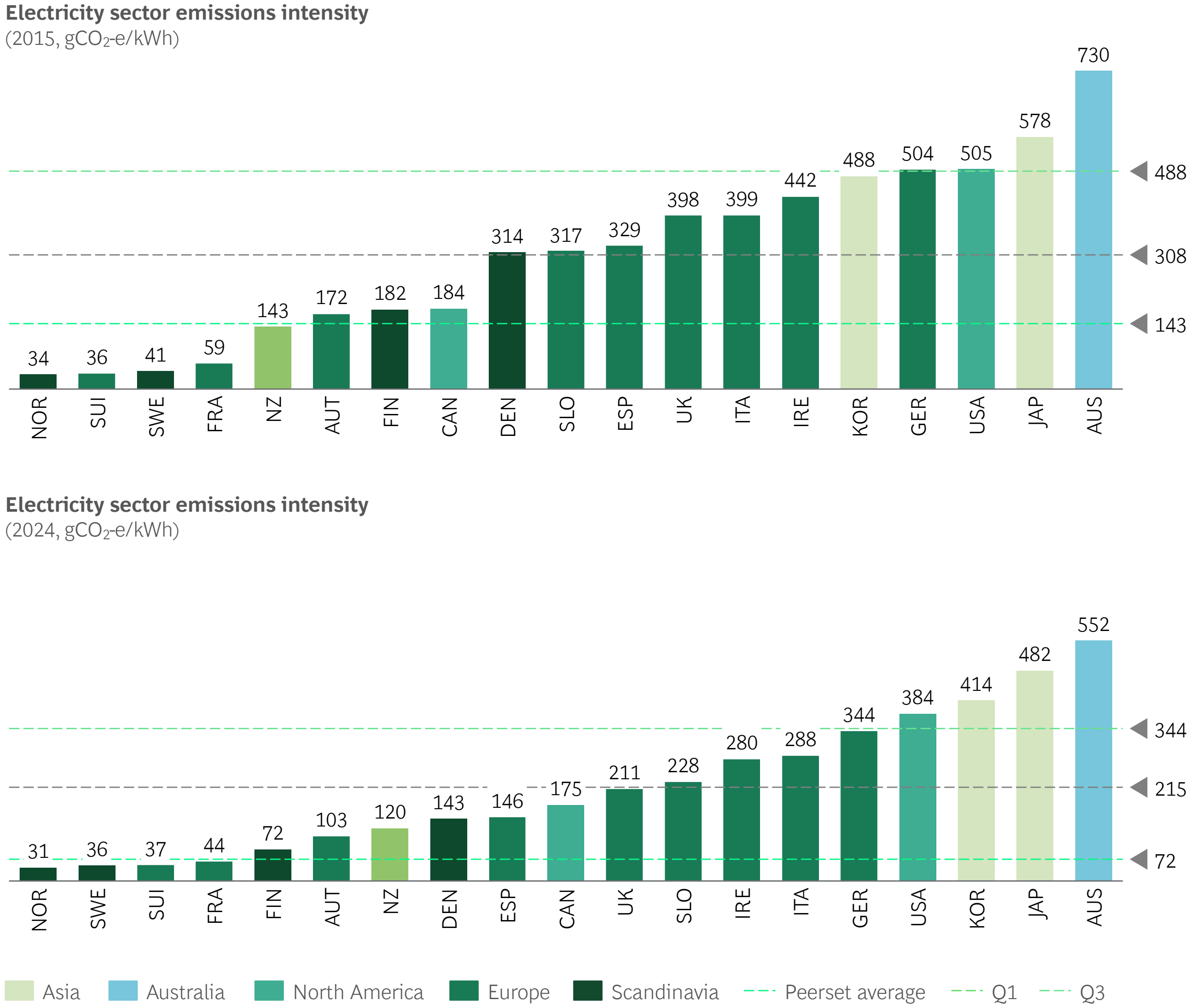
**Emissions over time (2005 to 2023) – electricity, domestic transport and other sectors[1]**
Kilotonnes carbon dioxide equivalent (kt $CO_2$-e)




1. Other includes Agriculture, Forestry and Fishing, Commercial and Residential
Source: MBIE Energy Sector Greenhouse Gas Emissions

**Electricity: New Zealand has a high share of renewables and a pipeline under construction to reach 95% renewable electricity by 2027**

Exhibit 76: International emissions intensity, 2015 and 2024




Source: Ember Research

From 2020 to 2024, New Zealand developed a significant amount of renewable generation, bringing online 4.2 TWh of renewable electricity compared to 0.3 TWh in 2015 to 2019. As a result, New Zealand reduced generation emissions intensity by 15%.

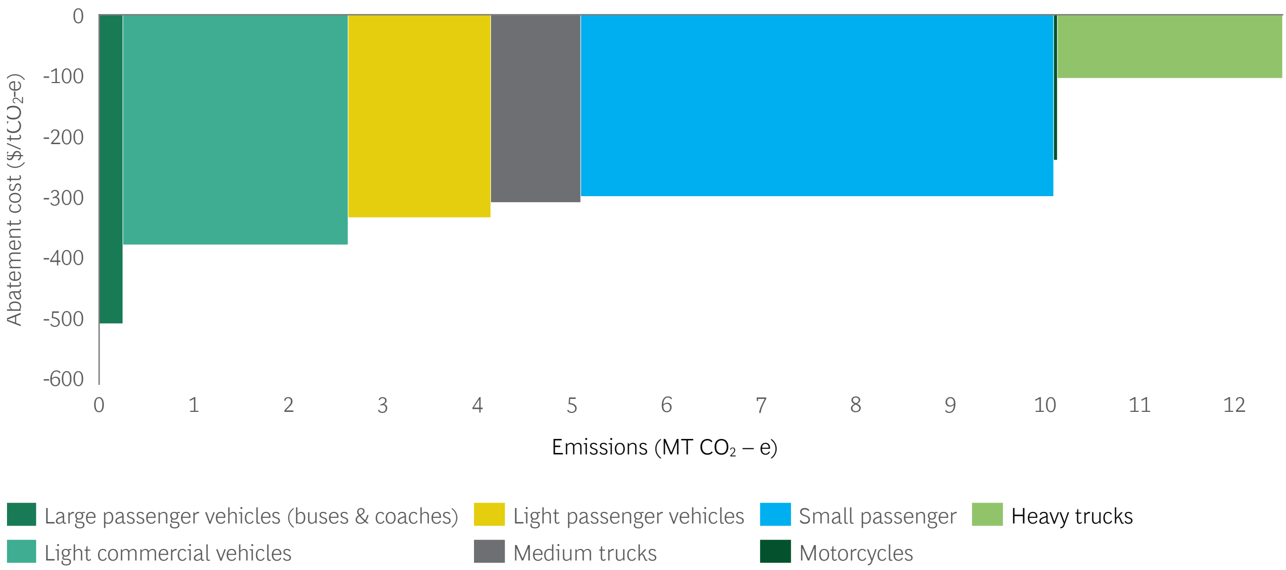
Planned projects to 2027 (see Section 4.1.1) would see a further 4.1 TWh of generation come online, lift renewable generation to over 95% and place New Zealand alongside Norway, Iceland and Costa Rica as OECD countries that generate this level of electricity from renewables. Beyond 2027 the pipeline is less certain. At present, 17 TWh of projects are in consenting processes and the progression of these developments to Final Investment Decision is critical to improving sustainability in the electricity sector.

**Transport: Electrification is a proven pathway to reducing transport emissions**

Electrification is a proven pathway to reducing the 12.5 MT of New Zealand's gross emissions, attributable to road transport, the second greatest source of emissions after agriculture (see **Exhibit 77**).

Exhibit 77: Abatement cost curve for transportation

**Transport MACC for 2030 – public benefit basis**




Source: Ministry of Transport, EV Database

Globally, the strongest near-term case for electrification is private vehicles and light and medium trucks, which account for 80% of transport emissions. Demonstrations are also underway to test the economics for heavy haulage and aviation. New Zealand has seen significant growth in electric vehicle (EV) ownership since 2017, with EVs representing over 80,000 new car purchases and 2% of the total fleet electric in 2025. This growth was driven by improving affordability of EVs and the Clean Car Discount, although momentum tapered after its repeal in 2023.[76]

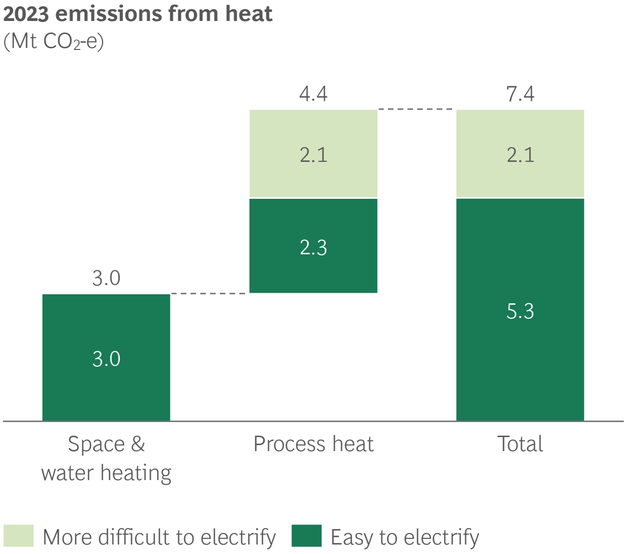
76 Ministry of Transport, Fleet statistics, 2025

**Renewable electricity offers a significant opportunity to decarbonise New Zealand industry**

Industry, excluding agriculture, is the third-largest contributor to emissions, accounting for 55–60% of total emissions. Renewable electricity is one of the strongest levers to decarbonise industrial activity, particularly by converting heat-intensive processes – usually powered by fossil fuels – to electricity, along with sustainable biomass. From 2019 to 2023, New Zealand reduced its annual process heat emissions by 2.2 MT CO2-e by switching to alternative fuels and increasing fuel efficiency, enabled in part by the GIDI fund, which had directly supported fuel switching and the displacement of 0.8 MT CO2-e of annual emissions.[77]

Compared with peers, New Zealand is well placed to electrify industry. About 70% of industry emissions are generated by low- and medium-temperature heat processes that can be converted with proven and available technologies and fuel – such as biomass boilers, electrode boilers and heat pumps (see **Exhibit 78**). New Zealand is also differentiated by its concentration of firm renewable generation that suits the steady, round-the-clock energy requirements typical of industry (see Section 3.3).

Exhibit 78: 2023 New Zealand process heat emissions




Source: EECA, Climate Change Commission

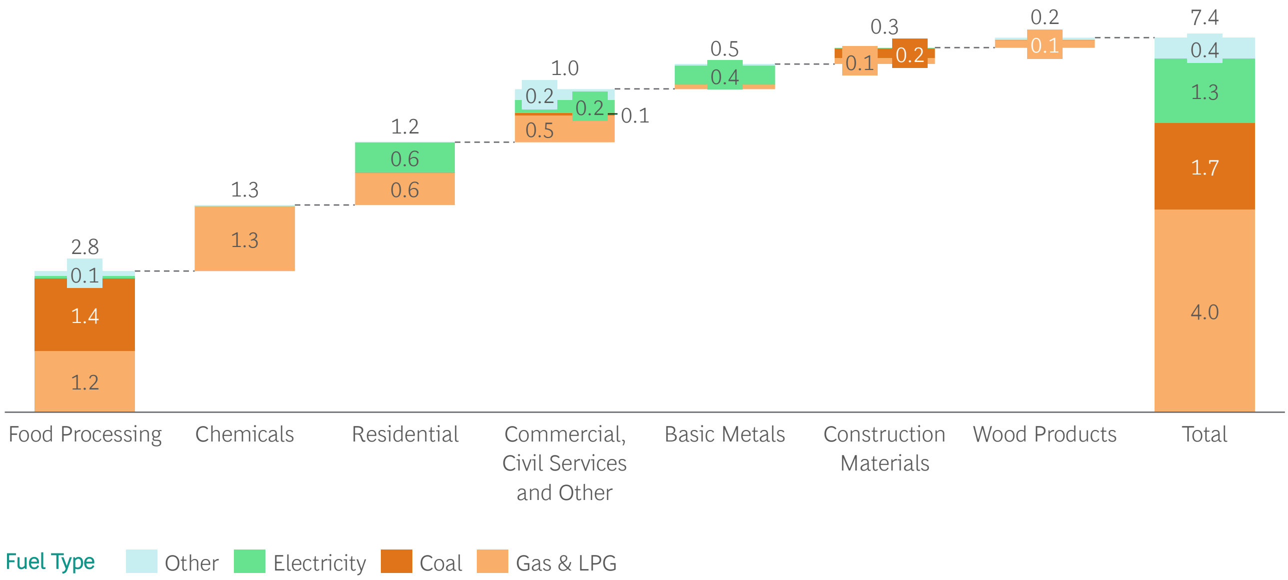
77 EECA, Approved GIDI projects, 2021–2023

With a number of industries suited to electrification, New Zealand could avoid an estimated 5.3 MT of CO2-e emissions each year by transitioning these industries to renewable electricity. The largest opportunities are in dairy, meat, wood processing, and heating for commercial, government and residential buildings. These opportunities alone account for 5 MT CO2-e of annual emissions (see **Exhibit 79**).

New Zealand's success in decarbonisation depends on it meeting rising electricity demand across the energy sector, industry and transport. It will require ongoing development of renewable generation, timely grid upgrades and storage, and a steady progression of projects through consenting and FIDs.

Exhibit 79: Process, space and water heating emissions across New Zealand

**Process, space and water heating emissions by industry and fuel**
(MT $CO_2$–e, 2023)




Source: EECA Process Heat Demand Dashboard, EECA Energy End Use Database 2023, MFE Emissions Factors 2023

5

# Priorities for improving energy outcomes over the next decade

The prior sections highlight the challenges and opportunities New Zealand's energy sector is facing – in energy affordability, security and sustainability, and economic growth. This section explores five priorities for improving trilemma outcomes over the next decade and capturing the opportunities that could come with an energy abundance mindset (see **Exhibit 80**).

These priorities are:

1. Accelerate renewable electricity generation development
2. Strengthen the electricity market and security mechanisms
3. Enhance lines infrastructure efficiently
4. Address gas supply decline and introduce domestic gas alternatives
5. Enable gas users to transition

The discussion informed the modelled scenarios explored in Section 6 and the specific recommendations in Section 7.

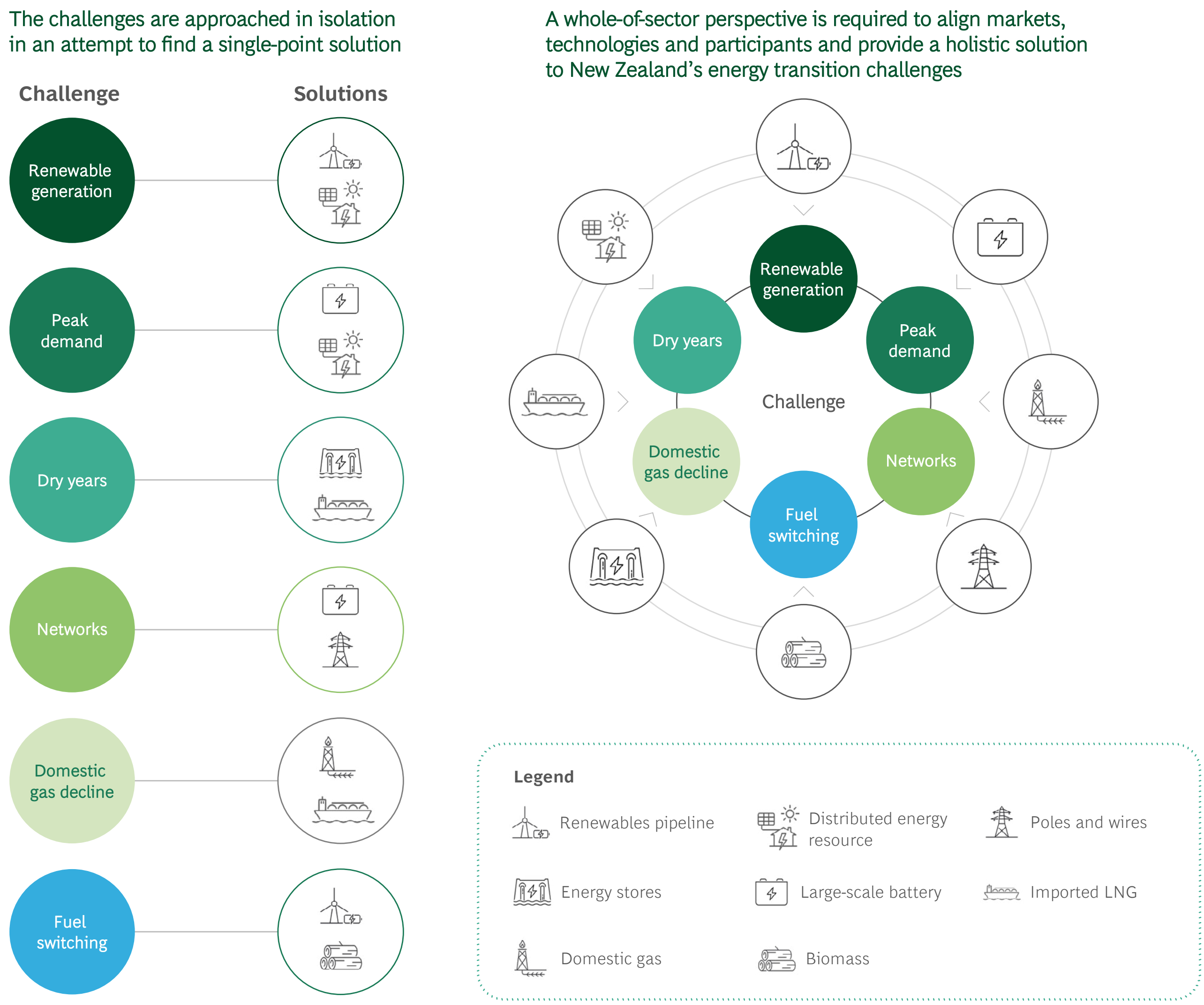
Exhibit 80: Priorities and their role in improving energy outcomes

| Priorities | Role in improving energy outcomes |
|---|---|
| Accelerate renewable electricity generation development | Ensures electricity gen runs ahead of demand growth (due to electrification / gas fuel-switching and economic growth) |
| | Displaces thermals in electricity generation, leaving them with targeted roles for solid fuels (dry year) and gas (intra-week) |
| | Weakens the gas-electricity price linkage, improving electricity affordability |
| Strengthen the electricity market and security mechanisms | Provides energy security and relative affordability through dry and/or windless periods (months/seasons) and provides gas electricity generation alternatives to 'cap' gas price |
| | Increases electricity security by growing evening peak delivery and redundancy at an affordable price |
| Enhance lines infrastructure efficiently | Enables timely generation and demand connections |
| | Provides grid stability (e.g. in weather events) and flexibility (e.g. North-South transfer) lifting security outcomes |
| Address gas supply decline and introduce domestic gas alternatives | Provides gas market price relief |
| | Extends runway for gas to electricity/biomass conversions by industry |
| | Enables balancing of gas supply and demand, with storage helping move gas through seasons and years during the next decade of the energy transition (e.g. absorbs gas post potential Methanex exit for use by electricity generation in future dry/windless periods) |
| | Provides supply security via fuel source flexibility if the domestic gas decline continues unabated |
| | Creates a 'price' ceiling on domestic gas at the point cost parity is reached with alternative |
| Enable gas users to transition | Minimises gas demand destruction (due to industrial gas shortages) |
| | Equips stakeholders, especially industrial users, with the information to make better investment and contracting decisions |
| | Educates the public on the domestic gas decline so are empowered to further pursue electrification |

These priorities, while each critical in their own right, together present a holistic approach to managing the energy transition and improving energy trilemma outcomes. For example, while it is critical that the electricity industry continues to build renewables at pace, building new renewables alone cannot address the industry's challenges – renewables must be complemented with thermal fuel flexibility, storage and investment in lines networks. Likewise, addressing tight supply in the gas market not only improves gas bills but also eases pressure on electricity prices because it lowers the cost of firming (see Section 4.3.1 'At a glance: Factors influencing wholesale prices').

Players across New Zealand's energy system must therefore work together to deliver solutions across renewable generation, thermal fuels, dry-year energy storage, grid transmission and distribution networks, gas production and gas demand (see **Exhibit 81**).

Exhibit 81: Whole-of-sector perspective to growing electricity supply and improving security



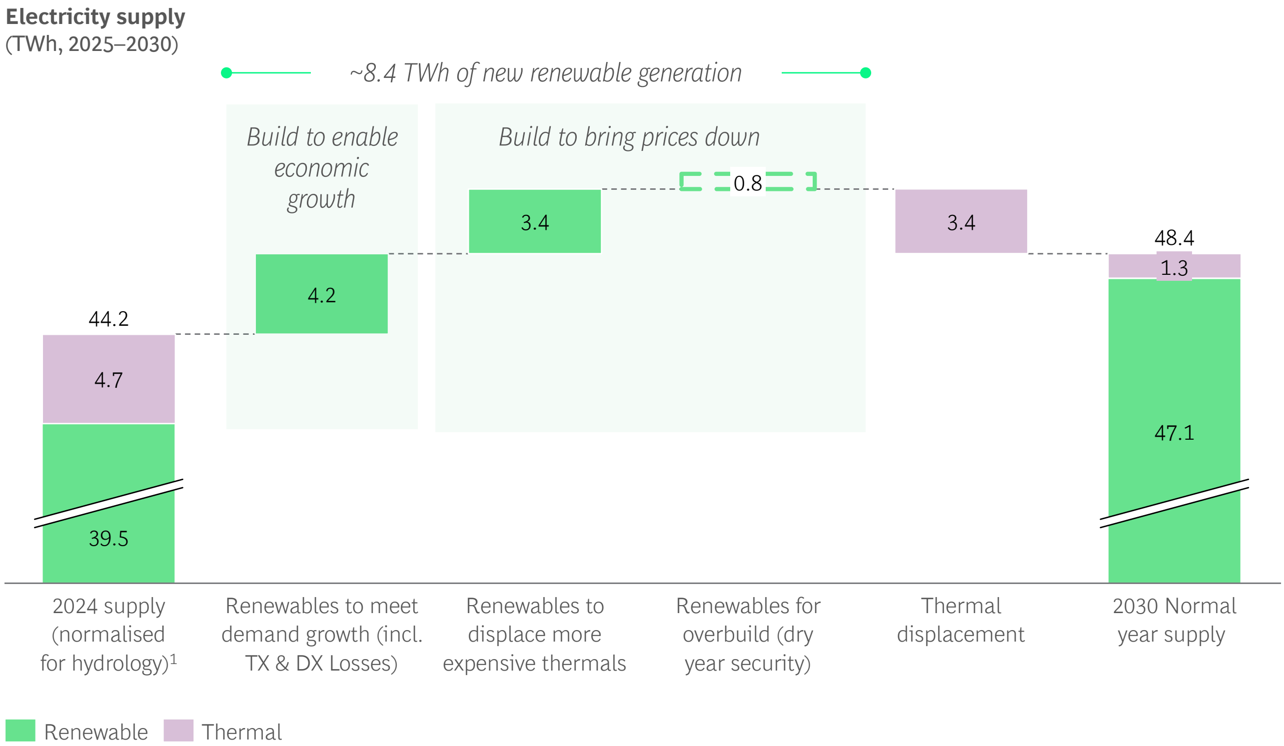
## 5.1 Accelerate renewable electricity generation development

To improve energy security, affordability and sustainability, renewable generation developers must consistently deliver new renewable generation. This will help New Zealand meet annual demand growth of 0.5–1.0 TWh and displace thermal generation to further lift renewable generation's share of total electricity supply. Displacing more expensive thermal fuels and building renewables to achieve modest spill in a normal hydrological year is also important in moderating electricity prices.

**By 2030, New Zealand will need 8.4 TWh of new renewable generation to meet demand and improve trilemma outcomes**

New Zealand will need to build 4.2 TWh renewable generation to meet demand associated with economic growth,3.4 TWh for thermal displacement and 0.8 TWh for renewable overbuild to meet dry years (see **Exhibit 82**).

Exhibit 82: Renewable development needed to meet demand and bring prices down by 2030

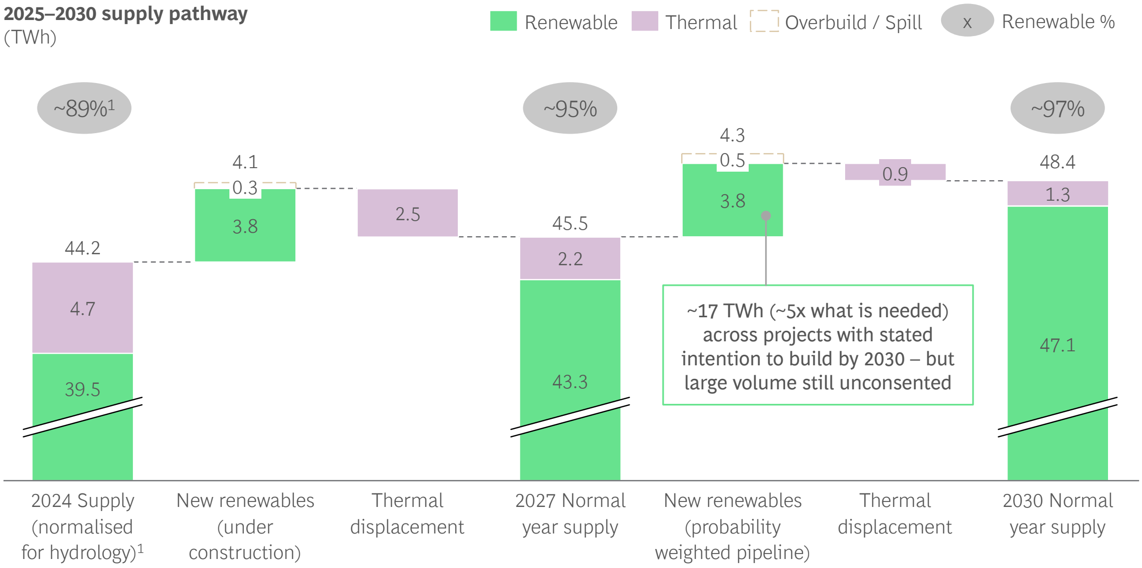



1. Normalised for a mean hydrological year; 2024 actual supply of 42.2 TWh with 0.3TWh Tiwai Demand Response added; not including co-generation
Note: Numbers may not add due to rounding
Source: MBIE Electricity Generation, Concept Consulting Weighted Development Pipeline

**The current pace of renewable development provides confidence that New Zealand can meet demand and improve trilemma outcomes to 2027**

From 2025 to 2027, projects already under construction or committed are expected to deliver around 4.1 TWh of new generation (~10% of current supply). This will allow the system to displace thermal generation while also meeting new industrial demand with modest spill of 0.3 TWh. On this basis, renewable generation is projected to reach 95% of supply by 2027 (see **Exhibit 83**). Even in dry years, renewables would still cover close to 90% of demand, providing a strong foundation for New Zealand's energy transition.

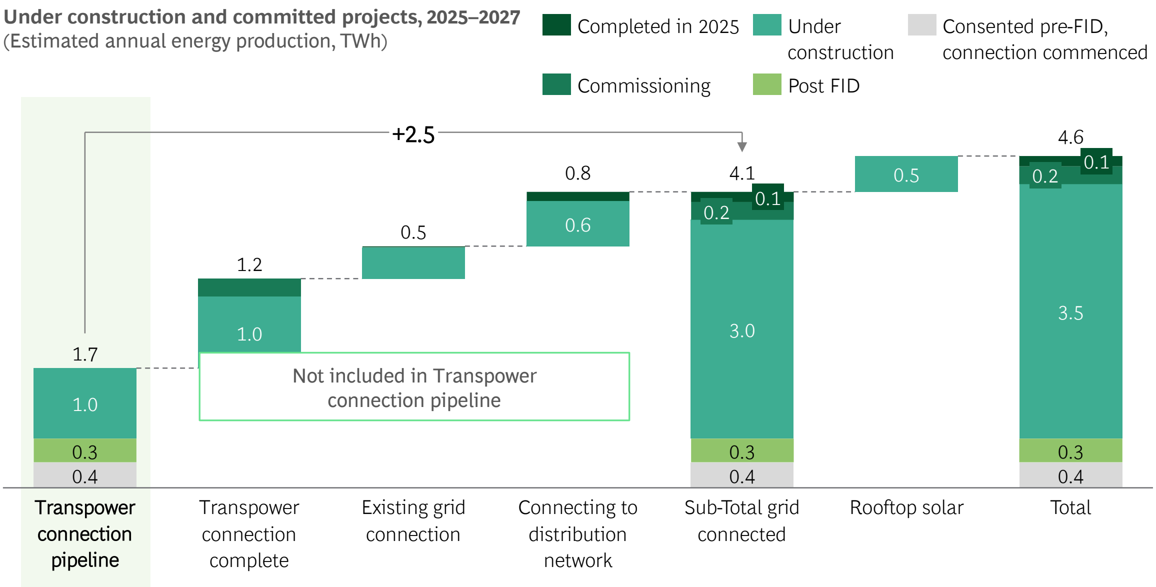
### Exhibit 83: New Zealand's renewable generation supply pathway to 2030




1. Normalised for a mean hydrological year; 2024 actual supply of 43.9 TWh with 0.3TWh Tiwai Demand Response added; includes co-generation
Note: Numbers may not add due to rounding
Source: MBIE Electricity Generation, Concept Consulting Weighted Development Pipeline

Of projects coming online between 2025 and 2027, 2.5 TWh of renewable generation sits outside the Transpower Connection Pipeline (1.7 TWh is in the pipeline). This is because the project has already been completed in 2025, Transpower completed the grid connection before this new generation was commissioned, the new generation is at an existing site, or the new generation connects to the distribution network (see **Exhibit 84**).

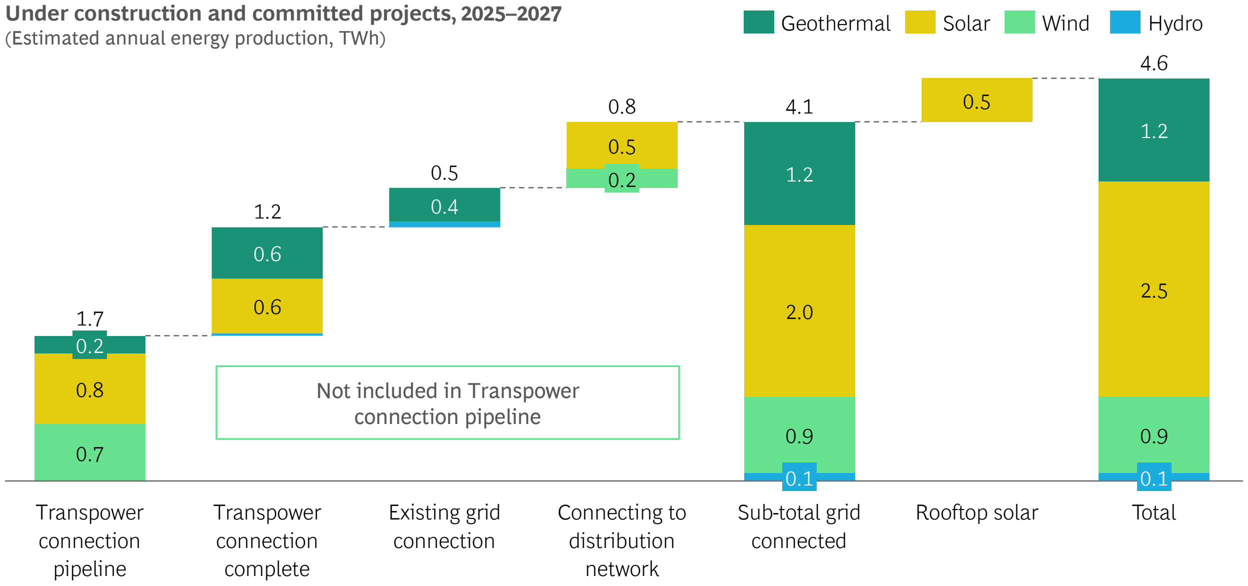
### Exhibit 84: Incremental generation from projects under construction or committed, due to come online between 2025 and 2027




Note: Excludes The Point Solar Farm (0.5TWh) due to high uncertainty; Numbers may not sum due to rounding
Source: Transpower, Concept Consulting, BCG Analysis

It is also common for smaller solar projects to connect directly to distribution networks rather than Transpower's national grid – and solar accounts for the largest volume of generation under development (see **Exhibit 85**).

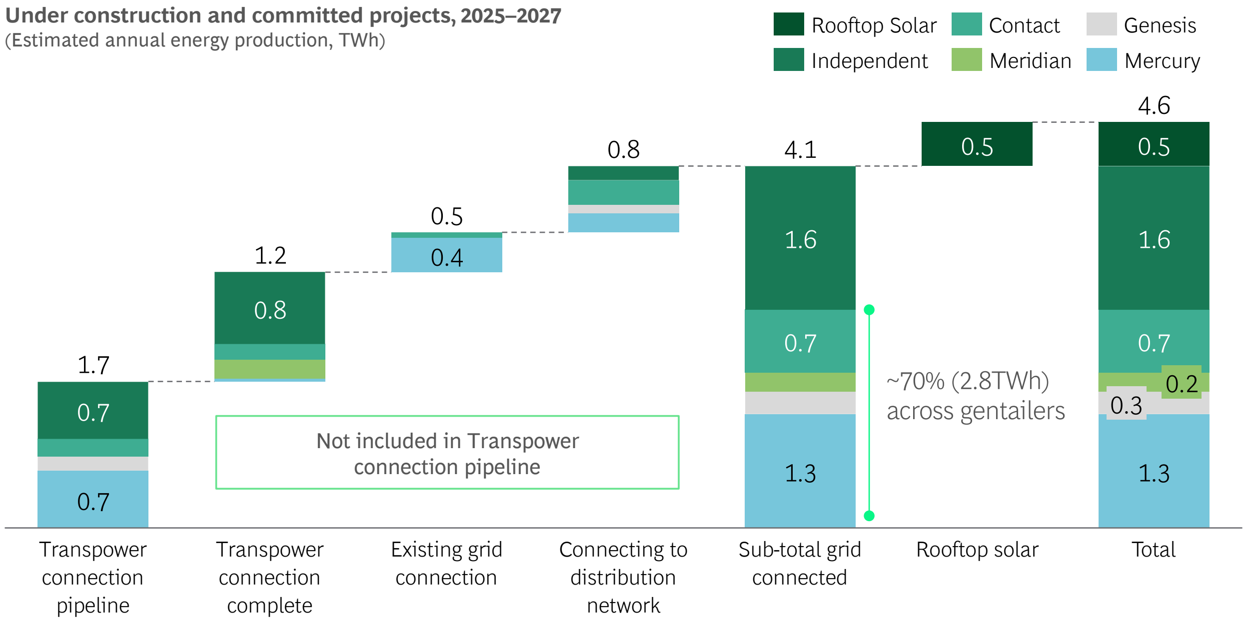
## Exhibit 85: Incremental generation by generation type for projects due to come online between 2025 and 2027




Note: Excludes The Point Solar Farm (0.5TWh) due to high uncertainty
Source: Transpower, Concept Consulting, BCG Analysis

New Zealand's four Gentailers are responsible for 70% or 2.8 TWh of the grid-connected development pipeline (see **Exhibit 86**). Notable projects include Mercury's Kaiwera Downs Stage 3 wind farm (0.6 TWh), Nga Tamariki geothermal expansion (0.4 TWh) and Kaiwaikawe wind farm (0.2 TWh), and Contact's Te Mihi Stage 2 (0.2 TWh net uplift) and Kowhai Park solar installation (0.3 TWh).

## Exhibit 86: Incremental generation by developer for projects due to come online between 2025 and 2027




Note: Excludes The Point Solar Farm (0.5TWh) due to high uncertainty
Source: Transpower, Concept Consulting, BCG Analysis

**Renewable developers must continue this momentum from 2027 to 2030, while tracking consenting and financial investment decisions to demonstrate their progress**

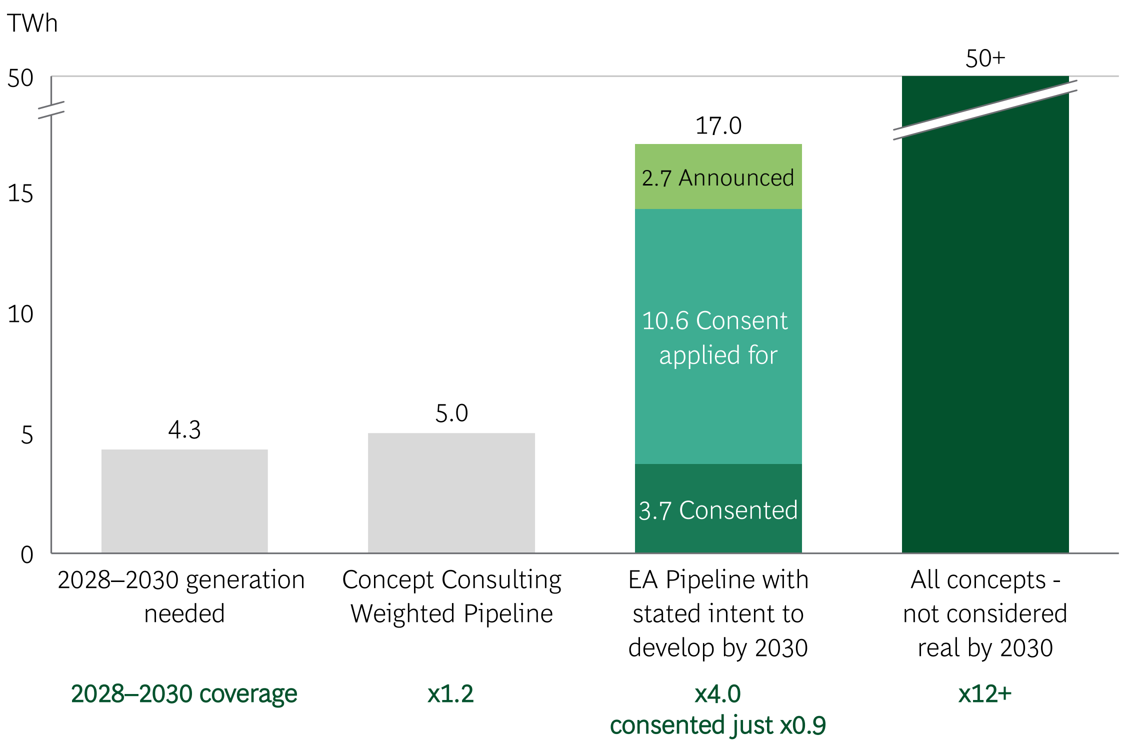
Beyond 2027, the challenge becomes sustaining this pace with around 1.4 TWh of new generation required each year, equating to 4.3 TWh across 2028 to 2030. The EA's pipeline indicates 17 TWh of new energy will be delivered by 2030, or four times what is required. Yet Concept Consulting's modelling for this report found only 5 TWh is probable when weighted by historic delivery rates based on the project's milestones status (see **Exhibit 87**).

This gap between the EA's pipeline and Concept Consulting's weighted pipeline reflects the considerable execution risk associated with consenting, equipment supply, project economics, connections and construction. In the EA's pipeline, 80% of projects with 2028–2030 commissioning dates are yet to gain consent – history suggests many will face considerable delays or fail to gain investment.

There is a real risk that the build rate for renewable generation may fall short unless projects continue to move decisively through consenting and investment stages. Tracking and public reporting of this momentum in consenting and final investment decisions will be critical to provide the market confidence that New Zealand is building renewable generation fast enough.

Realising the targeted renewable pipeline would materially change the shape of New Zealand's energy system. Renewable penetration would lift to 95% by 2027 and reach 97-98% by 2030. Even in dry years, renewables would still cover an estimated 90–92% of demand. This scale of build would displace thermal assets, anchor new industrial loads and ease the reliance on gas for setting market prices. A system operating at this level of renewable penetration would not only limit exposure to fuel cost shocks but would support affordability for consumers while strengthening security of supply.

Exhibit 87: The generation pipeline for projects due to come online between 2028 and 2030 versus requirements



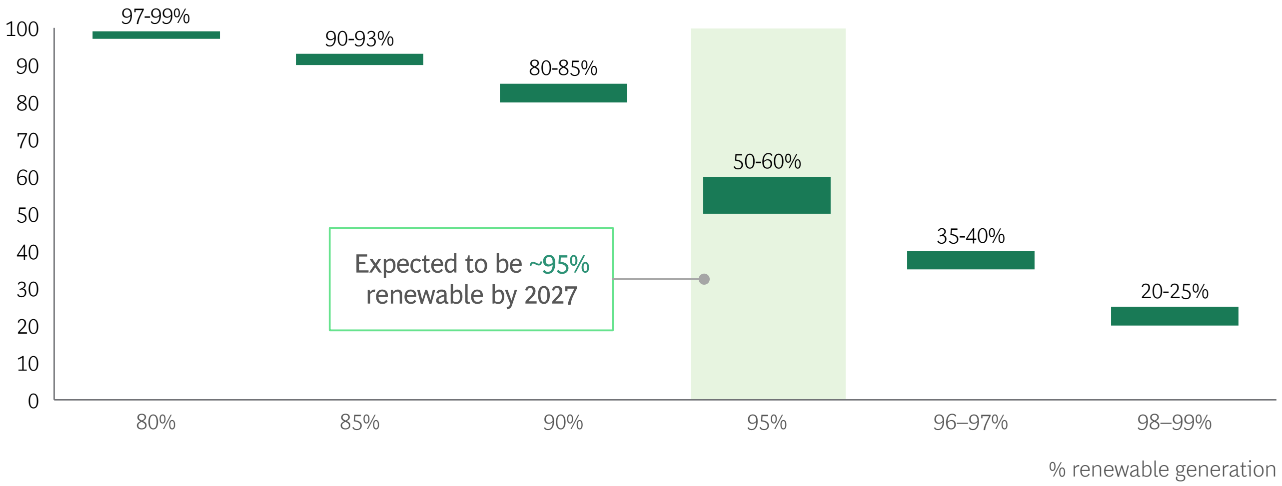

Source: Electricity Authority, Concept Consulting, BCG Analysis

### Growth in renewables will reduce the influence of gas prices on electricity prices and improve affordability

Expanding renewable generation also creates an opportunity to reduce the influence of gas in setting wholesale electricity prices. Today, the wholesale electricity price is highly exposed to gas – gas generation is under 10% of total electricity supply yet influences wholesale electricity prices 70–90% of the time. Modelling suggests that at 95% renewable penetration, gas would influence the price only 50–60% of the time (see **Exhibit 88**). Continued renewable build is therefore central to moderating volatility, reducing exposure to gas market dynamics, and delivering more affordable prices to consumers.

Exhibit 88: Frequency at which gas produces in an hour under different levels of renewable generation

**Frequency at which gas clears at different levels of renewable generation**
% of time gas clears in an hourly period




Source: Concept Consulting Electricity Clearance Modelling, BCG Gas Demand Forecasts

Even as renewables replace coal and gas in the generation stack, gas will retain a smaller targeted role in the electricity industry. Demand fluctuations across days and weeks, particularly during winter and low-wind periods, will require flexible gas generation to ramp up and down to meet peak demand. It is in those periods that gas prices will continue to influence the price of electricity.

### Geothermal and hydroelectric resources are the most promising in building New Zealand's competitive advantage in the long term

Beyond 2030, New Zealand will need more geothermal and hydropower resources to unlock its competitive advantage. Geothermal is a stable 24/7 generation source and hydropower is unique in being a dispatchable renewable source to complement intermittent solar and wind. Commitments to develop geothermal and hydro generation capacity will help attract energy intensive growth industries such as data centres to New Zealand. The New Zealand Government's draft Geothermal Strategy underscores the potential, targeting a doubling of geothermal output to 8 TWh by 2040.

### Stability and affordability outcomes are dependent on new supply being delivered in line with incremental demand, especially for large new loads

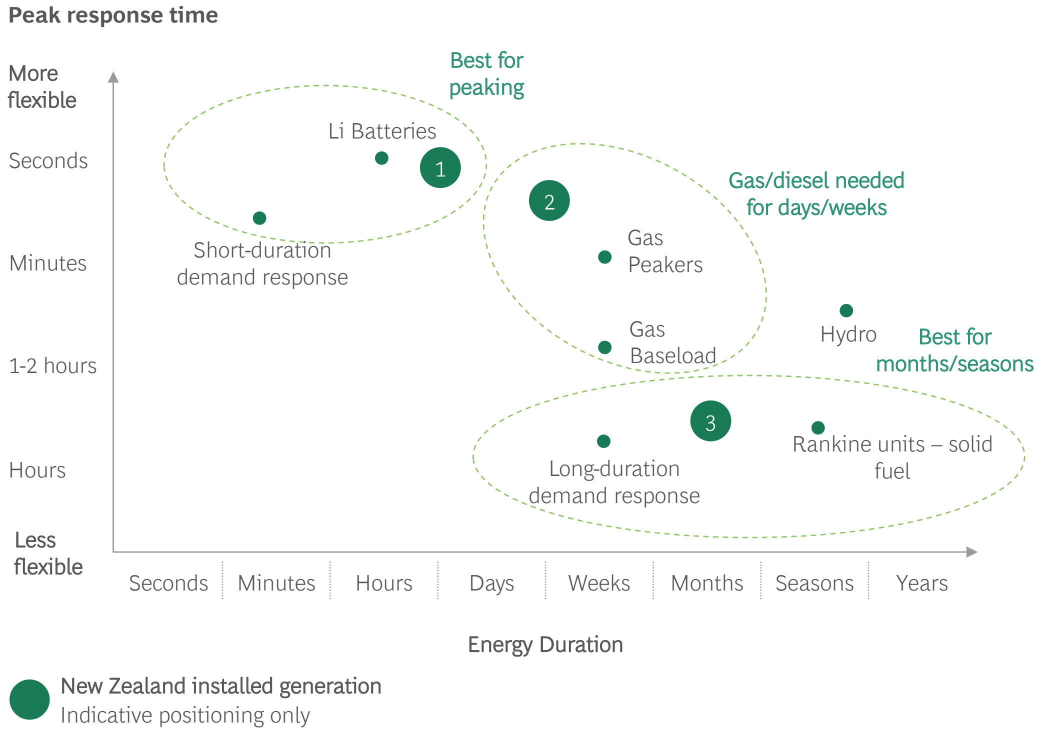
At the same time, demand growth must be closely matched by the timely delivery of new generation. If large new loads, such as data centres, arrive before additional supply is available, the system will fall back on thermal generation more frequently. This would expose consumers to higher and more volatile electricity prices, particularly in periods of tight gas supply. The key risk is therefore not only whether projects proceed, but whether they come online in time to meet demand as it grows. Without continued development and timely commissioning of new renewable projects, the market will face greater reliance on existing generation, including gas, and face sustained upward pressure on prices.

## 5.2 Strengthen the electricity market and security mechanisms

**An effective electricity system requires firm energy across three time horizons**

To ensure system security and affordability, a well-functioning electricity system must be able to meet demand reliably and affordably across three distinct time horizons: short-duration peaks, medium-duration balancing and long-duration energy. Each horizon requires a tailored mix of dispatchable capacity, sufficient fuel storage and access to firmed fuel supply (see **Exhibit 89**).

Exhibit 89: Firm energy requirements split across three time periods



### 1 Short-duration peaking capacity

Short-term peaking capacity to support short-term surges in demand load

| | Requirements |
|---|---|
| Capacity and generation | High nameplate capacity |
| Duration | Up to 4 hours |
| Response time | Instantaneous |
| Suitable fuels/tech | *Short-duration demand response*<br>*Li Batteries* |

Short-duration peaking capacity provides flexibility to respond to rapid demand spikes, particularly on cold winter evenings when renewable output is low. While overall capacity has increased in the last decade, the majority of new capacity has been intermittent renewable generation, leaving the dispatchable capacity, required to meet surges in demand and supply, unchanged once accounting for thermal exits. At the same time, New Zealand is working on integrating Distributed Energy Resources (DERs) to meet demand peaks and spikes. While renewables have supported decarbonisation, the volume of dispatchable generation that is able to respond instantly to peaks has remained largely unchanged, exposing the system to risk during stress events.

### 2 Medium-duration flexible capacity

Fast-start thermal capacity to enable system demand provisioning during dry or windless periods

| | Requirements |
|---|---|
| Capacity and generation | Fast-start, flexible thermal capacity (OCGT) |
| Duration | Up to 2-3 months |
| Response time | Minutes to hours |
| Suitable fuels/tech | *Natural gas*<br>*Liquid fuels (diesel, condensate)* |

Medium-duration flexible capacity covers the hours, days and weeks between supply and demand, stabilising the system when renewable output fluctuates. Historically this role was provided by gas-fired generation, which can start quickly to meet peaks (short-duration peaking capacity) and can also run for several days to provide energy. However, declining domestic gas production and limited storage have constrained this capability, raising concerns about whether gas can continue to meet both reliability and affordability requirements. Medium-duration flexible capacity is often referred to as the 'missing middle' because it sits between batteries which are very effective for short-duration peaking and baseload thermal which is very effective for long-duration energy. It provides a critical service that neither of these resources can consistently provide - balancing energy across hours, days and weeks while quickly and flexibly meeting peaks.

