2026 Gas Supply & Demand Study

March 2026

Contents

Glossary

Definitions

C&I	Commercial and Industrial
DPP	Default Price-Quality Path, under Part 4 Commerce Act regulation
EECA	Energy Efficiency & Conservation Authority
FSRU	Floating Storage Regasification Unit
GDB	Gas Distribution Business
Gas Industry Co	Gas Industry Company Limited
GJ	Gigajoule
HFO	Huntly Firming Options
ICP	Installation Control Point
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MBIE	Ministry of Business, Innovation and Employment
MC	Marginal cost of gas transition
MWh	Megawatt Hour
PJ	Petajoule
RETA	Regional Energy Transition Accelerator
SME	Small and Medium Enterprise

Definitions

Normal Year	A year with average or typical hydro inflows and electricity generation conditions.
Dry Year	A year with significantly below-average hydro inflows, reducing hydro generation and increasing reliance on thermal or alternative generation.
Regasification	The process of converting LNG back into gaseous form for distribution and use.
Upstream gas	Gas exploration and production activities, including extraction of natural gas from underground reservoirs.
Gentailers	Companies that both generate electricity and retail it directly to customers.
Process heat	Where gas is used to produce heat for industrial and manufacturing processes, excluding space, steam and water heating.

Executive summary

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Introduction

The 2026 Gas Supply and Demand Study, commissioned by Gas Industry Co, explores how New Zealand's gas market may respond to declining indigenous supply, major demand shifts, and the introduction of LNG

Introduction

The 2026 Gas Supply and Demand Study (the Study) is undertaken at an inflection point for the New Zealand gas sector, as declining indigenous supply intersects with rising electricity security risks and questions about the pace and coordination of the energy transition.

The Study examines how the gas market may respond as major existing sources of both supply and demand exit, and as decisions are made about the role of gas in supporting energy security, affordability and decarbonisation.

The analysis focuses on two supply scenarios:

1 **Indigenous Gas Only:** Continued reliance on declining indigenous gas supply.

2 **Indigenous Gas + LNG:** Indigenous supply continues to fall but is supplemented by LNG imports from 2028.

These supply scenarios in turn are used to explore three critical demand uncertainties:

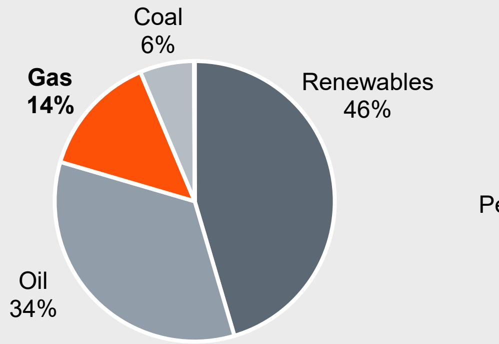
- the pace and timing of the transition away from gas for each customer segment
- the implications of closure of the Māui gas field (Māui) and Methanex methanol production plants (Methanex)
- the role of gas in electricity security of supply.

We draw on existing work and use scenario forecasting and economic analysis to project future gas supply and demand out to 2035. The outlook to 2050 is also explored to understand future uncertainties and risks.

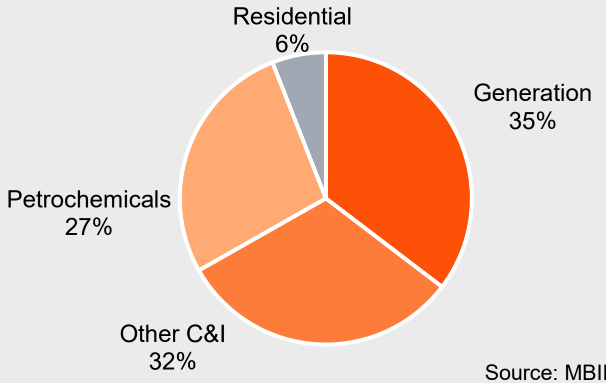
Many uncertainties and risks remain over the future of gas. Rather than trying to focus on singular market scenarios and outcomes, the Study seeks to illustrate market dynamics, highlight pressure points, and support informed discussion on timing, coordination, and transition pathways over the next decade and beyond.

Gas is New Zealand's third largest source of primary energy and is vital for industry and electricity generation

New Zealand Sources of Energy (2024)



Gas Use by Consumer Segment (2024)



Source: MBIE

Market Context