### 3 Long-duration energy capacity

Base-load fuel storage or firm supply and capacity to support dry-period hydro inflow shortfalls

| | Requirements |
|---|---|
| Capacity and generation | Steady, thermal baseload (CCGT, Rankine units) |
| Duration | 6+ months |
| Response time | Hours to days |
| Suitable fuels/tech | *Solid fuels (incl. biomass 2030+)*<br>*LNG (2027+)* |

Long-duration energy capacity underpins the ability to meet demand during extended dry or windless periods. Hydro storage remains the foundation of this capacity, supported by geothermal baseload. Solid fuel reserves are critical in dry years to meet seasonal energy needs. As renewable generation expands it will be critical to continue to investigate fuel and storage options like biomass to continue to meet long duration energy needs.

Although the New Zealand energy market continues to meet demand across these horizons, changing fuel dynamics and ageing thermal assets have increased the cost of maintaining system security. Rising thermal fuel prices, tighter supply chains and reduced gas storage have pushed up wholesale electricity prices. These pressures, combined with a growing share of intermittent renewables, higher N-1 contingency risks (the risk of losing a single energy asset), and more variable weather patterns have amplified volatility and increased the premium for firming capacity (see **Exhibit 90**).

## Exhibit 90: Increase in intra-day and intra-season variability observed across market

| | Avg. price 2015 to 2019 period | | | | | Avg. price 2020 to 2024 period | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Morning | Day | Evening | Night | Total | Morning | Day | Evening | Night | Total | Delta |
| Spring | 154 | 142 | 138 | 111 | 131 | 124 | 110 | 127 | 87 | 105 | -28 |
| Summer | 117 | 129 | 122 | 92 | 110 | 142 | 156 | 165 | 110 | 136 | 26 |
| Autumn | 112 | 112 | 122 | 85 | 102 | 234 | 215 | 255 | 179 | 210 | 108 |
| Winter | 138 | 115 | 134 | 95 | 114 | 229 | 204 | 258 | 182 | 208 | 94 |
| Total | 131 | 126 | 131 | 97 | 115 | 183 | 173 | 204 | 143 | 167 | 42 |
| | | | | | Delta | 52 | 46 | 73 | 46 | 42 | |

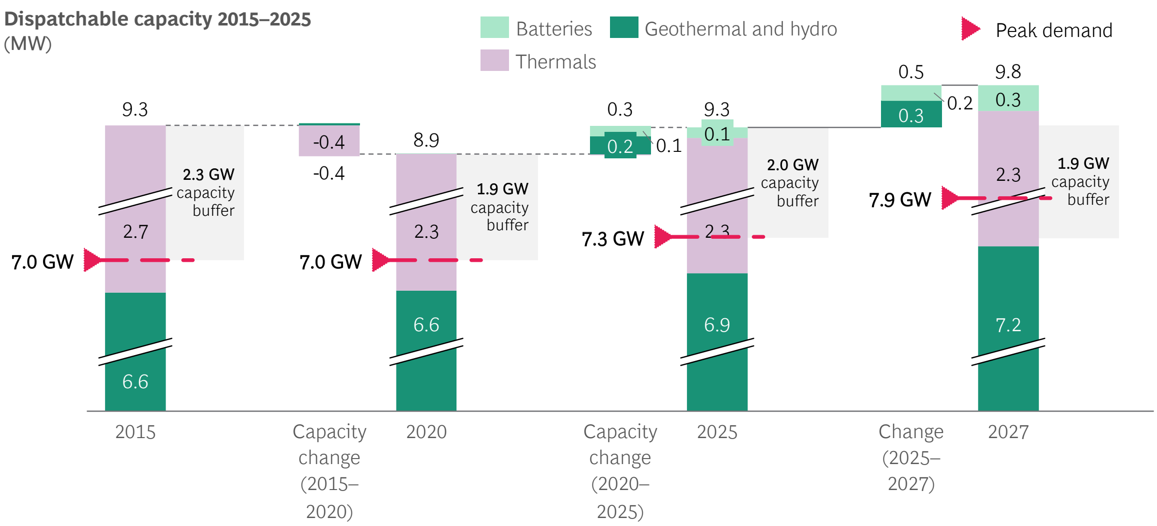
Looking ahead, maintaining affordability and reliability will require an improvement in building, storing and dispatching firming and fuel resources across the three time periods.

### Short-duration peaking capacity

**As the economy grows and electricity demand increases, peak demand will increase by up to 1.5 GW by 2035, even with smart system initiatives**

Modelling indicates that total peak demand will rise by around 1.5 GW over the next decade, driven by industrial demand and widespread residential electrification. This volume already accounts for smart system initiatives, like demand response and the integration of DERs, which are effective in smoothing grid demand, reducing peak load by an effective 0.8 GW. Meeting higher peak demand will require new firm and dispatchable generation to ensure there is capacity in the system to manage contingency events such as loss of a generating unit (see **Exhibit 91**).

## Exhibit 91: New Zealand's dispatchable capacity and buffer versus peak demand




Note: Excludes intermittent renewable generation (wind and solar)
Source: EMI Dispatch Generation Plant Dashboard, Transpower Security of Supply, Concept Consulting

### The sector expects to maintain 1.5–2 GW of short-duration peaking capacity surplus as demand rises

Around 0.5 GW of new dispatchable capacity is expected to be commissioned by 2027, but most of this will come from geothermal generation, which will typically run as a stable base load. Ongoing gas market challenges further limit the reliability of flexible gas generation (via open-cycle gas turbines (OCGT) to balance demand. While until 2027, it looks as though New Zealand has enough capacity to meet peak demand, uncertainty gas supply beyond 2027 raises concerns about short-duration peaking capacity as peak demand grows.

### To accelerate the development of additional short-duration peaking capacity via batteries or gas generation, New Zealand could consider a new market mechanism

Closing this gap will require a combination of short-duration storage and additional firming capacity to provide confidence in supply. Batteries will play an increasingly important role, offering low-cost firming capacity that can shift renewable output into peaks, reduce hydro spill and soften intra-day price volatility. Their integration also improves hydro management, enabling reservoirs to be run with more confidence over longer periods. New market mechanisms, such as reform of reserve pricing and performance frameworks could accelerate investment and strengthen firm energy supply. Provided market design is efficient, strengthening short-duration capacity will directly reduce price volatility and help make electricity more affordable for all users.

## Long-duration energy capacity

### Increasing long-duration firm energy by 1.1 TWh would provide additional security and ensure dry periods can be met affordably

Low rainfall reduces New Zealand's hydro inflows by 2 TWh in an average dry season across 6 months and up to 4 TWh in worst-case scenarios or in consecutive dry years (see Section 4.3.2). To provide confidence that New Zealand has adequate energy for worst-case scenarios, and can meet these dry periods affordably, the electricity sector must be able to provision for 4.5 TWh of long duration firm energy, either in:

- Thermal fuel storage (i.e. stored gas or solid fuels)
- Via firm delivery contracts (e.g. primarily contracted firm gas or LNG cargoes and some condensate or diesel)
- Contingent hydro storage freed up and made available to operators (dependent on the sector's ability to procure sufficient firm thermal fuel contracts)
- Contracted demand response (e.g. Tiwai electricity demand response)

This proposed level is greater than the worst-case drop in hydro, to ensure fuel flexibility given the country's thermal generation mix and provide additional market confidence to mitigate any adverse pricing impacts.

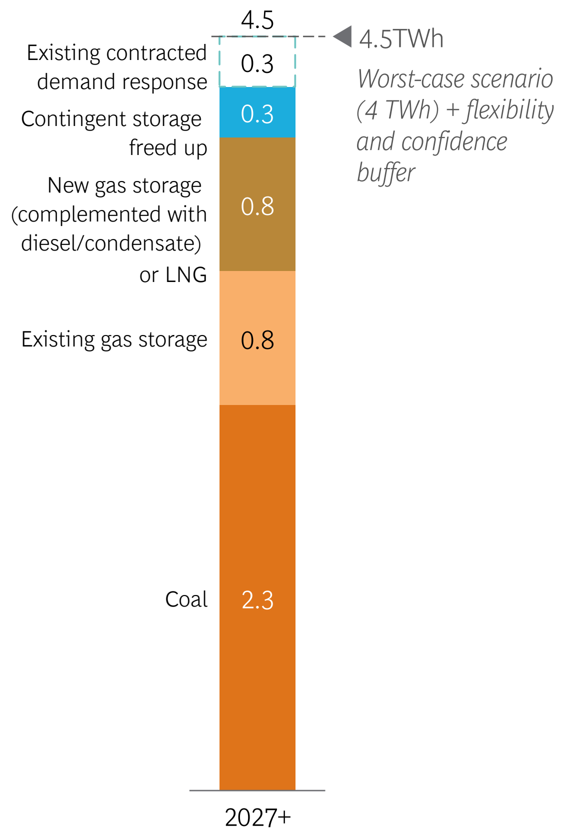
Reaching this proposed level of 4.5 TWh would require a 1.1 TWh increase on existing long-duration firm energy stores or contracts. The sector currently expects to have 3.4 TWh of firm energy or contracts entering winter 2026, of which 0.8 TWh is expected to be stored at Ahuroa (6 PJs of gas), 2.3 TWH at Huntly (1,100 kt of coal), and 0.3 TWh across an average Tiwai demand response profile.

The incremental 1.1 TWh of long-duration firm energy could be provided by:

- 0.8 TWh additional domestic gas storage and firm supply, complemented by smaller quantities of liquid fuel stores and potential retrofitting of existing OCGT plants to burn these, or firm LNG import agreements, and
- 0.3 TWh freed contingent hydro storage provided the above 0.8 TWh can be achieved

## Exhibit 92: Long-duration firm energy and corresponding capacity

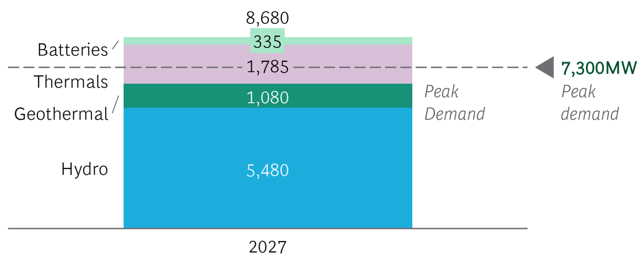
**Long-duration firm energy**
(Electricity energy, TWh)




**Thermal capacity**
(Nameplate generation, MW)

| | Fuel/plant suitability | | | | | |
|---|---|---|---|---|---|---|
| | Rankines | CCGT | OCGT | Whirnaki | Compatible gen. capacity (MW) | Full capacity generation stores (hours) |
| Coal / Biomass | ✓ | | | | 750 | 1650 |
| Gas | ✓ | ✓ | ✓ | ✓ | 1585 | 665 |
| Diesel | | *Flexibility added via retrofitting* | ✓ | | 605 | 250 |
| Conden-sate | | | ✓ | | 450 | 340 |
| Total (MW) | 750 | 385 | 450 | 155 | | |

**Total capacity versus peak demand**
(Nameplate generation, MW)




**Although solid fuels can provide adequate bulk energy, diversifying firming fuels enables dry periods to be met more affordably**

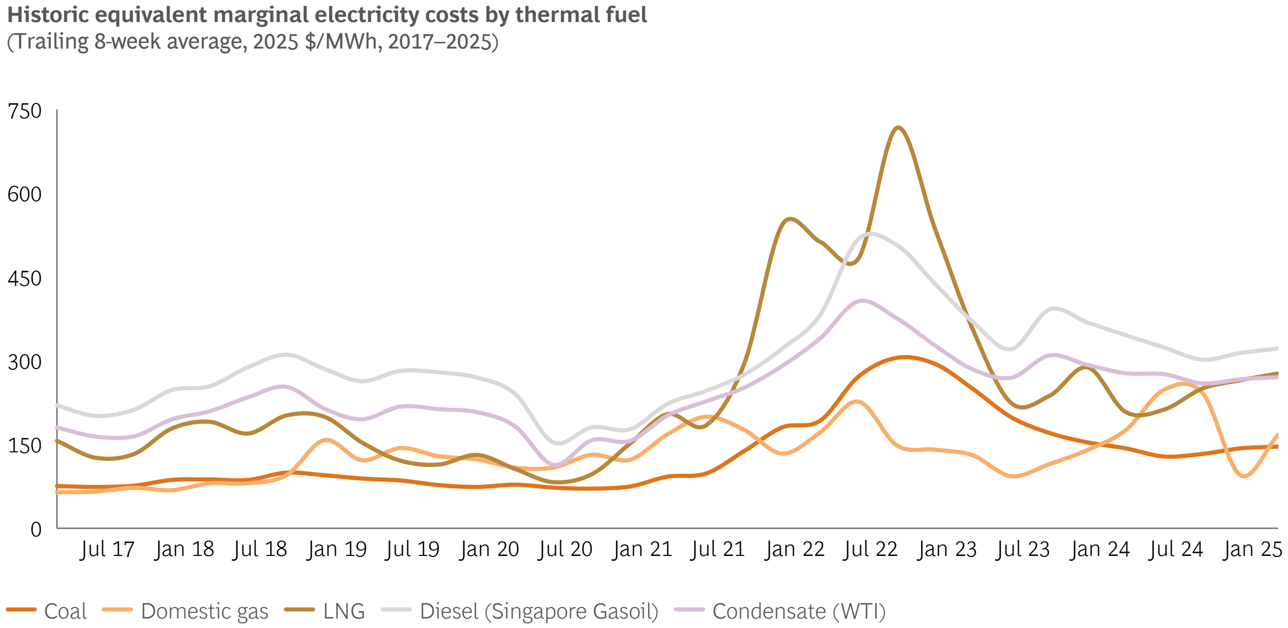
The rising cost of fuel, in the form of domestic gas, is a key driver of increasing wholesale electricity prices. This is a significant issue today. Even if new gas power plants are developed, if the fuel going through them is more expensive it will not result in more affordable electricity.

In 2025, gentailers agreed to Huntly Strategic Energy Reserve Firming Options which will lift solid fuel stores to 1,100kt and support the extended operations of the three Rankine units at Huntly Power Station to 2035. This also enables diversification from gas. The Rankine Units (1, 2 and 4) have a capacity of 0.75GW meeting roughly 10% of New Zealand's highest peak demand of 7.3GW. Due to this, during peaks, gas often dispatches alongside these Rankine Units, meaning gas often sets the price even when solid fuels are being burned. As a result, even with solid fuels, gas is still often required and plays a critical role in determining the affordability of electricity.

Solid fuels, while very valuable for providing dry year energy, are also exposed to global shocks such as export restrictions or international price surges, as demonstrated in Exhibit 93.

There is therefore value in considering a wider range of firming fuels, to both complement the use of solid fuels and provide alternatives to gas if domestic production continues to fall. Exhibit 93 illustrates the value of fuel diversity as different fuels have different relative affordability depending on market conditions.

Exhibit 93: Historic equivalent marginal electricity costs by thermal fuel




Note: Includes carbon and transport. Assumes 37% efficiency for coal (Rankine unit thermal efficiency), 50% thermal efficiency for gas and LNG (Generation weighted average efficiency across OCGT plant and Huntly CCGT unit), 37% thermal efficiency for diesel and condensate.
Source: HBA Indonesian Coal Index, JKM LNG Spot Price, Platts MOPS, NYMEX WTI Spot Price, GIC Wholesale Gas Prices, NZU Carbon Prices, WSP Generation Stack, BCG Analysis

Options to diversify exposure to domestic gas include LNG, condensate and diesel, each of which has different trade-offs. LNG requires significant investment but provides access to a deep global market and can use New Zealand's existing generation capacity. Condensate is a domestic alternative, currently exported from Taranaki where storage tanks exist today. It could act as a valuable hedge yet requires investment for fuel treatment and to convert existing OCGTs. And diesel has well-established import and distribution supply chains but has a very high marginal cost.

If New Zealand decides to pursue LNG imports in the future, access to small volumes of alternatives, such as condensate and diesel as backup fuels is a potentially pragmatic way to cushion against future global price spikes or supply disruptions.

## Exhibit 94: High-level assessment of firming fuel options

### High level assessment of fuel options for dry periods

| | | Cost | | Dry-year security | | | Sustainability | |
|---|---|---|---|---|---|---|---|---|
| | | Marginal generation cost ($/MWh) | Investment (to 2035) | Storage/flexibility | Underlying availability | Plant capacity | Carbon emissions (t $CO_2$-e/MWh) | Potential role |
| Inter-year security | Coal | 120–190 | L *Limited investment* | H *2.3 TWh* | H *Liquid intl. markets* | 750 MW | 0.9 | Primary inter-season store |
| Inter-year security | LNG - CCGT (2027 Onwards) | 160–260 Lower end if no capex/fixed O&M amortised into fuel cost | H *$0.5–1b investment in import, storage* | H *Up to 1.8 TWh* | H *Liquid intl. markets* | 385 MW | 0.4 | Primary inter-season store |
| Inter-year security | Domestic Gas - CCGT | 115–190 | M *$200m investment for additional storage* | M *Up to 1.8 TWh* | L *Challenged supply-demand balance* | | 0.4 | Historic inter-season store |
| Inter-year security | Biomass (2030 Onwards) | 180–300 | L *Req. supply chain establishment* | M *Further investigation required* | M *Global market developing* | 750 MW (Assuming Huntly fungibility) | 0.02 | Complementary inter-season store (post 2030) |
| Inter-week security | Domestic Gas - OCGT | 145–210 | M *$200m for additional storage* | M *Up to 1.8 TWh* | L *Challenged supply-demand balance* | 450 MW | 0.4 | Primary inter-week/day flex option |
| Inter-week security | LNG - OCGT (2027 Onwards) | 185–395 Lower end if no capex/fixed O&M amortised into fuel cost | H *$0.5–1b investment in import, storage* | H *Up to 1.8 TWh* | H *Liquid intl. markets* | | 0.4 | Primary inter-week/day flex option |
| Inter-week security | Diesel | 300–400 | M *~$20m investment in storage, plant retrofit* | M *Would need new storage* | H *Liquid intl. markets* | 205 MW | 0.6 | Complementary inter-week/day fuel store (post 2027) |
| Inter-week security | Condensate | 250–350 | M *~$40m storage, treatment & plant retrofit* | M *Existing storage at Taranaki; needs treatment* | M *Domestic production* | 200 MW (w/ conversion of Stratford Peakers) | 0.6 | Complementary inter-week/day fuel store (post 2027) |

## Medium-duration flexible capacity

### Gas alternatives are also valuable in meeting the missing middle

Gas is used to balance the system across days and weeks, with OCGTs able to ramp up quickly and run for as long as needed; for example, starting as the wind drops in a windless period. As gas availability decreases, there is a risk that the New Zealand energy sector is left with a missing middle, with batteries only able to meet short durations and solid fuel power plants being too inflexible.

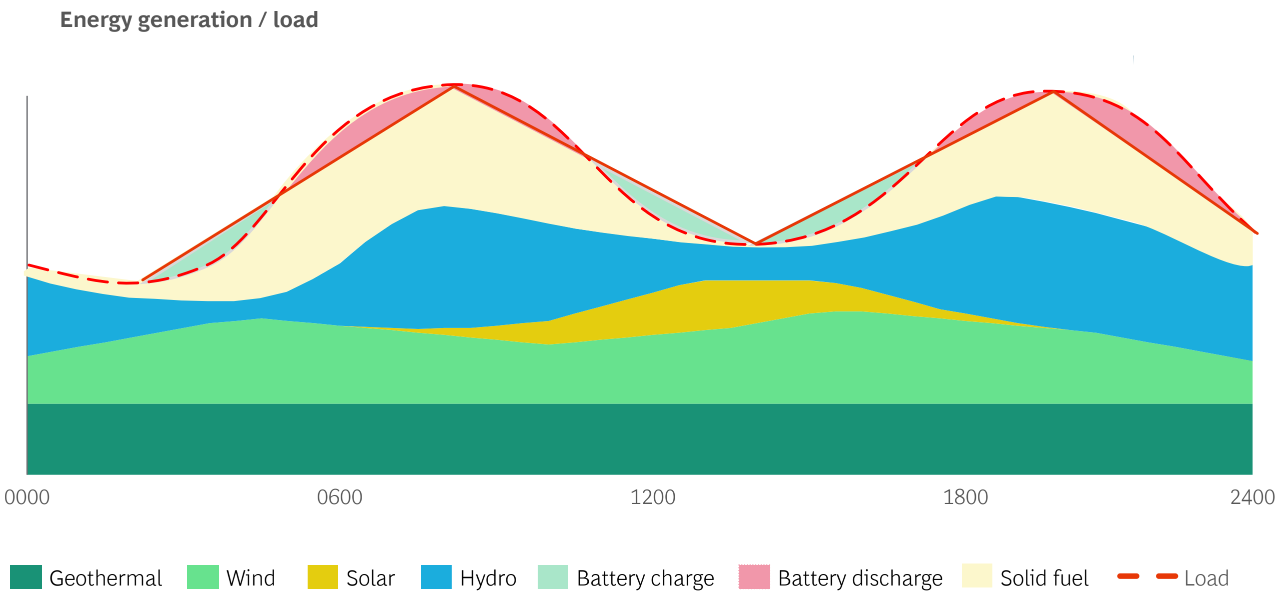
Therefore, when considering alternative fuels for dry years, it is highly valuable if these fuels can replicate gas in balancing the market across a period of days to weeks. This is why LNG, condensate and diesel which can run through OCGTs can be valuable, even at slightly higher marginal costs.

### When solid fuels are the cheapest option, pairing them with batteries can also deliver medium-duration balancing and displace gas

Solid fuel power plants are restricted in their operational flexibility during ramp-up and ramp-down and rapid system changes. They require extended ramp-up periods and have slower ramp-up and ramp-down rates. Batteries function as an effective complement for solid fuels during these periods as they can instantaneously inject or absorb power. Batteries therefore provide short-duration support until the solid fuel power plants reach steady operation (see **Exhibit 94** highlighting in grey the illustrative role of batteries). Hydro further enhances system flexibility by supplying operating reserves and firm, dispatchable capacity that can be adjusted as grid conditions evolve.

Together, batteries and hydropower smooth ramp-ups for solid fuels to meet peaks, reduce renewable curtailment when ramp-downs occur slowly and minimise unnecessary cycling of solid fuel units. This can reduce reliance on gas for meeting the missing middle.

Exhibit 95: Battery usage as a complement to solid fuels




Note: For illustrative purposes only.

**Exploring new approaches to managing firming would strengthen resilience across affordability, security and sustainability**

As domestic gas supply continues to decline, enhancing firming capacity and fuel diversity will be critical to maintaining affordable electricity security. There is value in exploring new approaches to how these outcomes are delivered including regulation, joint market agreements and market mechanisms to incentivise investment in infrastructure and fuel across the three distinct time periods. Condensate, LNG, diesel, and biomass or coal paired with batteries each provide an alternative when gas supply is constrained. However, each fuel comes with different trade-offs, such as the balance of domestic energy independence versus participation in global commodity markets. And carrying additional fuel often comes at a cost. These different costs and risks need to be considered by the market and industry stakeholders. Continued assessments of these fuels and the value they can provide will be important to ensure dry periods can be met affordably.

## 5.3 Enhance lines infrastructure efficiently

**Investment in lines infrastructure is growing, but the sector needs a clear vision to minimise costs to consumers**

Investment in new transmission and distribution assets is critical to enabling the continued development of renewable generation and firming. The 2022 Future is Electric report found there would need to be $10 billion invested into transmission and $25 billion invested into distribution networks in the 2030s. While the scale of required investment is large, investment has already started to grow and Transpower has started important upgrades to the grid.

For transmission, Transpower's capital expenditure increased by 32% to $2.25 billion in the 2025–2030 regulatory period (RCP4) versus the prior five-year period. The Commerce Commission also approved additional spending for Phase 1 of Transpower's New Zero Grid Pathways (NZGP) programme in 2024. The programme enabled Transpower to begin three projects to enhance the national grid: upgrades to central north island transmission lines, upgrades to Wairakei transmission lines and enhancements to the HVDC link between the North and South Island to lift transfer capacity. Consultation is underway for a separate package of work to replace the HVDC inter-island cable, which alone is a $1.4 billion investment in the early 2030s.

For distribution, increases in capital allowances for 2025-2030 will support electrification and integration of distributed energy resources like EVs, solar and batteries. Increased use of system smarts is being adopted by distribution networks, which will enable deferral of physical grid expenditure delivering cost efficiency.

Given the scale of investment required to deliver a stronger and more efficient grid, it is critical that the sector develops a clear vision and acts with discipline to minimise costs, which ultimately flow to electricity users. The sector must address four challenges:

1. **Roadmap clarity:** Given it takes typically 7–10 years to build transmission assets, a clear vision and blueprint for grid development to 2050 will support the development of required infrastructure
2. **Connection funding models:** Today, grid connection assets are typically paid for by the customer (e.g. generator, distributor or large industrial user). In some regions, interconnection style transmission investments could enable growth in renewable generation, but today they are sometimes classified as a connection asset with the first mover (i.e. renewable developer) bearing the cost, impacting project economics. Mechanisms to spread costs could lead to faster development of renewable resources in new locations (e.g. Northland).
3. **Information transparency:** Increasingly, mid-scale wind and solar developments are connecting to distribution networks, rather than Transpower's transmission national grid. However, in some networks developers may not have the capacity information available to find the best connection points. Many distribution networks are already providing great transparency of current distribution network capacity which others could use as a blueprint. This will benefit developers and lead to higher utilisation of existing lines.
4. **Lines company productivity:** Research commissioned by the Commerce Commission found the productivity of Electricity Distribution Businesses (EDBs) fell 1.4% per year between 2008 and 2023 on a total factor productivity basis.[78] Cumulatively this equates to a 20% drop in productivity across the period. Addressing this productivity decline will be critical to ensure future network investments deliver maximum value for energy users.

78 CEPA, EDB Productivity Study, June 2024

## 5.4 Address gas supply decline and introduce domestic gas alternatives

**New Zealand can slow the decline in domestic gas supply by adding new gas flexibility and preparing for the option of LNG**

New Zealand no longer has cheap, reliable and abundant gas. Declining field performance and limited new supply have created a gap between supply and demand that will continue to widen, especially over the next five years. With gas supply declining, it will be imperative to safeguard energy affordability and security throughout the energy transition.

There are three levers, that when pulled together, stabilise domestic gas supply, soften price spikes and create optionality for temporary alternatives when gas supply is tight:

- **Slow the decline in domestic gas supply** with targeted field interventions and regular investment.
- **Add new gas flexibility** by expanding gas storage to strengthen security during outages and mitigate dry-year impacts on the energy system.
- **Prepare LNG as an option** to complement domestic gas and provide energy system security through early, low-cost preparations in case it is needed.

These levers are explored below.

### 5.4.1 Slow the decline in domestic gas supply

**Developing existing fields is the best option to mitigate gas supply decline**

One of the fastest ways to reduce the risk of price spikes and de-industrialisation is to slow the expected decline in domestic gas production over the next few years. Prioritising development in existing fields is the lowest-risk, highest-return way to steady supply and buy time for the transition. These fields are known, have been assessed for deliverability, have shorter cycle times and have shared infrastructure, which reduces marginal costs. Development can also be paced so success of programmes can be assessed before further investment.

Increasing supply with new exploration drilling can support long-term stability but timing is crucial. New development wells in existing fields could contribute as early as 2027, while new standalone fields are unlikely to produce before 2032. By 2030, a large amount of downstream demand may already have been destroyed if gas is not drilled soon, so late-arriving volumes risk missing the pinch period in the transition and stranding capital. The focus, therefore, should be on gas that can be delivered in the near-term.

Onshore developments outperform offshore projects in terms of speed, cost, and execution risk, as they typically have shorter lead times, lower capital intensity, and clearer consent pathways. Offshore developments, by contrast, face limited weather windows, scarce rigs and vessels, and higher delivery costs. However, given the sharp decline in domestic gas production, offshore drilling will also be required to increase the chances of mitigating the rapid fall in gas supply.

**Development could also include wells and fields with high $CO_2$ content**

Alongside conventional development, there is also a need to examine existing wells and fields with higher $CO_2$ content. This broadens the supply pool but comes with emissions and cost considerations that need to be weighed against the benefits of securing near-term supply. New Zealand has experience processing such gas at Kapuni, where $CO_2$ is removed before sale with scrubbing. There are several other high $CO_2$ fields and unlocking this type of gas would likely require investing in new transport infrastructure to the Kapuni plant or new modular scrubbing units.

**Slowing decline buys time for the energy transition**

Finally, slowing the near-term decline buys real options for the wider energy system. It cushions the electricity market and strengthens dry-year cover, giving industry time to convert heat processes in an orderly way. If demand falls faster than expected, development can be tapered. If the system remains tight, incremental gas supply from existing fields, including those high in $CO_2$, can help keep prices and reliability in check. And if LNG is pursued, these efforts can bridge supply until the LNG import terminal comes online. Taken together, these factors make upstream development in today's fields, including high-$CO_2$ prospects (e.g. Kaimiro), the best path to manage demand as the economy electrifies.

**What is carbon scrubbing?** When natural gas comes out of the ground, it sometimes has a lot of carbon dioxide ($CO_2$) mixed in. This gas can't be used directly, so it needs to be cleaned before it goes into the pipeline. Carbon scrubbing is the process of taking the $CO_2$ out, usually with special liquids or filters.

**Does New Zealand have scrubbing facilities?** New Zealand's Kapuni Gas Treatment Plant removes $CO_2$ from gas.[79] But if New Zealand wants to produce more gas from new high-$CO_2$ fields, it may need extra equipment or even a new scrubbing plant.

**What is important to consider when using high-$CO_2$ gas?** Using high-$CO_2$ gas could help New Zealand manage its tight gas supply, but it also creates more $CO_2$ to deal with. Some can be sold (for example, for food processing), some could be released and paid for under the emissions trading scheme, and in the future, it could potentially be stored underground if carbon capture and storage becomes viable.

### 5.4.2 Add new gas flexibility

**New Zealand faces new challenges in managing gas supply with demand flexibility**

Another emerging challenge for New Zealand is gas demand and supply flexibility. Flexgas' Ahuroa gas storage facility and Methanex have historically supported the gas industry to meet seasonal demand variation and smooth supply volatility. While Ahuroa has provided storage, Methanex has adapted its gas consumption to accommodate periods of high demand. In the last decade a lot of this flexibility has been lost due to the downgrade of Ahuroa from 18 PJ working capacity to 6–8 PJ (due to water ingress in 2022) and Methanex's production decline to one train.[80] Methanex's eventual exit from New Zealand will further exacerbate the problem and the system will struggle to manage the gap between when gas is produced and when it's needed.

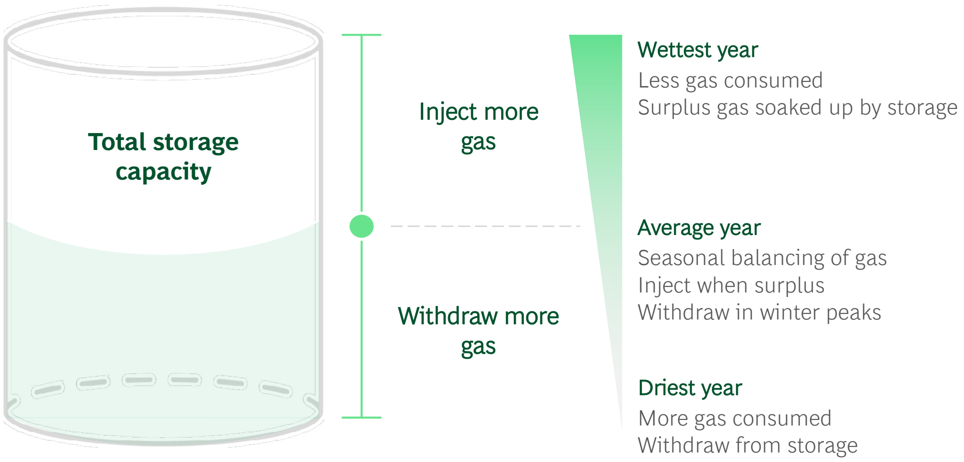
79 Taranaki Regional Council, Todd Monitoring Programme Annual Report 2023/24, 2024

80 MBIE and EY, Future of Gas Considerations, 2023

### Storage is critical to balancing temporal gas supply and demand

Storage is an effective tool to balance supply and demand across time periods. New Zealand can store gas in low-price periods and withdraw it in peaks, dry years and outages (see **Exhibit 96**). Storage provides upstream users with confidence to produce without fear of oversupplying the market and supports downstream users by stabilising prices, reducing curtailment risk and providing gas to quickly generate electricity in peaks and dry years. Storage also provides energy to industrial users that cannot readily switch processes to renewable electricity in the short and medium term.

Exhibit 96: Gas surplus soaked up by storage

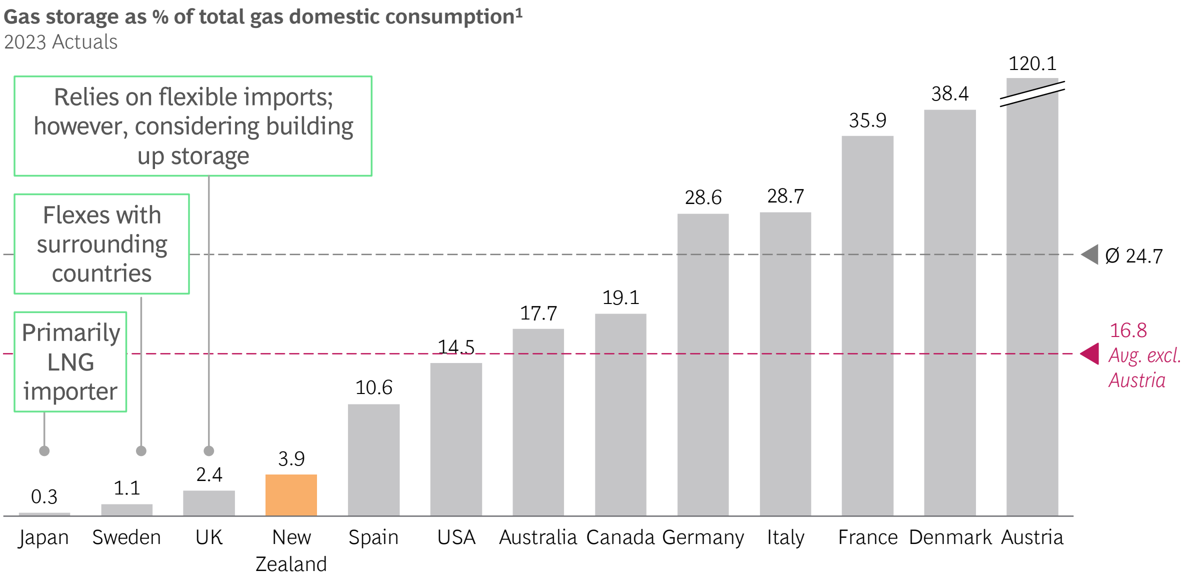



### New Zealand has significantly less gas storage than global leaders

Today, New Zealand's gas storage capacity and system resilience rests on one asset: Ahuroa underground gas storage. With field outages and seasonal electricity swings becoming more frequent, relying on this one asset leaves the system exposed.

In 2023, New Zealand gas storage equated to 4% of annual demand. In peer markets, this was 17% and among global leaders it was 25%. In 2025, New Zealand's ratio has lifted to 6%, but that is because gas demand is lower, not due to an increase in storage.

Exhibit 97: 2023 gas storage as percentage of total domestic consumption




1. Total natural gas consumed in the country regardless of source (i.e. domestic drilling, LNG import); Gas storage entails working gas capacity from underground gas storage (UGS)
Source: Enerdata; ONU; Eurostat

**The loss of Methanex's flexibility makes additional gas storage more important**

The New Zealand gas system is running with minimal padding, amplifying price volatility and tightening security margins. The situation will become worse if Methanex exits as it has provided much of the gas market's operational flex. Without an effective replacement, gas price volatility will increase and there may be periods where demand cannot be met.

While Methanex's exit poses risks, New Zealand could capitalise on the short-run surplus of gas Methanex would leave behind. With more storage, New Zealand could turn the temporary surplus into a strategic asset, providing s**easonal capacity** for dry years and electricity peaks. It could also ensure upstream producers can continue to drill confidently knowing that oversupply risk is mitigated.

For additional gas storage to be most effective, it would need to come online by the time Methanex exits so it can store the surplus gas. If the storage build is delayed, it runs the risk of not having enough gas to fill it.

**New Zealand's gas storage needs to double**

The size of additional gas storage should reflect gas' major role in firming New Zealand's electricity (during dry years and in winter peaks), with a small reserve for gas-system reliability. Today, roughly half of the flexibility in New Zealand's electricity system comes from solid fuel stockpiles (2.3 TWh), with the balance from Ahuroa gas storage (0.8 TWh equivalent) and demand flexibility from Methanex and Tiwai (1.2 TWh).

However, in a typical dry year hydropower drops 2 TWh, while in a worst-case scenario of consecutive dry and windless periods it could see a 4 TWh generation deficit (see section 4.3.2). The expected winter 2026 solid fuel stockpile and Ahuroa's capacity equate to 3.1 TWh and covers a typical year but is inadequate to meet the worst case. The sector therefore would rely on demand response in a worst-case scenario, in particular from large energy users such as Methanex and Tiwai. This reliance is not a robust strategy, especially with Methanex's potential exit.

To strengthen the system's resilience New Zealand needs to develop 8–9 PJ of additional working gas storage. This also allows the gas system to have supply insurance to ride through upstream outages or short-term firming needs without risk of undersupply.

Given Ahuroa's current 6–8 PJ of working capacity, the future target is between 14–17 PJ, roughly double today's storage. By 2030, this 14–17 PJ of working capacity will provide New Zealand gas storage equivalent to 27–32% of its total domestic consumption (based on the Managed Transition Forecast), in line with leading international players.

**More storage is essential for the security of New Zealand's gas market**

New Zealand is considering importing LNG to secure its energy supply. A full-scale LNG facility with 4–5 PJ of storage and the ability to deliver a similar volume through flexible, on-demand shipments, co-optimised with Ahuroa, could double the effective flexibility available to the market.[81] However, even this configuration would likely still require additional underground storage, such as Tariki, to ensure sufficient depth and flexibility.

While 4–5 PJ of LNG storage combined with shipment management may meet demand variability, underground storage remains valuable to reduce reliance on LNG, moderating price volatility, supporting upstream investment and strengthening the overall system resilience.

If a small-scale LNG facility is pursued, it would only offer up to 0.4 PJ of storage, which is insufficient on its own and would need to be supplemented by underground storage to provide the necessary flexibility and deliverability. Regardless of the LNG option chosen, investment in new underground storage will most likely be required to achieve the system flexibility New Zealand needs.

**Feasibility, economics and timing must be considered before developing gas storage**

Before finalising storage plans, there are several questions to address:

- Can storage be feasibly created? And are there viable sites available?
- Considering seasonality, could the storage increase and decrease its storage capacity throughout the year knowing the minimum cushion and demand of the market?
- Would the storage asset make an economic return over its lifetime and who is best to fund it?
- When would the underground storage come online, and when could it be filled?

An indicative example of a new underground gas storage

81 Gas Strategies Group Ltd, NZ LNG Import Feasibility Assessment 2025, 2025

unit is Tariki, which Genesis is considering developing. It would provide 10–20 PJ of potential storage capacity, subject to appraisal and permitting, at a cost of $100–200 million.

Ahuroa alone cannot provide New Zealand with enough gas storage. New Zealand's historic advantage of abundant and inexpensive domestic gas is fading. Its emerging advantage is reliable, dispatchable renewable electricity supported by diverse and flexible fuels. The best pathway to this advantage is to double New Zealand's gas storage capacity, providing critical flexibility and diversifying sites to cut systemic risk.

### 5.4.3 Prepare LNG as an option to complement domestic gas and provide energy system security

**If LNG is pursued, it may provide valuable security insurance for the wider energy system**

LNG is an option to offset domestic decline as a security backstop, providing scalable, albeit expensive, gas molecules. LNG diversifies supply, sets a price ceiling in tight periods and reduces volatility by providing guaranteed cover for peaks, dry years and outages. It also buys time while electrification and development drilling progress, avoiding disorderly industrial exits. To pursue LNG and capture these benefits:

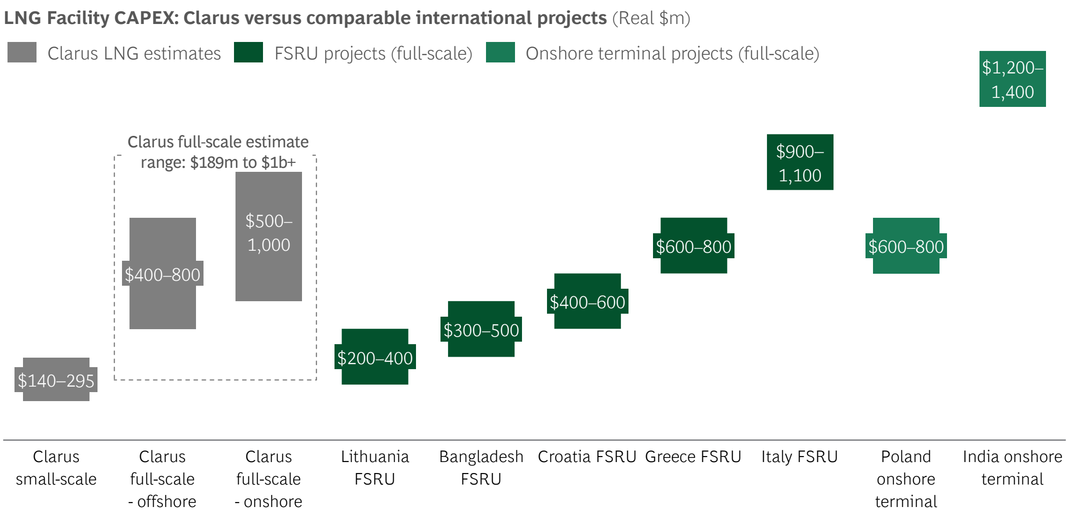
1. LNG must be delivered in sufficient quantity and before substantial industry exits.
2. LNG must be delivered at a price that is economically viable for customers and industry.
3. The net economic benefits must outweigh those of domestic alternatives.

**LNG can be delivered in sufficient quantity with required flexibility, but delivery may need to be expedited**

A fit-for-purpose LNG import solution could supply New Zealand with 12 PJ over three months – the volume New Zealand needs for industry and electricity generation during a dry year.[82] LNG also provides flexibility to deliver these dry year swing volumes via extra shipments and storage. Additionally, LNG can protect the energy sector from further downside gas supply risk which would impact affordability and cause potential industry disruptions.

However, LNG is expensive and can take several years to build. The cost of a full-scale facility can exceed $1 billion; however, an offshore import terminal would require less CAPEX and be faster to deliver than an onshore terminal.[83] Capital costs required for an offshore import terminal are around $400 million to $800 million depending on infrastructure, location and other factors. Clarus has assessed the full-scale LNG terminal options for New Zealand and its cost ranges are generally in line with international LNG terminal projects (**Exhibit 98**).

Exhibit 98: LNG facility CAPEX: Clarus versus comparable international projects




Note: Estimated figures in NZ $ in real terms; LNG country projects over last ~10 years; International projects used as LNG CAPEX benchmarks selected based on similar capacity ranges across offshore and onshore terminal solutions
Source: Clarus NZ LNG Import Feasibility Assessment and Small-Scale Addendum, EC, BCG Research, IGU 2025 World LNG Report, LNG Prime, KN Energies, Serbia Energy, Gasgrid, Acciona, Excelerate Energy, SNAM, GasTrade, Enerdata, Uniper, Offshore Energy, IndianOil LNG, Indian Infrasturcture, IndianOil, KIPIC, Gulf News, Portal Polskiego Radia SA, GAZ System

82 New Zealand GETS, LNG Import Facility Services, 2025

83 Clarus, NZ LNG Import Feasibility Assessment 2025, 2025

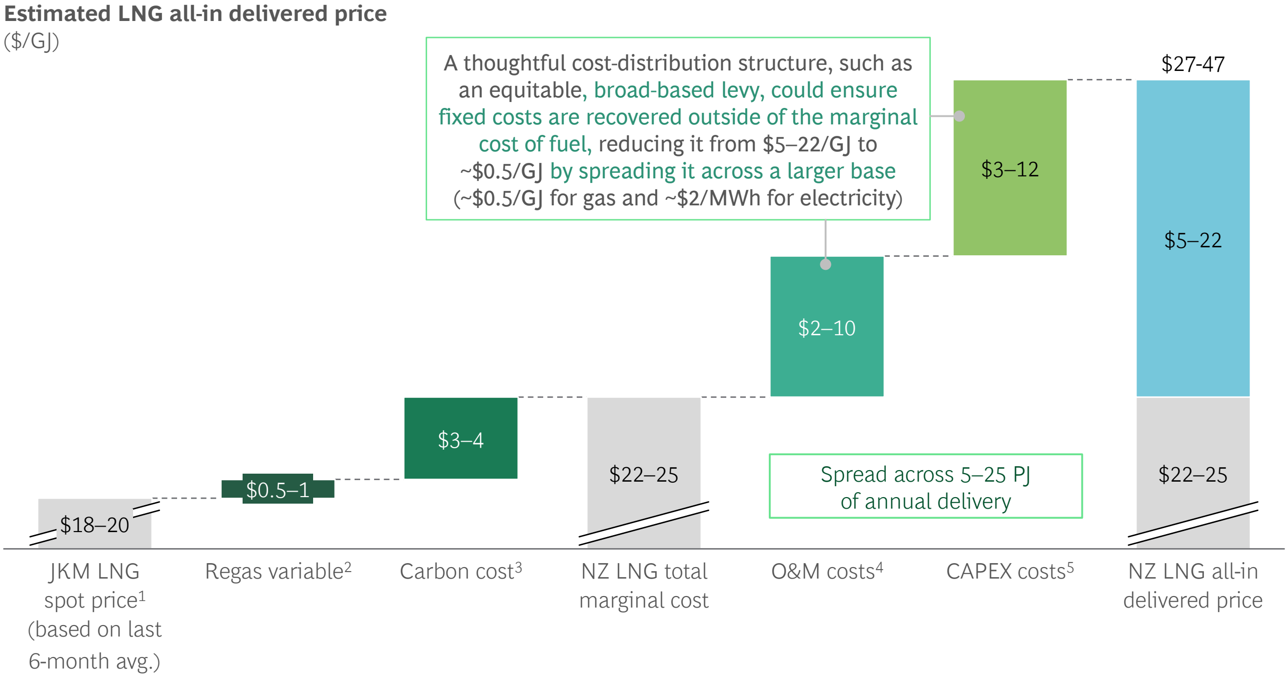
The government is looking to have an LNG facility online by June 2027.[84] Standard delivery of an LNG facility takes 4–5 years from business case to delivering first gas; however, there are several examples of LNG facilities (mostly FSRUs) being brought online in less than 12 months.

**LNG may be a prudent insurance backstop, but this flexibility comes at a price**

To purchase LNG, customers who don't already have contracts will need to pay the marginal LNG price – estimated to be $22–25 per GJ which includes $4–5 per GJ for regasification and carbon. While gentailers and commercial and residential users can most likely afford this price, industrial users' ability will vary.

To further ensure affordability, the capital and fixed costs for this insurance option will need to be spread across a large base. Otherwise, it risks adding $5–22 per GJ to the cost of fuel for an all-in delivered LNG price of $27–47 per GJ which would make LNG cost prohibitive. A thoughtful cost-distribution structure, such as an equitable, broad-based levy, could ensure capital and fixed costs are recovered outside of the marginal cost of fuel, reducing it from $5–22 per GJ to $0.5 per GJ by spreading it across a larger base ($0.5 per GJ for gas and $2 per MWh for electricity). See **Exhibit 99**.

Exhibit 99: Estimated LNG all-in delivered price




Note: All $ figures in NZ; JKM spot price delivered ex-ship (DES) – shipping/freight to the named port included in DES price; nominal transmission variable assumed
1. Average JKM spot price over last 6 months; 2. Regasification fees typically range between $0.5 and $1.0/GJ based on international LNG projects; 3. Carbon cost based on NZUs $60-80 per unit and natural gas emissions factor; 4. O&M assumes $40-50m p.a. across annual LNG import volume of 5-25 PJ; 5. CAPEX assumes $500m investment, 15-year payback, 8% WACC and amortisation across annual LNG import volume of 5-25 PJ
Source: Platts JKM (Japan Korea Marker) Liquefied Natural Gas (LNG) benchmark, IEA 2025 JKM Spot Prices, Japan Exchange Group (JPX), Palgrave Economics of Gas Transportation by Pipeline and LNG, Firstgas Transmission Fees, emsTradepoint Carbon Cost Estimates, 2025 Gas Strategies Group Ltd – NZ LNG Import Feasibility Assessment

84 New Zealand GETS, LNG Import Facility Services, 2025

Additionally, the LNG marginal cost of $22–25 per GJ does not include a potential ~10% premium that could be experienced due to New Zealand being a new entrant to the LNG market and its seasonal, irregular LNG demand.

LNG requires a willing party to underwrite the investment, guaranteeing payment for capacity and de-risking utilisation. The government could initially underwrite the development. In time a regulatory regime could be established with the LNG developer earning a regulated return via the broad-based levy.

**The economic benefits of LNG need to be considered against domestic alternatives**

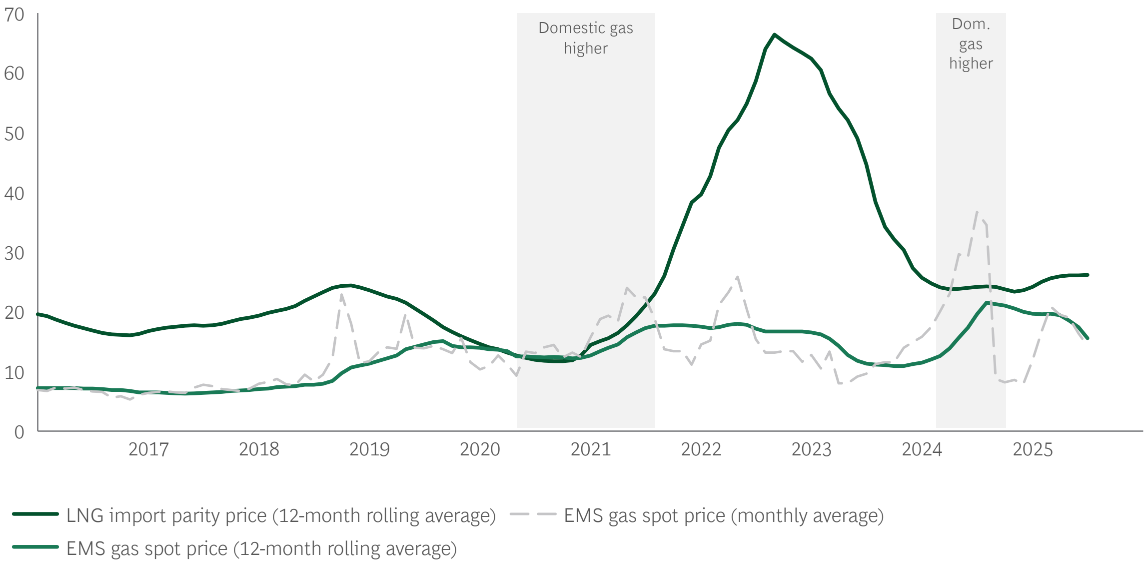
For LNG to serve as the gas sector's optimal insurance backstop, it should outperform economically, as domestic alternatives (e.g. condensate or diesel on the supply side for use in electricity) require smaller capital outlays and can be deployed faster. The expected price level is especially important as LNG or domestic alternatives will function as an effective price ceiling for gas prices during periods of tight gas supply. If capital and fixed costs are recovered outside of the cost of fuel, LNG would be lower cost per GJ than condensate or diesel.

LNG imports run the risk of repricing the whole gas market toward import parity, exposing New Zealand to global price volatility. Instead of today's $16–18 per GJ (average domestic spot gas over last 12 months, including carbon), all gas users would face gas prices that are $7–9 per GJ higher than today and susceptible to global shocks. Countries that rely on LNG typically have higher gas and electricity prices because they have exposed their energy market to global pricing dynamics. For example, LNG-dependent markets saw extreme spikes in 2022 when Russia invaded Ukraine, with Europe reaching around $155 per GJ and Australia briefly hitting around $55 per GJ, despite being a net exporter – illustrating the volatility imported into domestic bills.[85,86] Therefore, it is critical that if LNG is developed, it is only imported when absolutely required to minimise the domestic price trending towards LNG price parity and exposing New Zealand's energy system to global pricing shocks.

Historically, LNG import parity price has consistently sat above New Zealand's domestic gas spot price (see **Exhibit 100**). Even through recent tightness in the gas market, rolling averages show domestic gas is generally below LNG parity. As a result, it is highly preferable to have a well-functioning domestic gas market to one which relies extensively on LNG. This allows the New Zealand gas market to still have relatively more affordable gas prices despite tight supply.

Exhibit 100: EMS gas spot price versus LNG total marginal cost (including carbon and marginal regas cost)

**EMS gas spot price (including carbon) versus LNG total marginal cost (including carbon and regas)**
(Real $/GJ)




Note: LNG import parity price is based on JKM LNG index and adds in carbon cost and regas variable; does not include amortised CAPEX to build LNG terminal in New Zealand
Source: EMS Tradepoint, Concept Consulting, Platts JKM (Japan Korea Marker) Liquefied Natural Gas (LNG) benchmark, IEA 2025 JKM Spot Prices

85 Euro News, EU Countries Agree Gas Price Cap to Contain Energy Crisis, 2022

86 Australian Energy Regulator, Gas Market Report July 2022, 2022

Unless domestic gas prices consistently exceed import parity, LNG may not be economically viable. While global LNG prices are projected to decline in the near term, narrowing the gap with New Zealand's domestic gas prices, the cost of LNG would likely be higher if capital and fixed costs are included. Moreover, the global LNG market remains highly volatile and any price relief may prove temporary.

Introducing LNG would expose New Zealand to international price volatility, as the country would act as a price taker in global markets. LNG would also set the marginal price for domestic gas when it is being imported, pushing up overall prices and impacting affordability across all users. This impact would also translate to electricity prices, with the magnification depending on the percentage of renewable generation in the electricity mix.

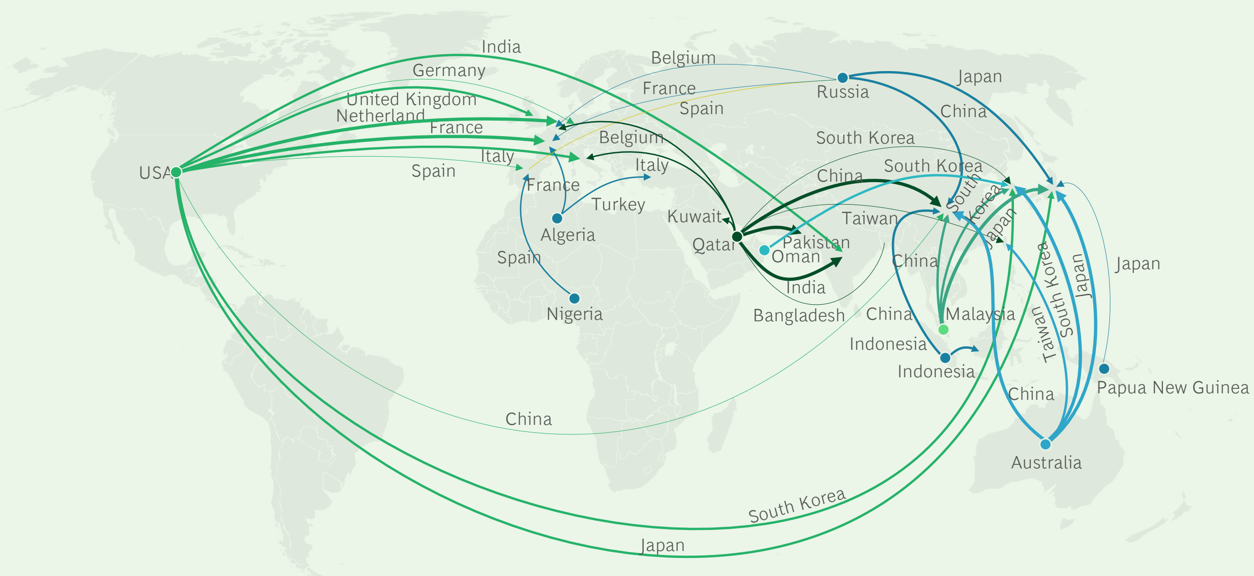
Industrial gas users are already struggling with current domestic prices. If some cannot absorb LNG import parity costs, the consequences could extend beyond energy costs, placing GDP, exports and jobs at risk. Despite this, if gas supply continues to decline at a rate much faster than demand New Zealand may have no other choice but to import LNG to protect from greater de-industrialisation.

## Global LNG market outlook

**LNG is now a fully global commodity, marked by growing complexity, structural shifts and ongoing volatility**

LNG has been a high growth market for over 30 years. Russia's invasion of Ukraine reshaped global trade patterns, with Europe emerging as an anchor market for LNG flows and new supply routes from the US, Qatar and Australia filling the gap (see **Exhibit 101**).[87]

### Exhibit 101: Major LNG flows in 2024




— Between 3 and 5 MT — Between 5 and 10 MT — >10MT

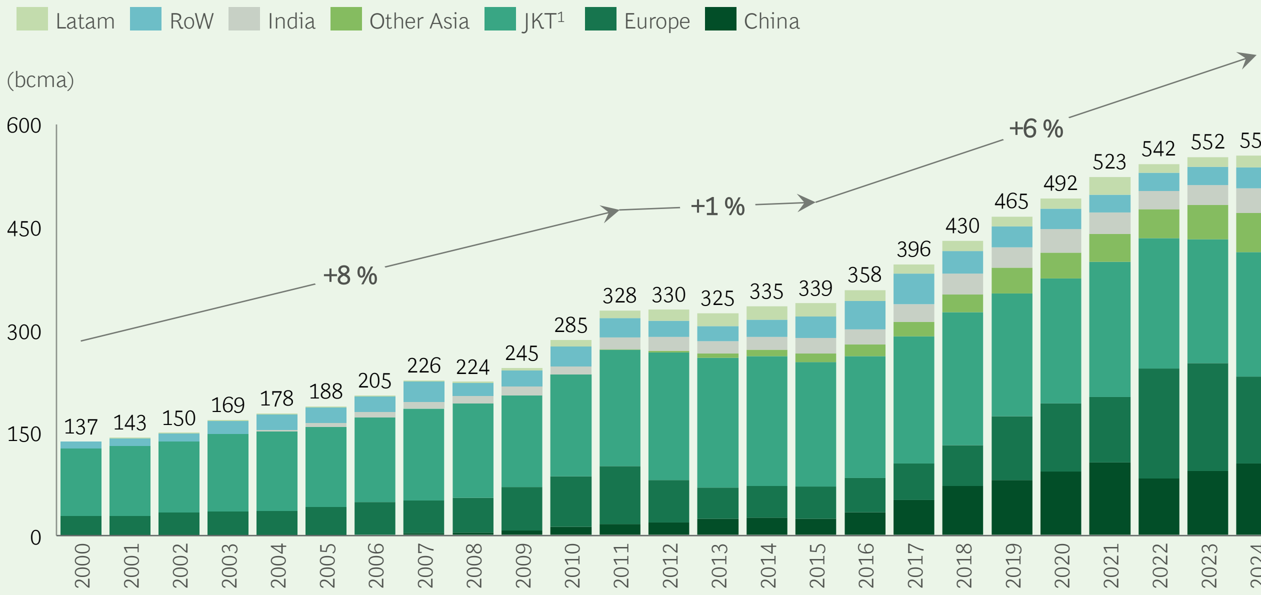
*Thickness of line indicates volume*

Source: GIIGNL

87 GIIGNL, GIIGNL Annual Report 2024, 2025

The demand outlook for LNG remains robust to 2030, with the majority of industry adjusting forecasts upwards. Today, demand growth is concentrated in China, India and Southeast Asia, while Europe remains an anchor market (see **Exhibit 102**). However, prices will be a key determinant of how strongly this growth materialises.

### Exhibit 102: Global LNG demand (2022–2024)




Note: Excluding re-exported cargoes and boil-off
1. Includes Japan, South Korea and Taiwan
Source: BCG LNG Long-Term Market Model

Supply growth is set to accelerate, with more than 300 bcma of new capacity expected – around half coming from the USA and Qatar.[88,89] This wave of supply is likely to loosen market conditions and could create a period of oversupply from 2027 to the early 2030s before tightening again in the mid 2030s as new projects are required to meet demand. A potential re-entry of volumes from Russia seeking alternative outlets or as part of a peace agreement with Ukraine could further impact prices.

Meanwhile, decarbonisation pressures are reshaping investment decisions. Future LNG projects are likely to be increasingly evaluated on their carbon intensity as low carbon credentials are becoming competitive prerequisites for securing offtake and financing. Shipping markets reflect the changing balance. The LNG carrier (LNGC1) market has entered temporary oversupply, with two-year time charters rumoured to be offered at US$5,000–10,000 per day. This showcases market expectation of oversupply before rebalancing by 2029 considering International Maritime Organization (IMO) driven factors (e.g. ships must meet the Energy Efficiency Existing Ship Index (EEXI)). [90]

**Volatility will remain a defining feature, even as prices are expected to decline in the near term**

The LNG market continues to be shaped by shifting trade flows and geopolitical risks. Through this, LNG trading continues to expand as a major profit pool, fuelled by regional price spreads and shifting benchmark dynamics. This volatility creates opportunities for portfolio optimisation but challenges point-to-point operators who are managing single spot cargoes with little optionality and exposed to price difference risk (e.g. delta between price indexes).

88 IEA, Gas 2025: Analysis and Forecasts to 2030, 2025

89 Bcma = Billion cubic metres per annum, a yearly flow/throughput measure for natural gas

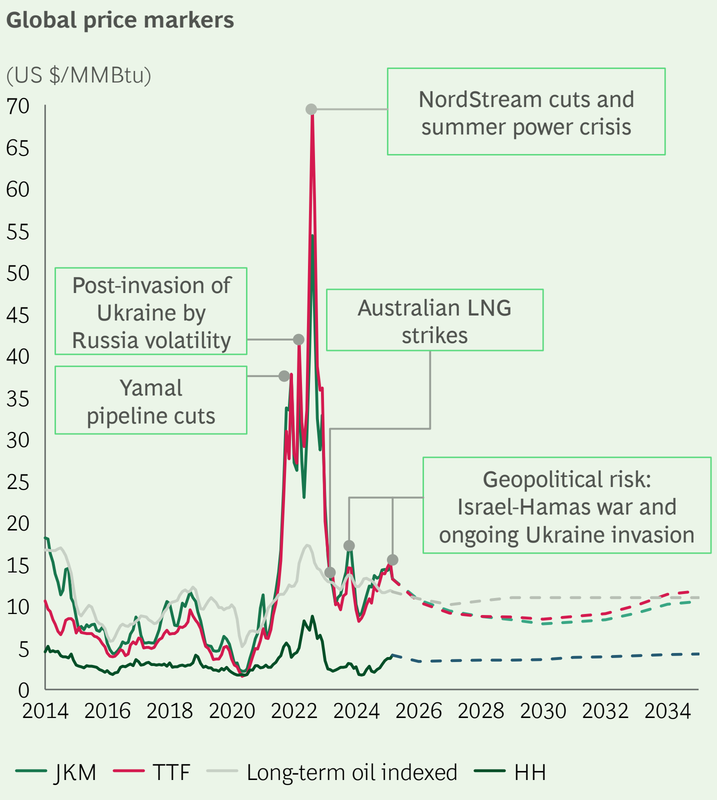
90 Drewry, Will There be Enough LNGCs by 2030?, 2025

Price behaviour varies across key benchmarks:

- **TTF (Europe):** Driven by storage levels and lingering uncertainty over Russian pipeline flows
- **JKM (Asia):** Influenced by weather-driven demand, restocking cycles and competition with European buyers
- **Henry Hub (US):** Supported by structurally higher domestic gas-fired generation, rapid growth in AI-driven electricity demand, rising USA LNG feedgas demand and Mexico pipeline exports

As new USA and Qatari liquefaction capacity comes online, European and Asian spot prices are expected to trend downward in the late 2020s, reflecting looser market conditions.[91,92] Beyond 2030, demand is projected to outpace committed supply. Unless new LNG projects (that have not reached Final Investment Decision (FID)) are developed, the market will tighten, and prices will rise (see **Exhibit 103**).

Exhibit 103: LNG pricing landscape




Source: Engie EnergyScan, Argus, Eikon, Rystad Energy, BCG Analysis

Overall, the LNG market is entering a new phase of maturity: global in reach, structurally diverse and increasingly shaped by decarbonisation and volatility. While potential near-term oversupply may ease prices, expected sustained demand growth and tightening supply-demand drivers after 2030 underscore LNG's enduring role in global energy security.

91 IEA, Gas 2025: Analysis and Forecasts to 2030, 2025

92 Liquefaction capacity = Total amount of natural gas that can be converted to LNG at a liquefaction facility

## 5.5 Enable gas users to transition

**Transitioning gas users to electricity and biomass where feasible will help to rebalance the gas market**

Accelerating industry's shift from gas to electricity and biomass would reduce gas supply pressure, improving gas affordability. It would also free up gas for industrial users who have little opportunity to convert to another fuel.

### 5.5.1 Accelerate gas to electricity or biomass conversion

**A managed transition will support industry to stay in New Zealand**

In New Zealand, industry is the largest consumer of thermal fuels, particularly gas, representing around 70 TWh of annual demand in August 2024 (53 TWh gas, 17 TWh coal, including Methanex and Ballance). Heat demand is heavily concentrated in processes for the manufacturing of food, wood products and chemicals.

Tightening gas markets are creating risk of higher prices, de-industrialisation, and relocation of critical New Zealand industry. Without reducing industrial gas demand, market conditions could drive significantly higher gas and electricity costs for all consumers. In worst-case scenarios, shortages could trigger industry demand destruction as soon as 2026, eroding the competitive economics that have supported industry, forcing exits and ultimately driving GDP loss. Some industrial players are ready to transition, and there are already projects underway or complete (e.g. Whareroa). However, further transition must be accelerated. Without coordination to improve sequencing and acceleration of gas conversions, New Zealand risks closure before industries can switch to electricity or biomass or before LNG can come online, risking demand destruction, loss of industrial capability and significant macroeconomic consequences.

If LNG does come online, it is still important for gas users to transition to electricity and biomass as it will support balancing domestic gas supply and demand. This will reduce the proportion of the time the market converges to LNG import parity, improving affordability for all gas users.

**Up to 32 PJ of annual gas demand across industry, commercial, and cogeneration could plausibly be converted to electricity or biomass**

Most industrial, civil services, and commercial gas demand is for boilers supporting low to medium process heat applications (0-500°C). This range is suited to heat pumps (up to 120C), electrode boilers and biomass boilers – which are all viable technologies and already deployed in New Zealand. Equating to 32PJ of gas that could be plausibly converted (see **Exhibit 104**).

The Energy Efficiency and Conservation Authority's RETA analysis and the Regional Heat Demand Dashboard which identifies boilers and process heat fuel consumption when combined with fuel economics from the IEA and Ministry of Environment, and an assessment of workforce capacity confirm the opportunity to transition 26.1 PJ of industrial gas demand (excluding co-generation) by 2035, including 17.3 PJ by 2030. [93] [94] [95]

93 Ministry for the Environment: Marginal Abatement Cost Curves Analysis for New Zealand, 2020

94 IEA: Renewables 2025: Analysis and Forecasts to 2030, 2025

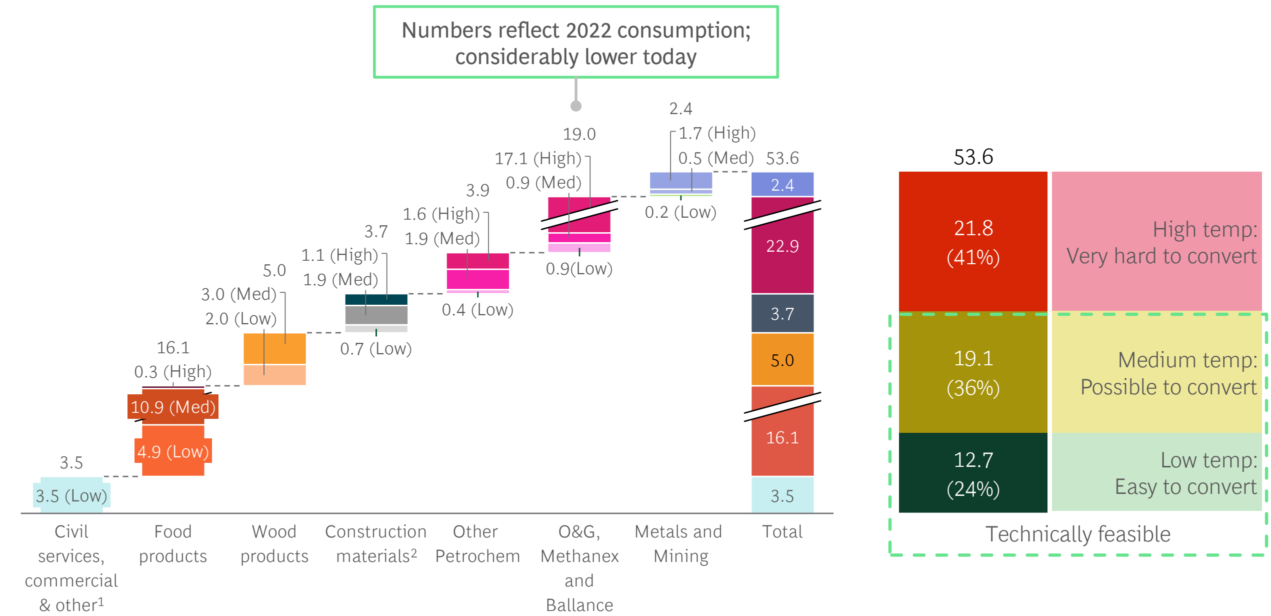
95 IEA: Ramping Up Heat Pumps in Moldova: A Roadmap, 2025

The most significant opportunities are in food processing, particularly dairy and meat (16.1 PJ), followed by commercial, civil services and other heating (3.5 PJ), wood products (2.5 PJ), low-temperature construction materials (1.5 PJ) and chemicals (2.0 PJ). Case studies such as electric and biomass boilers in the dairy sector demonstrate feasibility, while higher-heat industries including chemicals and some construction materials (concrete, quick lime and dry wall) remain difficult to transition (see **Exhibit 104**).

### Exhibit 104: Process heat gas consumption by industry and temperature

**Process heat gas consumption by industry and temperature**
(Gross PJ, August 2024

**Process heat temp breakdown**
(Gross PJ, August 2024)




**MBIE energy use classification**

- Basic metals
- Chemicals
- Construction materials
- Wood, pulp, paper & processing
- Food processing
- Other

**Temperature classification**

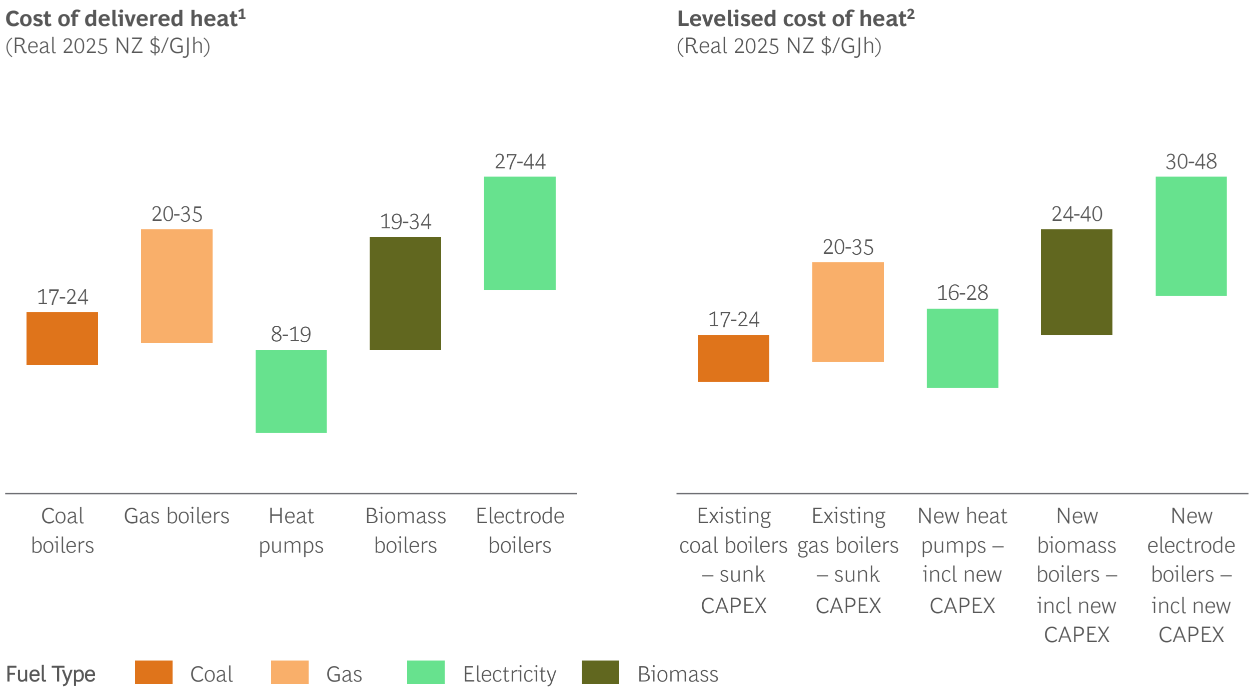
- High temperature (>500C)
- Medium temperature (100–500C)
- Low temp (0–100C)

1. Process heat gas consumption for commercial, education, government, health care, horticulture and waste management users; 2. Includes concrete, asphalt and dry wall manufacturing
Source: EECA Process Heat Demand Dashboard, MBIE Annual Gas Production and Consumption 2025 Q1, MBIE; IEA – Renewables for Industry, IRENA – Renewable Energy in Manufacturing; Renewable Thermal Collaborative

### However, industry faces some barriers to transitioning to these new energy sources

Commercial, financial and coordination challenges are barriers to delivery. Current conversion economics make switching away from thermal fuels unaffordable for many. Levelised cost of heat analysis shows that biomass boilers and heat pumps are competitive on a fuel, operations and maintenance basis, but upfront capital costs make all but heat pumps prohibitive without some financial support (see **Exhibit 105**). Grid connection timing, logistical complexity and technology availability create further risks.

Exhibit 105: Levelised cost of heat




Reflects Fuel and O&M costs; 2. Reflects CAPEX, Fuel and O&M costs; CAPEX removed for ops Benchmarking.
Source: EECA, EMI, GIC, BCG Analysis

Without a small increment of support for upfront capital costs the economics may not stack up leading to a missed opportunity to rebalance domestic gas supply-demand and restore more affordable pricing.

### A transition programme with financing support could support industry to switch at scale

The GIDI fund, run from 2020 to 2023, proved that financing support can help transition demand at effective support levels of $1.1 per GJ when spread across 15 years of fuel use (see **Exhibit 106**). With access to co-investment or government support of $200 million, New Zealand could feasibly displace up to 10-20 PJ of demand over the next decade, reducing industrial gas dependence, rebalancing supply and demand, and mitigating corresponding price pressures.

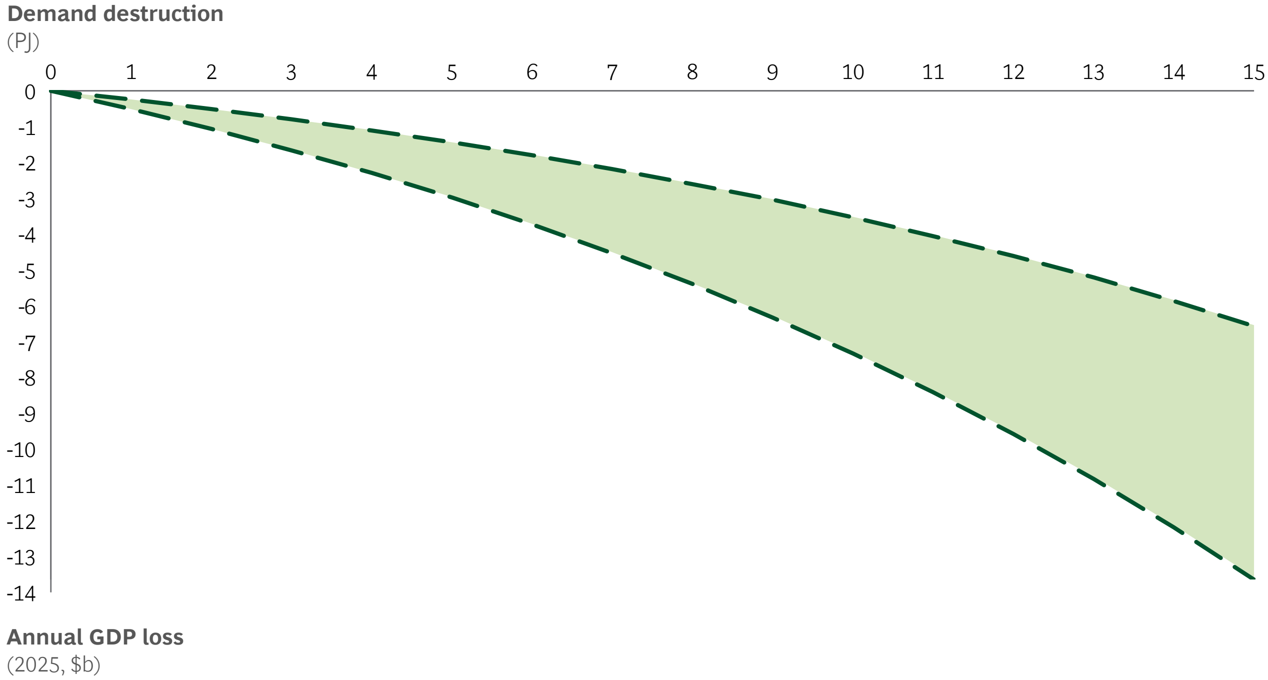
Exhibit 106: $ per GJ of GIDI funding required to switch

**Without transition support and coordination, New Zealand risks uncontrolled demand destruction, posing a significant threat to GDP**

While an industry transition fund presents a significant investment, temporal and ongoing shortages and limited visibility for industrial users could trigger and accelerate more significant economic damage. As gas availability tightens, curtailment will shift from lower-value consumers that use gas as a feedstock to higher-value consumers that use gas for heat and energy, causing GDP losses to rise non-linearly.

The first PJ of demand destruction (after a Methanex and Balance exit) equates to roughly $400 million in GDP loss, but the tenth incremental PJ corresponds to around $700 million. In total, 5 PJ of lost demand risks up to $3 billion in annual GDP losses, and 10 PJ could reach $7.3 billion p.a. which is nearly 2% of GDP (see **Exhibit 107**). The estimated industry transition funding from government required to shift 10 PJ of gas over to electricity or biomass is a one-off payment of between $100 and $200 million.

Exhibit 107: Estimated GDP impacts of gas shortage and affordability driven by industrial exits




Note: Only first order of GDP shown. Industrial players account for gas used as both feedstock and process heat. GDP estimated by mapping industrial gas consumption to sectoral GDP, ranking industries by likelihood of exit based on gas intensity, price sensitivity, and use as feedstock or process heat. Excludes Methanex and Ballance.
Source: EECA RETA and Regional Heat Demand Dashboard, Stats NZ, MBIE Annual Gas Production and Consumption, GIC Consumption statistics, Infometrics, NZ, IEA

**Preventing unnecessary demand destruction and supporting affordable gas must therefore be a core priority**

Even if new gas developments cannot fully restore supply, enabling switching and coordination across the system can materially reduce de-industrialisation. If LNG is pursued, support to shift to electricity and biomass is still valuable to de-risk the period until LNG is online and to reduce the proportion of time LNG price parity is reached. A dedicated transition mechanism is essential to balance gas supply and demand, safeguard critical industry and protect national economic value.

### 5.5.2 Increase gas market information available to stakeholders

Gas users, particularly industrial players, need transparency on forward supply and demand so they can make timely, informed decisions on fuel switching, hedging and investment. Today's lack of transparency has exacerbated the current situation.

Gas users need better information, with quarterly reporting on at least:

- **Future supply projections** by field with base, low and high scenarios
- **Production actuals** by field, showing daily volumes
- **Reserve scenarios** by field with base, low and high scenarios
- **Contract volume, planned and unplanned outages, and pricing disclosures** (strike prices, indices and terms anonymised per contract)

This will help ensure gas market users have what they need to make informed decisions on how best to address growing tightness in the gas market and minimise the risk of further demand destruction as gas consumers transition to alternatives.

# 6 Modelling and key findings

To understand the impact of delivering the five sector priorities outlined in Section 5, bespoke modelling was developed to both test critical sector choices and assess energy trilemma outcomes across a range of plausible scenarios. Modelling outcomes also informed the development of policy, market and regulatory recommendations covered in Section 7 by demonstrating the value of these recommendations to the sector and broader economy.

This section first introduces the six modelled scenarios, before providing the modelling outcomes across the three aspects of the energy trilemma, and then uses the modelling outcomes to answer six critical questions for the energy sector:

1. What is the required pace of renewable generation development to meet future energy needs?
2. What is the outlook for electricity prices and what does it mean for economic growth?
3. What is the best path forward for gas?
4. What is the required pace of fuel-switching and the value of accelerated approaches?
5. Does the market affordably provision for dry years across the scenarios, and how do the tested security actions influence outcomes?
6. Does the market affordably provision peak capacity, and how do the tested actions influence peaking security outcomes?

## 6.1 Introduction to the six energy scenarios

BCG partnered with Concept Consulting to model six scenarios, each reflecting a plausible path, testing policy and market levers for New Zealand's energy sector to 2040. Scenarios were designed to model a range of underlying economic conditions, sector priorities (e.g. balancing of the gas market in Scenario 2), or specific market interventions (e.g. LNG terminal development in Scenario 5).

The six modelled scenarios, their key assumptions and the main aspects they tested for are summarised below:

**Scenario 1: New Zealand's Full Potential**

This scenario presents a confident and growth-oriented energy transition. An energy abundance mindset and favourable policy settings give investors confidence and stimulate new industries, resulting in GDP growth above expectations. Meanwhile, gas development campaigns deliver strong results, restoring supply and demand confidence. At the same time storage development stabilises supply, easing gas prices and providing time for major users to transition to alternative fuels. The development of renewable generation and associated grid connections continues at pace, following strong demand growth.

***Main aspects tested:*** Economic opportunity from data centre development and market performance under high demand growth.

**Scenario 2: Managed Transition**

This pragmatic, steady scenario balances economic growth with the energy transition. It tests actions to address short-term gas market imbalances. On the supply side, these actions include developing gas fields and storage to slow the supply decline, albeit with no LNG import facility development; on the demand side, they include supporting major gas users to transition to alternative fuels and reduce gas demand. In the electricity industry, developers continue their strong and deliberate build of renewable generation and connections, aligning closely with new demand from electrification and growth in industry. Policies support the energy sector to provide predictability, avoid price shocks and support New Zealand's competitiveness.

***Main aspects tested:*** Impact of strong and timely renewable energy generation development and pulling multiple domestic levers to improve the supply and demand balance in the gas market.

### Scenario 3: Managed Transition and Electricity Security Mechanisms

Under this scenario, there is a concerted effort to position New Zealand for growth, manage the energy transition and improve electricity security of supply. It adopts the underlying market conditions and gas market actions taken under Scenario 2 and tests the impact of additional security mechanisms. These mechanisms incentivise additional thermal fuel storage for electricity generation in dry periods, dual-fuel conversion of electricity peaking units to enable burning of condensate or diesel when gas availability is limited, and an accelerated build-out of grid scale batteries.

***Main aspects tested:*** Security and affordability impacts of mechanisms to expand dispatchable capacity and thermal fuel storage (noting it builds upon other aspects tested in Scenario 2).

### Scenario 4: Bumpy Transition

In contrast to scenarios 2 and 3, this scenario leaves market pricing to balance the gas market. With little government intervention, industrial gas users react to high prices by either exiting the market or switching to alternative fuels. In the electricity industry, renewable generation continues to be developed but at a reduced rate from 2028 – reflecting lower electricity demand growth and a slower economy.

***Main aspects tested:*** Plausible outcomes from a low intervention, market-led approach without LNG.

### Scenario 5: Energy Importer

In Scenario 5, a full-scale LNG import terminal is developed to address the continued decline in the domestic gas market and maintain system stability. LNG imports are available from 2028 at $25 per GJ (including carbon) and provide gas supply security for local gas users and winter electricity generation. Additional measures in scenarios 2 and 3 to address imbalances in the domestic gas market are not implemented and the market quickly becomes reliant on LNG imports. The gas price converges to LNG import price parity during import periods but a price ceiling is established. LNG acts as a stop-gap measure for some major gas users to invest in biomass and electrification in the coming decade.

***Main aspects tested:*** Impacts of developing a full-scale LNG import facility in an environment where some levers to improve the domestic gas supply-demand balance are not pulled.

### Scenario 6: Handbrake

This scenario represents pessimistic economic and market conditions. An energy deficit, rather than an energy abundance, mindset is adopted. Restrictive gas development and consenting rules place a handbrake on energy supply development. Domestic gas production declines rapidly due to ageing gas fields, poor development results and limited investment. With this decline, market prices rise as demand exceeds available supply and energy-intensive industries close or scale-down due to high energy prices and a lack of reliability. Given the speed of decline and pessimistic economic outlook, few industrial users invest in switching to electricity or biomass – as a result, electricity demand is very low and the build of renewable generation slows after 2028.

***Main aspects tested:*** Impact of restrictive conditions for developing new energy supply and economic impact of the resulting de-industrialisation.

**Exhibit 108** summarises the market conditions and policy settings that define each of the scenarios.

### Exhibit 108: Market conditions and policy settings across the six scenarios

| | | S1: New Zealand's full potential | S2: Managed transition | S3: Managed transition and elec. security | S4: Bumpy transition | S5: Energy importer | S6: Handbrake |
|---|---|---|---|---|---|---|---|
| Market conditions | Economic growth incl. new industry | Strong | Consistent | Consistent | Slow | Consistent | Limited |
| | Domestic gas supply | Stabilised | Decline Slowed | Decline Slowed | Decline as Forecast | Decline as Forecast | Accelerated Decline |
| | Rate of electrification | Very High | High | High | Low | Moderate | Very Low |
| Policy settings | Gas fuel switch support | ✓ | ✓ | ✓ | ✗ | ✗ | ✗ |
| | Extended gas drilling support | ✓ | ✓ | ✓ | ✗ | ✗ | ✗ |
| | Electricity security mechanisms | ✗ | ✗ | ✓ | ✗ | ✗ | ✗ |
| | LNG import terminal | ✗ | ✗ | ✗ | ✗ | ✓ | ✗ |

Each scenario has been evaluated against the criteria outlined in **Exhibit 109** to assess relative and absolute energy trilemma outcomes in the short term (to 2028), medium term (to 2030) and long term (to 2035).

### Exhibit 109: Criteria to assess scenario outcomes

**Affordability**

- Relative system cost (CAPEX)
  - New generation
  - Lines Development
- Average wholesale prices
- Industrial, household energy costs
- GDP impact (fuel switching, demand destruction, lost growth, cost)
- Contract price including dry year risk premium

**Security**

- Generation stack by fuel source, including under dry years
- Capacity stack by fuel source, including to meet peak demand
- Quantity and cost of demand response
- Overall quantum of generation and capacity required to 2035
- Demand response and associated costs

**Sustainability**

- % renewable generation across pathways
- Annual energy emissions reductions (from generation and electrification)
- New Zealand emissions profile

### Modelling approach

BCG partnered with Concept Consulting to simulate electricity market and economic outcomes within each scenario. Two models were used to analyse the different scenarios and provide the full picture of outcomes:

- **ORC:** A model of the electricity market (e.g. generation, capacity stack and electricity prices).
- **ENZ:** A whole-of-economy model to estimate the impacts of electricity market dynamics and outcomes on the broader energy system and economy.

### ORC

ORC simulates the interaction of generation and demand across different market scenarios. For a given market scenario (i.e. a combination of what generation has been built, the level and composition of demand and fuel and CO2 prices), it models how generation and other resources, such as batteries, will be dispatched to meet demand.

ORC models each year chronologically, hour by hour, before iteratively refining outputs using data from 40 historical weather years. This allows it to examine how a given combination of supply resources perform across a realistic range of weather situations (varying hydro inflows, wind and sunshine) and is combined with a demand forecast to optimise the dispatch of its controllable resources.

ORC dispatches hydro generation, thermal generation (where available), storage resources (e.g. batteries) and demand response to find the lowest-cost way to meet demand. Long-term storage is tracked for hydro schemes, considering the effect of inflows, maximum and minimum storage levels and minimum flow constraints. Gas storage facilities and some other types of long-term storage can also be tracked.

ORC models the North Island and South Island as two entities, linked by the HVDC. It accounts for the need for instantaneous reserves to cover the potential loss of a major supply asset (e.g. one of the HVDC poles or a large generator). It also models outages at expected frequencies and durations.

The output for a given market scenario includes prices and total system costs, such as costs for fuel, CO2, capital and non-fuel operating and demand curtailment. The model is run iteratively, tweaking the capacity of generation and batteries until an optimal, low-cost solution is found. This iteration also ensures that each type of resource that is developed recovers sufficient revenue to cover its capital and operation costs.

### ENZ

ENZ is a model of New Zealand's emissions-producing economy. It was used by the Climate Change Commission to set New Zealand's carbon budgets. It has separate modules for agriculture, forestry, waste, energy supply (electricity generation and networks, gas production and networks), transport energy use and non-transport energy-use (including space and water heating, industrial process heat, steel, cement and petrochemicals).

It models the extent to which energy needs are met by different technology (or land-use change in the case of agriculture and forestry) in response to external scenarios regarding CO2 price, oil prices, commodity prices and population growth.

ENZ's integrated modules ensure that outcomes in one part of the economy consistently flow through to others. For example:

- Increased electricity demand due to the electrification of space heating will increase electricity prices and affect all other parts of the economy that use electricity. Increased prices will also affect the future rate of electrification of space heating in subsequent years.
- Switching from pipeline gas for one use (e.g. process heat) will affect gas network prices for remaining users of pipeline gas, which will accelerate any switching from pipeline gas.

### Combining ORC and ENZ

ORC and ENZ are separate models with no formal integration. ORC was run for different pathways and scenarios to model electricity system costs and prices. ENZ was run independently under different scenarios of external drivers, such as the prices of carbon and biomass. A range of wholesale electricity prices changes were also an exogenous input to the ORC model. These electricity price changes were used to simulate how rates of electrification for key end uses (industrial process heat, space and water heating, and transport) would vary with electricity price.

A separate integration model took the ORC outputs and ENZ's central projection of emissions reductions for the different parts of the economy. It used ENZ's electricity price electrification function to model the extent to which electrification would be different between scenarios due to differences in ORC-modelled electricity prices, and consequent variations in rest-of-economy emissions and non-electricity.

All of Concept Consulting's ORC and ENZ analysis is based on information from public sources, or information developed independently by Concept Consulting.

### Standard modelling assumption and characteristics

Two assumptions underpinned all scenario modelling:

- Models were run across 43 hydrological years and the average outcome was represented in all modelling findings.
- Building on the Future is Electric, 'smart systems' capabilities (e.g. vehicle to grid dispatch) were assumed across all scenarios.

## 6.2 Modelling outcomes

The scenario modelling provided insights that outline a clear pathway for New Zealand to perform strongly against the energy trilemma and support sustained economic growth:

- *Scenario 1: New Zealand's Full Potential* highlights both the economic benefits associated with data centre exports and the accompanying risks of rapid demand growth. The scenario underscores the need to align new large-load connections with generation and network expansion to avoid stretching system capacity.
- *Scenario 2: Managed Transition* demonstrates the importance of maintaining New Zealand's pace of generation development and pulling all levers (demand management, development drilling support) to stabilise the gas market.
- *Scenario 3: Managed Transition and Electricity Security Mechanisms* reinforces the benefits of incentivising dispatchable capacity development and increasing firmed fuel storage. These measures materially enhance electricity security, reduce dry-period exposure and moderate pricing volatility, providing a cost-effective path to a more resilient system.
- *Scenario 5: Energy Importer* shows that, where technically feasible, a full-scale LNG import capability can provide valuable security and affordability benefits. Additionally, it provides protection against downside risk if domestic gas supply falls unabated due to poor development drilling outcomes. The scenario highlights the importance of maintaining LNG optionality as an insurance mechanism.
- *Scenario 4: Bumpy Transition* and *Scenario 6: Handbrake* demonstrate the clear risks of inaction. Slower investment, weaker coordination and delayed responses to supply-side challenges result in lower economic growth and comparable affordability and security outcomes to other scenarios.

Collectively, the modelling insights suggest the best path forward is to pull a combination of levers tested across scenarios:

- Maintaining New Zealand's pace of renewable generation development
- Taking a deliberate and coordinated approach to addressing gas market challenges (pulling both supply and demand levers)
- Incentivising additional dispatchable electricity capacity and firmed fuel storage for security and affordability
- Maintaining LNG optionality

This combination of levers reflects a blend of key features explored in Scenario 3: Managed Transition and Electricity Security Mechanisms and Scenario 5: Energy Importer and will allow New Zealand to deliver balanced, resilient outcomes across affordability, reliability and sustainability while driving long-term economic growth.

**Exhibit 110** provides an overview of how scenarios compare on relevant metrics in 2030.

## Exhibit 110: Comparison of scenarios against relevant metrics in 2030

| | | Affordability | | | | Security | Sustainability |
|---|---|---|---|---|---|---|---|
| Pathway name | Relative system cost | Average wholesale electricity prices ($/MWh) | Household electricity prices ($/MWh) | Futures contract premium ($/MWh) | New economic investment stimulated | Demand response costs | Renewable electricity generation |
| **S1:** New Zealand's full potential | $21.6b | 120 | 392 | 16 | $50 – 70b | $12m | 98% |
| **S2:** Managed Transition | $19.8b | 117 | 379 | 15 | $41 – 56b | $10m | 98% |
| **S3:** Managed Transition and Electricity Security | $20.8b | 105 | 378 | 10 | $41 – 56b | $3m | 98% |
| **S4:** Bumpy Transition | $19.2b | 119 | 386 | 20 | $27 – 37b | $11m | 98% |
| **S5:** Energy Importer | $19.7b | 109 | 390 | 10 | $41 – 56b | $8m | 99% |
| **S6:** Handbrake | $18.0b | 117 | 368 | 19 | $20 – 27b | $10m | 98% |

### 6.2.1 Affordability

**Wholesale electricity prices vary in the short term but decline across all scenarios to 2035**

Across all scenarios to 2035, there is a decline in average wholesale electricity prices (see **Exhibit 111**). This is driven by the increasing share of low-marginal-cost renewable generation, with fewer time periods requiring higher-cost thermal fuels to clear the market.

The largest relative price differences between scenarios are observed in the short-term, to 2028. Scenario 6: Handbrake sees the most significant price reduction on today's prices, as tight gas market conditions lead to industrial closures, reducing demand and limiting gas-to-electricity fuel switching. Scenario 4: Bumpy Transition maintains elevated prices, with the market-led approach prolonging gas market tightness and high gas prices, which flow through to electricity prices. Scenario 5: Energy Importer sees similar prices in 2028 as the promise of secure gas supply from LNG keeps industrial gas users in the market, which elevates gas prices and therefore the cost of firming, with prices capped by LNG imports during the few short dry hydrological periods.

In the longer term, prices tend to converge at lower levels across the scenarios as the renewable build-out weakens reliance on gas. Scenario 3: Managed Transition and Electricity Security Mechanisms sees lower prices beyond 2035, supported by the introduction of a reserve market that encourages battery deployment and additional firming fuel storage that enhance system flexibility. Scenario 2: Managed transition and Scenario 1: New Zealand's Full Potential show marginally higher long-term prices, reflecting stronger demand from energy-intensive industries, population and economic growth.

**With more storage and firm fuels, forward contracting and dry-period risk premiums are lower**

While dry periods will continue to place upward pressure on electricity prices, ongoing renewable development and reduced dependence on thermal fuels are expected to moderate the impact of elevated fuel costs, even in dry years.

**Exhibit 111** shows that across all scenarios, forward prices and risk premiums are expected to converge toward long-run marginal cost (LRMC) levels. This convergence occurs most rapidly under Scenario 3: Managed Transition and Electricity Security Mechanisms, Scenario 1: Delivering on New Zealand's Full Potential, and Scenario 5: Energy Importer. Each of these scenarios benefits from improved access to firm fuels or storage, which reduces dry-year risk and stabilises contracting outcomes.

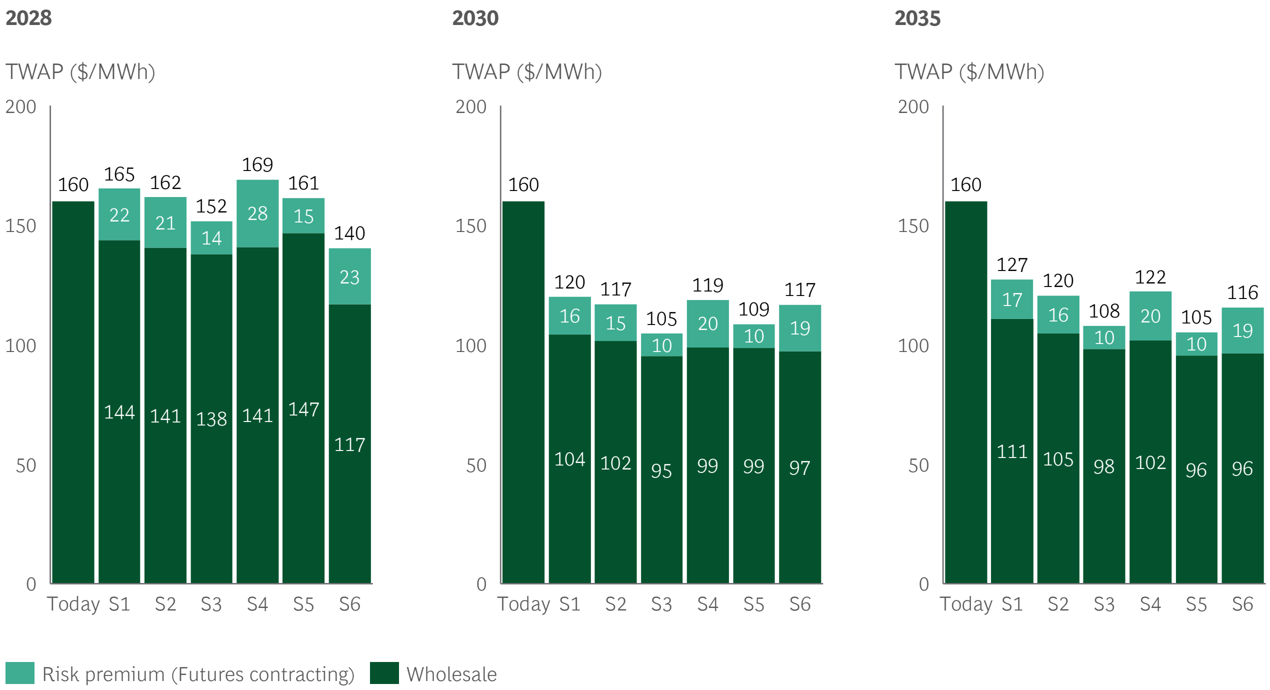
In Scenario 3, additional storage capacity and fuel flexibility, supported by enhanced winter firming, provide system security during dry conditions and reduce reliance on short-term thermal generation. Scenario 1 reflects improved gas market balance, with strong drilling results and a steady transition of demand away from gas improving supply stability and lowering volatility in forward gas contracts. Scenario 5 achieves a similar outcome with access to imported LNG, which provides an alternative firming source and limits upward pressure on thermal fuel prices in dry periods.

Across the scenarios with firm fuel or storage, contracting premiums are projected to trend toward 10% of the LRMC, or about $10 per MWh, reflecting reduced exposure to dry-year risk and greater confidence in fuel availability.

In contrast, scenarios without firming measures, including Scenario 2: Managed Transition, Scenario 4: Bumpy Transition, and Scenario 6: Handbrake, experience higher forward contracting prices. The absence of security products or storage options leaves these pathways more exposed to dry-year variability, relying instead on supply flexibility and demand response to manage risks. While prices in these scenarios also move toward LRMC over time, this improvement results from lower underlying electricity prices rather than reductions in contracting premiums, which persist at around 20% or $15–20 per MWh.

Overall, access to reliable firm fuel through expanded storage, improved gas market performance, or LNG imports is a key factor in moderating forward price volatility and accelerating convergence toward long-run cost levels across all transition pathways.

Exhibit 111: Time-weighted average price by scenario




S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake
Note: TWAP = time-weighted average price
Source: Concept Consulting modelling, BCG analysis

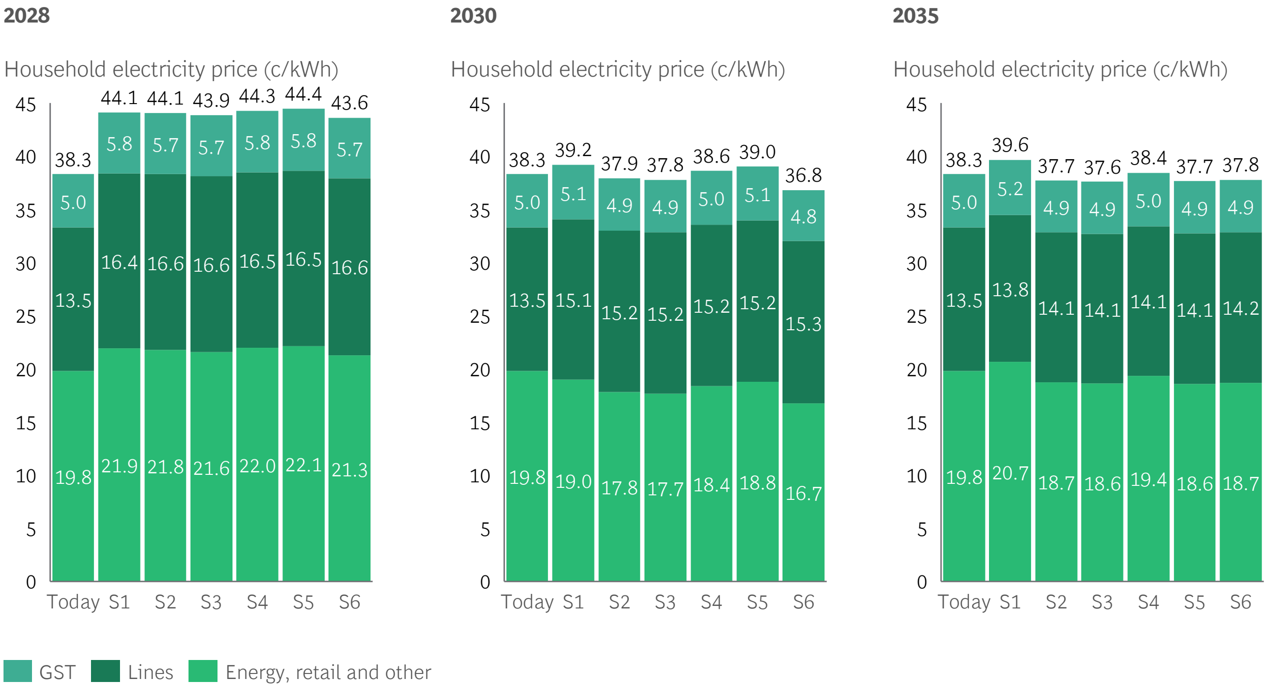
**Industrial and household energy costs rise to 2028 with increasing lines charges before declining as further new renewable generation enters the system**

**Exhibit 112** shows that electricity costs for households and industrial customers are expected to rise modestly across all scenarios in the short term driven by rising lines charges. This is informed by the Commerce Commission's approved schedule of regulated revenue increases for lines companies across the March 2025 to March 2030 regulatory period. These approved increases reflect both substantial capital investment programs by electricity distribution businesses (EDBs) and a higher weighted average cost of capital (WACC) applied to New Zealand's regulated asset base.

From 2030 onwards, electricity prices for residential and industrial users are projected to decline in both nominal and real terms as new lower-cost renewable generation enters the system. Demonstrating that proactive generation development can deliver affordable energy while supporting decarbonisation.

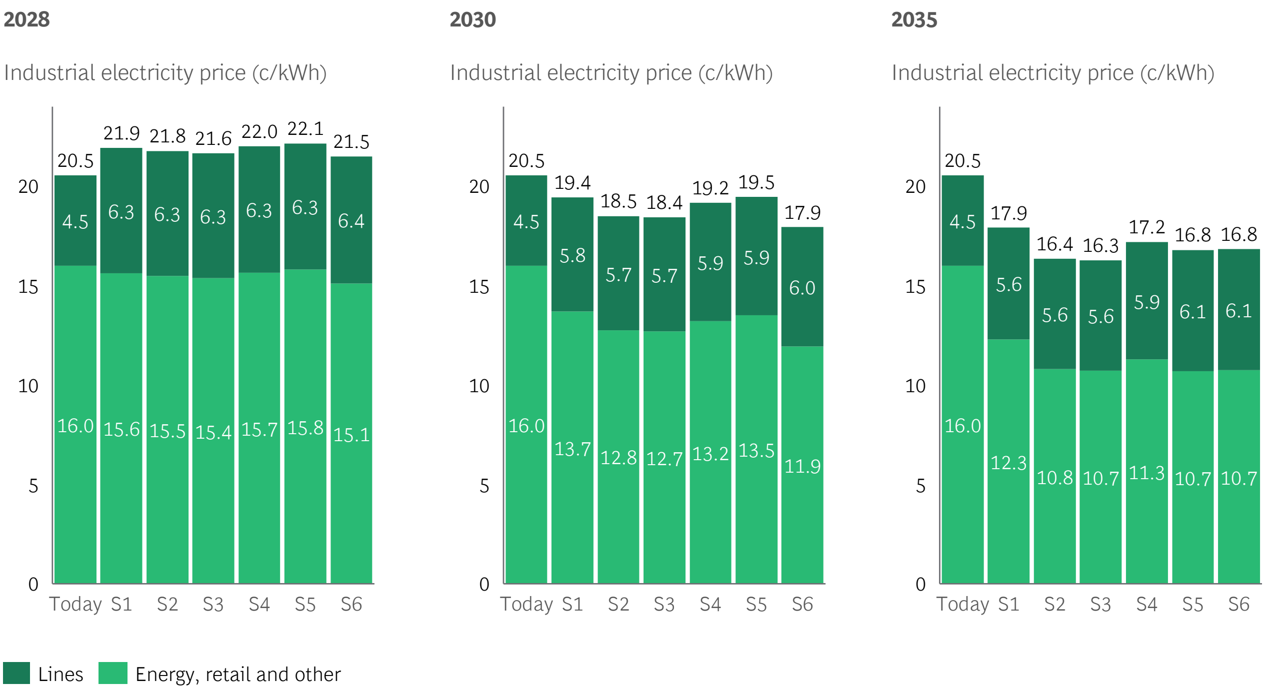
Scenario 1: New Zealand's Full Potential records the highest overall electricity costs by 2035, at around 39.6 cents per kWh for households and 17.9 cents per kWh for industrial consumers. This scenario's prices reflect stronger demand growth, and the capital intensity of accelerated infrastructure development across transmission, networks and generation to serve the growth.

## Exhibit 112: Residential electricity prices




S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake
Source: Concept Consulting modelling, BCG analysis

## Exhibit 113: Industrial electricity prices




S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake
Source: Concept Consulting modelling, BCG analysis

## Relative system costs are highest for scenarios with the greatest electricity demand growth

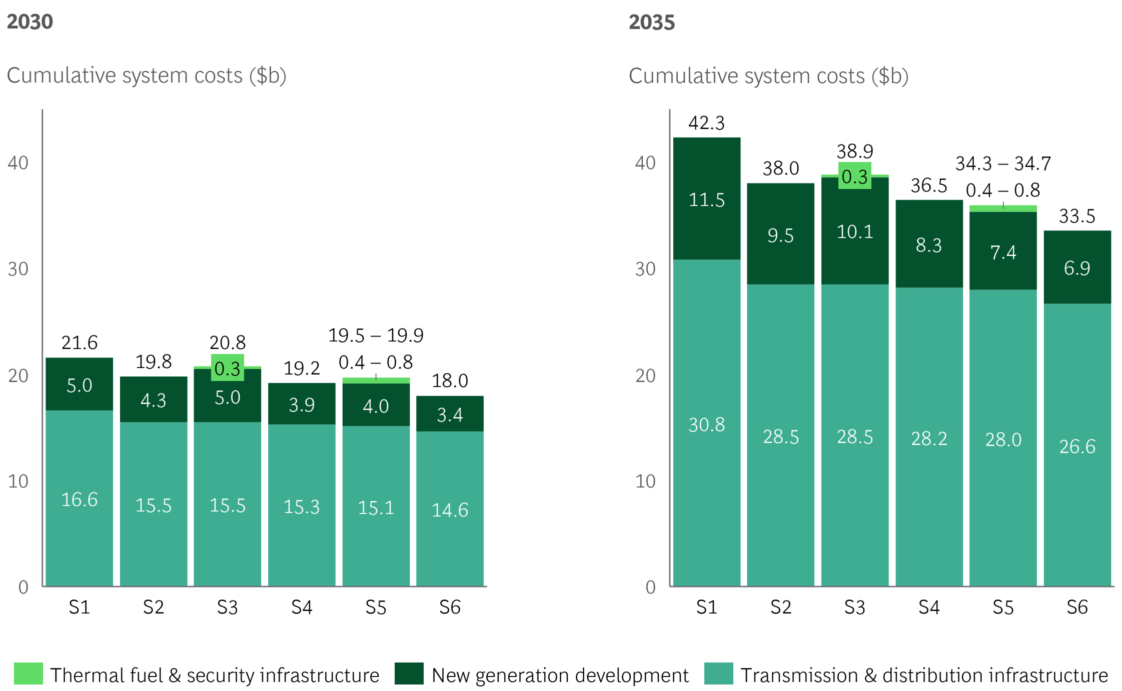
**Exhibit 114** presents the projected system costs for each scenario in 2030 and 2035. Outcomes reflect both sectoral choices on where and how to invest, alongside the elevated system costs required to meet incremental demand-driven economic activity and growth in energy-intensive industries. Broadly, system cost is correlated with overall demand, and correspondingly with the requirements for new generation, capacity, and infrastructure development, which in turn are a function of policy settings, investment levers, generation technology availability and build-rate outcomes. Across all scenarios, approximately 75% of system costs over the next decade are attributed to transmission and infrastructure development, with new generation and thermal fuel & security infrastructure, required for LNG import and new gas storage, making up the balance.

Scenario 6: Handbrake records the lowest system costs, reflecting slower demand growth and a reduced need for new generation, capacity, and network infrastructure.

For similar reasons, though to a lesser extent, Scenario 5: Energy Importer represents the second-lowest cost pathway. While system costs in Scenario 5 are initially elevated through 2030 relative to Scenario 4: Bumpy Transition, this is due to significant investment in LNG facilities. By 2035, this trend reverses as increased gas security to meet dry-year conditions, combined with slower rates of industrial electrification, moderates the demand for new generation and reduces overall system cost relative to Scenario 4.

At the other end of the spectrum, the strong demand growth and corresponding generation build-out required in Scenario 1: Delivering on New Zealand's Full Potential result in the highest system cost profile. Comparing Scenario 2: Managed Transition with Scenario 3: Managed Transition and Electricity Security Mechanisms highlight the cost premium associated with enhanced system security. Additional investment in battery storage, gas treatment, and OCGT conversions drives higher new-generation development costs in Scenario 3, demonstrating the trade-off between cost efficiency and the value of more secure, reliable energy supply for users from a total system cost perspective.

### Exhibit 114: Cumulative system cost by scenario



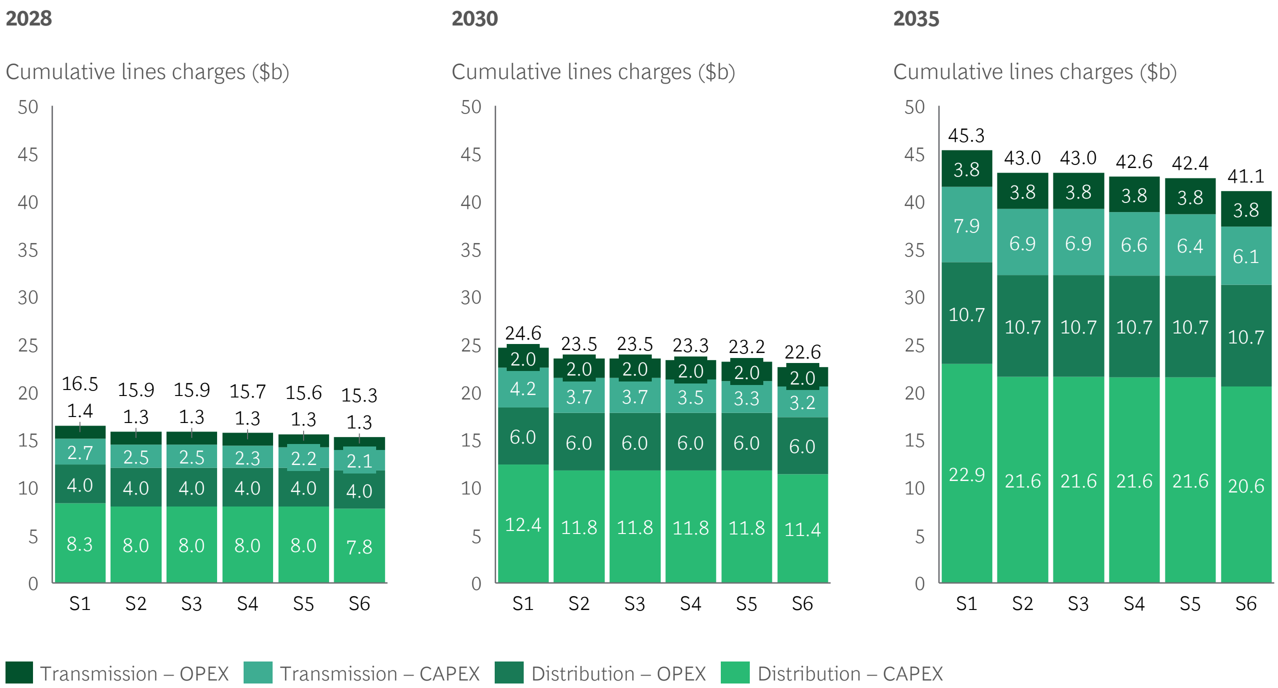

S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake
Note: CAPEX Only. Thermal Fuel and Security Infrastructure includes the cost of LNG import infrastructure, new thermal fuel storage development and plant retrofitting.
Source: Concept Consulting modelling, BCG analysis

**Transmission and distribution costs increase across all scenarios as upgrades and developments are needed to support higher loads**

Transmission and distribution infrastructure costs are expected to rise across all scenarios as electricity demand grows requiring infrastructure upgrades to add capacity, extend the network to new users and connect generation sites to the national grid. Improved system operation and technology advancements are expected to ease cost pressures beyond 2030.

Scenario 1: New Zealand's full potential represents the highest cost increase, with $45 billion required for lines to 2035, and Scenario 6: Handbrake represents the lowest cost, with an incremental $41 billion of lines spend (see **Exhibit 115**).

Exhibit 115: Cumulative transmission and distribution costs from 2025




S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake
Note: Reflects spend from 2025 to modelled year
Source: Concept Consulting modelling

### Positive economic impacts increase with renewable generation

While new demand drives energy system costs higher, it can generate meaningful economic impact across broader sectors of the economy. New energy generation and network infrastructure supports demand growth from energy-intensive industries such as data centres.

The New Zealand data centre market is currently relatively small, with approximately 125 MW of capacity in 2025.[96] Different data centre build-out rates were modelled across all scenarios to reflect varying levels of export market expansion, driven by the energy characteristics of each scenario, given energy supply and affordability are key investment drivers for data centre developers.

The total economic impacts to 2035 resulting from data centres across modelled scenarios are shown in **Exhibit 116**. These reflect new investment in energy generation to support centres, data centre construction and IT fit-out, ongoing operations and the indirect effects flowing through the upstream supply chain (as outlined in Section 3.3).

In Scenario 6: Handbrake, a moderate build rate to primarily support domestic-only services – held back in part by a constrained energy market – results in a modest total economic impact of $20–27 billion to 2035.

By contrast, Scenario 1: New Zealand's full potential sees significant expansion of the data centre market, including a substantial increase in export-oriented services. Underpinned by abundant renewable energy, this creates a new export industry for New Zealand and generates up to $70 billion in total economic impact to 2035.

Exhibit 116: Energy and economic impacts of data centre market growth, 2025–2035, by scenario

| | Data centre capacity increase (MW) | Energy demand increase (TWh) | New economic investment stimulated (2025 $b) |
|---|---|---|---|
| Scenario 1: New Zealand's full potential | 570 | 3.3 | $50–70b |
| Scenario 2: Managed transition | 450 | 2.5 | $41–56b |
| Scenario 3: Managed transition and electricity security mechanism | 450 | 2.5 | $41–56b |
| Scenario 4: Bumpy transition | 295 | 1.7 | $27–37b |
| Scenario 5: Energy importer | 450 | 2.5 | $41–56b |
| Scenario 6: Handbrake | 210 | 1.1 | $20–27b |

Note: Figures represent increases on 2025. Economic impact figures follow the assumptions outlined in Section 3.3.
Source: Concept Consulting modelling, BCG analysis

96 NZTech, Empowering Aotearoa New Zealand's Digital Future, 2025; UBS, Spark New Zealand Analyst Report, 2025

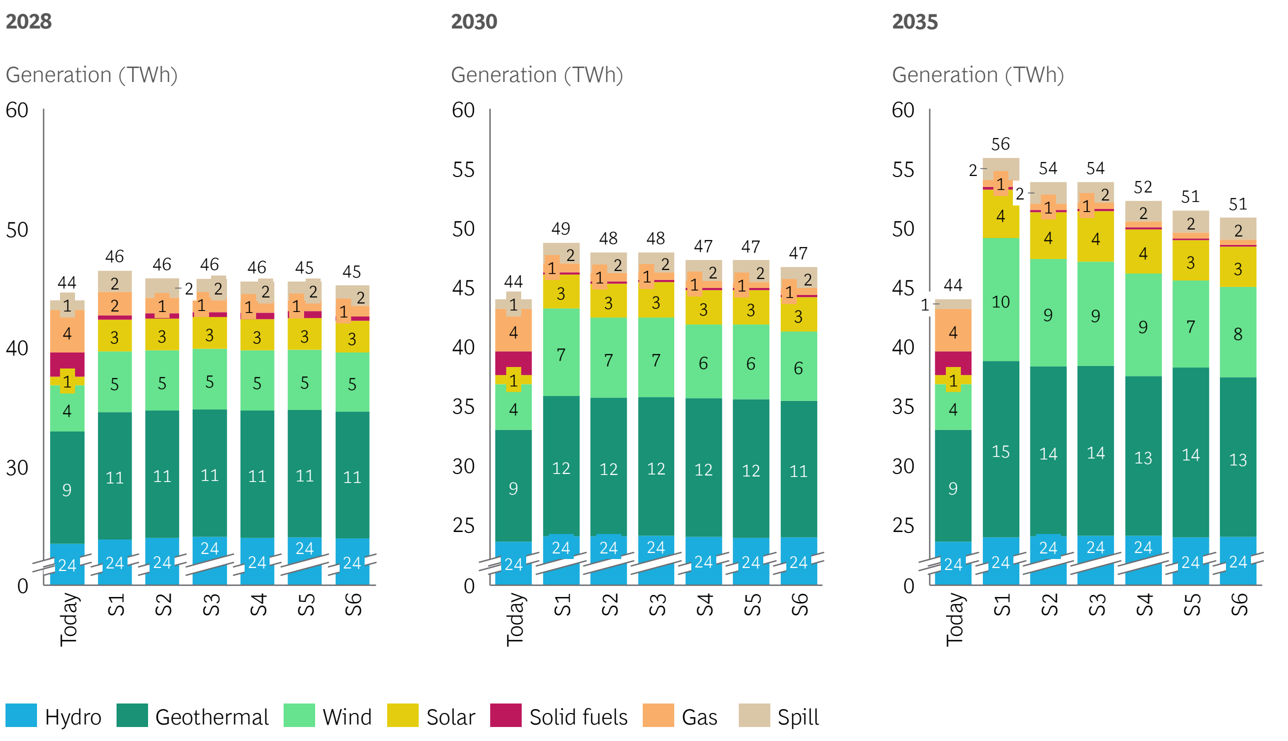
### 6.2.2 Security

**Renewable generation grows to serve incremental demand changing the overall mix**

**Exhibit 117** illustrates the average generation stack for an average year of hydrological inflows. In 2028, total generation is similar across all scenarios, with the short-term generation pipeline driving a 3–4 TWh increase in output. Greater divergence between pathways emerges in later years as evolving demand and demand expectations begin to shape the build-out. Scenario 1: New Zealand's Full Potential, Scenario 2: Managed Transition, and Scenario 3: Managed Transition and Electricity Security Mechanisms show the most significant renewable build-out, driven by electrification and data centre exports.

Across all scenarios, the model endogenously develops New Zealand's substantial wind resources (up to 5 TWh) and shows strong uptake of rooftop solar. It also expands geothermal generation by 2–5 TWh, reflecting the steady loads required for data-centre exports and industrial electrification. While Scenarios 4, 5, 6 include some growth from new industries and data centres, a larger share of new generation in these cases serves to displace incumbent thermal generation.

Exhibit 117: Generation stack by scenario – average year



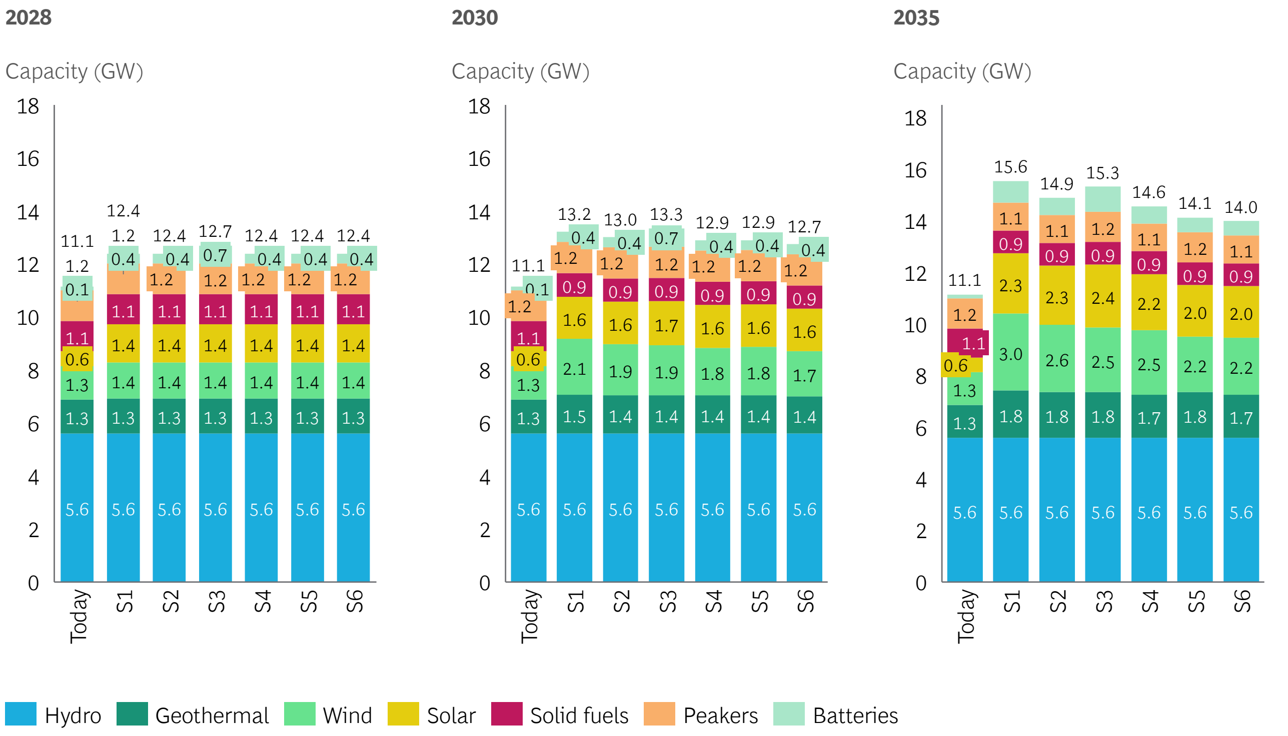

S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake
Note: Today reflects 2025 full year estimated generation
Source: Concept Consulting modelling, BCG analysis

### Geothermal, wind and solar developments drive capacity expansion to 2035

Across all scenarios, rising demand, generation and peak load drive capacity expansion broadly in line with total generation growth (see **Exhibit 118**). Scenario 1: New Zealand's Full Potential records the largest overall increase in total capacity, with growth of 5.5 GW to 2035. This is followed by Scenario 3: Managed Transition and Electricity Security Mechanisms, Scenario 5: Energy Importer, and Scenario 2: Managed Transition.

The majority of new capacity is delivered by geothermal, wind and solar developments. By 2035, these technologies add between 2.2 GW in Scenario 6: Handbrake and 3 GW in the highest case of Scenario 1: New Zealand's Full Potential, reflecting continued investment in low-cost, low-emission generation.

Exhibit 118: Capacity stack by scenario

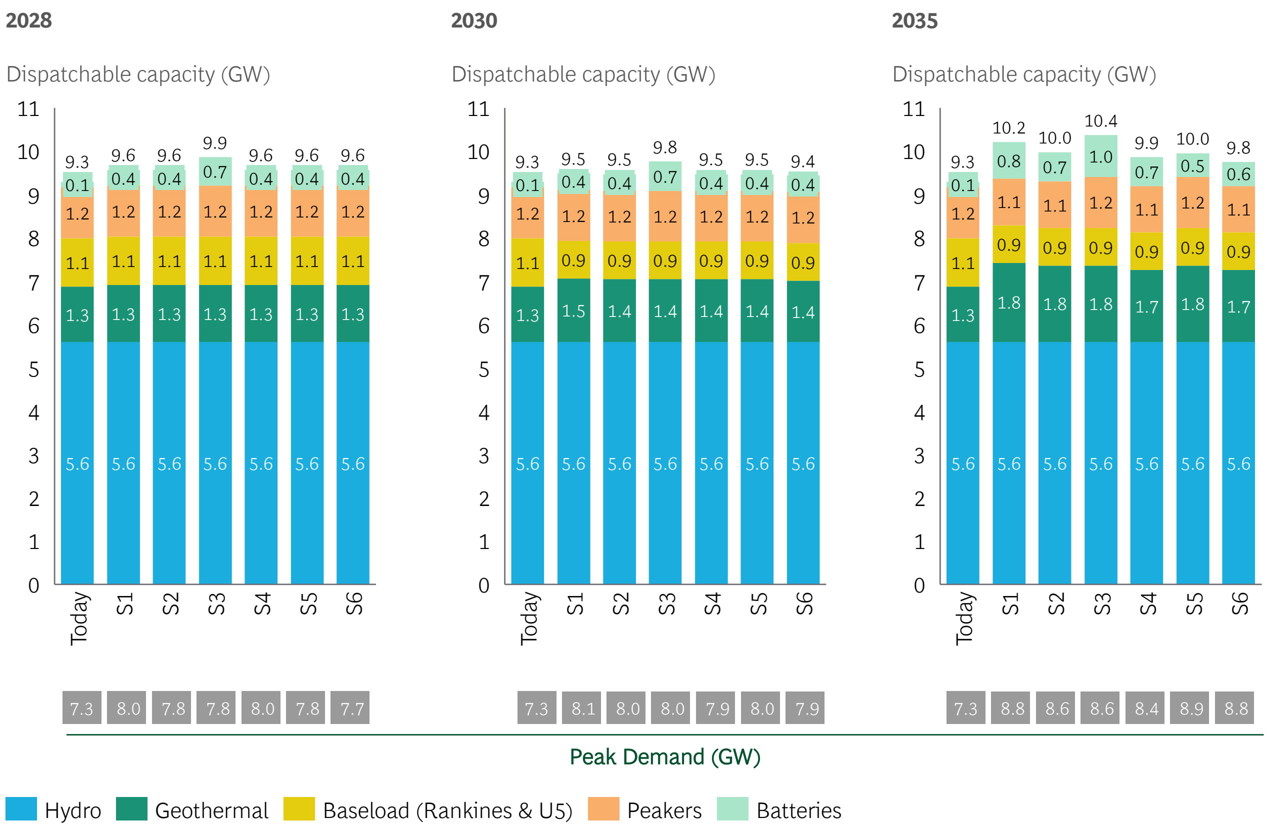



S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake
Source: Concept Consulting modelling, BCG analysis, MBIE

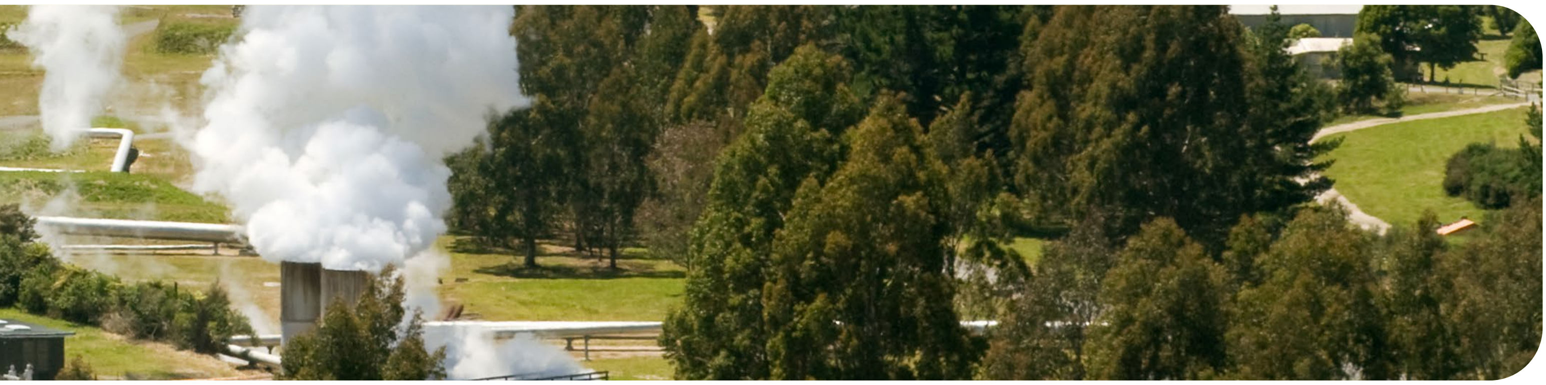
**Scenario 3 offers the greatest dispatchable capacity buffer**

Growth in dispatchable capacity is most pronounced in Scenario 3: Managed Transition and Electricity Security Mechanisms. It is driven by the introduction of a reserves mechanism that supports strong uptake of grid-scale batteries, adding 0.3 GW of dispatchable capacity by 2030. This delivers a dispatchable capacity buffer in the target range of 1.5–2.0 GW in 2030 and 2035 and improves system flexibility, reduces spill and moderates intra-day demand volatility (see **Exhibit 119**).

Exhibit 119: Dispatchable capacity versus peak demand




S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake



**Demand response volumes and costs are the lowest in scenarios with security mechanisms**

There are three types of demand response that can be activated at varied price points:

- Small-scale demand response: households and businesses opt-in to reduce demand during peaks
- Large-scale demand response: large users of electricity reduce their demand during peaks (e.g. Tiwai Point)
- Involuntary demand response: users are forced to reduce their demand on the grid when supply is insufficient – this is undesirable and comes with significant costs

Modelling demonstrates that two factors drive demand response requirements: (1) growth in overall energy demand and peak load, and (2) the rate of battery build-out or access to firming fuels to meet short-term peaks.

**Exhibit 120** shows that the largest demand response requirement occurs in Scenario 1: New Zealand's Full Potential, with around 20 GWh needed in on average across modelled hydrological sequences in 2035. This reflects strong demand growth and rising peak requirements. While Scenario 1 represents the largest demand response requirement in the long term, Scenario 4: Bumpy Transition shows the most significant demand response need to 2028. This is driven by a combination of moderate growth in demand and peak load requirements without corresponding battery development or strong outcomes in the domestic gas market, limiting the ability for the system to dispatch thermals quickly.

In contrast, Scenario 3: Managed Transition and Electricity Security Mechanisms benefit from widespread battery deployment (+0.3 GW by 2030), providing greater system flexibility completely avoiding blackouts and involuntary demand response to 2035. Scenario 5: Energy Importer shows a similar effect due to improved gas flexibility.

Exhibit 120: Demand response by scenario

**2028 demand response (GWh)**

| GWh | S1 | S2 | S3 | S4 | S5 | S6 |
|---|---|---|---|---|---|---|
| Small DR | 5.0 | 11.6 | 2.0 | 13.7 | 4.1 | 5.5 |
| Large DR | 0.4 | 0.7 | - | 1.9 | 0.3 | 0.3 |
| Invol DR | - | - | - | 0.1 | - | - |
| Total | 5.4 | 12.3 | 2.0 | 15.7 | 4.4 | 5.8 |

**2030 demand response (GWh)**

| GWh | S1 | S2 | S3 | S4 | S5 | S6 |
|---|---|---|---|---|---|---|
| Small DR | 10.6 | 9.7 | 3.7 | 12.2 | 7.3 | 10.5 |
| Large DR | 1.4 | 1.0 | 0.2 | 0.9 | 1.0 | 0.7 |
| Invol DR | - | - | - | - | - | - |
| Total | 12.0 | 10.7 | 3.9 | 13.1 | 8.3 | 11.2 |

**2035 demand response (GWh)**

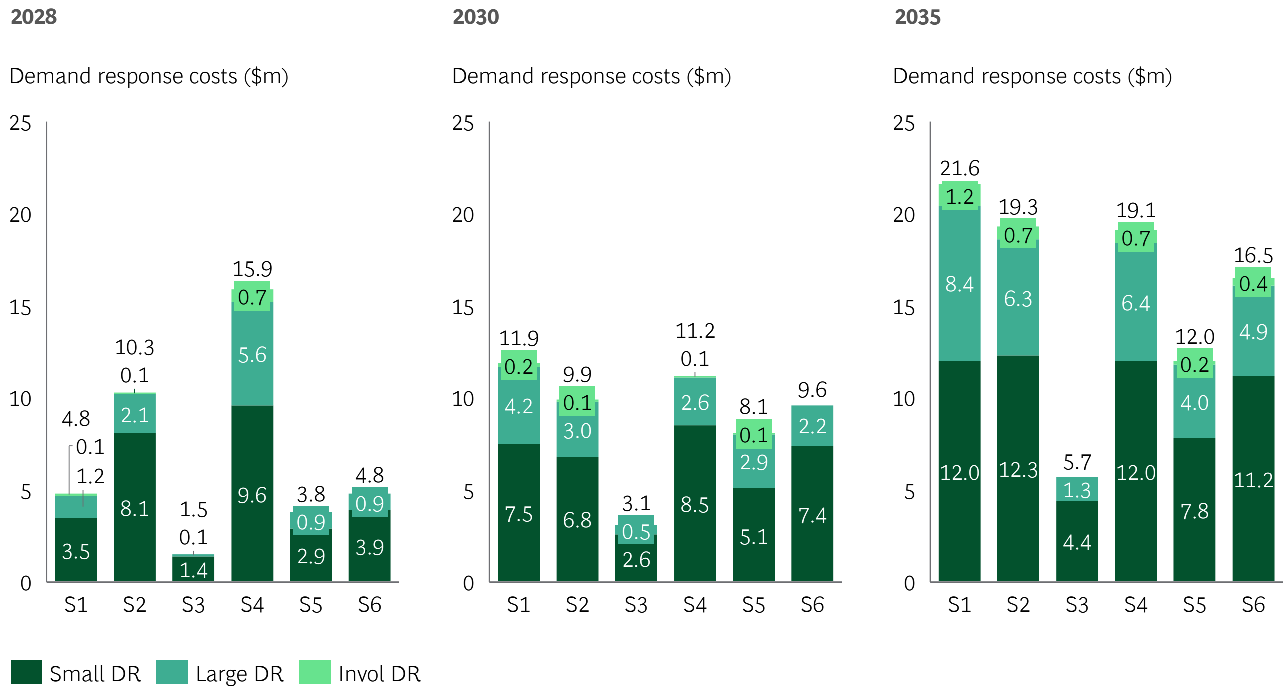
| GWh | S1 | S2 | S3 | S4 | S5 | S6 |
|---|---|---|---|---|---|---|
| Small DR | 17.1 | 17.6 | 6.3 | 17.1 | 11.2 | 15.9 |
| Large DR | 2.8 | 2.1 | 0.4 | 2.1 | 1.3 | 1.6 |
| Invol DR | 0.1 | 0.1 | - | 0.1 | - | - |
| Total | 20.0 | 19.8 | 6.7 | 18.2 | 12.5 | 17.5 |

S1 NZ's full potential
S2 Managed transition
S3 Managed transition and electricity security mechanism
S4 Bumpy Transition
S5 Energy Importer
S6 Handbrake

Note: Figures represent the average response across all 43 modelled hydrological sequences
Source: Concept Consulting modelling

**Exhibit 121** summarises total demand-response costs, which reflect both the scale of response outlined above and the rising economic cost of moving through successive demand tranches, with involuntary curtailment several times more expensive per GWh. Scenarios with greater flexibility and firm capacity, particularly Scenario 3: Managed Transition and Electricity Security Mechanisms, and to a lesser extent Scenario 5: Energy Importer show markedly lower economic costs as they largely avoid large and involuntary demand-response events and blackouts – which come at a high cost.

Exhibit 121: Demand response cost by scenario




S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake

### 6.2.3 Sustainability

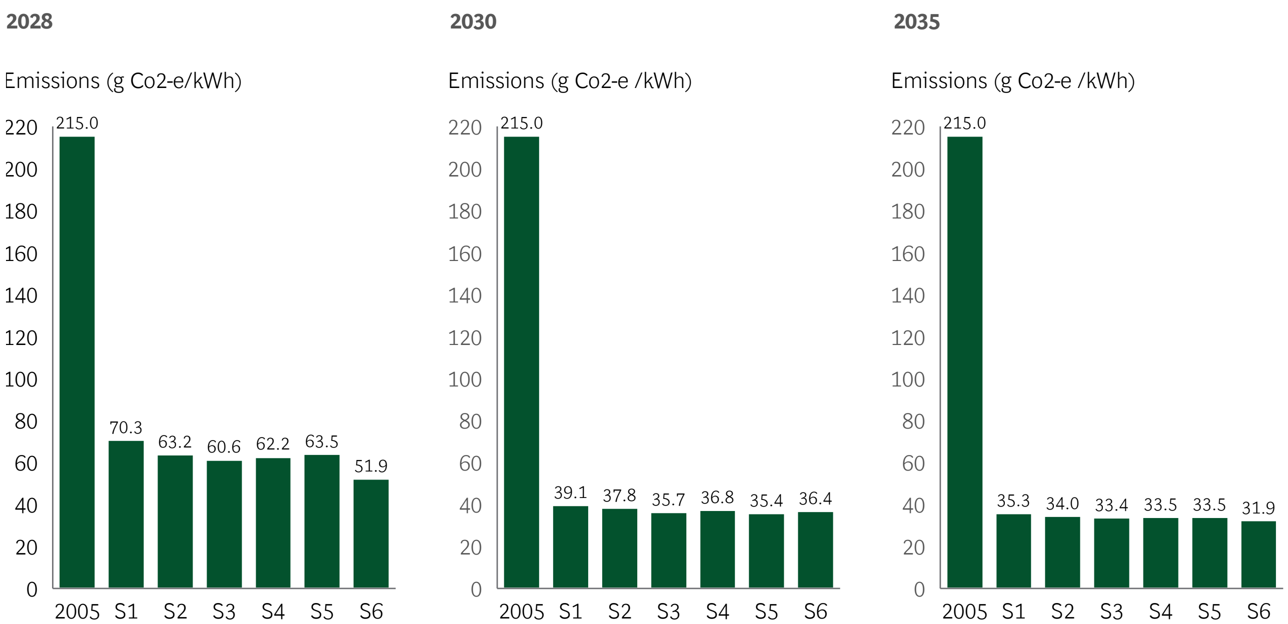
**New Zealand is on track to reduce its electricity sector emissions by 75% by 2035 versus 2005 across all scenarios**

Across all scenarios, renewable generation exceeds 95% by 2028 and reaches around 98% from 2030 onward, driving a sharp fall in electricity-sector emission intensity. By 2035, emissions intensity converges across all scenarios to around 33–36 g $CO_2$-e per kWh, representing an 85% reduction from 2005 levels.

This decline reflects rapid renewable development, progressive displacement of thermal generation and growing electrification demand. Scenario 6: Handbrake achieves the most pronounced reduction, around 50% lower electricity emissions, driven by strong near-term generation delivery and subdued demand growth, while Scenario 4: Bumpy Transition follows a similar but more moderate trajectory.

Higher-demand scenarios (1, 2, 3, 5) achieve comparable intensity improvements, with Scenario 5: Energy Importer showing the fastest short-term gains as elevated thermal-fuel costs accelerate renewable build-out and reduce reliance on gas (see **Exhibit 122**).

Exhibit 122: Electricity sector emissions intensity



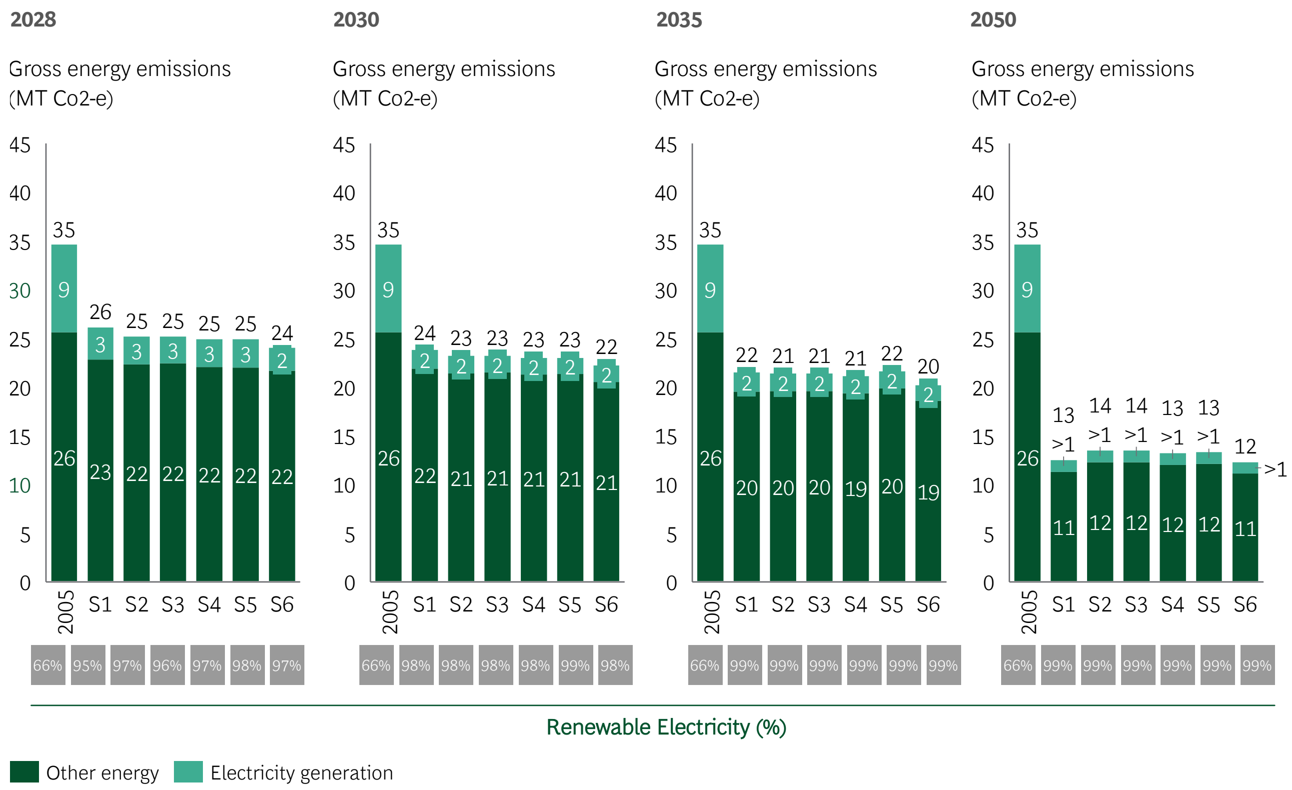

S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy transition; S5 = Energy importer; S6 = Handbrake
Source: Concept Consulting modelling, BCG Analysis, MBIE Energy Sector GHG emissions

**Total energy emissions to drop 40% across scenarios by 2035 and 65% by 2050 relative to 2005 levels; largest reductions in transport and industry to support achieving net zero carbon**

As shown in **Exhibit 123**, gross emissions decline by approximately 40% by 2035 relative to 2005 greenhouse gas inventory levels, across all scenarios. While electricity emissions fall 75% by 2035 across all scenarios, given the highly renewable electricity system, variation in total emissions primarily reflects differences in economic growth and overall energy activity. Scenario 6: Handbrake delivers the steepest reduction due to rapid renewable deployment and low demand growth, followed by Scenario 1: New Zealand's Full Potential, Scenario 5: Energy Importer, and the two Managed Transition scenarios, which feature stronger economic growth and correspondingly higher demand.

By 2050, total energy emissions reduce by over 60% across all scenarios versus 2005, indicative that long-term electrification of transport and industry is a key driver of system wide decarbonisation and is critical to achieving net-zero by 2050. These scenarios are consistent with net-zero by 2050 as residual gross emissions in the modelling are balanced by forestry sequestration.

Exhibit 123: New Zealand's energy sector emissions and renewable penetration




S1 = New Zealand's full potential; S2 = Managed transition; S3 = Managed transition and electricity security mechanisms; S4 = Bumpy

## 6.3 Evaluation of the fundamental questions

Using modelling outcomes, this section answers six questions, determining how various conditions influence the energy sector.

| | |
|---|---|
| 1 | What is the required pace of renewable generation development to meet future energy needs? |
| 2 | What is the outlook for electricity prices and what does it mean for economic growth? |
| 3 | What is the best path forward for gas? |
| 4 | What is the required pace of fuel-switching and the value of accelerated approaches? |
| 5 | Does the market affordably provision for dry years across the scenarios, and how do the tested security actions influence outcomes? |
| 6 | Does the market affordably provision peak capacity and reserves across the scenarios, and how do the tested actions influence peaking security outcomes? |

### 6.3.1 What is the required pace of renewable generation development to meet future energy needs?

**New Zealand needs to deliver up to 1.4 TWh of new electricity supply each year to 2035**

New Zealand is building new generation at the fastest rate on record, adding around 1.4 TWh per year from 2025 to 2027 to both meet demand growth and displace thermal generation. To sustain affordability and support growth in energy-intensive industries, this build rate will need to be maintained to 2035.

Exhibit 124: Required renewable generation development rate to meet demand growth

| | S1: New Zealand's full potential | S2: Managed Transition | S3: Managed Transition and electricity security | S4: Bumpy Transition | S5: Energy Importer | S6: Handbrake |
|---|---|---|---|---|---|---|
| 2025–28 | 1.4 | 1.2 | 1.2 | 1.0 | 1.0 | 0.6 |
| 2028–30 | 1.3 | 1.1 | 1.1 | 0.9 | 0.9 | 0.8 |
| 2030–35 | 1.4 | 1.2 | 1.2 | 1.1 | 1.1 | 0.8 |

Source: Concept Consulting modelling, BCG Analysis

**While the current pipeline covers demand to 2030, maintaining momentum to 2035 will require greater speed in consenting approvals**

While near-term demand is well covered to 2027–2028 and the current pipeline appears sufficient to 2030, ensuring adequate supply to 2035 will depend on maintaining strong momentum in consenting, FID and construction (see Section 5.1). Although modelling indicates these outcomes are achievable, they rely on improved transparency and consistent parameters around consenting timelines, grid connection and delivery performance to mitigate risks of delay.

Without greater efficiency in consenting and timely project execution, there is a material risk that new generation will not be delivered in time to meet emerging demand. Should large new loads come online before sufficient supply is available, the system could face upward pressure on prices, increased reliance on constrained thermal fuels and reduced energy security.

**Improved information disclosure and consenting processes will derisk the delivery of electricity generation projects**

To strengthen delivery confidence and sustain investment momentum, improvements are needed in consenting efficiency and sector-wide disclosure. Regular publication of generation development pipelines, project status updates and capacity availability maps will help provide visibility, reduce uncertainty, and reinforce investor confidence. Such measures will help ensure New Zealand remains well positioned to leverage its renewable advantage to drive growth, affordability, and long-term energy security.

### 6.3.2 What is the outlook for electricity prices and what does it mean for economic growth?

**By continuing to build renewables at pace and managing exposure to residual thermal generation, New Zealand can achieve long-term wholesale electricity affordability**

Across all user groups, energy affordability and forward price stability will depend on the continued expansion of renewable generation and effective management of residual thermal exposure. Modelling shows that if New Zealand can meet the required pace of renewable generation development, all scenarios indicate a plausible path to achieving 98% renewable generation by 2030, while remaining well positioned to manage global and domestic thermal fuel volatility and provide competitive electricity prices to consumers. By this point, gas will have a substantially reduced influence on total electricity costs, setting the marginal generation price 25–35% of the time versus 70-90% under current market conditions.

Over the same period, Scenario 2: Managed Transition demonstrates that investment in gas development, and targeted fuel switching support supply and demand balancing in the gas market.

In Scenario 3: Managed Transition and Electricity Security Mechanisms, the addition of gas storage and diesel or condensate, and in Scenario 5: Energy Importer, the addition of full-scale LNG imports provide insurance against dry-year risk, effectively placing a ceiling on marginal firming generation costs at around $25 per GJ of fuel or $240 per MWh.

**Combined with lower wholesale prices, tapering line charges from 2030 will deliver more affordable electricity**

While network charges remain elevated in the near term due to major infrastructure investment programmes and a higher regulated WACC, these pressures are expected to moderate beyond 2030. Combined with lower wholesale electricity prices, this will support affordable and globally competitive energy outcomes across all customer types.

**Additional thermal fuel storage cuts risk premiums and enables growth with competitive pricing**

Scenarios incorporating dedicated security mechanisms, such as Scenario 3: Managed Transition and Electricity Security Mechanisms and the introduction of LNG in Scenario 5: Energy Importer demonstrate the additional benefits of market stability measures. A new reserves market and firm fuel reduces forward contract risk premiums to 10% and enables independent developers and gentailers to more confidently offer more competitive contracts that attract and retain energy-intensive industries. In terms of total price from 2030, this results in longer term contracts of $105–110 per MWh, seen in Scenario 3, versus $115–120 per MWh in Scenario 2 (see Section 6.2.1).

### Mechanisms to enhance thermal fuel storage and enhance peak capacity deliver benefits that outweigh costs

Mechanisms to incentivise 300 MW of additional peak capacity and 0.8 TWh of additional fuel diversity improve system efficiency by reducing exposure to high price events. In 2030, in Scenario 3: Managed Transition and Electricity Security Mechanisms, the wholesale price reduces $7 per MWh and the futures price reduces $12 per MWh relative to Scenario 2: Managed Transition (i.e. the same scenario without security mechanisms).

The cost of implementing these mechanisms is roughly $2.30–2.80 per MWh or $110–135 million per year. The mechanisms, which could be market led, deliver $340–580 million in reduced consumer costs representing a 3–5x consumer benefit to consumer cost ratio.

In 2030 in Scenario 5: Energy Importer, the wholesale price reduces $3 per MWh and the futures price reduces $8 per MWh relative to Scenario 2: Managed Transition. While the benefits are not as great as Scenario 3, Scenario 5 has the additional benefit of protecting from downside supply outcomes in the gas market. Given this, a combination of LNG and electricity security mechanisms could deliver value for consumers if the gas supply situation continues to deteriorate.

**In summary, an effectively managed energy transition delivers affordable electricity to enable economic growth. It provides sufficient energy and globally competitive prices that are underpinned by a renewable supply mix.**

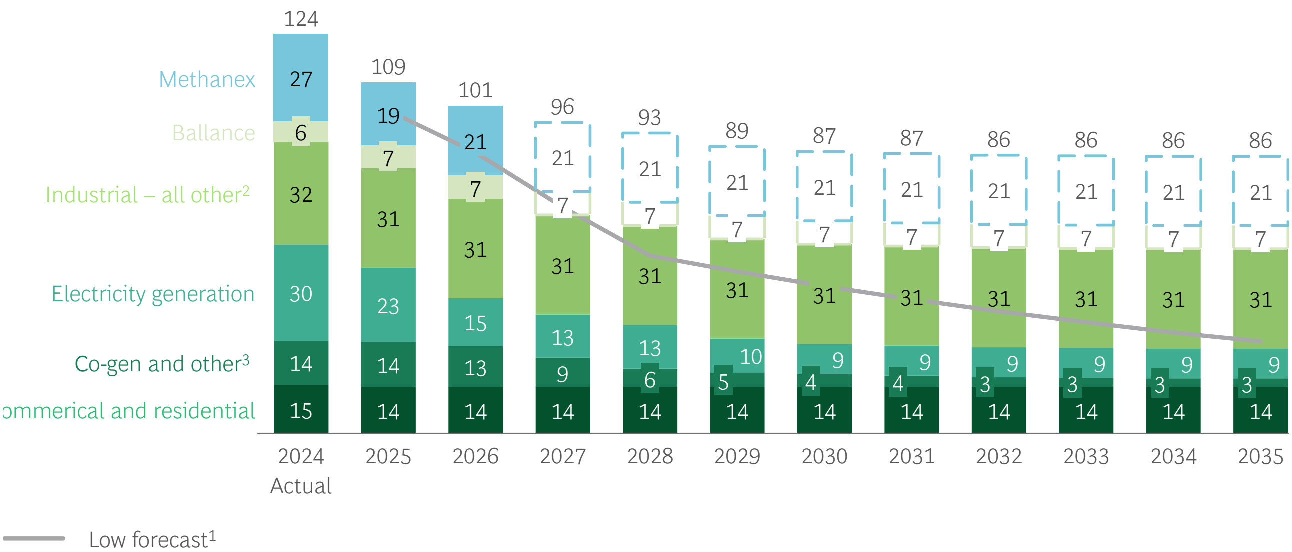
## 6.3.3 What is the best path forward for gas?

### The gas market should be strengthened with supply, demand and flexibility levers

Domestic gas production has declined faster than expected, with supply consistently landing below the MBIE Producer Forecasts, creating market imbalance. Looking ahead, the Low Forecast is the prudent base case for New Zealand's gas market (see **Exhibit 125**).

Exhibit 125: Underlying gas demand forecast across major users versus Low Forecast

**Underlying gas demand forecast across major users versus Low Forecast**
(Gross PJ, calendar year)




1. Low gas supply forecast based on adjusted Enerlytica scenario; 2. Includes Agriculture, Forestry, and Fishing; 3. 'Other' includes energy transformation (excluding electricity generation), non-energy use (minus Methanex and Ballance feed stock), and stock change
Source: MBIE Annual Gas Production and Consumption 2025 Q1, MBIE Electricity Report 2025 Q1, Gas Industry Co. Consumption, Enerlytica

The risks are asymmetric: if supply falls below demand, the damage (i.e. industrial exits) is far greater than if supply is slightly above demand. Addressing this requires coordinated action across supply, demand and flexibility levers.

**Supply**

Need to **turn around rapid rate of decline** in supply and consider LNG

**Demand**

Even with some supply turn around, some demand may need to **exit or switch to other fuels**

**Flexibility**

More **gas storage** needed to reduce Volatility

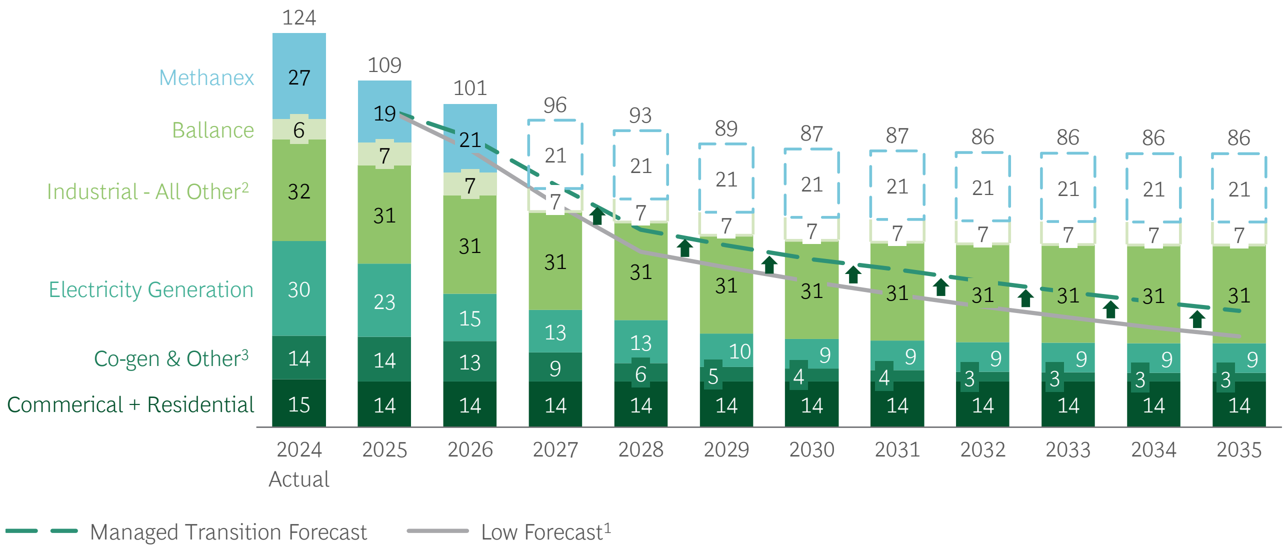
Given the risk trajectory and the potential for demand destruction under a Low Forecast, New Zealand needs a managed transition – one that acts on all available levers. This means working simultaneously to slow the rate of supply decline, enable and coordinate demand exit or switching, and build greater system flexibility to cope with variability and shocks. No single lever will be sufficient on its own; progress requires movement on all three fronts.

### Supply side levers, particularly domestic development, are imperative to fixing New Zealand's gas market

Reviving domestic gas production requires prompt development drilling, not just in Tūrangi and Mangahewa but across other existing fields. Advancing domestic gas supply levers helps ensure a more managed transition but it alone does not fully close the gap.

Exhibit 126: Underlying gas demand forecast across major users versus Managed Transition Forecast and Low Forecast

**Underlying Gas Demand Forecast Across Major Users vs. Managed Transition Forecast and Low Forecast**
(Gross Petajoules, PJ, Calendar Year)




1. Low gas supply forecast based on adjusted Enerlytica scenarios; 2. Includes Agriculture, Forestry, and Fishing; 3. 'Other' includes energy transformation (excluding electricity generation), non-energy use (minus Methanex and Ballance feed stock), and stock change
Source: MBIE Annual Gas Production and Consumption 2025 Q1; MBIE Electricity Report 2025 Q1; Gas Industry Co. Consumption; Enerlytica

Stimulating new supply should be the first priority because, if drilling is delayed or unsuccessful, gas production could decline so rapidly that demand destruction becomes an increasingly larger risk, regardless of demand levers such as incentives for users to switch to alternative fuels. Recent development results show that this risk is real: even with new development drilling, production could still trend along the Low Supply Forecast, forcing industrial exits and creating supply security concerns. Therefore, supply-side efforts must proceed quickly but with recognition that outcomes are uncertain and that contingency measures will still be required.

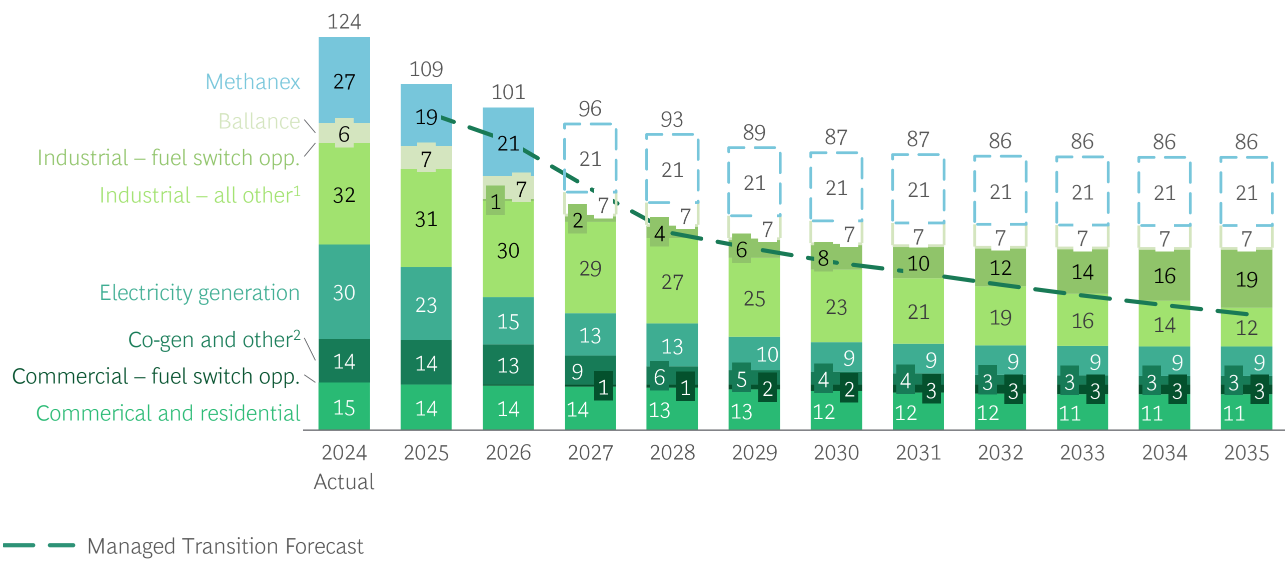
**On the demand side, it is critical to manage fuel switching to de-risk the pathway**

At the same time, managed demand reduction can help cushion the gas transition (see **Exhibit 127**). Some switching is already underway. In the electricity sector, rapid growth of renewables, batteries for peaking and dry-year backup using solid fuels is projected to reduce gas by roughly 60% (9 PJ consumed) in a typical hydrological year and 45% (13 PJ consumed) in a dry year by 2027 under a Managed Transition Forecast.

Actioning demand levers, in addition to supply levers, enables market balance as further fuel switching brings demand in line with supply.

## Exhibit 127: Underlying gas demand forecast across major users versus Managed Transition Forecast

**Underlying gas demand forecast across major users versus Managed Transition Forecast**
(Gross PJ, calendar year)




1. Includes Agriculture, Forestry, and Fishing; 2. 'Other' includes energy transformation (excluding electricity generation), non-energy use (minus Methanex and Ballance feed stock), and stock change
Source: MBIE Annual Gas Production and Consumption 2025 Q1, MBIE Electricity Report 2025 Q1, Gas Industry Co. Consumption, Enerlytica

### Flexibility through increased storage is necessary to reduce volatility and minimise dry-year risk

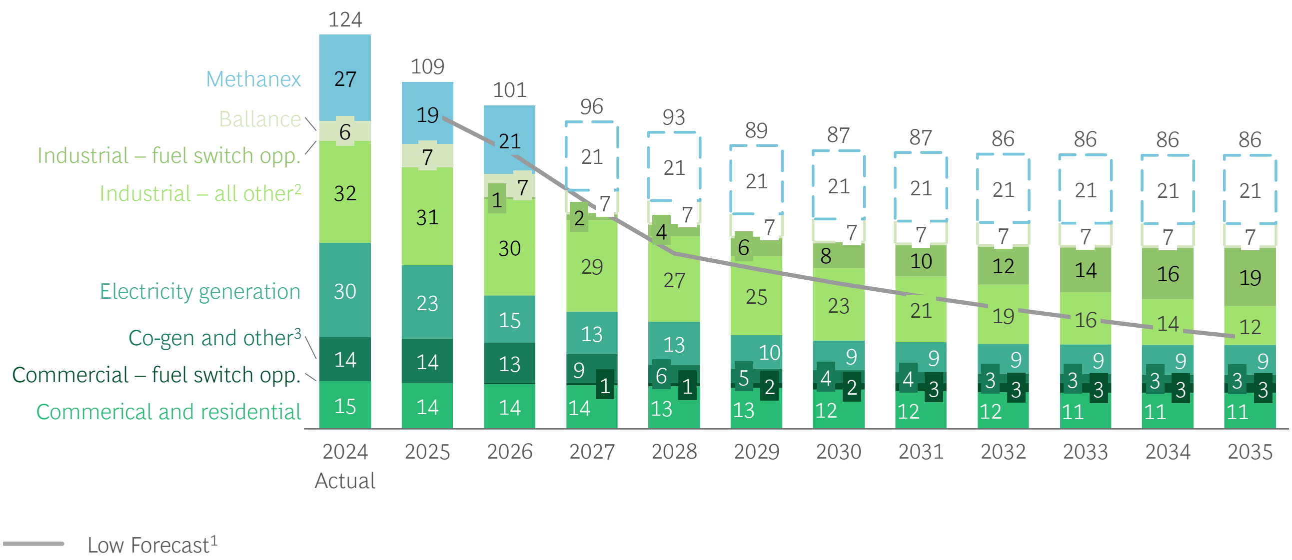
This forecast in Exhibit 127 view shows a normal hydrological year. It shows that even if supply and demand become more balanced, New Zealand's winter-heavy consumption profile and variable hydrology require greater system flexibility. Additional gas storage is essential in the short term to smooth daily, seasonal and annual imbalances across both electricity generation and industrial demand. Without Methanex or new gas storage, flexibility would depend on limited fuel switching within the electricity sector. Expanding storage provides a buffer that prevents demand destruction and better equips the system to manage dry-year stress events.

### LNG may be a prudent backstop for New Zealand's gas market security risk

While LNG may not be required in the Managed Transition Forecast for gas supply, if domestic development drilling underperforms, gas supply could quite conceivably slip to the Low Supply Forecast (see **Exhibit 128**). Furthermore, new demand switching projects could stall, leading to demand destruction.

Exhibit 128: Underlying gas demand forecast across major users versus Low Forecast

**Underlying gas demand forecast across major users versus Low Forecast**
(Gross PJ, Calendar Year)




1. Low gas supply forecast based on adjusted Enerlytica scenario; 2. Includes Agriculture, Forestry, and Fishing; 3. 'Other' includes energy transformation (excluding electricity generation), non-energy use (minus Methanex and Ballance feed stock), and stock change
Source: MBIE Annual Gas Production and Consumption 2025 Q1, MBIE Electricity Report 2025 Q1, Gas Industry Co. Consumption, Enerlytica

The economic cost of this demand destruction, driven by higher energy prices, forced industrial exists and dry-year reliability risks, would be substantial. It is therefore prudent to have a credible backstop for gas.

LNG acts as a backstop for New Zealand's gas transition. A full-scale LNG import solution could effectively substitute for additional underground storage, by delivering 4–5 PJ of flexible capacity that could be co-optimised with Ahuroa. In practice, this pairing could double the effective storage capability available to the market. Without LNG, New Zealand would likely need to invest in new underground facilities to achieve similar flexibility, which would take time and carry its own risks.

**The affordability impacts of LNG can be minimised with thoughtful planning**

If LNG is pursued, its role should be that of insurance. Because of the capital intensity and the expected infrequent use of LNG, building its infrastructure would most likely require government involvement. The priority should be to maintain and improve domestic gas prices at roughly $16-18 per GJ – the average spot price (inclusive of carbon) for the last 12 months, under normal conditions. It should only temporarily converge to import-parity levels ($25 per GJ) when LNG imports are absolutely needed.

To preserve affordability, the capital cost of the LNG infrastructure must not be embedded into the marginal fuel price, as spreading the costs across limited LNG volumes would make the fuel uneconomic for end users. Instead, the cost-recovery mechanism should ensure that LNG remains a true contingency measure, providing security and flexibility only when required.

New Zealand's gas market transition calls for a balanced, pragmatic approach: minimise supply decline, support demand switching and build flexibility with additional storage. Even with progress on development drilling and demand switching, it is prudent to create LNG optionality so it can provide a security backstop if needed.

### 6.3.4 What is the required pace of fuel-switching and the value of accelerated approaches?

**Coordinated fuel switching is essential to managing gas market tightness and protecting industrial demand**

Modelling demonstrates that timing is critical to the success of the gas market transition. Across all scenarios, the rate of fuel switching required reflects underlying supply-side pressures, with transition shortages emerging as early as 2028 in some scenarios. To avoid this, a coordinated mechanism and targeted funding are required to improve project economics, prioritise the highest value conversion opportunities and prevent supply shortfalls from constraining industry.

As outlined in Section 5.5.1, fuel switching progress is constrained by several factors: the capital costs of conversion, uncertainty around technology readiness, supply chains and access to alternative fuels. In worse-case scenarios, illustrated by Scenario 6: Handbrake, if these constraints persist and short-term project delivery cannot be managed effectively, gas market tightness deepens, leading to higher prices, reduced flexibility and the risk of permanent demand destruction.

A comparison of Scenario 4: Bumpy Transition and Scenario 2: Managed Transition illustrates this point. In Scenario 2, stronger gas market performance and greater conversion support enable higher levels of fuel switching, preventing demand destruction entirely. In Scenario 4, while switching volumes are similar, delayed project delivery and market tightness lead to higher gas prices that improve the economics of switching but not quickly enough to avoid demand loss. As a result, demand destruction occurs as soon as 2028, with each incremental PJ of lost demand reducing GDP and industrial output. Across the system, New Zealand faces up to $5.4 billion in annual GDP losses by 2035 (see **Exhibit 129**).

Exhibit 129: Incremental gas fuel switching and demand destruction across scenarios

| | | New Zealand's Full Potential | Managed Transition | Managed Transition + Security Mech. | Bumpy Transition | Energy Importer | Handbrake |
|---|---|---|---|---|---|---|---|
| 2028 | Fuel switching (PJ) | 2.9PJ | 3.2PJ | 3.2PJ | 2.4PJ | 2.4PJ | 2.6PJ |
| | Demand destruction (PJ, $m) | - | - | - | 2PJ<br>*~700m* | 1-2PJ<br>*~500m* | 5PJ<br>*~2,200m* |
| 2030 | Fuel switching (PJ) | 9.5PJ | 10.0PJ | 10.0PJ | 8.3PJ | 8.0PJ | 8.7PJ |
| | Demand destruction (PJ, $m) | - | - | - | 3PJ<br>*~1,200m* | 3PJ<br>*~1200m* | 7PJ<br>*~3,300m* |
| 2035 | Fuel switching (PJ) | 22.6PJ | 22.9PJ | 22.9PJ | 19.2PJ | 9.5PJ | 19.5PJ |
| | Demand destruction (PJ, $m) | - | - | - | 5PJ<br>*~2,200m* | 3PJ<br>*~1200m* | 10PJ<br>*~5,400m* |

Note: Implied destruction calculated from supply–demand balance, outcomes of development campaigns. Estimated ~11 PJ of conversion works in progress (& will be delivered 2025-2030). Total value calculated against a 2025 baseline of ~60 PJ gas use across process heat, commercial, residential, and co-gen. Demand Destruction estimates based off I/O assessment of New Zealand Industrial gas consumption. Calculated Demand Destruction excludes Petrochemical industries. GDP Demand destruction estimated through assessment of sector fuel switching potential, marginal productivity of gas use (I/O). Above excludes in progress/completed fuel switching and efficiency projects (e.g. Pan Pac Whirinaki, WoolWorks Awatoto, Fonterra Whareroa, Kapuni, Te Rapa, Morrinsville, and Edgecumbe).
Source: BCG Analysis, Concept Consulting modelling, EECA RETA, Enerlytica, Stats National Accounts Input-Output Tables

### Improving transition economics and coordination strengthens energy system security and economic resilience

Current project economics and constrained access to capital limit the pace of large-scale fuel switching. Introducing a mechanism to support the transition would improve commercial feasibility, enabling switching to proceed at an average cost of $10–20 million per PJ. For 10 PJ of required, incremental conversion, it is estimated to require $100-200 million of support.

Such a mechanism would stabilise the gas market by balancing supply and demand throughout the transition period and preventing costly demand destruction. It would also safeguard industrial capacity, support regional employment and maintain affordability as the system evolves. If New Zealand transitions to LNG it could de-risk the pathway until the project is complete and minimise price convergence to LNG import price parity once it is in place.

By improving confidence in project delivery and investment recovery, coordinated transition support would sustain economic competitiveness, ensure energy security and allow New Zealand to manage its pathway toward lower emissions without compromising growth.

### Accelerating high-value fuel switching strengthens affordability for gas and electricity users

By maintaining balance between supply and demand and offsetting gas supply decline, domestic gas prices could remain near $16–18 per GJ to 2030, $7–9 per GJ lower than outcomes where prices converge to global LNG import parity at $25 per GJ.

Across a 60 PJ user base, this represents a system-wide benefit of roughly $420–540 million per year, reducing energy costs for users who don't, or cannot, switch fuels and supporting broader market stability. Coordinated switching therefore serves as both an industrial resilience measure and an affordability lever, lowering costs for gas consumers while supporting reliability and competitive pricing across the wider energy system.

### 6.3.5 Does the market affordably provision for dry years across the scenarios, and how do the tested security actions influence outcomes?

**Procuring additional fuel that de-risks domestic gas reduces volatility and delivers strong economic value in dry years**

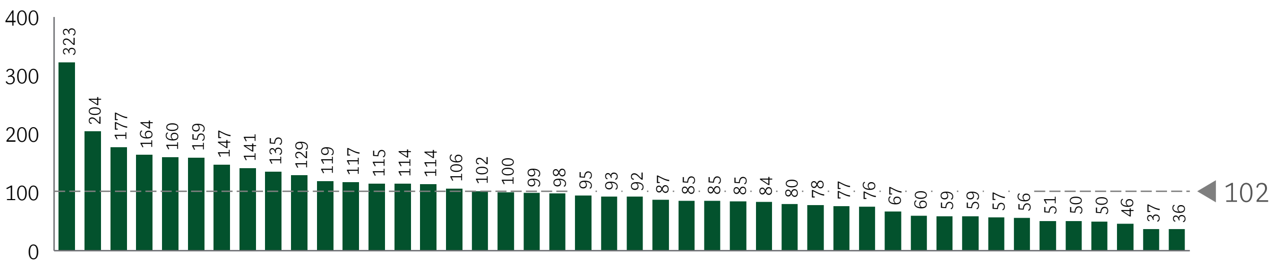
Modelling demonstrates that adding additional firm fuel in the form of gas storage or LNG enables the market to affordably and reliably meet demand, even under adverse hydrological conditions. These actions can help the energy system maintain an effective price cap of around $25 per GJ, materially reducing dry-year costs and limiting price volatility, ensuring both consumers and industry are shielded from extreme market fluctuations.

A comparison of Scenario 2: Managed Transition and Scenario 3: Managed Transition and Security Mechanisms illustrates the value of improved fuel storage. In a typical year, the presence of additional fuel storage reduces wholesale electricity prices by $6–7 per MWh on an annual Time Weighted Average Price (TWAP) basis. This translates into an economy-wide benefit of up to $300 million per year in reduced electricity costs across a demand base of 50 TWh. In a year with an extreme dry period, modelling demonstrates that more fuel storage can reduce prices by $77 per MWh (see **Exhibit 130**).

Exhibit 130: Comparison of pricing outcomes with and without additional thermal fuel storage in 2030

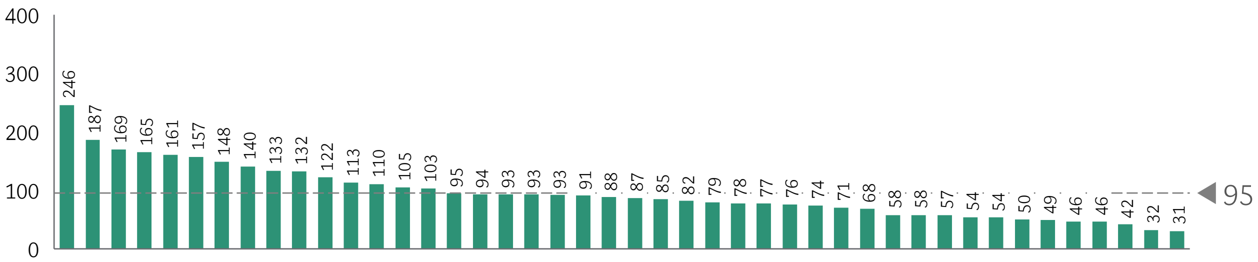
**Managed Transition**

TWAP across 43 hydrological years ($/MWh, 2030)




**Managed Transition with Security Measures**

TWAP across 43 hydrological years ($/MWh, 2030)




Source: Concept Consulting modelling

Scenario 5: Energy Importer delivers a similar stabilising effect. It shares the same effective price cap of $25 per GJ via imported LNG, producing comparable price moderation but at a higher system cost, with CAPEX of $400–800 million and annual operating expenses of $40–50 million. This contrast highlights the cost-effectiveness and efficiency of a domestic firmed fuel security mechanism to manage dry-year risk and price outcomes. Even with this consideration, if supply for gas falls rapidly then LNG will be needed anyway to prevent de-industrialisation and ensure enough gas for the electricity market.

Additional supporting measures, such as the introduction of earlier and clearer guidance around contingent hydro triggers, could further reduce dry-year risk and improve price outcomes.

### 6.3.6 Does the market affordably provision peak capacity across the scenarios, and how do the tested actions influence peaking security outcomes?

**A mechanism to incentivise capacity development would expand dispatchable peaking capacity and provide greater system flexibility**

New Zealand's dispatchable capacity is expected to expand steadily as new geothermal, wind and solar projects come online; however, these resources provide limited flexibility to meet short-duration peaks and manage dry-year variability. While the modelling suggests the electricity system will increase its capacity, rising peak demand and ongoing constraints in the gas market are expected to narrow capacity margins beyond this period, heightening exposure to volatility.

Modelling shows that Scenario 3: Managed and Security Mechanisms provisions appropriately for this challenge, introducing a reserve mechanism that enables an additional 0.3 GW of dispatchable capacity in the form of batteries. Historically, New Zealand has maintained a dispatchable capacity buffer of 1.5–2 GW over peak demand and Scenario 3: Manage Transition and Security Mechanisms is the only scenario that maintains this (see Section 6.2), underscoring the importance of a structured mechanism to incentivise timely capacity development.

# 7 Policy, market and regulatory recommendations

New Zealand's energy system is at a pivotal point. To achieve a secure, affordable and low-emissions future, it needs an integrated set of policy, market and regulatory recommendations that enables faster investment decisions, supports new technologies and ensures energy security during the transition. The current market structure, which is built for incremental change, needs to evolve to deliver large-scale renewable build, robust system reliability and sustained productivity improvements across generation, transmission and distribution.

To meet this challenge, this report puts forward a coordinated set of recommendations across five priorities: (1) Accelerate renewable electricity generation development; (2) Strengthen the electricity market and security mechanisms; (3) Enhance lines infrastructure efficiently; (4) Address gas supply decline and introduce domestic gas alternatives; (5) Enable gas users to transition.

These recommendations will strengthen New Zealand's domestic energy market, safeguard energy security during the transition to electrification and create conditions for long-term competitiveness and resilience in a decarbonising global economy.

Exhibit 131: Priorities and recommendations

| Priorities | Recommendations |
|---|---|
| 1 Accelerate renewable electricity generation development | 1.1 Continue to build renewables at pace |
| | 1.2 Deliver faster consenting |
| | 1.3 Improve pipeline information |
| 2 Strengthen the electricity market and security mechanisms | 2.1 Investigate new reserve market to mitigate system risk and incentivise capacity |
| | 2.2 Investigate industry, regulatory and market actions to affordably meet dry periods |
| | 2.3 Revise contingent hydro level and triggers |
| | 2.4 Widen hydro operating consents |
| | 2.5 Continue to implement smart system measures |
| 3 Enhance lines infrastructure efficiently | 3.1 Ensure Transpower's Grid Blueprint provides a bold vision for grid development to 2050 |
| | 3.2 Investigate new transmission funding mechanism for regional transmission |
| | 3.3 Develop an accelerated Major Capital Approval path for low regret, high benefit transmission projects |
| | 3.4 Move to a trailing average approach for weighted average cost of capital |
| | 3.5 Continue to enhance grid connections while retaining an open access model |
| | 3.6 Publish capacity availability maps for lines companies |
| | 3.7 Commence productivity benchmarking for lines companies |
| 4 Address gas supply decline and introduce domestic gas alternatives | 4.1 Ensure 'Gas Security Fund' funding model addresses drilling risk and weights focus to near-term gas supply |
| | 4.2 Develop gas storage for flexibility |
| | 4.3 Create LNG optionality |
| | 4.4 Enable drop-in alternatives for peaking |
| | 4.5 Help establish biomass supply chains |
| | 4.6 Accelerate energy audits to consider alternatives for gas for commercial and industrial users |
| 5 Enable gas users to transition | 5.1 Introduce an Industry Resilience fund for lowest cost fuel switching to biomass and electricity |
| | 5.2 Enhance sector disclosures |
| | 5.3 Run a public information programme to bring consumers on the journey |

Primary owners:
Government; Gentailers; EPA; EA; Transpower; Commerce Commission
Lines Companies; MBIE; EECA; Existing thermal plant owners

## 7.1 Recommendations to accelerate renewable electricity generation development

New Zealand has a strong pipeline of renewable generation projects. Its current renewable build rate of around 1.5 TWh per year is enough to support economic growth, meet rising demand and place downward pressure on prices to 2030. However, maintaining and accelerating this momentum is critical to avoiding bottlenecks later this decade.

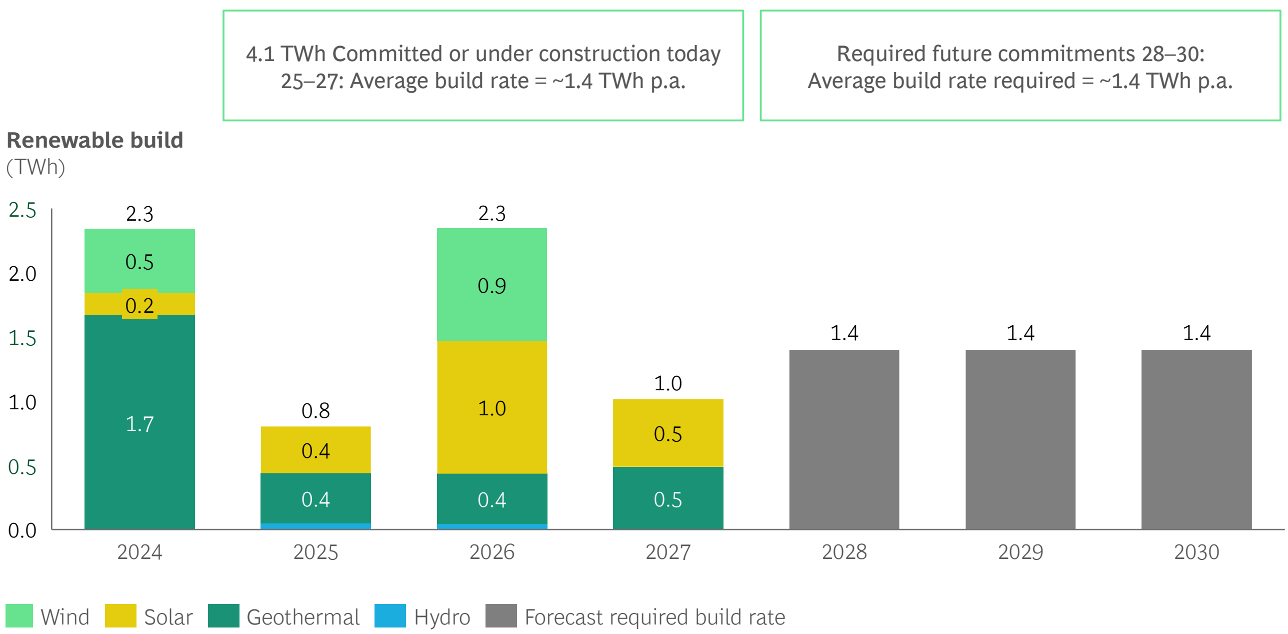
This momentum depends on three recommendations: (1) Continue to build renewables at pace so developers continue commissioning new generation each year; (2) Deliver faster consenting processes to unlock more projects; and (3) Improve pipeline information so investors and policymakers can plan with confidence. These actions will help turn New Zealand's renewable ambitions into tangible supply, strengthen energy security and keep electricity affordable throughout the transition.

Developing 1.5 TWh of generation per year would also help New Zealand build around 25% more generation than it did in the peak of its Think Big hydro programme in the 1970s. And it would see New Zealand rank among the top performers globally for new renewable development relative to system size, placing 9th worldwide by the World Energy Council.

### 7.1.1 Continue to build renewables at pace

Renewable generation developers play an important role in ensuring New Zealand has the infrastructure to provide affordable, secure energy supply and support economic growth into the future – and that new projects move from development to construction and come online in time to meet future demand. They must continue to build renewables at pace, exploring and commissioning new projects, applying for consent, completing costing studies and achieving final investment decisions (FIDs). Continued delivery will also support investor confidence and sector capability (see **Exhibit 132**).

Exhibit 132: Required build rate for 2028–2030




Note: Excludes The Point Solar Farm (0.5TWh) due to high uncertainty; Numbers may not sum due to rounding
Source: Transpower, Concept Consulting, BCG Analysis

This renewable development needs to be supported with faster consenting, improved visibility of the project pipeline and timely network investments – recommendations that are detailed in following sections. Together, these will help ensure the delivery of around 1.5 TWh of new renewable capacity each year, and that progress remains on track to 2030.

### 7.1.2 Deliver faster consenting

Consenting is the main bottleneck preventing new renewable projects from being built in a timely manner and adds considerable costs to developers. While there is 4.1 TWh in developments under construction today to be delivered between 2025 and 2027, there is a risk of losing pace from 2028. From 2028 to 2030, New Zealand needs 4.3 TWh of developments but there is only 3.7 TWh consented today. On top of consent, projects also need to reach the 'financial close' stage, meaning they need a buffer to ensure timely delivery. This challenge applies equally to hydro projects: consenting for new builds and reconsenting for existing schemes can delay or constrain upgrades and refurbishment.

The pace of consenting needs to match the pace of demand growth. Without faster approvals, projects will stall and New Zealand risks falling short on the energy it needs for its growth and emissions goals.

In December 2024, government passed the Fast-track Approvals legislation which created a permanent fast-track consenting pathway, under the Fast-track Approvals Act 2024, replacing the temporary Covid-19 Recovery Fast-track Consenting (2022) and Resource Management Interim Fast-track Consenting (2023) paths.[97] Initially, the 2024 Act listed 149 projects, of which 22 were renewable energy, which could apply directly for consideration by an expert panel to fast-track approvals. The government then opened applications for new projects in February 2025. Today as of November 17, there are 29 renewable energy projects logged on the Fast-track project tracker, six relate to reconsenting of hydroelectric schemes and 23 are for new generation with collective annual output of approximately 9.5 TWh.[98] The speed and effectiveness of the Act in accelerating energy projects is still to be proven. To unlock the pipeline of projects needed for 2030 and beyond, the fast-track system must deliver timely, predictable approvals.

Before the Act, there was an interim pathway set up to fast-track approvals. Timelines under the interim pathways were lengthy given the various application steps. For example, Solar P LP and Transpower New Zealand first applied to the interim pathway in December 2023 for the Glorit Solar Farm, with a substantive application to the expert consenting panel in November 2024.[99] Consent was not approved until October 2025.

Through delivery of amendments, currently under consideration, the Act could be strengthened with revised deadlines for referrals and decisions, and priority given to standard renewable and grid projects. Queue times, approvals and throughput can be reported to the public, and consenting agencies need more staff and technical capacity. These steps will turn the current backlog into a steady flow of consented projects.

Reforms to the Resource Management Act (RMA) are also critical to accelerating consenting timelines for energy projects. It can shift from being prohibitive to enabling, where environmental benefits outweigh impacts once reasonable mitigation measures have been considered. While a recently passed amendment (in effect from October 2025) established a one-year consent processing timeline for renewable energy activities, like the Fast-track legislation, this change is untested. Broader reforms of the RMA can strengthen the consenting framework and provide clear national direction for energy infrastructure development, including recognition of energy infrastructure's role in achieving decarbonisation and economic growth objectives.

### 7.1.3 Improve pipeline information

A clear view of New Zealand's generation and storage project pipeline is important for renewable build transparency and tracking. It gives policymakers and market participants a clear view of when and where new capacity will truly materialise. It also helps investors by reducing due diligence, improving price discovery and identifying constraints.

Good progress has been made towards achieving this visibility, with the Electricity Authority creating a generation investment dashboard and Transpower publishing a pipeline of in-progress high-voltage connections. These tools are valuable steps forward, but they still do not provide a complete, whole-of-sector view of what is being developed and when it is likely to be delivered.

97 Ministry for the Environment, Fast-track Approvals Act, 2024

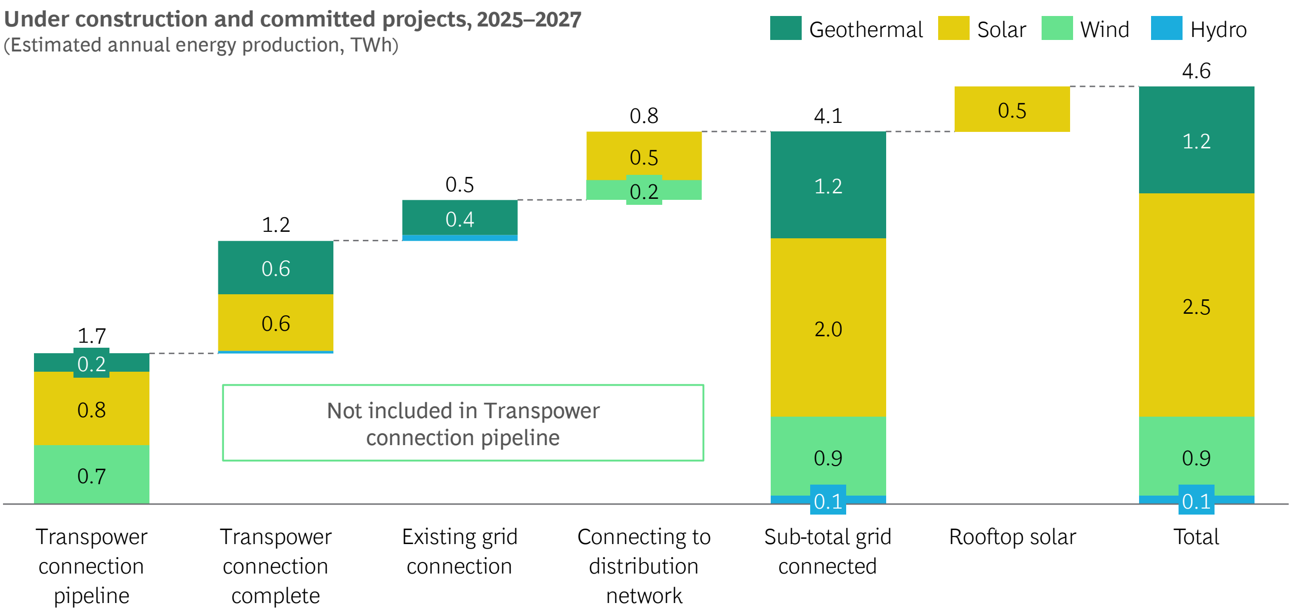
98 Environmental Protection Authority, Fast-track Project, accessed October 2025

99 Environmental Protection Authority, Glorit Solar Farm, accessed October 2025

This fragmented picture means policymakers and investors cannot easily determine whether new capacity is being added fast enough to meet electrification and climate goals. A clearer national view would allow faster identification of emerging gaps in supply, grid capacity or consenting progress.

Transpower's data, while accurate for in-progress transmission-level projects, excludes connections at the local distribution voltage level and those that have completed their transmission connection but are not fully commissioned. This means Transpower's connection pipeline outlines only 1.7 TWh across developments with a Transpower connection in design or delivery phase, versus the 4.1 TWh known to be under construction or committed between 2025 and 2027 (see **Exhibit 133**; also Section 5.1).

Exhibit 133: Incremental generation by generation type for projects due to come online between 2025 and 2027




Note: Excludes The Point Solar Farm (0.5TWh) due to high uncertainty
Source: Transpower, Concept Consulting, BCG Analysis

Meanwhile, the Electricity Authority's dashboard lacks granularity on generation output, making it difficult to assess the total committed capacity.

A comprehensive, whole-of-system pipeline, integrating transmission and distribution projects, and consistent data on capacity, generation output and milestones (consent applied, consented, final investment decisions and under construction), could be developed and maintained by the Electricity Authority and Transpower. This will give industry, investors and government a single source of truth on the pace of New Zealand's renewable build.

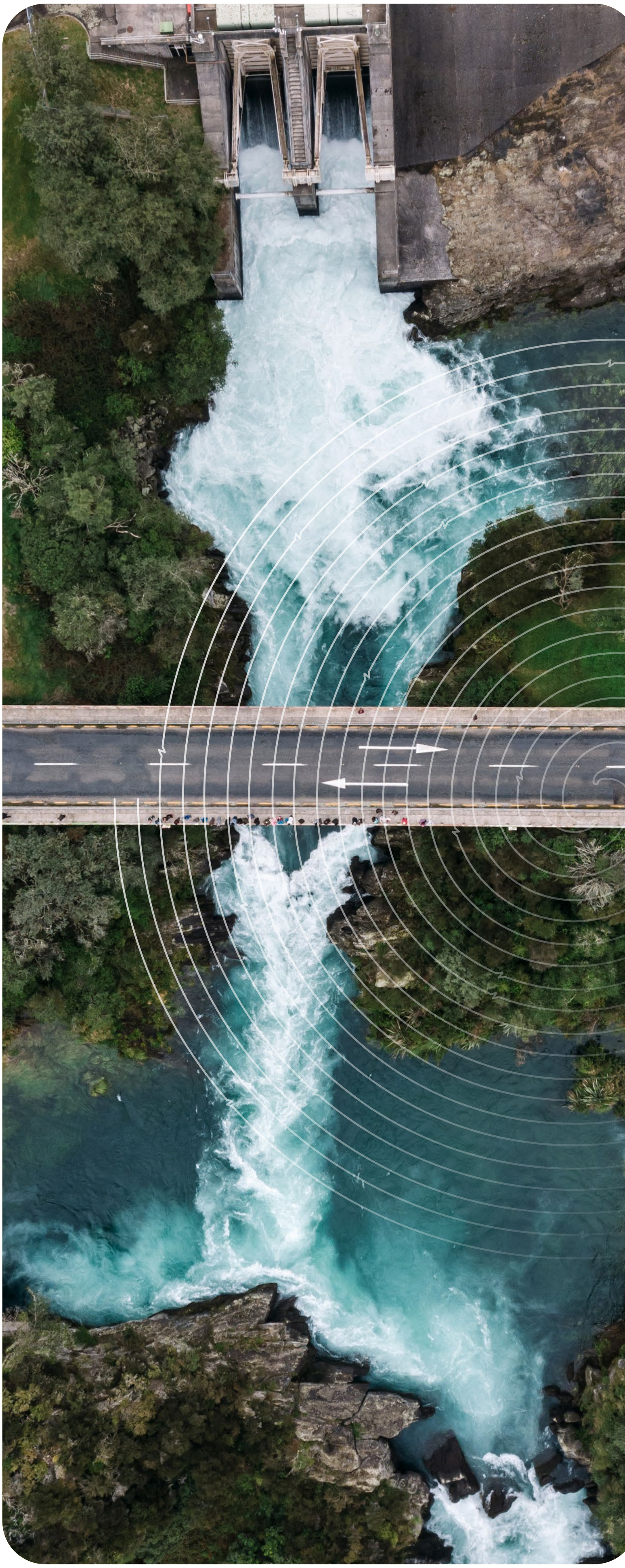
## 7.2 Recommendations to strengthen the electricity market and security mechanisms

The recommendations in this section look to strengthen New Zealand's electricity market and security mechanisms to meet its future needs. In recent years, rising gas prices have increased the cost of firming, while insufficient fuel storage has created volatility. Government's October 2025 ***New Zealand Energy Package*** includes a "Build Stronger Markets" section, which tasks the Electricity Authority (EA) with Action 2.5: "Build reliability and resilience in the market – strengthen the current regulatory framework to ensure that dry-year risk will not re-emerge in the future."[100] BCG has reviewed options the EA could take to deliver this action, recognising that it will require both capacity and fuel storage solutions.

There are five key recommendations:

1. Investigate new reserve market to mitigate system risk and incentivise capacity;
2. Investigate industry, regulatory and market actions to affordably meet dry periods;
3. Revise contingent hydro level and triggers;
4. Widen hydro operating consents; and
5. Continue to implement smart system measures.

These recommendations ensure New Zealand's electricity system has affordable, diverse fuel and sufficient capacity to provide firming and meet demand during dry periods and peaks.



100 Beehive, At a Glance: New Zealand's Energy Package, 2025

Across electricity markets, a range of mechanisms can be designed to incentivise fuel storage and capacity, including energy-only markets, ancillary or reserve markets, capacity markets and contract markets.

***Energy-only markets***

In energy-only markets, the spot price is cleared in regular auctions (often every five minutes) to the most cost-efficient bids. New Zealand currently operates an energy-only market as it is considered to provide the best dynamic and allocative efficiency (i.e. it dynamically allocates the most cost-efficient resources to meet demand and sends efficient price signals for long-term investment).

***Ancillary or reserve markets***

All energy-only markets have ancillary or reserve markets that incentivise firming to meet system needs that are not directly addressed by the energy market. Ancillary or reserve markets are usually 'co-optimised', meaning a resource cannot be dispatched to generate in the real-time market and held in reserve at the same time. These markets typically provide incentives for resources that can start quickly and provide frequency stabilisation during unexpected events (i.e. a large power station unit stops working).

Ancillary or reserve markets keep backup generation, storage or demand response available to maintain system stability. New Zealand operates a fast response (six-second) and a slow response (sixty-second) reserve market, which typically clear simultaneously with the energy-only market (usually every five minutes).

The system operator clears both markets together to find the most efficient, least-cost combination of dispatched and reserve resources. Co-optimisation maintains dynamic and allocative efficiency, delivering the lowest-cost outcome for consumers.

***Capacity markets***

Some markets use a capacity mechanism to provide incentives for new and existing firming capacity (MW of storage such as batteries or thermal power plants), separate from an energy-only market. Capacity is remunerated through stable, annual availability payments that provide a constant revenue stream (i.e. paying power providers to be available).

Capacity markets are typically introduced when policymakers believe capacity will not earn enough money from the energy-only market. This can occur when certain capacity types operate only a few hours in the year and cannot recover their costs through energy prices alone.

Capacity markets are usually run as auctions, where the system operator determines the required level of capacity and procures it competitively. Capacity markets are generally considered to not always maximise dynamic and allocative efficiency as they usually rely on a central procurement agency to determine both the amount and mix of capacity needed (i.e. the response speed and duration of different resources). Because the central buyer decides how much capacity to buy and what mix, capacity markets may not always deliver the most efficient long-term mix or the optimal combination suppliers and consumers would select through prices alone. New Zealand does not have a capacity market.

***Contract markets***

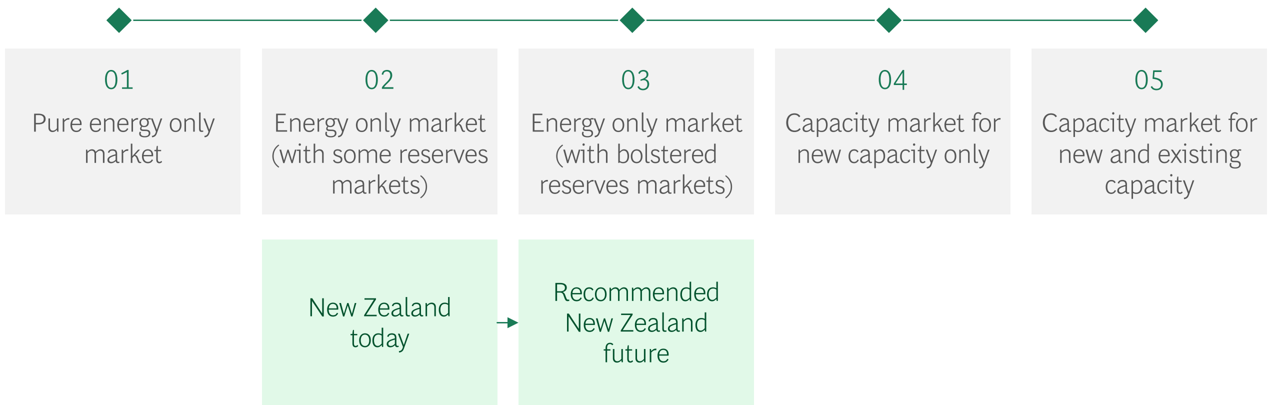
Most markets have contract mechanisms alongside energy-only markets to help generators and buyers manage price risk. These contracts allow participants to lock in electricity prices or hedge against volatility through financial instruments such as exchange-traded futures and options (e.g. ASX-listed NZ electricity derivatives) or over the counter (OTC) contracts. Long-term power purchase agreements (PPAs) are also commonly used to provide developers and lenders with stable revenue streams that support new investment. Together, these contract markets provide price certainty, improve investor confidence, and reduce exposure to fluctuations in the energy-only market. Contract markets enhance risk management, forward price signals and financing certainty. They complement rather than replace energy-only or reserve markets.

**To deliver security improvements, New Zealand needs bolstered reserve markets**

Debates around electricity market design often hinge on a simple view of energy-only markets versus capacity markets. When capacity or fuel supply appear constrained, policymakers may be drawn to capacity markets, even though they are not always the most efficient solution.

Based on BCG's assessment of potential markets for New Zealand, the most effective model for New Zealand is an energy-only market with bolstered reserve markets. This would strengthen ancillary and reserve markets to complement and reinforce the core electricity market. Such an approach preserves the dynamic and allocative efficiency aspects of real-time market clearing, where the lowest cost bids set prices, while evolving the system to meet the changing needs of a 21st century electricity system.

Exhibit 134: Conceptual overview of markets across the sliding scale




**New Zealand's reserve markets have not kept pace with changing dynamics**

New Zealand's reserve markets have not kept pace with market dynamics, and have been a contributing factor to an increase in volatility across all time scales (hours, days, weeks, months, seasons and years). Volatility itself is not inherently negative; when it reflects efficient market signals, it supports investment and efficient market prices. However, because price movements are asymmetric (as detailed in Chapter 5.2) they can lead to poor affordability outcomes if not managed with efficient investment signals, timely deployment of new resources and appropriate risk mitigation tools.

Several changing dynamics in New Zealand's electricity market underscore the need to strengthen its reserve markets. These include:

- **Increasing intermittent generation:** Due to weather, intermittent renewable energy sources can stop producing energy for short timeframes, sometimes suddenly or unexpectedly. The impact of these sudden drops increases as the proportion of intermittent generation increases in the system.
- **Ageing thermal power plants:** Ageing plants are more likely to trip or experience unexpected outages.
- **Increased natural disasters:** Disasters can disrupt power station operations or power lines that transmit electricity from power stations.
- **Volatile fuel supply chains and storage:** New Zealand gas supply is declining and its fuel storage facilities are ageing, presenting system risk (i.e. recent downgrade of Ahuroa Gas Storage from 18 PJ to 6–8 PJ due to water egress).
- **Greater reliance on electricity in the economy:** As the economy continues to electrify, including industrial processes, data, heating and transport, increased backup energy is important for resilience.

New Zealand's reserve markets procure reserve for the greatest credible contingent event (e.g. large thermal unit tripping). However, in recent years, major outages in developed countries have often involved multiple simultaneous failures rather than a single event. For example, in August 2021, a blackout in New Zealand left 34,000 homes and businesses without electricity on one of the coldest nights of the year.[101] The outage was a result of several factors that occurred across a few hours, including:

- **Record demand peak:** Demand reached 7,083 MW – the highest ever recorded.
- **Large, planned outages:** Approximately 602 MW of capacity was offline, mostly from South Island hydro.
- **Slow-start thermal units unavailable:** Key plants such as Taranaki Combined Cycle (360–385 MW) and Huntly Rankine (240–250 MW) were not started.
- **Wind generation shortfall:** Output fell by around 200 MW over approximately three hours and was approximately 200 MW below expectations at the peak.
- **Tokaanu hydro constraint:** Weed ingress into the intake reduced production of the Tokaanu Power Station by roughly 200 MW within an hour.
- **Interruptible load under-utilised:** Demand response was under-utilised due to visibility and co-ordination challenges. For example, an estimated 112 MW of hot water load could have been shed through ripple control by distribution network operators.
- **Operational errors:** Mistakes in the system operator's load shedding calculations and communications led to unnecessary customer disconnections.

### New Zealand's reserve markets are far lower in volume and value than global peers

Compared to other energy-only markets globally, like Australia's National Electricity Market (NEM) and Texas's Electric Reliability Control of Texas (ERCOT), New Zealand currently clears relatively low value through its reserve markets (noting in other markets these are sometimes called 'ancillary markets'):

| Energy-only markets | Average annual ancillary / reserve market value per MWh (2022–2024) |
|---|---|
| New Zealand | $1.0 per MWh |
| Australia National Electricity Market | $1.4 per MWh |
| Singapore | $3.2 per MWh |
| Norway | $3.8 per MWh |
| Texas ERCOT market | $2.8 per MWh |
| Alberta | $4.5 per MWh |

101 Beehive, Shortcomings Revealed in Power Cut Investigation, 2021

This relatively low value per MWh for New Zealand is largely due to two factors:

**Abundant flexible generation:** New Zealand's hydroelectric and baseload geothermal generation help stabilise frequency, reducing the overall need for reserves.

**Limited reserves products:** New Zealand operates two relatively small reserve markets, whereas other markets such as Texas offer a greater range of reserve products.

**Increased incentives for reserve capacity and fuel storage, alongside maximised hydropower generation, will help meet New Zealand's future electricity needs**

New Zealand has an opportunity to strengthen its electricity market by modestly increasing reserve market incentives to better support capacity and fuel storage. A slight rise in reserve value would improve investment signals for firming capacity and fuel storage, helping ensure adequate backup during peak demand periods without distorting the energy-only market. Investigating a new firming market, such as sustained reserve market mechanism for peaking capacity, is further detailed in Section 7.2.1.

In parallel, actions should be investigated to affordably meet dry periods when hydro and gas availability are most constrained. As outlined in Section 7.2.2, while the energy sector can mathematically meet dry-year needs today, it remains critical to ensure affordability across dry periods by enabling more diverse and cost-effective fuel options to reduce exposure to potential periods of higher-priced domestic gas.

Refining contingent hydro triggers would allow gentailers to deploy stored water more confidently and predictably during tight conditions. To get the most out of existing hydro, Transpower and the Electricity Authority could open up access to 300 GWh of contingent hydro. For the remaining 530 GWh, Transpower and the Electricity Authority should provide more predictable access to contingent hydro storage. Gentailers would work with consenting authorities and key stakeholders to operate existing lakes higher and lower than today. Furthermore, widening hydro operating consents would strengthen system flexibility and resilience. These two hydro strategies are further detailed in sections 7.2.3 and 7.2.4.

Lastly, continuing to implement Smart System Measures as detailed in section 7.2.5 can support security through smoothing demand peaks and building redundancy within local networks mitigating the impact of network outages including from adverse weather events.

Together, all these measures reinforce New Zealand's energy-only market design, providing reliable, more affordable electricity and a secure supply during peak and dry periods, while maintaining efficient investment signals for a future dominated by renewables.

### 7.2.1 Investigate new reserve market to mitigate system risk and incentivise capacity

**New Zealand may require a mechanism to address the risk of capacity shortfalls that last 2–4 hours**

Today the electricity market procures reserves for the single greatest contingent event (i.e. a unit at Huntly tripping). To strengthen its reserve markets, New Zealand could procure reserves for multiple failures that cumulatively exceed the size and timeframe of the largest contingent event. This could help New Zealand avoid events like the outage on 9 August 2021 where multiple failures across a 2+ hour period led to a blackout. It would also help avoid situations like on 9 May 2024 where Transpower had to ask consumers to reduce power consumption the following day between 7–9 am on a very cold winter morning, to ensure the lights could stay on.

Firming capacity would be able to meet these reserves requirements. As New Zealand's electricity system transitions from 90% renewables today to 95% by 2027, the utilisation of firming capacity is likely to decrease significantly, reflecting an equivalent decrease in thermal generation demands (see Section 6.2.2 for further detail on generation). Thermal capacity and, by extension, grid-scale batteries will also need to recover revenue across fewer hours. Yet in these time periods, firming will be highly valued at a system level, and spot prices for electricity should send a positive price signal.

However, relying solely on few and infrequent pricing events makes it difficult to build the business case for investment as the market continues to evolve, especially with:

- **Volatile earnings:** Increasingly volatile inter-year earnings create unattractive risk profiles for investors who value revenue stability.
- **Limited contract market depth:** While contract markets can enable revenue stability, as buyers can provide stable pricing to suppliers, it does not always occur.
- **Fuel and carbon risk:** New gas projects face uncertainty over long-term gas supply and exposure to carbon pricing.

### A thoughtfully designed reserve mechanism could reduce market risk and support peaking capacity

A new or revised reserve mechanism could be designed to encourage development of new peaking capacity or grid-scale batteries that can deliver sufficient sustained (2–4 hour) energy to cover the full evening peak profile and longer events. Any new reserves product could also be added to New Zealand's existing Fast Instantaneous Reserves (FIR) and Slow Instantaneous Reserves (SIR) markets (i.e. it wouldn't replace these markets, but be added to them).

Potential reserve mechanism design options generally fall into three categories:

1. **Introduce new reserves products for variable generation and demand events.** New products could be introduced to procure capacity for contingencies such as unexpected drops in intermittent generation, forecasting errors and large load ramps (e.g. data centres). These products would help manage frequent, short-term fluctuations rather than the rare, large contingency events. Examples include the ERCOT Contingency Reserve Service (ECRS) in Texas which delivers reserves within 10 minutes to cover big forecast errors, replace deployed reserves, restore frequency and help to meet steep net-load ramps. It is procured because Texas's traditional reserve markets alone are not always enough as renewables and demand ramps grow. Texas also has a Non-Spin Reserve that deploys reserves within 30 minutes to cover forecast errors and backfill other deployed reserves.
2. **Add a new reserve market that increases the duration that resources are required to provide response for (noting the existing requirements are 1 minute for FIR and 15 minutes for SIR).** Adding a new market that has longer durations would improve system resilience during sustained disturbances. It would also augment the FIR and SIR markets to meet system needs over different timeframes. The ECRS in Texas requires reserves capable of sustaining response for up to two hours. In practice, around 80% of activations last less than two hours – resources are compensated for the volume of response they provide and at the same rate per MWh, even when dispatch duration is shorter.
3. **Increase the reserve market to cover the risk of multiple or cascading failures, rather than the single greatest contingent event**. New Zealand could increase the level of reserves procured in its existing markets (FIR and SIR). It could look to systems like the National Electricity Market of Singapore (NEMS), which defines the largest contingency as the largest primary unit plus all designated secondary units that could trip simultaneously, or to the Electric Reliability Council of Texas (ERCOT), which procures its Responsive Reserve Service to withstand the simultaneous loss of the two largest units.

There is merit in investigating both a new market mechanism that combines the design outcomes of 1 and 2, and revisions to the existing FIR and SIR markets to lift the level of reserves, as noted in 3 above.

### A new Sustained Reserve market could provide security across peaks and longer duration events

A new Sustained Reserve could be created to deliver reserves within 10 minutes, and for a duration of 2–4 hours, to cover big forecast errors and substantial changes in intermittent generation, replace deployed reserves, restore frequency and help meet steep net-load ramps. The Electricity Authority could create this new market and it could be implemented by Transpower to better align reserves with evolving system needs

### A modest incremental incentive is sufficient to accelerate investment

Establishing a Sustained Reserve market would secure 2–4 hours of peaking capacity at low system cost to deliver good system outcomes. A modest $1.80 per MWh increase in reserve market value could unlock 300 MW of additional capacity. In 2035, this is modelled to reduce wholesale electricity prices by $2 per MWh, reduce demand response requirements by $10–15 million, and ensure no blackouts in this 10-year period.

Table 2: Impact assessment of sustained reserve market

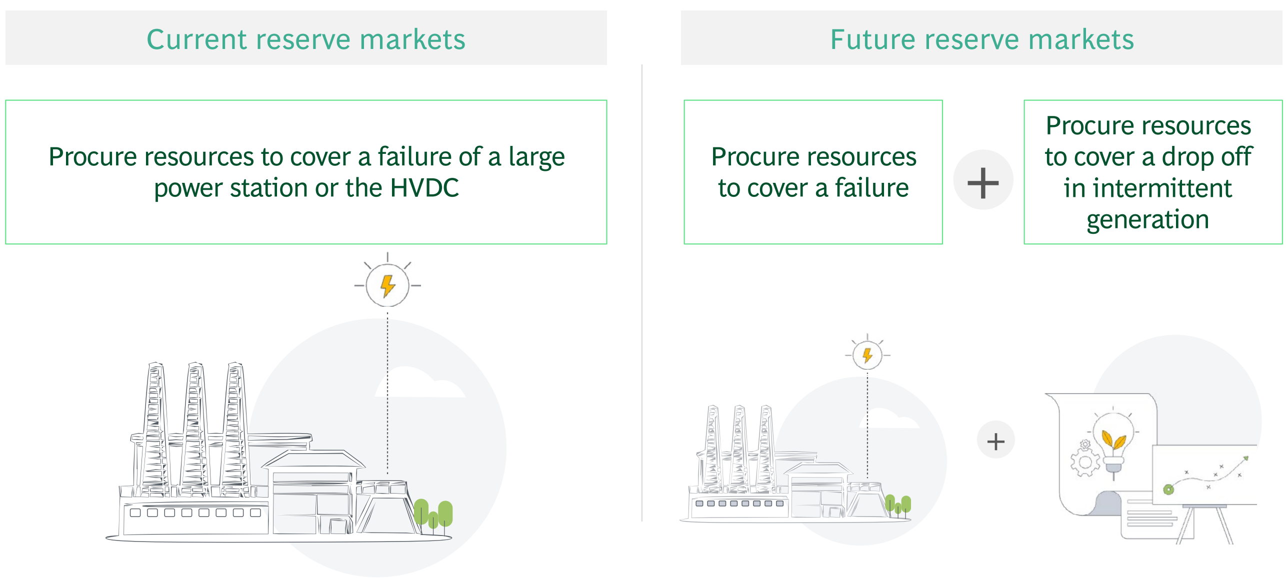
| Sustained reserve market | Impact | Detail |
|---|---|---|
| 1. Improves capacity assurance | Positive | Should increase incentive to manage peak risk appropriately |
| 2. Improves energy assurance | Somewhat positive | Should support capacity that can provide long-duration energy or complement long-duration energy |
| 3. Maintains energy affordability | Neutral | Some net benefit illustrated in modelling – $0.20/MWh reduction + $10–15m lower DR costs |
| 4. Maintains market competition | Neutral | Would be co-optimised with the spot market |
| 5. Minimises intervention | Somewhat positive | Ensures capacity investments are still driven by the market |
| 6. Can be unwound | Neutral | Could be unwound or changed as required |
| 7. Risk | Positive | Low risk, but introduces further complexity into the market |

**Investigate revising existing FIR and SIR design to procure more reserves than the greatest contingent event**

While a Sustained Reserve market would support energy security if multiple events occurred across a period of hours, another option is expanding the existing FIR and SIR markets to provide additional cover beyond the greatest single contingent event (i.e. a unit at Huntly power station tripping).

As a contingent event, a sudden, unexpected drop in weather dependent generation could exceed the failure of a large power station or the HVDC. A system with appropriate risk management will provision reserves for both potential drops in weather dependent generation and a failure of a large power station at the same time (see **Exhibit 135**).

Exhibit 135: Illustration of how increasing levels of intermittent generation will require increased reserves cover



One way to do this would be to procure reserves for FIRs and SIRs to the level of the greatest contingent event at a single clearing price. Then further reserves beyond this could be procured on a declining price scale, reflecting the fact that reserves beyond the greatest contingent event would be required less often. Another option would be to price cap tranches of reserves beyond the greatest contingent event.

In the below example reserves would be procured up to 250 MW (the size of 1 Rankine unit). The next 250 MW would be procured at a much lower and declining rate.

Exhibit 136: Illustration of an extended FIRs reserves concept[102]

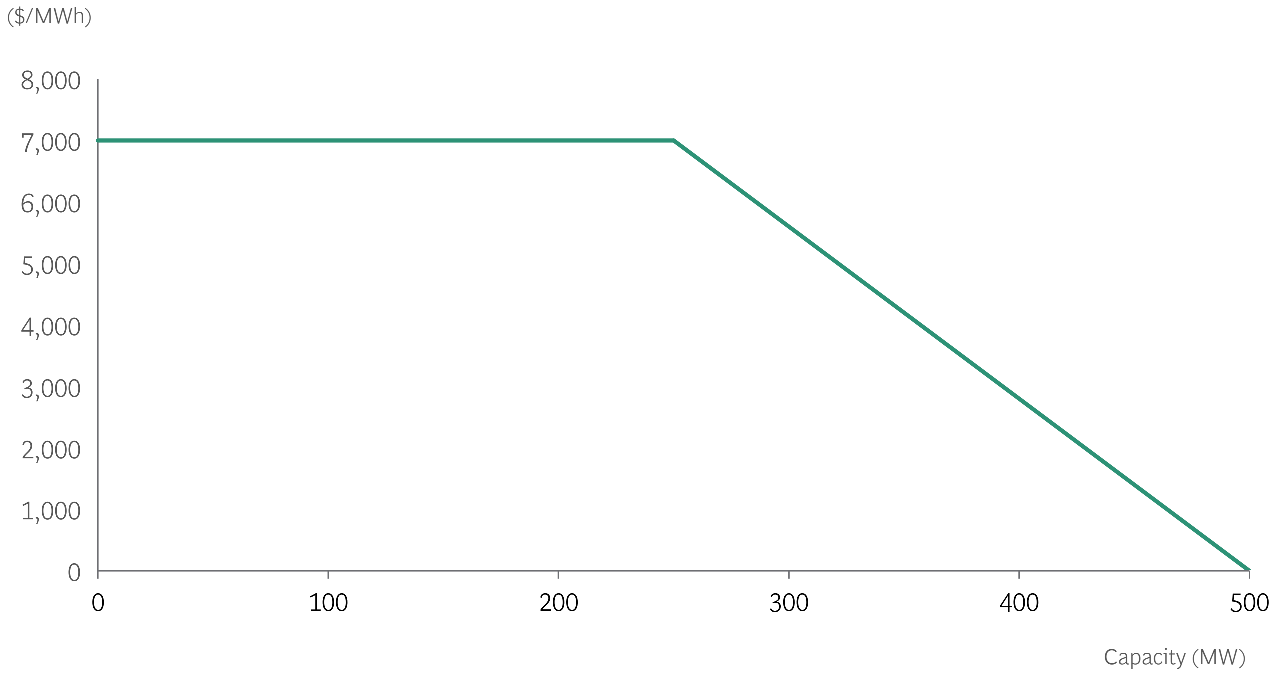



Table 3: Impact assessment of expanded FIRs and SIRs

| Revised FIR / SIR adopting Operating Reserve Demand Curve | Impact | Detail |
|---|---|---|
| 1. Improves capacity assurance | Positive | Enables improved reserve cover to meet peak needs |
| 2. Improves energy assurance | Neutral | Enables greater peak cover which could provide energy when not needed for reserves |
| 3. Maintains energy affordability | Neutral | Likely to be some cost but would be a cost efficient way to provide more reserves to meet evolving system needs |
| 4. Maintains market competition | Somewhat positive | Would be co-optimised with the spot market |
| 5. Minimises intervention | Somewhat positive | Ensures capacity investments are still driven by the market |
| 6. Can be unwound | Neutral | Can be unwound if it proves to be of low value |
| 7. Risk | Positive | Low risk, but introduces further complexity into the market |

102 Adapted from Hogan, Electricity Scarcity Pricing through Operating Reserves: An ERCOT Window of Opportunity, 2012

### 7.2.2 Investigate industry, regulatory and market actions to affordably meet dry periods

High wholesale electricity prices during dry periods in New Zealand are often driven by elevated gas prices. This is because the wholesale electricity price is highly exposed to gas – gas generation is under 10% of total electricity supply yet influences wholesale electricity prices 70–90% of the time. Improving fuel affordability during dry periods therefore requires a coordinated set of actions: accelerating renewable generation, stabilising the domestic gas supply-demand balance, increasing gas storage and diversifying into new fuels such as LNG, condensate and diesel.

The increase in gas storage and diversification of fuel mix is important from an affordability standpoint. Fuel storage has improved since 2024, particularly with greater solid-fuel stocks at Huntly, providing greater resilience in dry years. However, while New Zealand can mathematically meet the energy (MWh) requirement for a typical dry year, it still lacks sufficient fuel diversity and storage to ***affordably*** meet that need. Given gas turbines need to often produce at the same time as the Rankines in winter, gas would still set the marginal price a lot of the time in the market. In this situation, adding substantial quantities of solid fuels may not necessarily help to affordably meet dry periods.

New Zealand continues to remain vulnerable to consecutive or extreme dry periods. The modelling identifies the two driest years out of 43 hydrological sequences modelled (<5%) increase average prices by $3.5–5.5 per MWh (based on Scenario 2 modelling). For New Zealand to not remain vulnerable to consecutive or extreme dry periods, BCG analysis identifies total need of approximately 4.5 TWh of fuel storage and firm supply per year (detailed further in Section 5.2) before considering contingent storage. This would enable New Zealand to withstand the worst dry year (4 TWh) and still have enough thermal fuel stores to maintain relatively affordable supply through that period (i.e. the stored fuel needs to be greater than 4 TWh to provide confidence and flexibility given the thermal generation mix). To affordably provide this energy security, a sufficient, diverse fuel stack needs to be considered.

The electricity sector should provision the 4.5 TWh of long duration firm energy across:

- 2.3 TWh of solid fuels
- 0.8 TWh of stored gas (i.e. via Ahuroa gas storage)
- 0.3 TWh contingent hydro storage freed up and hence made available to operators (dependent on the sector's ability to procure sufficient firm thermal fuel contracts)
- 0.3 TWh contracted demand response (e.g. Tiwai Electricity Demand Response)
- 0.8 TWh via firm delivery contracts (e.g. primarily contracted firm gas with storage or LNG imports and possibly some condensate or diesel)

Modelling shows this fuel flexibility could lower costs to consumers by up to $250–500 million per year by 2035, based on a $5 per MWh reduction in wholesale prices and a $10 per MWh reduction in futures prices across a 50 TWh demand base. This diverse fuel stack can be achieved through different mechanisms as there is no single lever that can deliver energy security at low cost. To affordably meet dry-period demand, there are a number of options that should be investigated. One or a combination of the options may be required:

- **Part 1: Investigate improving New Zealand's stress-test regime** to better reveal system fragilities and align with international best practice.
- **Part 2: Investigate developing hedge disclosure obligations for fuel and fuel storage contracts** to better enable buyers and sellers of electricity to understand market risks.
- **Part 3: Investigate developing a Gas Strategic Reserve Agreement** focused on some combination of gas storage, an additional firm gas supply contract and gas power plant capacity as an addition to the solid fuels Huntly Strategic Energy Reserve agreement.
- **Part 4A: Investigate full-scale LNG imports** as a dry-year insurance backstop and for industrial gas use.
- **Or Part 4B: Investigate a Winter Firm Fuel Product (WFFP)** as a targeted, low cost out-of-market mechanism for incremental fuel if full-scale LNG is not pursued or delivery of it will be beyond 2028.

### Part 1: Investigate improving New Zealand's stress-test regime

Regardless of whether New Zealand investigates LNG imports or a Winter Firm Fuel Product, strengthening the stress-test regime is a critical component to ensuring the energy sector is successfully managing dry period risk.

New Zealand's current stress-test regime provides transparency on market participants' exposure to extreme price and supply events.[103] Each quarter, disclosing participants apply standard energy and capacity stress scenarios and report results to their Boards and an independent Registrar (NZX). The Registrar collates anonymised summaries for the Electricity Authority (EA), which publishes them on the EMI platform.[104] The EA notes it makes no judgement about participants' differing risk tolerances in those results.[105] Accordingly, the regime is designed for transparency and Board oversight rather than for a resilience assessment or for any further action from the EA.

Strengthening the stress-test regime would better align it with New Zealand's most significant system vulnerability, dry period risk, and with international best practice on resilience. The 2024 dry year illustrated that the stress-test regime was likely not robust enough, as fragilities in the market were exposed. A large issue with the 2024 dry year was the failure of gas contracts to be delivered upon when gas supply was short.

The EA has highlighted the distinction between winter peak capacity and dry-year risk in a renewable dominated system, and MBIE has flagged work to strengthen the regulatory framework for dry years. This could help to identify systemic exposure earlier, enhance hedging discipline and improve confidence in security-of-supply management.

The EA could investigate targeted improvements to the regime's scope and oversight. Options include introducing an EA independent review or benchmarking of submissions, publicly publishing richer insights on aggregate market exposure, identifying potential system fragilities, and regularly refreshing scenario design and price levels to reflect evolving hydrology, fuel availability, robustness of fuel contracts and demand. To address fuel risk the EA could also review positions to ensure they are backed by firm fuel – either via firm supply and transport contracts, or stored energy. This builds on the EA's May 2025 update to the regime's methodology and parameters.[106]

The stress-test regime could even extend as far as transparently reporting where participants are taking what is deemed to be excessive risk, and could report the gap that would need to be closed to remedy the situation. While the commercial decisions for firms would still be at their discretion (i.e. the EA would not have the power to make an entity do something) this would provide firms with improved information upon which to base these decisions.

A more active and transparent stress-testing framework would provide clearer visibility of system-wide risk, support prudent commercial behaviour and strengthen the sector's preparedness for extended dry-year conditions.

This improved information will enable better decision making from sellers and buyers in the market to ensure appropriate risk management.

103 Electricity Authority, Stress Tests, 2025

104 NZX, Stress Test Registrar, 2025

105 Electricity Authority, Stress Testing Regime – Stress Tests, 2025

106 Electricity Authority, Changes to Stress Test Regime Now in Effect, 2025

Table 4: Impact assessment of stress test regime

| Stress test regime | Impact | Detail |
|---|---|---|
| 1. Improves capacity assurance | Somewhat positive | Should increase incentive to manage peak risk appropriately |
| 2. Improves energy assurance | Somewhat positive | Should increase incentive to manage energy risk appropriately |
| 3. Maintains energy affordability | Neutral | Limited regulatory overhead required to implement |
| 4. Maintains market competition | Somewhat positive | Does not adversely impact competition |
| 5. Minimises intervention | Somewhat positive | It relies on information disclosure without impacting price signals in the market |
| 6. Can be unwound | Somewhat positive | Could be unwound or changed as required |
| 7. Risk | Positive | Publishing aggregated information is relatively low risk |

**Part 2: Investigate developing hedge disclosure obligations for fuel and fuel storage contracts**

Today electricity market participants are required to disclose information to the Electricity Authority in relation to risk-management contracts for electricity. A lot of data is required, including dates, quantities, prices, types of contracts (e.g. options versus contracts for difference) and key clauses. A lot of this information is anonymised and published.

An addition to this could be disclosure obligations for fuel and fuel storage to enable market participants to see anonymised information such as dates, quantities, prices and types of contracts for gas contracts and other fuel contracts. This would provide greater transparency of prices for solid fuels, gas, liquid fuels and biomass for electricity use. If deemed valuable, this could even be further extended to capture this information for non-electricity purchases of fuels, which would assist process heat users with understanding their fuel options.

The purpose of this would be to provide greater information for regulators, Transpower and market participants to use to inform decisions.

Table 5: Impact assessment of hedge disclosure for fuel

| Hedge disclosure for fuel | Impact | Detail |
|---|---|---|
| 1. Improves capacity assurance | Neutral | Limited impact |
| 2. Improves energy assurance | Somewhat positive | Assists with understanding firmness of fuel contracts and benchmarking of prices |
| 3. Maintains energy affordability | Neutral | Limited regulatory overhead required to implement |
| 4. Maintains market competition | Somewhat positive | Improves market information provided it remains anonymous |
| 5. Minimises intervention | Neutral | It relies on information disclosure without impacting price signals in the market |
| 6. Can be unwound | Somewhat positive | Could be unwound or changed as required |
| 7. Risk | Positive | Publishing aggregated information is relatively low risk |

**Part 3: Investigate developing a Gas Strategic Reserve Agreement**

The Huntly Strategic Energy Reserve Agreement between gentailers has increased the volume of solid fuel available for dry periods. An additional Gas Strategic Reserve Agreement would enable some combination of gas supply (new firm contract), new gas storage, and existing (or new) gas power plant capacity required to deliver more affordable and secure electricity. While solid fuels are beneficial for improving affordability and very valuable for addressing dry years, they often dispatch alongside more expensive gas in winter (i.e. gas is still the marginal price setter in many instances where solid fuels are generating). Therefore, ensuring secure and affordable access to gas is critical for meeting dry periods affordably.

This additional Gas Strategic Reserve Agreement could differ from the existing Huntly Strategic Energy Reserve Agreement, as it would not necessarily rely on stockpiling gas to hold in reserve. Instead, it could operate as a more flexible, dynamic arrangement driven by market and price signals. Under this approach, the electricity industry could on-sell gas when it is not required, with proceeds from these sales being recovered across gentailers involved in the Agreement. This would lower overall costs and deliver greater benefits to the broader energy sector, as fuel costs would only be incurred for gas actually used and for the carrying cost of stored fuel.

Additionally, if New Zealand pursues LNG imports to address gas supply challenges, this could be integrated into the Gas Strategic Reserve Agreement where insurance (e.g. via options to buy LNG at $1.70 per GJ) could be purchased as a low-cost way of providing a price cap against increasing domestic gas prices in dry periods. If this occurs, the electricity sector will have less impact on the price of gas in dry periods which will support more affordable electricity prices and gas prices for non-electricity gas users.

To meet the overall 4.5TWh requirement, and to deliver sufficient diversity to current domestic gas, the Gas Strategic Reserve Agreement would need to be at least 0.8 TWh (equivalent to at least 8 PJ). This is equivalent to doubling today's gas storage or two full-scale shipments of LNG. This additional 0.8 TWh could enable the freeing up of 0.3TWh of contingent storage to have unfettered access (see Section 7.2.3). This change to contingent storage levels would be supported by greater confidence in the availability of long-duration firm energy during dry periods.

These actions would reduce wholesale prices by $5 per MWh and futures prices by $10 per MWh in line with Scenario 3: Managed Transition and Electricity Security Mechanisms – noting the additional benefit of freeing up 0.3 TWh of contingent storage has not been modelled.

The agreement could be between all of the gentailers or a subset of the gentailers depending on risk exposure and commercial drivers. The gentailers who form the agreement would need to do so voluntarily and in response to market signals (i.e. this should not be mandated through policy or regulation). The benefit of this type of arrangement is that it would be market driven.

Table 6: Impact assessment of Gas Strategic Reserve Agreement

| Gas Strategic Reserve Agreement | Impact | Detail |
|---|---|---|
| 1. Improves capacity assurance | Positive | Would underwrite gas power plant capacity |
| 2. Improves energy assurance | Positive | Would underwrite long-duration firm energy in the form of firm supply contracts and storage |
| 3. Maintains energy affordability | Somewhat positive | Would improve wholesale and futures prices consistent with modelling in Scenario 3: Managed Transition and Electricity Security Mechanisms |
| 4. Maintains market competition | Possible, but depends on structure | Would need to be done in a way that complies with anti-competition. Huntly Strategic Energy Reserve agreement is a precedent for this |
| 5. Minimises intervention | Positive | It relies on market participants responding to market signals and forming an agreement voluntarily, rather than in response to intervention |
| 6. Can be unwound | Somewhat positive | Could be unwound or changed as required |
| 7. Risk | Positive | Relatively low risk |

### Part 4A: Investigate full-scale LNG imports

Enabling LNG as a contingency option would provide prudent insurance against fuel shortfalls, particularly during dry periods. A full-scale LNG import terminal, capable of accepting standard 4–5 PJ shipments, would offer scalable access to global LNG markets, enhance system flexibility and ensure sufficient gas availability for electricity generation when domestic supply is tight. As a dry period insurance mechanism imported LNG could be used only when required and could be used to balance the gas system and protect New Zealand from the risk of de-industrialisation.

To maintain affordability, LNG should remain a last-resort measure, activated only when domestic sources cannot meet demand. Capital recovery and fixed operations and maintenance costs should be shared across the energy system to avoid sharp price spikes in the periods when LNG is drawn upon. If these costs are amortised into the marginal cost of fuel LNG will be cost prohibitive.

For fuel purchasing, the market is best placed to manage risks related to LNG procurement. Based on BCG modelling, an annual option cost of $1.70 per GJ equates to approximately $13 million per year for the initial additional 0.8 TWh needed from firm delivery contracts for gas. This is a relatively low insurance cost to guarantee substantial supply and de-risking of dry periods. The $13 million would also enable 0.3 TWh of contingent storage to be released with unfettered access (equivalent to $45 million worth of water at $150 per MWh).

This small premium would secure New Zealand's energy sector against dry period risk while maintaining domestic gas as the primary source of firm capacity. LNG could therefore be preserved as a strategic backstop, a flexible safeguard that strengthens resilience without undermining progress toward a low-cost, renewable-led system firmed by secure domestic gas. Further details on the imported LNG solution can be found in Section 7.4.3 outlining the required infrastructure costs and considerations if this option is pursued.

### Part 4B: Investigate a Winter Firm Fuel Product (WFFP)

If LNG imports are delayed beyond 2028, a small-scale LNG import facility is pursued, or LNG is not pursued, a Winter Firm Fuel Product (WFFP) could offer a targeted alternative to ensure affordable, diverse fuel availability during dry periods. It would also not be required in an instance where there is a Gas Strategic Reserve Agreement committed to by market participants.

The level of optionality provided by diverse fuels effectively caps thermal fuel costs at around $25 per GJ (including carbon) by enabling generators to switch to lower-cost alternatives such as condensate, small-scale LNG shipments, and/or stored gas. The WFFP would act as an insurance mechanism, funding only the option cost or carrying cost of incremental fuel. It could also be used to fund the CAPEX for storage. The volume required for procurement would vary depending on the pace of achieving renewable overbuild. If required, the WFFP would only serve as a temporary bridge through this transition and would ideally be phased out within 5–10 years as renewable overbuild and other solutions are developed.

There is some international precedent for this approach. Texas's Firm Fuel Supply Service (FFSS) and New England's Winter Reliability Program (operated from 2013-2018) both pay the carrying cost of standby fuel rather than for unused capacity. The FFSS, introduced after Texas's 2021 widespread winter power outages, costs $70–85 million annually in a market 11 times larger than New Zealand's, equivalent to about $7–8 million per year if pro-rating to the size of the New Zealand market. New England's programme cost roughly $70 million per winter in a market three times New Zealand's size, approximately $25 million per year on a pro-rated basis. These examples demonstrate that targeted fuel insurance schemes can deliver substantial reliability benefits at minimal system cost.

In New Zealand, the WFFP could be administered by Transpower in two phases:

**Phase 1 (2026/27 tender for 2027/28 winter):** Support to develop storage/firm fuel supply as Transpower would determine the level and diversity of fuel required and provide initial funding to incentivise new storage and, where necessary, dual-fuel conversions to enable firm fuel supply; and

**Phase 2 (from 2027 onward):** Focus on securing firm fuel only once infrastructure is established. Over time, as situations change (e.g. new demand leads to an increasing dry-year need or renewable overbuild leads to a reducing dry-year need) Transpower can adjust the required volume to be procured. In time this could lead to the cessation of the programme if other mechanisms like renewable overbuild reduce the need for the programme to zero.

Support under the Winter Firm Fuel Product would only be available to new, additional storage and fuel requirements. For example, existing industry arrangements for a solid fuel stockpile would be exempt, and existing gas contracts and storage arrangements would be exempt. In Phase 2, Transpower could run a tender process to procure firm fuel – this would cover the 'insurance cost' of options to purchase fuel or the carrying cost of unused physical fuel that is purchased and stored. Importantly, this would ensure that costs are minimised and that any costs incurred would not be amortised into the marginal cost of fuel. Costs would be recovered through a modest security levy of around $0.8 per MWh ($33 million per year).

Exhibit 137: WFFP costing for upfront investment and fuel option

**Upfront investment cost**

**$250 million**

*Estimated upfront investment covering storage, treatment facility and plant conversions*

**$20 million**

*Annual cost based assuming 50% of investments is funded through the WFFP mechanism and is amortised over 10 years at 10% WACC*

**$0.5 per MWh**

*Annual cost per MWh assuming estimated annual electricity demand of around 40 TWh*

+

**Option to purchase fuel cost**

**$1.7 per GJ**

*Cost for option to purchase fuel when required*

**$13 million**

*Annual cost based on 0.8 TWh*

**$0.3 per MWh**

*Annual cost on bills*

=

**Total cost**

**$33 million**

*Annual levy encompassing both the cost of upfront investment and the option to purchase fuel when needed*

or

**$0.8 per MWh**

*Annual cost on bills*

Based on the modelling of Scenario 3, implementing the WFFP to incentivise security investments could reduce wholesale price by $5 per MWh and $10 per MWh in futures contracts, representing an approximate 5:1 to 10:1 benefit ratio versus the $0.8 per MWh costs of the Winter Firm Fuel Product. However, this does not factor in any unintended consequences or market inefficiencies arising from having an out-of-market product. These potential adverse effects need to be given very careful consideration as they could outweigh benefits.

Compared with broad capacity or strategic reserve mechanisms used overseas, the WFFP is more targeted and lower-cost. It preserves price signals by letting the market decide when fuel is dispatched, rather than relying on administrative triggers, and would also enable earlier and more predictable release of contingent hydro storage, unlocking up to 300 GWh immediately (equivalent to $45 million worth of water at $150 per MWh) and improving use of the remaining 532 GWh. This is further detailed in Section 7.2.3.

However, the WFFP would be an out-of-market product which could dilute signals for investment from the spot electricity market. For example, the WFFP could dampen scarcity pricing signals if it is not well designed. Effective scarcity pricing is the most important component of a well-functioning energy only market. A WFFP could also set the precedent for further out-of-market interventions, like capacity markets, down the track which would further dilute the efficiency of the spot market and impact investment signals. Therefore, a participant-led approach driven by the gentailers or a subset of the gentailers (e.g., a Gas Strategic Reserve Agreement) would be highly preferable to a WFFP.

If it were to be implemented, the WFFP would need to be established by the Electricity Authority and implemented by Transpower using clear guidelines. It would be critical that it would not be subject to political interference which would impact the market.

Table 7: Impact assessment of the Winter Firm Fuel Product (WFFP)

| Winter Firm Fuel Product | Impact | Detail |
|---|---|---|
| 1. Improves capacity assurance | Neutral | Not targeted to address capacity |
| 2. Improves energy assurance | Somewhat positive | Would support firm fuel supply |
| 3. Maintains energy affordability | Requires further investigation | In theory, would improve wholesale and futures prices consistent with modelling in Scenario 3: Managed Transition and Electricity Security Mechanisms but may have unintended consequences |
| 4. Maintains market competition | Neutral | Would be a competitive tender, but may favour certain solutions depending on how it is designed |
| 5. Minimises intervention | Somewhat negative | It relies on out-of-market procurement that would be run by Transpower |
| 6. Can be unwound | Neutral | Could be unwound or changed as required – but could also lead to further interventions |
| 7. Risk | Somewhat negative | Some risk of unintended consequences |

***Other options considered***

Several other ideas were assessed but were not considered valuable to investigate. These included the following market considerations where analysis was conducted in the original Future is Electric report:

- Secure strategic reserves
- Consolidate thermal assets (Thermalco)
- Introduce a capacity market
- Introduce government incentives for capacity

One idea that was not analysed in the original Future is Electric report was also assessed and was considered not valuable to investigate. This is the Colombia Firm Energy market.

Colombia's firm energy market operates similarly to a capacity market, where centralised auctions are held and generators bid for firm energy obligations – requiring them to generate under certain conditions. Each month, a scarcity price is calculated based on system variables and the cost of heavy fuel oil. Firm energy obligations are triggered when the wholesale price exceeds the scarcity price.

Generators receive a reliability payment for providing this service. The mechanism is comprehensive, as obligations are assigned at the power-plant level and aggregated to the company level. On average, the premium paid across all electricity is about $30 per MWh. By contrast, Texas's firm fuel supply service adds only around $0.10 per MWh, while the New Zealand WFFP is estimated to cost $0.8 per MWh under an option without full-scale imported LNG. Alternatively, a Gas Strategic Reserve Agreement would be a market-led and better option than the WFFP.

The key reason for this difference is that Colombia's scheme effectively provides an insurance payment to nearly all generators for capacity and fuel. In contrast, the WFFP is highly targeted, covering only the insurance cost (option cost or carrying cost) for a small level of incremental fuel.

Table 8: Impact assessment of the Colombia Firm Energy market

| Colombia Firm Energy market | Impact | Detail |
|---|---|---|
| 1. Improves capacity assurance | Somewhat positive | Supports capacity |
| 2. Improves energy assurance | Positive | Is very good at supporting firm energy supply |
| 3. Maintains energy affordability | Likely negative | Would increase costs substantially (e.g. $30/MWh from precedent markets) and may not provide commensurate benefit |
| 4. Maintains market competition | Neutral | Would be a competitive tender, but may favour certain solutions depending on how it is designed |
| 5. Minimises intervention | Negative | Relies on very large volumes of out-of-market procurement |
| 6. Can be unwound | Neutral | Could be unwound or changed as required – but could also lead to further interventions |
| 7. Risk | Neutral | Some risk of unintended consequences, but could also enable improved risk management |

### 7.2.3 Revise contingent hydro level and triggers

**Clear, predictable triggers will help gentailers use contingent hydro confidently**

Contingent hydro is currently treated as a 'last-resort' dry-year mechanism, only to be released under extreme conditions. In 2024, there was insufficient clarity around whether contingent hydro would be made available, compounded by consenting constraints that could have delayed or limited access even if it was triggered. Ultimately, Transpower decided to temporarily adjust the contingent storage access triggers for September and October 2024.[107]

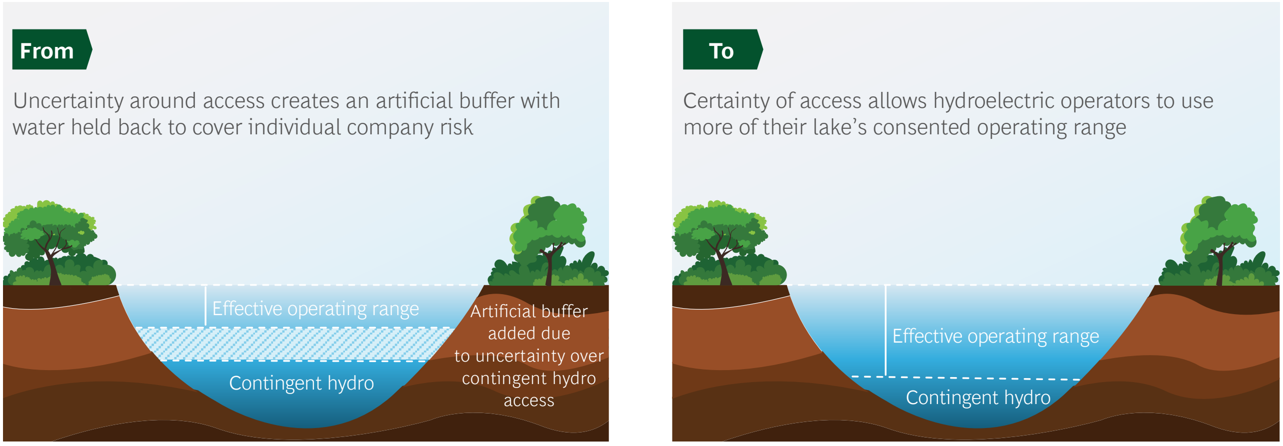
Uncertainty around contingent hydro access consistently creates market hesitation and elevates spot prices, as it affects how water is priced across hydro risk curves. These hydro risk curves are priced up to account for this uncertainty. Clarifying rules around existing water and freeing up additional supply would reduce the risk of using water today, helping to lower spot prices.

**Earlier and more transparent activation can strengthen confidence and lower costs**

Some gentailers effectively treat the contingent level as the bottom of the lake, conserving additional water and driving prices higher during already constrained periods. This is rational market behaviour given the uncertainty that currently exists around if and when contingent hydro could be used. Freeing up contingent hydro storage earlier on the hydro risk curves would reduce unnecessary use of fossil fuels and lower price volatility. Paired with additional fuel security (options detailed in Section 7.2.2), the system could activate contingent storage in a more transparent, risk-managed way freeing up more access to hydro storage without compromising overall supply security (see **Exhibit 138**).

107 Transpower, Adjustment to Alert Contingent Storage Release Boundary, 2024

Exhibit 138: Contingent hydro schematic




## There is value in freeing up hydro for security benefits

New Zealand currently holds around 832 GWh of contingent hydro storage in October to March and 612 GWh the rest of the year. Of this, roughly 300 GWh could be unlocked for unfettered access once sufficient long-duration firm energy (800 GWh) is procured via the selected option(s) in Section 7.2.2. This 300 GWh would no longer be classified as contingent storage. Note, the exact level of contingent storage that could be freed up, subject to option(s) in 7.2.2, would require further analysis.

This would leave 532 GWh of contingent hydro in October to March or 312 GWh the rest of the year to be released through additional tranches tied to defined trigger points.[108] Even the lower level of 312 GWh is more than Transpower's emergency floor of 214 GWh plus the 50 GWh default buffer.[109] After providing 300 GWh of unfettered access (tied to successful option(s) implementation in 7.2.2), the EA could consider changes to the Alert Contingent Storage Release Boundary (CSRB) buffer to allow earlier access to the first tranche (268 GWh out of the 532 GWh new contingent level in October to March).[110] This structure would maintain system security while providing clearer market signals and smoother price formation.

The value for this unfettered 300 GWh hydro storage is estimated at around $45 million (approximate estimated value of water at $150 per MWh). By comparison, the option to purchase 800 GWh equivalent of imported LNG would cost an estimated $1.7 per GJ totaling $13 million per year. [111] The $13 million cost would primarily enable diverse, affordable and sufficient fuel supply for dry periods. However, it would also unlock 300 GWh of contingent hydro to free up $45 million worth of water.

This high-level analysis is intended to illustrate the value of freeing up hydro for affordability and security benefits (tied to successful option(s) implementation in 7.2.2) and would require more detailed modelling. In BCG modelling (Scenarios 3 and 5), additional contingent hydro access was not explicitly incorporated, though the analysis recognises that clear and predictable trigger settings would support more efficient prices.

Allowing the market to access contingent hydro more predictably would help to reduce the current dry-year premium, estimated at 20–25% based on current futures prices versus modelled forecasts. Transpower and the Electricity Authority should therefore help enable more predictable, simple and stable access to contingent hydro storage. Doing so would help unlock a more efficient, renewable and resilient electricity system.

108 Transpower, Electricity Risk Curves 101, 2024

109 Transpower, Electricity Risk Curves 101, 2024

110 Transpower, Electricity Risk Curves 101, 2024

111 Assuming a weighted thermal efficiency of 0.45 across the New Zealand gas fleet

### 7.2.4 Widen hydro operating consents

**Wider hydro operating consents would strengthen energy system resilience**

Hydroelectricity is New Zealand's core competitive advantage in energy, providing flexible, low cost and renewable generation. To maximise its value, existing hydro schemes should be enabled to operate more dynamically with consents that widen their allowable storage and operating ranges within reason.

Gentailers could work with consenting authorities and stakeholders to operate existing lakes higher and lower than today. For example, Contact Energy has publicly indicated interest in changing its operating band by two metres in wetter years and allowing an additional six metres of drawdown in dry years under a contingent storage trigger.[112]

The benefit of this is really clear – the hydro dams already exist so it would be a very low cost way of accessing more highly flexible renewable fuel. Expanding these operating limits across suitable schemes would strengthen system resilience, improve seasonal energy management and reduce the energy system's reliance on higher-cost thermal generation.

### 7.2.5 Continue to implement smart system measures

The previous Future is Electric report outlined a number of smart system recommendations to deliver greater and more efficient use of flexible energy resources like distributed energy resources and demand response. This focused on price-based signals, smart managed tariffs, flexibility contracts and use of off-peak electric vehicle charging.

There has been substantial progress in the last 3 years with these measures. This includes distribution connection pricing reform, time varying retail pricing, consultation on an Emergency Reserve Scheme and uptake of non-network alternatives by lines companies.[113,114,115]

As hundreds of thousands of smart devices like solar, batteries, EV chargers and heat pumps are connected to the grid in the next decade it will be important that progress continues to be made so consumers can access the value and benefit of these resources. Similarly, where these resources can provide value for the electricity system (e.g. by reducing peak demand) it can reduce costs for all consumers and avoid, or defer, the need for new physical infrastructure.

There is also a lot of work being done to drive further progress. The Electricity Authority released a decentralisation green paper in April 2025.[116] FlexForum, a cross-industry coalition for electricity flexibility, released its second Flexibility Plan in May 2025 with 41 proposed actions.[117] In the same month Ara Ake released its National Flex Discovery Fund, to help flexibility service providers connect to flexibility platforms and scale capacity.[118] EECA also released a green paper in October 2025 that focuses on unlocking product-based flexibility in households through defining voluntary specifications for flexibility-ready EV chargers, heat pumps and other devices in the home.[119]

This positive work across the industry is a great example of industry collaboration with key regulatory and government agencies to deliver improvements. As this work continues it will be important to focus on measures that provide financial benefits for flexibility services that are valuable to the grid. Ultimately, flexibility will only be unlocked at scale if consumers and flexibility service providers can receive a financial benefit for valuable services they provide. Additionally, consumers and flexibility service providers need to be able to easily access the markets that offer this financial benefit. The presence and adoption of marketplace platforms like Piclo, which is used by a number of lines companies in the United Kingdom, Europe, United States and Australia, can help to improve this access to financial benefit.

112 RNZ, Contact Energy Seeks to Dip Deeper into Lake Hāwea, 2025
113 Electricity Authority, Distribution Connection Pricing Reform, 2025
114 Electricity Authority, Time-Varying Price Plan Requirements – Retailer Guidance, 2024
115 Electricity Authority, Establishing an Emergency Reserve Scheme, 2025
116 Electricity Authority, Working Together to Ensure Our Electricity System Meets the Future Needs of All New Zealanders, 2025
117 Electricity Authority, Electricity Authority Welcomes Plan for Boosting Consumer-Supplied Flexibility, 2025
118 Ara Ake, Ara Ake National Flex Discovery Fund, 2025
119 EECA, Unlocking the Potential of Demand Flexibility – A Residential Product Perspective, 2025

## 7.3 Recommendations to enhance lines infrastructure efficiently

New Zealand's renewable and electrification build will only move as fast as its national transmission grid and local distribution networks allow. While New Zealand has a strong grid, capacity is tightening. New regional connections could soon be needed to unlock the next wave of renewable projects and electrification demand. Transmission projects can take close to a decade to plan, consent and deliver, so action now is critical to avoiding bottlenecks in the 2030s.

A stronger and more efficient grid will require both vision and discipline. To achieve this, the recommendations are: (1) Ensure Transpower's Grid Blueprint provides a bold vision for grid development to 2050; (2) Investigate a new transmission funding mechanism for regional transmission; (3) Develop an accelerated Major Capital Approval path for low-regrets, high-benefit transmission projects; (4) Move to a trailing average approach for the weighted average cost of capital; (5) Continue to enhance grid connections while retaining an open access model; (6) Publish capacity availability maps for lines companies (noting many, but not all, lines companies already do this well); and (7) Commence productivity benchmarking for lines companies.

Together, these recommendations will ensure New Zealand's grid can keep pace with the renewable build, support affordability and reliably deliver electricity as the country electrifies.

### 7.3.1 Ensure Transpower's Grid Blueprint provides a bold vision for grid development to 2050

Globally, transmission capacity is increasingly becoming a critical bottleneck for the energy transition, constraining the growth of renewable electricity supply and the pace at which it is deployed. New Zealand has so far been fortunate. Its strong transmission grid was designed to move large volumes of power from southern hydro stations to northern demand centres such as Auckland; this has provided the foundation for reliable supply and enabled the integration of new renewables and load growth over recent decades.

Transpower's work on Net Zero Grid Pathways, which commenced in 2021, and the associated 'least regrets' upgrades that have been delivered or are being delivered, will continue to strengthen the core grid and support new connections to 2030.[120] In parallel, Transpower is optimising the existing grid to maximise its utilisation.

However, beyond the near term, new lines will likely be required. Building these assets typically takes 7–10 years given the need for long-range planning, community engagement, consenting, property access and regulatory approvals before construction can begin.

This long lead time means Transpower must act now to deliver the transmission capacity that New Zealand will need from 2030 to 2040. As existing grid capacity is progressively consumed by new renewable projects and electrification, Transpower should invest in:

- Expanding the core grid backbone to strengthen north-south transfer capacity
- Developing regional connections to unlock high potential renewable zones and future demand centres
- Maximising existing assets while new lines are built
- Building resilience and climate adaptation to help ensure security
- Publishing transparent, adaptive planning for progress transparency

Transpower's forthcoming Te Kanapu Grid Blueprint should therefore set out a bold, forward-looking vision for grid development to 2050: one that mobilises early planning, anticipates future load growth and renewable zones and ensures transmission capacity does not become the constraint on New Zealand's clean energy transition.

120 Transpower, Net Zero Grid Pathways 1, 2022

### 7.3.2 Investigate new transmission funding mechanism for regional transmission

Today there are two types of transmission assets in New Zealand:

- **Connection assets:** Assets that physically connect a specific customer to the national transmission grid (e.g. generator, distributor or large industrial user). The connected customers pay the connection charges that recover Transpower's costs for those assets.
- **Interconnection assets:** Any grid assets that are not connection assets and provide shared services to multiple customers across the national transmission grid. Costs are recovered under the Transmission Pricing Methodology (TPM, benefit-based and residual charges).

For connection assets, the user pays to connect. The designated transmission customers fund the asset via Transpower's connection charges under the TPM and a transmission agreement.

For interconnection assets, Transpower follows an established development pathway: it identifies need and consults stakeholders. The Commerce Commission then assesses and approves major capital expenditures if the cost-benefit stacks up. Once approved, Transpower recovers costs from beneficiaries via benefit-based charges (BBCs) under the TPM, with any residual charges recovered from load customers.

However, in some regions, notably Northland, assets that could unlock major renewable developments are physically configured as radial lines and therefore classified as connection rather than interconnection. This classification limits cost-sharing and weakens investment incentives, even when projects would deliver system-wide benefits.

The Northland case illustrates this challenge.[121] While there are 2.7 GW of new potential renewable generation projects in Northland, limited transmission is constraining their potential. To take advantage of these projects, Transpower would need to enable transmission within Northland to connect and export energy to the Auckland–Marsden line (which is currently under-utilised). Transpower's Energy Bridge work identified several upgrade options to achieve this, but under current rules, most of the upgrade costs would fall on Northland consumers, despite broader benefits to generators and Auckland demand.[122]

Without more flexible cost-allocation tools, essential regional transmission may not proceed, leaving high-value renewable resources stranded. A new funding mechanism that allows fairer cost sharing across beneficiaries could enable timely investment in grid expansions.

One option could be to allow a connection asset to be reclassified as an interconnection asset by the Commerce Commission if it meets strict criteria demonstrating that reclassification is in the long-term interests of consumers. The criteria would need to be rigorous to ensure this occurs only in niche cases where the cost-benefit is compelling.

For example, there are several relatively low-cost upgrades on the Kaikohe-Maungatapere line, currently a connection asset, that could unlock substantial new renewable generation and make better use of the existing grid (e.g. the Auckland-Marsden line). While a single project proponent could fund this upgrade as a connection asset, a first-mover disadvantage may arise if it is uneconomic for them to bear the full cost. Across multiple generation projects, however, the investment would make sense, yet the coordination challenge of co-funding among developers means it is unlikely to occur.

In such niche instances, reclassifying the asset as an interconnection asset could help overcome the first-mover disadvantage. Transpower would still be required to submit a specific proposal in these cases (even if the project falls below the $20 million Major Capital Project threshold), and the Commerce Commission would still need to confirm that the cost-benefit case is robust. Reclassification alone would therefore not automatically enable the project; it would still need to be demonstrated as viable and in the long-term interests of consumers.

121 Electricity Authority, Northland Tower Collapse 20 June 2024, 2024

122 Transpower, Resilience, Reliability and an Energy Bridge Te Tai Tokerau Northland, 2024

### 7.3.3 Develop an accelerated Major Capital Approval path for low regret, high benefit transmission projects

It often takes 5–10 years to develop new transmission projects in New Zealand. As the energy transition accelerates, this long timeline could stall the development of new data centres, electrification and electricity generation – which will constrain economic growth and raise electricity prices.

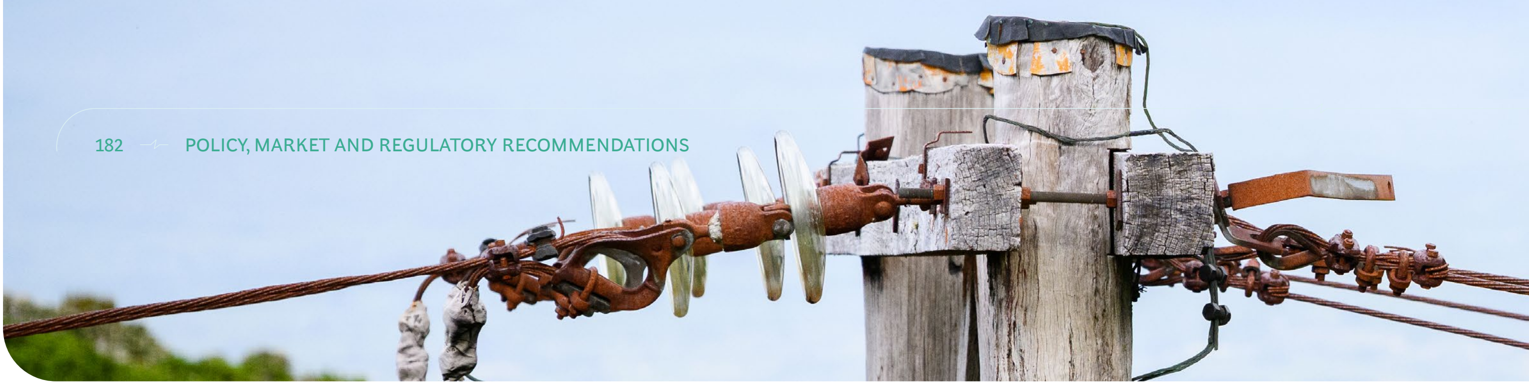
Today, Transpower is required to develop a Major Capital Proposal (MCP) for projects over $30 million. The Commerce Commission reviews the MCP and will approve it if it meets the long-term best interests of consumers. In simple terms, this usually means that there needs to be a clear and compelling benefit to cost ratio.

The process for getting an MCP over the line can take 2–3 years and involves:

- Transpower submitting a Notice of Intention to the Commerce Commission
- Transpower running a long-list consultation of transmission options
- Transpower running a short-list consultation of transmission options
- Transpower submitting a proposal to the Commerce Commission
- The Commerce Commission publishing a draft decision and seeking submissions
- The Commerce Commission receiving cross-submissions, where stakeholders submit on others' submissions
- The Commerce Commission delivering the final decision

While it is important that this rigorous process is maintained in many instances to ensure efficient spend for consumers, there could be situations where the benefits so clearly outweigh the costs from the outset that the formal process could be significantly condensed.

This could involve steps like having one Transpower consultation, rather than a long- and short-list consultation. It could also streamline the submission process on draft decisions to deliver faster outcomes. While the specifics would need to be worked through in more detail, it is important that low-regrets, high-benefits transmission projects are not unnecessarily held up by lengthy processes.



### 7.3.4 Move to a trailing average approach for weighted average cost of capital

The interest rates used to set revenue for lines companies are based on a 'point in time' approach. The current point-in-time method creates sharp step changes in allowable revenues every five years and, in turn, customer bills. Under the 2025 price reset for lines companies, the weighted average cost of capital (WACC) rose from 4.6% (April 2020) to 7.1% (April 2025) and was a key driver of higher network charges. The Commerce Commission estimates this uplift will add around $10–$25 per household per month in 2025, and a further $5–$10 per month, each year to March 2030 (ex GST).

A trailing average approach for the WACC smooths revenues through rate cycles for lines companies and reduces bill volatility for customers, supporting consumer affordability and providing more stable investment signals. For lines companies, it improves returns certainty – improving timing, cost, and efficiency of investments. Had the Commerce Commission applied a five-year trailing average to the risk-free rate when determining the 2025 WACC, the WACC could have been closer to 6%, reducing the step up from +2.5 percentage points to +1.4 percentage points.

The Commerce Commission could adopt a trailingaverage approach (e.g. five-year window) and implement it from the next Distribution Price Path reset from April 2030, with a clear transition signalled well in advance. This will support consumer affordability while strengthening investment signals.

### 7.3.5 Continue to enhance grid connections while retaining an open access model

New Zealand's transmission grid connection process works well today: it is flexible, customer focused and founded on open access. Prospective connectors can apply to connect anywhere, and no one can buy or reserve transmission capacity.

Transpower has also been very effective at revamping its connection processes and scaling up resourcing to process many more enquiries and deliver connections at a high pace. Despite this strong progress locally, grid connections have become a bottleneck in many other jurisdictions globally. The Electricity Authority could continually update the Electricity Industry Participation Code 2010 (the Code) , and Transpower should keep evolving its processes, so New Zealand avoids similar bottlenecks as connection volumes increase.

The recent BCG report, 'Mind the Queue: Connection Reform for the Electricity Grid', outlines options for countries to adopt practical reforms to enhance connection processes.  Below are some possible options for Transpower that could work in New Zealand's context of open grid access and avoid central planning:

1. **Add readiness gates and expiry rules to the connection queue.** Connecting to the grid is on a 'first-ready, first-served' basis, which should be retained, but with added readiness gates (e.g. achieving land rights, consents or deposits) and expiry rules (e.g. 'use it or lose it' provisions) to keep the queue moving. This would encourage developers to progress projects, knowing that they can be moved up or down the queue depending on their readiness. This could be supported by quarterly publication of queue health metrics.

2. **Batch studies and standardise assumptions.** Where multiple projects target the same node or corridor, batch studies with common data and timelines are an option to reduce Transpower's workload and enable faster processing. This would help reduce duplication while retaining applicants' choice of location.

3. **Offer optional non-firm ('connect and manage') access.** If the core grid starts to become more constrained there may be a need to curtail generation at times. If a project is ready to connect and Transpower is unable to guarantee 100% firm connection (i.e. guarantee no curtailment), then there should be an option for a non-firm connection where the developer can take on the risk with clearly defined curtailment terms, enabling investors to price the risk.

4. **Keep hosting capacity maps and the public connection pipeline current.** Transpower's capacity maps and public connection pipeline should continually be reviewed and updated so developers and large users can select the least cost connection locations – lowering total upgrade needs.



New Zealand's open-access approach and Transpower's recent process upgrades are strong foundations. The above enhancements preserve open access, avoid central planning and follow proven reforms in leading jurisdictions, reducing delays, improving investor certainty and ensuring the grid remains an enabler rather than a bottleneck.

### 7.3.6 Publish capacity availability maps for lines companies

Of the total generation committed or under construction in New Zealand today, around 2.2 TWh (5% of New Zealand's demand) will connect to Transpower's national transmission grid, while 2.4 TWh will connect to local distribution networks. The local distribution networks, comprising medium voltage lines, are often well suited to hosting mid-scale wind and solar projects, which can alleviate pressure on the national transmission grid and support more geographically distributed renewable development. Like Transpower, these networks have been significantly improving their connection processes in recent years.

However, identifying the optimal connection points on the local distribution network can be more difficult than on the national transmission grid. Transpower provides open, detailed capacity maps showing where there is capacity for new connections on the transmission grid, but similar visibility is not consistently available across the 29 electricity distribution businesses (EDBs).

Many EDBs, such as Powerco, have been developing similar interactive capacity maps for the distribution sector, demonstrating the potential benefits of greater transparency. Extending this practice across all EDBs would help developers and large users identify the most cost-efficient and timely locations to connect new renewable generation and electrification loads. This in turn would improve investment coordination, reduce connection delays and alleviate emerging constraints on the transmission system.

### 7.3.7 Commence productivity benchmarking for lines companies

Productivity is critical for delivering affordable electricity network prices. It ensures capital is allocated to the most valuable projects and that those projects are delivered at the lowest cost, freeing up capital for further investment.

The current regulatory process for electricity distribution incentivises efficiency with the Default Price Quality Path (DPP), with the option of a Customised Price-Quality Path (CPP) where warranted.[123] When electricity distribution businesses (EDBs) deliver below their regulatory CAPEX and OPEX allowances, they retain approximately one-third of the benefit, with the remainder flowing to consumers via lower future charges. This sharing mechanism encourages cost efficiency and ultimately benefits consumers.

In Australia, the Australian Energy Regulator (AER) has a long history of benchmarking electricity distribution network service providers (DNSPs) using multilateral total factor productivity and related measures. This approach measures how much is delivered to customers (e.g. connections, energy delivered, ratcheted maximum demand, network size and peak capacity) relative to the total inputs (OPEX and CAPEX). It enables the AER to rank DNSPs by efficiency, providing transparency and accountability across the 13 distribution networks it regulates on the East Coast of Australia.

In New Zealand, similar benchmarking is not yet systematically applied. While performance is likely to vary across the 29 EDBs, the absence of consistent productivity measures makes it difficult to assess relative performance or identify best practice.

In June 2024, the Commerce Commission released CEPA's Final Report (Phase 1) on sector-wide total factor and OPEX partial productivity benchmarking for 2008–2023. Phase 2 (a proof-of-concept comparative efficiency study) has not yet progressed to an annual, formalised benchmarking exercise as the AER conducts in Australia.[124,125]

123 Commerce Commission, Electricity Lines Price-Quality Paths, 2025

124 CEPA, EDB Productivity Study, 2024

125 Commerce Commission, Productivity and Efficiency Study of Electricity Distributors, 2025

Overall, EDB productivity has declined by about 20% since 2008, falling from a score of approximately 1.0 to 0.8 by 2023. For example, real OPEX has risen by roughly 45% since 2008, while ratcheted maximum demand has increased by only 18%.[126]

Several contextual factors have contributed to lower potential productivity compared with 2008 that are not fully accounted for in the analysis, including:

- Greater resilience and reliability requirements
- Hosting and management of distributed energy resources like EVs and solar
- Decarbonisation-related upgrades
- Inflationary cost pressures in supply chains for materials and labour
- Increased frequency and severity of weather events driving resilience and restoration costs

Despite these factors, robust and regular productivity benchmarking remains essential. Publishing adjusted, EDB-level metrics that take account of contextual factors would clarify the difference between structural cost pressures and operational inefficiency. Establishing this as a regular Commerce Commission publication would strengthen regulatory transparency, enable performance-based comparison across EDBs and ensure future network investments deliver maximum value for consumers.

## 7.4 Recommendations to address gas supply decline and introduce domestic gas alternatives

With domestic gas supply declining rapidly, New Zealand needs a coordinated set of actions to stabilise gas production, manage demand and protect energy security and affordability. Immediate efforts should focus on extending the life and deliverability of existing fields through targeted development drilling and new storage to manage seasonal variability and strengthen resilience.

Advancing drop-in fuel alternatives for gas peaking, developing scalable biomass supply chains and accelerating energy audits across major users will also help reduce reliance on gas and improve system flexibility. In parallel with these domestic efforts, enabling an LNG option is prudent as New Zealand's energy system may need it, while better solutions are put in place and assessed.

The recommendations are: (1) Ensure the 'Gas Security Fund' addresses drilling risk and weights focus to near-term gas supply; (2) Develop gas storage for flexibility; (3) Create LNG optionality; (4) Enable drop-in alternatives for peaking; (5) Help establish biomass supply chains; (6) Accelerate energy audits to consider alternatives for gas and commercial industrial gas users.

### 7.4.1 Ensure the 'Gas Security Fund' funding model addresses drilling risk and weights focus to near-term gas supply

**The government's recently announced expansion of the 'Gas Security Fund' to include development drilling is critical to mitigating a supply shortfall in 2028–2030**

New Zealand had previously set aside a $200 million Crown co-investment fund for new gas fields. However, the need to stabilise the stark decline in domestic gas supply has propelled the government to expand the scope of this fund to now include development drilling in existing fields and production facility upgrades.[127] Redirecting this funding to proven fields will help deliver faster, lower-risk outcomes compared to exploration, helping to mitigate the expected 2028–2030 supply shortfall.

126 CEPA, EDB Productivity Study, 2024

127 Beehive, Widened Scope for Co-Investment in New Gas, 2025

Prioritising development wells within known fields offers the lowest risk and fastest path to stabilise supply. These fields are already assessed for deliverability, supported by existing infrastructure and capable of bringing new volumes online as early as 2027 – this is well before new exploration prospects, which are unlikely to produce before 2032. By focusing on near-term deliverability, the government, through the fund, can now help prevent avoidable demand loss and better manage New Zealand's transition from gas.

Development wells in existing fields can lift production where approvals and facilities are already in place, allowing incremental gas to flow quickly into the market. A programmatic, multi-campaign approach to development drilling, supported by government, would increase the likelihood of achieving aggregate gas volumes. Visible government participation would also signal urgency, crowd in private capital and provide investor confidence in the near-term drilling outlook.

**Introducing $CO_2$ scrubbing as a production-enhancing mechanism unlocks further supply opportunities**

To increase the output of existing assets, $CO_2$ scrubbing could be considered as part of the production facility upgrades to complement development drilling. New Zealand already has scrubbing capacity at Kapuni. If there is spare scrubbing capacity at Kapuni and infrastructure to transport high $CO_2$ gas from other fields, this could be an option to use high $CO_2$ gas from reservoirs such as Kaimiro or other fields. Where new infrastructure is needed to transport high $CO_2$ gas to the Kapuni facility, those costs could fall within scope of the fund. The Kapuni scrubbing plant would also need to be technically capable of treating gas with different $CO_2$ concentrations from those currently processed.

If this is not feasible, or if the additional available capacity is insufficient, new $CO_2$ scrubbing capacity could be required or new investment in the existing Kapuni facility may be needed. New scrubbing trains and $CO_2$ management systems could unlock gas that is currently uneconomic, extending the productive life of key assets and potentially reducing New Zealand's reliance on LNG imports.

$CO_2$ scrubbing initiatives could be treated as short- to medium-term operational enhancements (1–3 years) within the existing fund's framework. Any support could incorporate lifecycle emissions accounting, align with emerging carbon capture, utilisation and storage (CCUS) policy settings and ensure fiscal discipline with milestone-based cost recovery.

**A thoughtful funding model and governance will ensure the most effective use of the $200 million funding**

Adjustments to the $200 million fund could include clear qualification criteria to ensure any funded projects are additional or target near-term, material outcomes. Funding could prioritise projects that meet the following principles:

- **Additionality** – projects that would not otherwise occur without government support, such as new development drilling or high $CO_2$ gas scrubbing; or
- **Acceleration** – projects that would proceed at least 12 months sooner as a result of support

For qualifying projects, two conditions need to be considered:

- **Materiality** – projects delivering at least 5 PJ per year of additional gas (5% of market supply)
- **Immediacy** – projects that will commence within six months of approval

Funding models could focus on addressing the downside risk where drilling outcomes are worse than expected as this is a key barrier to investment. There are several ways to do this. Funding models could range from equity co-investment to loans, designed to balance drilling risk and crowd in private capital. One option could be a loan structure with a first-loss feature, providing downside protection where drilling results in low-yields (e.g. below P25 outcomes) while allowing the Crown to share in upside returns (P75+ upside) through a ratcheted interest mechanism. This model offers greater leverage of public funds, aligns incentives and attracts low-cost debt financing from commercial banks.

There are several high $CO_2$ fields in various stages of development. Bringing this supply to market, could require investment in $CO_2$ scrubbing facilities which usually cost around $200 million per facility. Competitive allocation of funds could be ensured through a tender process, with bidders proposing project scope, funding type (concessional loans with first loss mechanism, concessional loans, equity co-investment, etc.), repayment terms and timelines. Governance could remain time-bound, milestone-based and transparent, with funding tranches linked to progress and performance.

The expansion of the 'Gas Security Fund' to include both development drilling and $CO_2$ scrubbing represents the most practical and immediate pathway to stabilise domestic gas supply. By focusing on the near-term, lower-risk opportunities within existing fields, New Zealand has the opportunity lift deliverability, reduce price volatility and provide industry with greater certainty throughout the transition period.

### 7.4.2 Develop gas storage for flexibility

**New Zealand's gas flexibility buffer is increasingly fragile**

Today, the energy system relies primarily on a single underground gas storage facility at Ahuroa and limited ad-hoc industrial swing capacity from users such as Methanex. With Ahuroa's effective working capacity reduced to around 6–8 PJ (down from historical levels near 18 PJ) and Methanex potentially exiting New Zealand, the country's overall ability to balance supply and demand is shrinking. New Zealand's gas storage only represents roughly 6% of annual demand, compared to around 17% in peer markets and 25% among global leaders.

Expanding storage capacity is critical to restoring resilience as domestic supply declines. Gas storage underpins the system's ability to cushion supply-demand imbalances, manage seasonal demand swings, respond to unplanned outages and build reserves to support electricity generation during dry or low-renewable periods. To deliver this flexibility, New Zealand's needs double the amount of working gas storage it has today. Increasing capacity to 14–17 PJ would provide coverage equivalent to 27–32% of total domestic consumption by 2030, based on the Managed Transition Forecast – a level consistent with high-performing international systems. Many of the leading international players (e.g. Germany, Italy, etc.) who rely on high levels of storage are also large importers of LNG, leveraging both for flexibility and security of supply.

**Storage development needs to be thoughtful in its approach and the commercial parties it involves**

A layered approach to storage development will be essential to ensure security of supply and market stability. Both underground storage (e.g. repurposing depleted onshore fields with suitable geology such as Tariki) and LNG storage at a potential import terminal are viable and complementary options.

If New Zealand pursues LNG imports and a full-scale LNG import facility, 4–5 PJ of storage, combined with strategic management of LNG shipments, may be enough to meet demand variability. However, additional underground gas storage would still offer significant benefits and may still be required alongside a full-scale LNG facility.

Underground storage, such as Tariki, would add value in several ways:

1. **Reduce reliance on LNG,** limiting the periods when LNG sets the marginal price and thereby helping to moderate overall gas prices
2. **Support upstream investment,** providing greater confidence in drilling activity and improving flexibility to manage supply-demand imbalances
3. **Help manage gas molecule distribution and ensure system resilience,** injecting gas at key points in the network to support effective distribution across New Zealand's gas system

If a small-scale LNG facility is pursued, this would likely offer only around 0.4 PJ of storage, which is insufficient on its own. Therefore, additional underground capacity would be required to provide the necessary depth, flexibility and deliverability if a small-scale LNG or no LNG option is pursued.

Gentailers would likely play some role in funding or contracting storage services, but development and operation could fall to a dedicated gas infrastructure partner – similar to how Flexgas currently operates Ahuroa under long-term capacity rights with Contact Energy. Financing and utilisation could be de-risked with transparent cost-recovery mechanisms, such as an energy storage levy or a structured tolling framework underpinned by a strategic energy reserve agreement. As outlined in Section 7.2.2, a number of options exist to develop new storage including the gentailers, or a subset of gentailers, committing to a Gas Strategic Reserve Agreement or the Electricity Authority investigating the introduction of a Winter Firm Fuel Product.

Replacing today's reliance on low levels of gas flexibility with more storage backed by structured and transparent flexibility products is essential. Building a layered flexibility stack of underground gas storage and appropriate LNG storage, will provide the reliability and resilience that New Zealand needs to navigate the domestic supply decline and maintain system stability through its energy transition.

### 7.4.3 Create LNG optionality

**As a security measure, New Zealand could enable LNG as an option with early, low-cost preparations in case it is needed**

New Zealand faces a narrowing window to secure its gas supply. With the priority being to stablise the rapid decline in domestic production, there are a number of levers government can pull including supporting further development drilling, providing incentives for demand switching and expanding gas storage.

However, if these levers prove insufficient or are not pursued with coordinated action from government, industry and asset owners, New Zealand may need to consider LNG as an insurance backstop against supply shortfalls and seasonal balancing:

- If additional gas is required only in dry-year conditions, more affordable alternatives may suffice (e.g. a combination of gas storage and liquid fuels).
- If shortfalls extend beyond dry-year variability, LNG may serve as a prudent backstop to ensure energy security and mitigate de-industrialisation.

Therefore, as it works to stabilise domestic gas supply-demand balance, government can also take low-regret actions to enable the option for LNG, dependent on three beliefs (see **Exhibit 139**).

Exhibit 139: Three beliefs for pursuing LNG

LNG can be delivered in sufficient quantity and before substantial industry exits

- Timing: Consenting and building is fast enough (operational by 2028) to provide gas before the market pinch drives demand destruction, if there is no demand transition support. If there is demand transition support, operational by 2030 is likely OK
- Scale: There is enough import capacity (at least 12 PJ across any 3 months) to close the supply gap in the gas market during a dry period; thus, need full-scale solution for capacity requirements
- Flex: Swing volumes can be delivered for electricity generation in a dry year via extra shipments or storage

LNG can be delivered at a price that is economically viable for customers and industry

- All-in cost (incl. amortised CAPEX): Customers (who don't already have contracts) can and will pay the fully delivered LNG price which may be inclusive of the CAPEX investment for the full-scale solution build
- Underwriting: A party is willing to guarantee pay for capacity and de-risk utilisation
- LNG market access: Cargoes can be sourced despite seasonal, irregular demand without significant premiums

The net economic benefits outweigh alternatives

- LNG versus domestic gas alternatives: LNG is more economic than alternatives in providing supply and fuel security for electricity generation in dry-years (e.g. condensate on supply-side, demand switching, etc.)
- Total market price impact: It is preferable if LNG lands near domestic prices; a premium would push gas prices to import parity during periods of import and lift costs for all gas users, who would have otherwise had lower prices
- Supply risk and security: GDP impact is safeguarded from demand destruction in the worst-case scenario (noting in a managed domestic gas scenario, demand destruction likely to be minimal)

LNG optionality has been evaluated against these beliefs to assess whether it can serve as an effective insurance policy for New Zealand's energy security if needed (see **Exhibit 140**).

### Exhibit 140: LNG beliefs assessment

| Must believe | Current understanding of the facts |
|---|---|
| Delivered in sufficient quantity before industry exits | ? **Timing:** Standard delivery of an LNG facility takes 4–5 years from business case to build; however, there are examples of LNG facilities (FSRUs) being brought online in <12 months<br>● **Scale:** A full-scale LNG terminal can provide the 12 PJ gas capacity minimum needed for underlying industrial users and electricity generation<br>● **Flex:** A full-scale solution allows for flex/capacity benefits (up to 48 PJ annual volume and 4–5 PJ storage); \$400m–800m for offshore terminal (lower CAPEX/faster option vs. onshore) while some international projects have skewed higher |
| Price that is economically viable | ● **All-in cost:** LNG marginal price comes to \$22–25/GJ when including \$4–5 per GJ for regas and carbon cost, based on spot; all-in LNG price is \$27–47 per GJ when considering O&M[1] (\$2–10 per GJ) and CAPEX[2] (\$3–12/GJ) distributed across 5–25 PJ of import volume; gentailers, residential and commercial customers are able to this pay rate, but industry varies<br>? **Underwriting:** Unclear – it is likely this would require government intervention and support<br>? **LNG market access:** Sporadic demand could result in modest premium |
| Economic benefits outweigh alternatives/do nothing | ● **LNG versus domestic gas and alternatives:** Other efforts (e.g. development drilling, demand conversion, liquid fuels for dry year, etc.) can offer lower cost and faster delivery to address the near-term crunch – but if the market is structurally short, there may be no other option<br>? **Total market price impact:** LNG countries have higher gas and electricity prices as the gas price for the whole market often converges to LNG price parity; if periods of time importing LNG can be minimised to only when needed this is better<br>● **Supply risk and security:** LNG could supply needed gas to industry in a worst-case supply scenario where demand destruction is a risk |

● LNG viable solution ● LNG suboptimal ? Uncertain/unknown

Note: All \$ figures in NZD
1. O&M assumes \$40-50m p.a.; 2. CAPEX assumes \$500m investment, 15-year payback and 8% WACC
Source: Clarus 2025 NZ LNG Import Feasibility Assessment; Platts JKM (Japan Korea Marker) Liquefied Natural Gas (LNG) benchmark; IEA 2025 JKM Spot Prices

Uncertainties relate primarily to the delivery timeline of an LNG facility. An LNG solution would be most valuable if it is operational before the projected 2028–2030 gas shortfall, which would require an expedited development pathway. Beyond timing, the commercial framework remains unclear, including underwriting arrangements, LNG market access and potential price impacts. These factors must be clarified to determine the most appropriate path for progressing LNG.

While LNG offers energy security benefits, it is likely to be suboptimal on a cost basis, particularly compared with domestic gas and other alternatives given current prices and delivery timelines. Therefore, LNG would be a security measure and a last resort if domestic options cannot meet demand to protect New Zealand from de-industrialisation and provide gas for electricity.

### If pursued, a full-scale LNG facility is the optimally sized solution for managing economic impact while providing needed flexibility and security of supply

For an LNG solution that can meet New Zealand's energy needs in both scale and flexibility, it's critical to determine the optimal terminal size, structure and delivery capability that would support dry-year risk and provide broader energy market security.

LNG options range from small to full-scale facilities, depending on available capital and timelines. A small-scale facility would be able to accommodate LNG shipments of up to 0.4 PJ via a bespoke and dedicated vessel, while a full-scale facility could accept 4–5 PJ shipments via standard sized vessels (of which there are 800 globally). For New Zealand, a full-scale LNG terminal would be the preferred option, as it can deliver the 12 PJ of supply over a 3 month period the government has targeted via a 2025 procurement process, while also scaling up to enhance overall energy security when needed.[128]

A full-scale facility would enable year-round flexibility, with access to roughly 90% of global LNG carriers – a key advantage for a small market entrant like New Zealand seeking reliable supply access. Because there is depth in the 4 PJ market, it enables access to hedging and risk management products (e.g. options to buy) which reduce the need for deliveries, preserving the market signal for domestic drilling and reducing the proportion of time the gas market is at LNG price parity.

By contrast, a small-scale facility would be cheaper to build and operate but would have limitations in market access, capacity and operational flexibility. It would be worth the additional capital investment to pursue a full-scale LNG facility capable of meeting all potential use cases. **Exhibit 141** shows a comparison of full-scale and small-scale solutions.

### Exhibit 141: LNG import facilities: full-scale (standard) versus small-scale (bespoke)

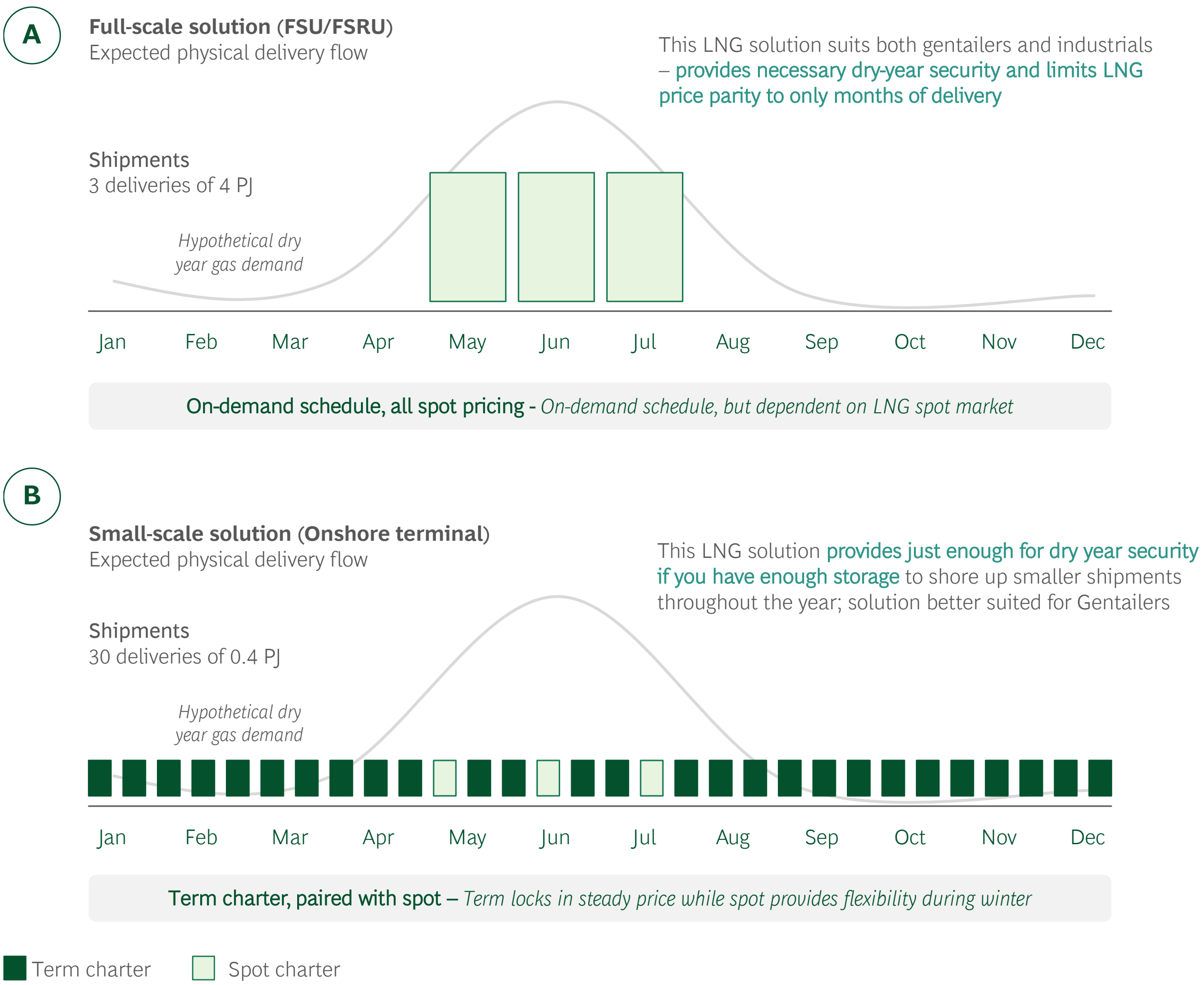
| | A Full-scale LNG solution (standard) | B Small-scale LNG solution (bespoke) |
|---|---|---|
| Description | Full-scale LNG import facility. Configuration options: Offshore (FSRU or FSU + onshore regasification) vs. conventional onshore terminal. Robust large carriers require less shipments, all-weather delivery capability | Small-scale LNG import terminal at Port Taranaki. Configuration options: Standard (with storage) vs. minimum storage (leveraging Ahuroa). Delivery constrained by small-ship availability & weather risks |
| CAPEX | \$400–800m for offshore[1] \| \$500m–1b+ for onshore | \$300m for standard \| \$150m[2] for minimum |
| OPEX | \$30–75m p.a.[4] | \$3–6m p.a.[4] |
| Shipment size | 4–5 PJ / 150–188k m³ | Up to 0.4 PJ / 15k m³ |
| Available carrier fleet | 800 of 900[5] (90%)<br>*LNG carriers which can deliver 4–5 PJ shipments* | 50 of 900[5] (5%)<br>*LNG carriers which can deliver up to 0.4 PJ shipments* |
| Annual delivery capability | Up to 48 PJ<br>*Actual market need is 12PJ in 3 months* | 9 PJ for standard[3] \| 7 PJ for minimum[3] |
| Storage | 4–5 PJ<br>*Full-scale LNG storage is enough to manage shipment volumes* | 0.4 PJ for standard \| 0.08 PJ for minimum<br>*Not enough storage to shore up LNG; requires more storage* |
| Commissioning timeframe | 1–5 years<br>*Most solutions take 3–4 years as reduced timeline dependent on facility type (e.g. leasing existing FSRU) and govt. fast tracking* | 1–5 years<br>*An expedited timeline dependent on govt. fast tacking* |

Note: All \$ figures in NZ
1. For full-scale LNG solution the offshore option is lower CAPEX but greater OPEX vs. onshore option; 2. Does not include cost of incorporation with the Ahuroa gas storage (AGS) facility as part of the LNG terminal; 3. 15,000 m³ LNG would come very 13-16 days; 4. Accounts for fixed operations and maintenance costs (O&M) and energy cost; 5. Total existing and orderbook of worldwide LNG fleet (excl. FSRUs, FSUs, and FLNG, no assumption for scrapping, or LNGC conversion to FSRUs)
Source: Clarus 2025 NZ LNG Import Feasibility Assessment and Addendum on Small-Scale LNG, ICU/Enerlytica LNG Fleet Analysis, Clarksons, Drewry

128 New Zealand GETS, LNG Import Facility Services, 2025

LNG delivery profiles vary by facility size and align with different objectives. A full-scale facility would provide dry-year security while limiting the months in which LNG sets market prices for the actual delivery period. This avoids a small-scale ‘drip-feed’ model, where cargoes of roughly $25 per GJ arrive every couple of weeks, prolonging LNG price parity and discouraging domestic drilling. To deliver the government’s targeted 12 PJ supply, the small-scale facility would need to do 30 shipments throughout the year if working with a small cargo ship of 0.4 PJ capacity, compared to three shipments of 4 PJ with a full-scale solution (see **Exhibit 142**).

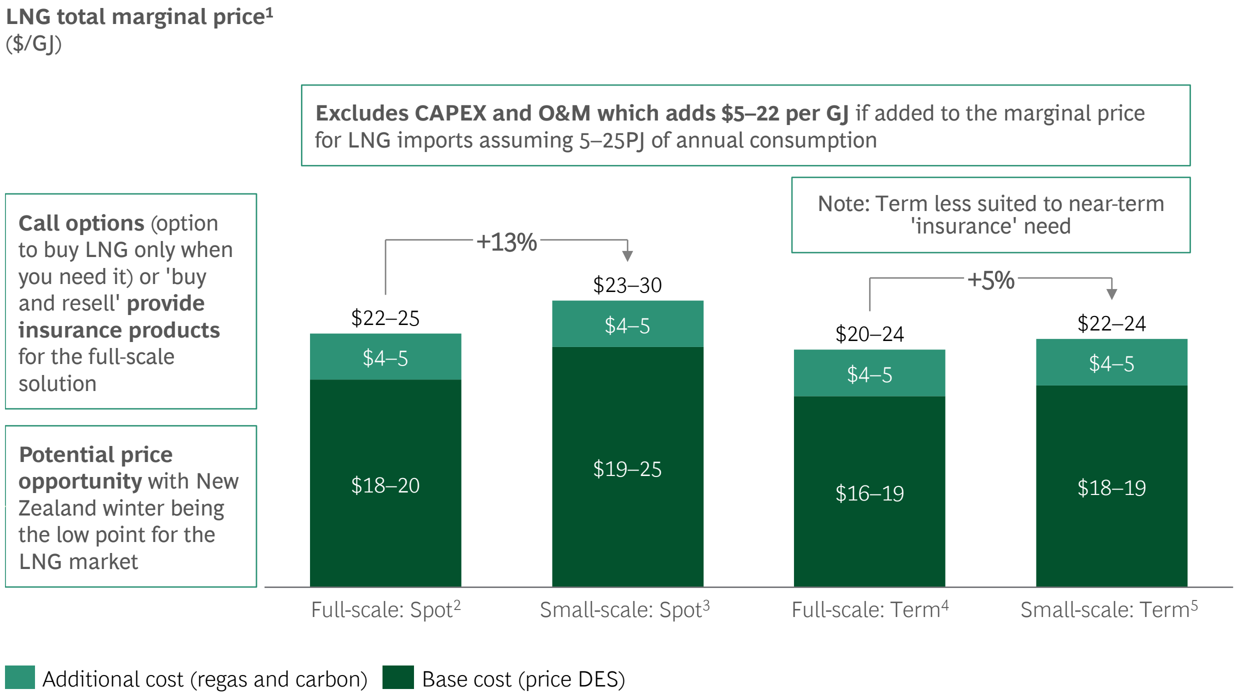
Exhibit 142: LNG delivery schedule: full-scale versus small-scale



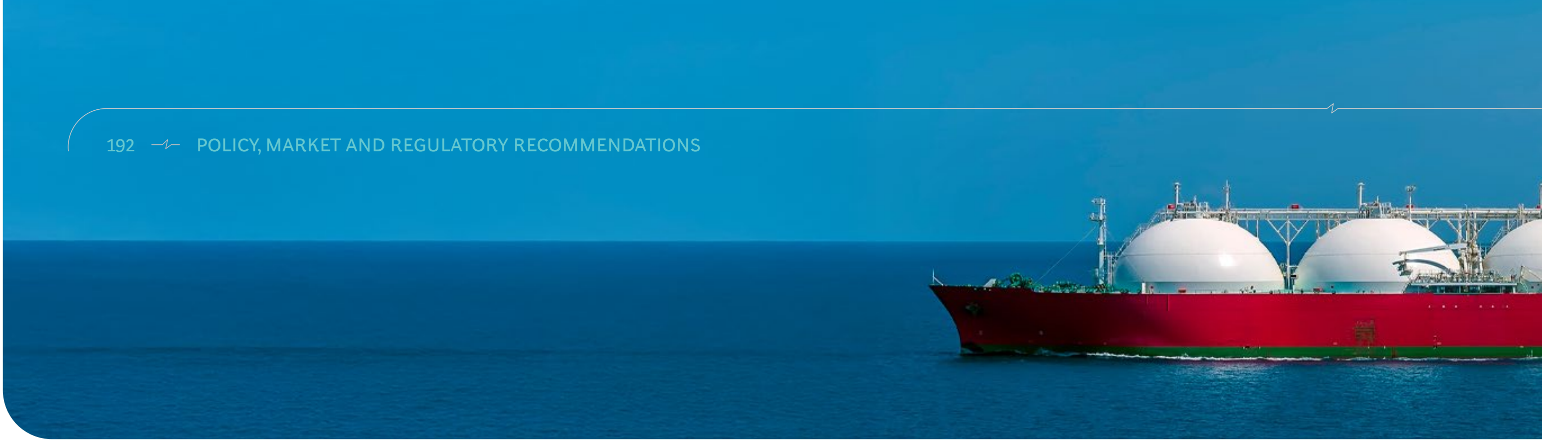

Source: Clarus 2025 NZ LNG Import Feasibility Assessment and Addendum on Small-Scale LNG

Given New Zealand will likely have intermittent LNG demand in the first few years of operation, the country would unlikely be a term buyer. As a result, New Zealand would likely purchase spot or short-term products versus a term contract. Small-scale LNG typically costs around 13% more than full-scale, making the latter more economical overall for New Zealand's demand type (see **Exhibit 143**). Over the longer term (2030+) if a large structural year-round shortfall in domestic supply materialises, LNG contracting could move more towards a term buyer arrangement.

Exhibit 143: LNG total marginal price: full-scale versus small-scale




1. Regas variable and carbon cost added to price to get LNG total marginal cost; 2. Average JKM spot price DES (price delivered ex-ship) over last 6 months; 3. Assumes shipping cost premium for small-scale LNG facility of US $1–2 MMBtu; 4. Indexed to Brent oil price average last 12 months (US $72/bbl), long term contracts 12–14% slope to Brent; 5. Based on Clarus 2025 NZ LNG Small-Scale LNG assessment for annual 9 PJ delivery to Port Taranaki at USD$11.41/MMBtu to US $11.92/MMBtu
Source: Clarus 2025 NZ LNG Import Feasibility Assessment and Addendum on Small-Scale LNG, S&P Global, Platts JKM (Japan Korea Marker) Liquefied Natural Gas (LNG) benchmark, Japan Exchange Group (JPX), IEA 2025 JKM Spot Prices, FTI Consulting LNG Freight Rate Estimates 2023



To further manage cost and delivery risk, market participants could purchase call options (rights to buy LNG only when needed) and re-sell unneeded cargo where feasible. This approach ensures LNG is only delivered as needed while minimising risk management costs. Such 'buy and resell' mechanisms enhance overall market flexibility. Moreover, New Zealand's winter demand period, which typically aligns with a seasonal low in global LNG prices, presents a potential pricing advantage that could be leveraged under a full-scale solution.

In summary, if an LNG import terminal is pursued the preferred solution would be a full-scale facility based on these five points:

1. **One-off investment:** Delivers a durable, future-proof solution – no need for repeated upgrades or piecemeal expansions
2. **Access to deep markets:** Connects New Zealand to liquid global LNG hubs, enabling flexible sourcing and stronger risk management
3. **Lower operational risk:** Avoids reliance on a single vessel or supplier, reducing exposure to disruption
4. **Stronger security of supply:** Provides capacity and redundancy to withstand global or domestic supply shocks
5. **Superior economics and price control:** A full-scale terminal supports dry-year security while limiting the period LNG sets domestic prices. It avoids having small, frequent cargoes (at $25 per GJ) that prolong high prices and deter domestic drilling

**If LNG is pursued, the priority is to preserve affordability for consumers**

LNG should serve as an insurance mechanism for supply security, used only when required to manage domestic gas shortages. Importing LNG only when needed limits the periods of price convergence with international LNG price benchmarks, helping to maintain affordability for consumers.

During import periods, the marginal cost of LNG should reflect only the JKM spot price, with the variable regasification and carbon cost added. Capital and fixed costs should not be embedded in the marginal fuel price; including these additional costs would make LNG uneconomical.

Given LNG demand would likely start low in the early years, recovering the capital and fixed costs across a few units of use would have two consequences:

- The high cost of LNG would be prohibitive, reducing its viability as an insurance option.
- If LNG were still needed at these very high prices, the additional cost would flow through to the marginal fuel price, significantly increasing gas and electricity costs.

For illustration, if LNG was introduced in 2028 at 12 PJ per year (three 4 PJ shipments for dry-year security), the cost passed to electricity users could reach approximately $1.4 billion per year. This assumes 97% renewable generation by 2028, with gas setting prices for around 37% of total generation hours.

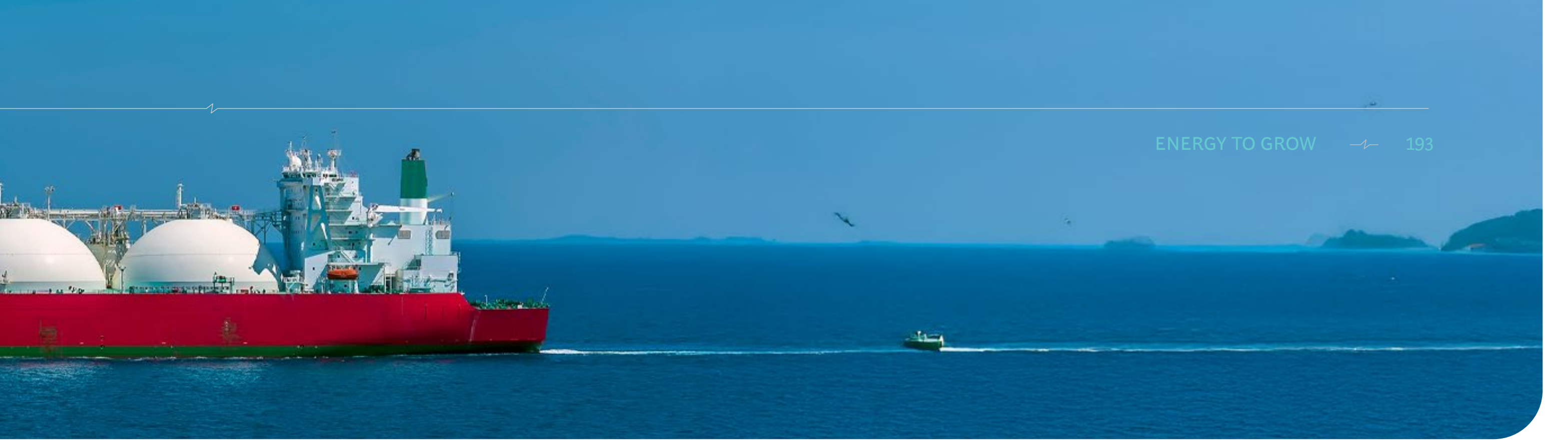
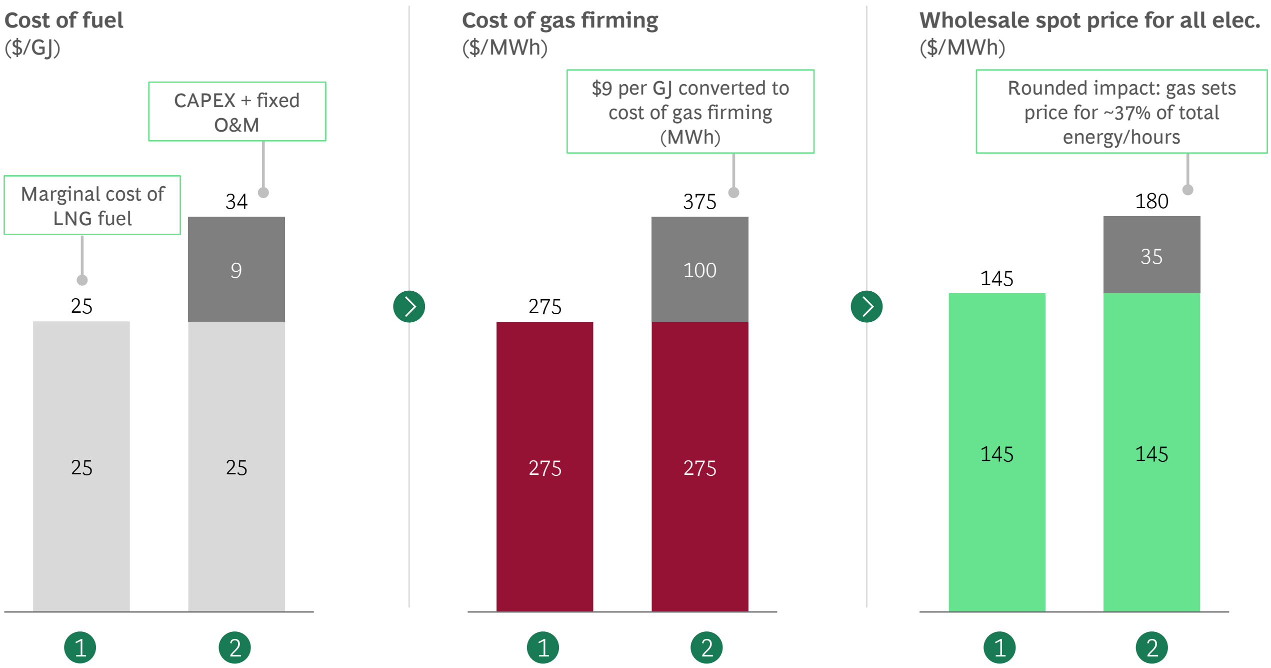


**Exhibit 144** demonstrates how recovering LNG fixed costs via fuel compounds these effects, reinforcing the consequences outlined above. Case 1 outlines the cost before LNG fixed costs are recovered via fuel, whereas Case 2 outlines the cost impact.

At a marginal cost of $25 per GJ, full-scale LNG imports would also need to recover capital and fixed costs, estimated at $110 million per year (based on $500 million CAPEX, $40 million annual OPEX, 15-year recovery, 8% WACC). Spreading this cost across just 12 PJ of annual LNG imports equates to an additional $9 per GJ, which would lift gas firming costs by $100 per MWh and wholesale electricity prices by $35 per MWh across all units of electricity. With estimated annual electricity demand of 40 TWh in 2028, this results in a total system-wide cost increase of $1.4 billion per year for electricity customers.

Exhibit 144: Cost impact from LNG fixed cost recovery via fuel




LNG fixed cost recovery via fuel

$35 per MWh

*Approximate impact to wholesale spot price for all electricity from recovering LNG fixed cost (CAPEX + fixed O&M) via fuel*

×

40 TWh

*Approximate annual electricity demand at time of LNG imports*

=

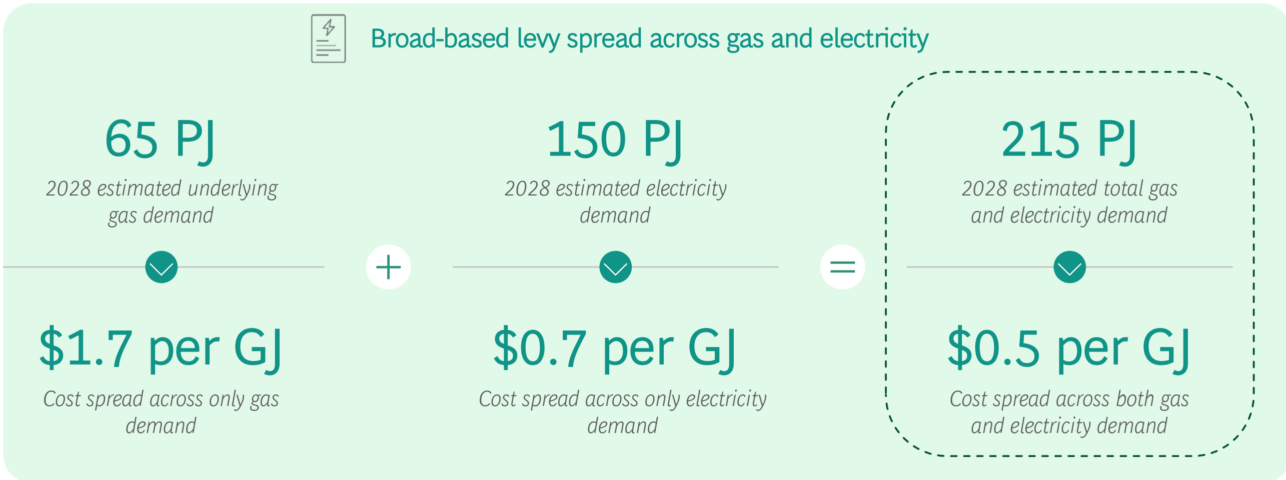
$1.4 billion

*Annual cost to electricity customers from recovering LNG fixed cost (CAPEX + fixed O&M) via fuel*

While these static calculations in **Exhibit 144** assume all else is equal, in practice, higher prices would accelerate renewable investment, eventually easing price pressure, but only after these additional renewables have been built.

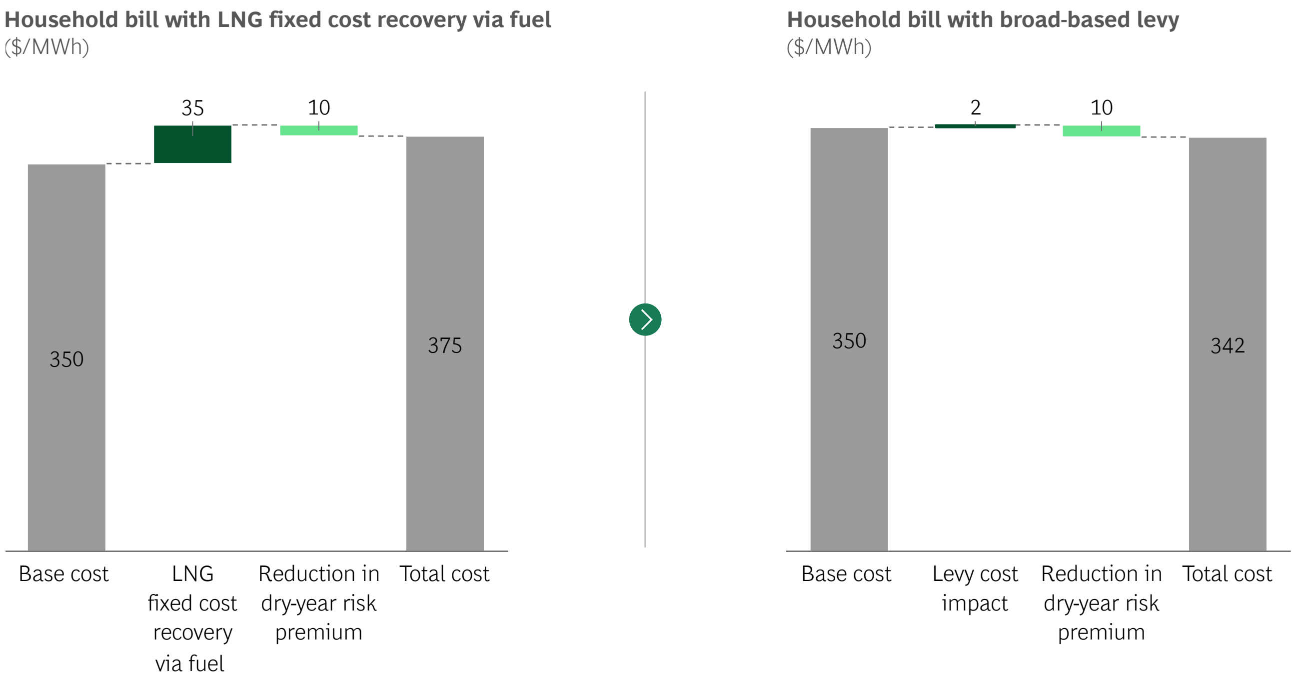
To avoid recovering LNG fixed costs via fuel, a broad-based levy could be used to recover these fixed costs across total gas and electricity demand rather than solely from LNG imports. In 2028, combined gas and electricity demand is expected to be 215 PJ. Allocating the $110 million annualised cost across this large base equates to roughly $0.5 per GJ – a fraction of the $9 per GJ cost with LNG fixed cost recovery via fuel (see **Exhibit145**).

Exhibit 145: Cost impact of a broad-based levy



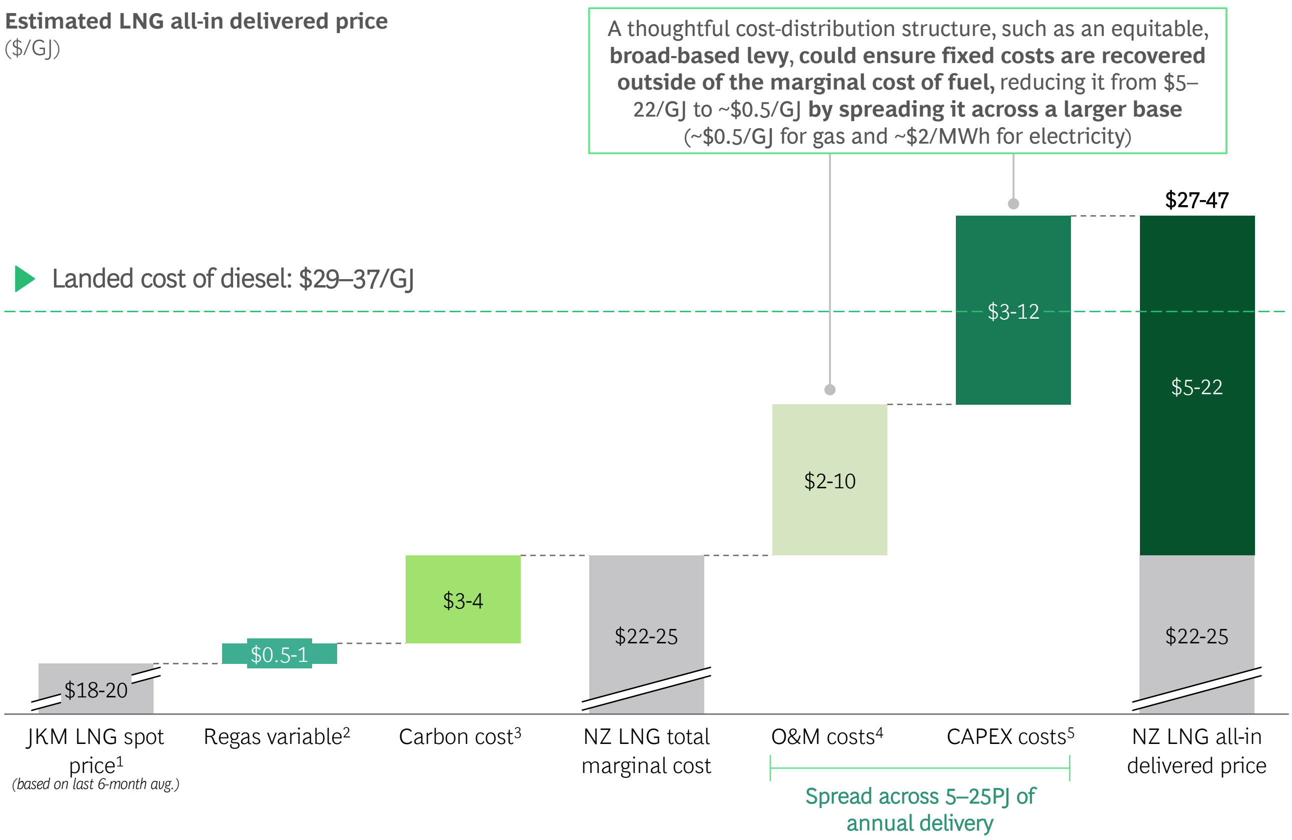

This approach limits the price uplift to about $2 per MWh for electricity, $33 per MWh lower than recovering LNG fixed costs via fuel (see **Exhibit 146**).

Exhibit 146: Illustrative cost impact to household bills



This approach keeps the marginal fuel price economically viable at $22–25 per GJ, with a broad-based levy adding only $0.5 per GJ, compared with $27–47 per GJ under LNG fixed cost recovery via fuel, depending on the annual LNG import volume (see **Exhibit 147**).

## Exhibit 147: Estimated LNG all-in delivered price




Note: All $ figures in NZ; JKM spot price delivered ex-ship (DES) – shipping/freight to the named port included in DES price; nominal transmission variable assumed
1. Average JKM spot price over last 6 months; 2. Regasification fees typically range between $0.5 and $1.0/GJ based on international LNG projects; 3. Carbon cost based on NZUs $60–80 per unit and natural gas emissions factor; 4. O&M assumes $40–50m p.a. across annual LNG import volume of 5–25 PJ; 5. CAPEX assumes $500m investment, 15-year payback, 8% WACC and amortisation across annual LNG import volume of 5–25 PJ
Source: Platts JKM (Japan Korea Marker) Liquefied Natural Gas (LNG) benchmark, IEA 2025 JKM Spot Prices, Japan Exchange Group (JPX), Palgrave Economics of Gas Transportation by Pipeline and LNG, Firstgas Transmission Fees, emsTradepoint Carbon Cost Estimates, 2025 Gas Strategies Group Ltd – NZ LNG Import Feasibility Assessment

When considering fuel alternatives, the all-in delivered cost of LNG ($27–47 per GJ) is likely higher on average than the landed cost of diesel ($29–37 per GJ, including carbon). As a result, importing LNG is then not economically justified when LNG fixed costs are recovered via fuel, knowing diesel would be cheaper and entails lower capital and infrastructure risk.

**Maintaining a single gas price hub would maximise price signal efficiency and market transparency**

New Zealand should avoid splitting domestic gas and LNG access by user group; instead, all users should face a unified market price when LNG imports set the marginal cost.

In liberalised gas markets, countries recover LNG costs in different ways, but a common outcome remains: prices converge when LNG becomes the marginal supply.

Exhibit 148: LNG approach comparison by country

| | UK | Germany | Spain | Netherlands | Italy | Lithuania |
|---|---|---|---|---|---|---|
| LNG activity | 3 LNG terminals; importing since 2005/2009 for security of supply | First FSRU 2022; total 4 operating LNG terminals; built for rapid crisis response and supply diversification | Large multi-terminal system; high regas flexibility (mature import system) | 2 FSRUs live since 2022/2011 and continually importing LNG; built for security of supply | 3 FSRUs since 2025/2023/2013; needed for security and diversification of supply | FSRU operating since 2014 for supply security |
| Pricing and LNG impact | NBP pricing hub; LNG raises hub prices only while it is the marginal supply | THE pricing hub; '22-'23 spikes were crisis-driven and not a permanent uplift once supply expanded and demand fell | MIBGAS (PVB) hub; LNG tightness lifts prices when marginal; effects recede as LNG supply loosens | TTF hub; retail prices were temporarily capped in 2023; normalisation of price post 2022 peaks | PSV hub; LNG spikes lift prices while marginal but not a structural uplift | Regular trading via GET Baltic; prices reflect hub conditions and LNG does not permanently elevate prices |
| LNG cost distribution | Treasury-funded household bill support; no permanent consumer levy; hub pricing kept | Temporary, federally-funded price caps for gas and electricity | Cap on gas-for-power; cost recovered on electric bills (temporary) | Government-financed 2023 retail price cap for households using gas and power (temporary) | Temporary VAT cut and removal of system charges on gas (time-limited) | Security-of-supply levy across gas users to cover fixed FSRU costs |
| Learnings | Wholesale pricing hub-based kept; fiscal shields only used in shock periods vs. permanent levy | FSRUs can be deployed quickly for security; any retail shielding should be temporary and centrally funded | If LNG is mainly a power-sector backstop, recovery can sit with electricity users, not gas users | Transparent hub index maintained and any household price caps kept temporary | If affordability is a concern, prefer budget-funded, time-limited tax/charge relief over permanent levies | A transparent gas-user levy can underwrite fixed FSU/FSRU costs while leaving wholesale pricing to the hub |

Note: All countries listed have hub-based, liberalised gas pricing
Source: National Grid, National Gas, GOV UK, Federal Ministry of Economic Affairs, Eurofound, Mibgas, Enerdata, EemsEnergy Terminal, Snam, ARERA, KN Energies, European Commission, GET Baltic, BMMWK, National Grid, Enagas, Rijksoverheid

### Developing the business case for LNG can help government assess LNG against viable domestic levers

Given LNG imports may serve as a prudent backstop if domestic supply and demand levers prove insufficient, government could continue developing the business case for LNG and compare it against viable domestic alternatives, selecting the preferred solution based on need, cost and timing.

Following the current procurement period led by MBIE, the Cabinet is expected to decide by year-end on next steps for LNG development.[129] At that decision point, government could initiate Phase 1 preparations over the subsequent 6–12 months. This would involve:

1. Concept and integration design, including commercial model development
2. Consenting activities
3. Pre Front-End Engineering Design (Pre-FEED) and FEED readiness

As the government proceeds with Phase 1, several strategic considerations can help it ensure LNG is delivered efficiently, affordably and without undermining upstream investment incentives (see **Exhibit 149**).

Exhibit 149: Key considerations if New Zealand decides to move forward with LNG

**Define optimal LNG solution** 01

- What facility size and storage mix best fits NZ – both in terms of need and energy pricing impact?
- Who should own/operate the LNG facility and under what model (government entity or private sector)?

**Manage LNG implications on domestic gas market** 02

- How can NZ structure a liberalised market that only achieves full price parity when LNG imports are required?
- How can we ensure the right environment for a 'domestic first' gas approach (e.g. continued drilling)?

**Design cost/tolling structure for economic affordability** 03

- Who should pay for this and how (written off as taxpayer expense, amortised as levy across gas and elec. markets, passed through transmission charges to gas users, etc.)?
- How to best structure amortisation/levies to minimise whole of energy system impact? (i.e. balancing gas and electricity price implications for users, noting 11x magnification at 95% renewables through to the electricity market if the levy is on marginal fuel cost)

**Identify LNG buy-side mechanisms** 04

- To what extent can call options be used as insurance, allowing New Zealand to secure LNG only when required and thereby limiting greater levels of price-parity exposure?
- What capacity is needed to support on-demand options?
- What storage strategies help manage shipments?

129 Beehive, Securing New Zealand's Energy Future, 2025

Phase 1 could require approximately 5–7% of total project costs ($25–35 million) based on a total CAPEX of around $500 million, and represents a 'no-regrets' investment to maintain LNG optionality. The 6–12-month timeline assumes these steps can be expedited to ensure potential operational readiness by winter 2028, should domestic gas measures not deliver sufficient outcomes.

At the end of Phase 1, a formal checkpoint could assess whether domestic gas levers, development drilling, demand switching and storage build, have achieved desired outcomes. If not, New Zealand could advance to Phase 2, proceeding to a Final Investment Decision (FID) and commencing LNG facility construction.

Through this dual-track approach (testing lower-cost, faster domestic levers while retaining LNG as an insurance option) New Zealand can safeguard energy security, knowing it is highly preferable for New Zealand to have a well-functioning domestic gas market, rather than one that relies extensively on LNG.

### 7.4.4 Enable drop-in alternatives for peaking

**Drop-in alternatives for gas peaking can help New Zealand manage system reliability and dry-year risks**

Where feasible, some of New Zealand's existing gas peakers could be retrofitted for dual-fuel capability to generate electricity using condensate or diesel. Condensate is priced at slightly more than $25 per GJ and offers a comparable substitute to LNG ($25 per GJ) for use in electricity with lower upfront costs (requiring a small investment in fuel treatment versus LNG's facility build). However currently there are no power plants in the country that are retrofitted to use it. Diesel, which is pre-treated, is more expensive than condensate at >$30 per GJ but can be more easily accessed and used immediately in current facilities for generation.

Where retrofitting existing peakers for condensate is not viable, new fast-start, high-efficiency dual-fuel peaking capacity (i.e. able to switch from gas to condensate) could be considered in the longer term, particularly when current older units retire to balance intermittent renewable supply and mitigate supply risk during dry years.

**Fuel diversity can protect New Zealand from global energy shocks**

Even if the government decides to pursue a full-scale LNG facility, maintaining small volumes of alternative fuels could help limit the electricity market's exposure to global LNG price shocks. Conversely, if a small-scale LNG facility is pursued, LNG is delayed beyond 2028 or not pursued at all, New Zealand may need to deploy these alternative fuels at a larger scale.

**Market mechanisms help strengthen demand response and incentivise investment**

Additional fuel and capacity could be supported through measures outlined in sections 7.2.1 and 7.2.2. In the near term, asset owners could investigate retrofitting selected units for dual-fuel capability to strengthen operational flexibility. Over the longer term (beyond 2030), asset owners could consider targeted investment in incremental dual-fuel peakers and new peaking plants as demand grows and older units are retired. Together, these actions could enhance New Zealand's firming resilience and reduce electricity pricing risks from LNG imports.

### 7.4.5 Help establish biomass supply chains

**To unlock biomass as an alternative fuel, New Zealand needs a robust supply chain**

The government, through the Energy Efficiency and Conservation Authority (EECA), could help establish a robust and coordinated biomass supply chain to unlock the potential of biomass as a scalable alternative to gas for process heat. Biomass helps New Zealand reduce energy emissions and provides an economically valuable alternative to gas.

To help establish the supply chain, EECA could continue to take action to stimulate demand, reduce supply risk and build confidence among industrial users considering fuel switching. Without targeted support, the biomass market could remain nascent, constrained by limited processing capacity, underdeveloped logistics and fragmented contracting structures.

There are encouraging signs of large-scale fuel switching to biomass in practice, such as Fonterra's conversion of coal boilers to wood pellets at its Clandeboye facility, and its conversion of its 43 MW Te Awamutu boiler from coal to locally sourced wood pellets in 2020 with EECA support.[130],[131] It is also electrifying process heat (i.e. an electrode boiler at Edendale) and has plans to exit coal by 2037.[132] Despite this progress there are still bottlenecks in the current biomass supply chain.

There are willing buyers and sellers of biomass, but both sides face uncertainty: suppliers are hesitant to invest in pelletisation without guaranteed demand, while users are reluctant to commit without reliable supply. This dual challenge prevents the biomass market from reaching meaningful scale.

### Importing biomass in the near-term can help build confidence and scale

A pragmatic way to overcome these early challenges is to import biomass in the near term, to signal demand while local infrastructure matures. Fonterra has demonstrated the success of this approach by importing pellets from Vietnam to initiate fuel switching at one of its plants which is sending a strong investment signal for South Island pelletisation capacity.[133]

Importing offers a way to secure immediate supply and de-risk investment while domestic producers can scale up sustainably. Imported white pellets from Vietnam are priced at US $140–150 per tonne free on board (FOB) based on Japan imports.[134,135] This translates to an FOB cost of NZ $14–15 per GJ before adding freight and insurance costs. Compared domestically, white pellets would cost NZ $15–25 per GJ.[136] Torrefied or black pellets, which can displace solid fuels, are less common globally but can also be sourced from Vietnam, typically at a higher price.[137,138] Torrefied pellets typically cost in the range of NZ $18–30 per GJ domestically, accounting for the additional torrefaction cost.

Depending on the application, different pellet types offer flexibility to substitute multiple fuels. In New Zealand, Genesis Energy has partnered with Foresta to supply torrefied wood pellets for Huntly Power Station and pursued agreements with Carbona to produce torrefied wood pellets.[139,140] Torrefied wood pellets can help displace coal use at Huntly while also offering fuel diversity and risk mitigation if international coal prices were to exceed biomass prices. However, local production costs remain sensitive to residue pricing, plant scale and inland transport.

EECA can provide information on import options for potential converters to biomass, building confidence for early adopters while domestic processing and logistics mature. Over time, as domestic capacity strengthens, New Zealand can wind down imports in favour of local resources.

### Industry and suppliers need a clear long-term commitment to develop a strong, local supply chain

A strong, domestic supply chain requires investment in pelletisation facilities, commercial partnerships with foresters and landowners, and infrastructure upgrades to streamline transport storage and distribution.

EECA has recently issued an RFP for $3 million of co-funding to support wood energy aggregation facilities, and has previously confirmed a $6 million grant programme for new wood energy supply manufacturing

130 Fonterra, Clandeboye's $64 Million Renewable Energy Conversion On Track, 2025

131 EECA, Fonterra Coal Boiler Conversion, 2020

132 Fonterra, Fonterra's Decarbonisation Journey, 2025

133 RNZ, Bioenergy Sector Hopeful Green Energy Demand Will Fire Up Wood-to-Power Supply Chain, 2025

134 Forest Trends, Vietnam Exports Wood Pellets in Q1 2024, 2024

135 Te Uru Rākau New Zealand Forest Service, Woody Biomass Literature Review, 2023

136 Bioenergy Association, Pricing of Different Biomass Fuels, 2021

137 IRENA, Solid Biomass Supply for Heat and Power Technology Brief, 2019

138 IDEMITSU, World's Largest Scale Black Pellet Plant Starts Commercial Operation, 2025

139 Genesis, Genesis and Foresta in Biomass Supply Negotiation, 2025

140 Beehive, Boosting Energy Security – Wood Pellets Set to Cut Coal Dependence, 2025

facilities, which is a strong start.[141,142] To further grow market scale and liquidity, EECA could facilitate offtake agreements, pooled procurement mechanisms and clear contracting frameworks that give both suppliers and users visibility and confidence. These measures would help establish transparent, comparable pricing, making it easier for energy users to evaluate wood energy alongside other fuel alternatives.

Together, these measures would enable a self-sustaining domestic biomass market, strengthening New Zealand's energy security and delivering a renewable replacement for process heat and solid fuels.

### 7.4.6 Accelerate energy audits to consider alternatives for gas for commercial and industrial users

**Energy audits will expedite the transition from gas to viable fuel alternatives**

Comprehensive, independent energy audits can provide gas consumers with a critical evidence base for investment decisions, reduce uncertainty and stimulate stronger, faster demand for fuel-switching as industries transition away from gas. EECA could expand its co-funding support for energy audits to accelerate audits for large or industrial gas consumers (consuming more than 0.5 PJ per year).[143]

Each audit could evaluate the technical and economic feasibility of multiple alternatives, including LNG backup, diesel, biomass and electrification options that are tailored to each site's specific demand profile and operating requirements. Outputs could include transparent benchmarking of costs, emissions and an overview of energy security trade-offs, enabling industrial users to make well-informed, forward-looking investment choices.

By accelerating these audits, EECA can create better information, lower stranded-asset risk and enable an orderly, coordinated transition away from gas, supporting industrial competitiveness and long-term energy security.

## 7.5 Recommendations to enable gas users to transition

As domestic gas supply continues to decline, a coordinated demand-side response is essential to maintain gas affordability, preserve industrial competitiveness and restore the supply-demand balance in the gas market. Targeted support can reduce gas dependency where viable, empower consumers to make informed choices and improve market transparency to support better investment and contracting decisions.

Demand-side recommendations include: (1) Introduce an Industry Resilience fund for lowest cost fuel switching to biomass and electricity; (2) Enhance sector disclosures; and (3) Run a public information programme to bring consumers on the journey.

### 7.5.1 Introduce an Industry Resilience fund for lowest cost fuel switching to biomass and electricity

**A $100–200 million fund would help resolve the gas supply-demand imbalance, ensure more affordable domestic gas and reduce exposure to LNG prices**

To safeguard industrial competitiveness and restore the supply demand balance in the gas market, a $100–200 million Industry Resilience fund, established by government and administered by EECA, could provide co-investment or interest-free loans for capital projects that convert gas-fired industrial processes to alternatives.

The fund could operate in tranches, with annual releases of funding to manage fiscal exposure and maintain flexibility as supply conditions evolve. Allocation could be determined via a competitive reverse auction, ensuring support is directed at the lowest-cost on a $ per GJ basis, ready-to-convert projects with milestone-based payouts tied to verified conversion performance. As the purpose of the fund is to restore the supply-demand balance in gas, the mechanism could be scalable, allowing government to reduce or close the fund if new drilling materially stabilises the gas supply decline.

141 Beehive, Accelerating Bioenergy in New Zealand, 2025

142 EECA, Request for Application, 2025

143 EECA, Energy Audits, 2025

This fund is critical if LNG import capacity remains small-scale, is only delivered after 2028 or not pursued. Even if full-scale LNG is pursued, this fund would still be valuable as it would lead to more affordable domestic gas and reduce reliance on LNG to decrease the periods of time throughout the year that the gas price converges to LNG import parity for all users.

**The fund would minimise the risk of demand destruction by jumpstarting conversions**

An Industry Resilience fund would enable consumers with viable alternatives to gas to transition, while allowing those without alternatives to continue operating with gas. By supporting early movers in technically convertible sectors, the fund would help mitigate the forecast demand supply shortfall in 2028–2030, preserving high-value production, protecting jobs and easing price pressure for remaining gas users. Without targeted support, many conversion projects would remain uneconomic or delayed due to high upfront capital costs and limited financing access.

10 PJ of demand destruction in industry (after a potential Methanex and Ballance exit) could lead to $7.3 billion p.a. of GDP loss which is nearly 2% of GDP. The estimated industry transition funding from government required to shift 10 PJ of gas over to electricity or biomass is a one-off payment of between $100 and $200 million to co-fund a portion of the capital conversion.

Given that domestic gas remains more cost-effective than LNG, all levers (supply, demand and storage) will need to be activated to restore balance in the domestic market, even if LNG development proceeds. Introducing an Industry Resilience fund would complement LNG initiatives by accelerating industrial fuel switching, stabilising the gas market and ensuring both affordability and energy security through the 2030s.

### 7.5.2 Enhance sector disclosures

**Sharing more detailed gas market information will improve transparency and empower participants to make informed decisions**

Improving transparency in the gas market is critical for timely, well-informed investment and contracting decisions by all stakeholders, particularly industrial users. Reporting is currently fragmented and limited, and in addition gas market uncertainty has increased electricity price levels and volatility, underscoring the need for better collection and publication of gas market information.

Greater visibility of supply, reserves and outages would bring the gas sector in line with electricity market transparency standards (e.g. publicly available data on hydro storage levels and generation plant outages). Publishing information on contract volumes and strike prices would also strengthen market confidence. With upstream production becoming more concentrated and only a few large gas retailers in the market, accessible and reliable data are critical to ensure fair pricing, good competition and efficient investment across the energy system.

MBIE could lead and fund the development of a national Gas Transparency Dashboard, in partnership with the Gas Industry Company (GIC), to oversee data collection and standardisation. The dashboard would be the single source of truth for New Zealand's gas market data, consolidating field-level information and forward outlooks in a clear, accessible format. The dashboard could be integrated within existing tools (e.g. EMI website or WITS) or be a standalone, separate dashboard.

Table 9: Potential dashboard features

| KPI | Unit and granularity | Time period | Refresh frequency | Proposed variations/ranges |
|---|---|---|---|---|
| Production forecasts | TJ/day by field | Daily for next 10 years | Quarterly | Base vs. low vs. high |
| Production actuals | TJ/day by field | Daily for last 10 years | Quarterly | NA |
| Reserve outlooks | PJ/year by field | Annually for next 10 years | Quarterly | Base vs. low vs. high |
| Planned outage calendar with expected deliverability impacts | TJ/day by field, TJ/day by processing facility | Daily for next 12 months | Quarterly | NA |
| Unplanned outages with delivery impacts | TJ/day by field, TJ/day by processing facility | Daily for last 12 months | Quarterly | NA |
| Contracted share of output (contract volumes) | PJ/month, aggregate/not counterparty-specific | Monthly for the next 5 years | Quarterly | NA |
| Contract and pricing information | Strike prices, indices and terms anonymised per contract | Monthly for the next 5 years | Quarterly | NA |

Quarterly forward supply projections could be submitted by participants (producers, major buyers, pipeline or storage operators) aligned to MBIE and GIC templates to provide participants with relevant information. Independent auditing would confirm the accuracy, credibility and timeliness of published data. In addition to a centralised performance dashboard, MBIE could use the collected information to publish frequent reports on the gas market, covering performance both on the supply and demand side.

**Frequent, high-quality reporting will support New Zealand's energy transition**

More comprehensive reporting would align New Zealand with best practice in other markets by improving information transparency. It would empower industrial users to make informed hedging and fuel switching decisions, while giving government and regulators greater visibility to manage security-of-supply risks. Establishing a trusted, centralised gas data dashboard with frequent complementary reports on the gas market performance would also boost market confidence, reduce risk premiums and enable all participants to plan with greater certainty through the transition period.

### 7.5.3 Run a public information programme to bring consumers on the journey

**Increasing public awareness of gas market performance will shape expectations and speed the shift toward electrification**

A dedicated national information programme, building on existing campaigns and run by the government and EECA, could encourage households and commercial users to electrify their homes and buildings. The new programme could highlight the benefits of electric appliances, such as heat pumps, induction cooktops and hot water systems, for replacements and new builds.

The programme could highlight the domestic gas decline and ongoing price pressure, and electrification's upside: lower lifetime energy costs, reduced exposure to volatile gas prices and material emissions reductions. Engaging the public and encouraging behaviour change is essential to the success of the broader initiatives and will help to normalise fuel switching as a viable, low risk option and convert awareness into large scale electrification.

**This new programme would need to be targeted and backed by electrification benefits to deliver meaningful adoption of electric alternatives**

It could combine targeted outreach to households, SMEs and homeowners with mass-media communications supported by practical tools that build on existing information like conversion guides, cost calculators and information on available subsidies.

This programme would build social proof and public momentum, replicating the success of earlier national programmes in energy efficiency and home insulation. By strengthening awareness and confidence in electrification, the initiative would also protect households and businesses from future gas price shocks and reinforce broader investment in clean energy. Over time, it could aim to achieve measurable uptake of electric alternatives by 2030, delivering enduring reductions in gas demand (approximately 2–3 PJ per year) and emissions.

# 8 Conclusion

**New Zealand's energy system is one of the best in the world, ranked 9th across the energy trilemma by the World Energy Council. However, with domestic gas supply down 45% in the last six years, the country's energy system is facing a short-term supply crunch, most evident in dry periods such as 2024. The good news is, as this report lays out, there is a clear path to overcome this crunch and create a stronger energy system.**

New Zealand can build an abundance of firmed, renewable energy and set itself up to grow. It can retain the existing industries that are critical to its economy and support them to decarbonise, while positioning itself as a destination of choice for new industries looking for low-carbon and affordable fuel for their operations.

There is already strong momentum. Developers are building new renewable generation faster than ever before – more than 25% faster than during New Zealand's Think-Big hydro era. To maintain and build on this momentum, this report identifies five priorities with specific recommendations for the energy sector and government bodies.

The five priorities are:

1. **Accelerating renewable electricity generation development** by continuing to invest in projects at pace, delivering faster consenting and improving market information
2. **Strengthening the electricity market and security mechanisms** by investigating new firming markets, actions to affordably meet dry periods and ways to maximise the use of existing hydropower storage
3. **Enhancing the planning and delivery of lines infrastructure** by enabling efficient connection of new renewables and lifting the productivity of lines companies
4. **Addressing the gas supply decline and introducing domestic gas alternatives** by focusing on near-term gas supply via the 'Gas Security Fund' and exploring alternative thermal fuels – while creating optionality for LNG imports by accelerating preparations in case the domestic gas decline continues sharply
5. **Managing gas demand and accelerating the transition** by supporting industrial gas users to switch to biomass or electricity and bringing the public on the transition journey

If successfully implemented, these recommendations can see New Zealand achieve a managed transition, characterised by higher economic growth, lower average energy prices, additional security and lower carbon intensity – allowing New Zealand's energy sector to provide the foundations for prosperity for generations to come.

9

# Glossary

This section clarifies all acronyms and technical terms as they are used in the report.

| Term | Description |
|---|---|
| APAC | Asia-Pacific region |
| Baseload generation | Continuous electricity production from power plants that operate at constant rates |
| BCG | Boston Consulting Group |
| CAGR | Compound annual growth rate |
| Capacity factor | The ratio of actual electricity output over a period of time to the maximum possible output if the plant operated at full capacity continuously over the same period |
| CAPEX | Capital expenditure |
| CCGT | Combined Cycle Gas Turbines |
| Contract market | The forward/hedge market for electricity where participants manage wholesale price risk using exchange-traded futures and options and OTC contracts |
| CPTPP | Comprehensive and Progressive Agreement for Trans-Pacific Partnership |
| Decarbonisation | Reduction or removal of carbon dioxide emissions from a process |
| Demand response | A programme or system that adjusts consumer demand (for example via price signals or dispatch) to match available supply or grid-conditions |
| Dry period or dry year | An extended spell of below-average rainfall that lowers hydro lake storage, raising the risk of an energy shortage for New Zealand's hydro-dependent electricity system |
| EA | Electricity Authority |
| EECA | Energy Efficiency and Conservation Authority |

| Term | Description |
|---|---|
| Energy sector | Activities that produce, transform, transmit and distribute energy |
| Electricity industry | The value chain that generates electricity, moves it over the high-voltage grid, delivers it via distribution networks, and sells it to customers (retail) |
| Energy sector | Activities that produce, transform, transmit and distribute energy |
| ENZ | A whole-of-economy model to estimate the impacts of electricity market dynamics and outcomes on the broader energy system and economy |
| EPA | Environmental Protection Authority |
| Fast-Track | Refers to the 2024 Fast-track Amendment Bill |
| Final Investment Decision (FID) | The formal decision to proceed with a project, typically the point of financial close or start of construction |
| Firm capacity | Capacity that can be reliably counted on by the system operator to meet demand (under normal conditions) |
| Futures price | The agreed price for a commodity or asset in a futures contract, reflecting market expectations of its value at a specified future date |
| Gas industry | The exploration and production (upstream) of natural gas, high-pressure transmission pipelines, local distribution networks, and retail supply to consumers |
| GDP | Gross Domestic Product |
| GenAI | Generative artificial intelligence |
| Geothermal resources | Naturally occurring heat sources beneath the ground that can be harnessed for energy generation |
| GIC | Gas Industry Company |

| Term | Description |
|---|---|
| GIDI Fund | Government Investment in Decarbonising Industry Fund |
| Gross emissions | The greenhouse gases that an economy produces, ignoring carbon offsets (e.g. from forestry) |
| GST | Goods And Services Tax |
| GW | Gigawatt |
| GWh | Gigawatt Hours |
| Huntly | Refers to Huntly Power Station |
| Huntly Strategic Energy Reserve Agreement | Refers to the 10-year 150 MW Huntly Firming Options agreed between gentailers and authorised by the Commerce Commission. The agreement will enable 600 kt of coal to be stored and covers maintenance of Unit 2 to retain it as dry year cover |
| HVDC | High-Voltage Direct Current – often refers to the inter-island cable, connecting Benmore (Canterbury) to Haywards (Wellington) |
| Hydroelectric power (hydropower or hydro) | Electricity generated by moving or falling water, typically using dams or diversion/run-of-river schemes to drive turbines |
| Hydrology | The science of water – its occurrence, distribution, movement and properties across the hydrologic (water) cycle |
| IEA | International Energy Agency |
| Intermittency | Variation or unpredictability in energy generation, often due to weather reliance (e.g. wind and solar) |
| Reserve market | An ancillary services market that procures instantaneous reserve to keep system frequency stable after sudden outages; it is co-optimised with the energy market |

| Term | Description |
|---|---|
| Solid fuels | Coal or biomass, that can be stored effectively and then burnt to generate electricity via plants such as the Rankine units at Huntly |
| Thermal fuels | Fuels such as natural gas, coal, diesel or biomass that are burned to generate heat for electricity production or industrial use |
| Latency | The time delay between a request being sent and a response being received |
| LRMC | Long run marginal cost – the expected cost of long-term, future capacity expansion. Where electricity prices = LRMC, a market can be said to sit in long-run equilibrium |
| MBIE | Ministry For Business, Innovation and Employment |
| Methanex | A methanol production company, and large gas consumer |
| Mt | Mega tonne |
| MW | Megawatt |
| MWh | Megawatt hours |
| NEM | National Electricity Market (Australia) |
| Net emissions | The greenhouse gases that an economy emits minus those gases taken out of the air (e.g. by new forestry planted) |
| NZ | New Zealand |
| OCGT | Open cycle gas turbines |
| Offtake | Energy demand of a user, often agreed contractually |
| OPEX | Operating expenditure |
| ORC | A model of the electricity market (e.g. generation, capacity stack and electricity prices) |

| Term | Description |
|---|---|
| PJ | Petajoule |
| PPA | Power Purchase Agreement |
| Rankines/Rankine units | A type of steam turbine currently in use at Huntly power station |
| Residual load | The amount of electricity that cannot be met by intermittent renewable capacity (e.g. wind and solar) |
| RMA | Resource Management Act |
| SRMC | Short run marginal cost – current dispatch cost of existing plant |
| Tiwai Point (Tiwai) | Refers to the aluminium smelter located at Tiwai Point |
| TWh | Terawatt hours |
| WEC | World Energy Council |
| Workload | A set of tasks and applications processed by a data centre |

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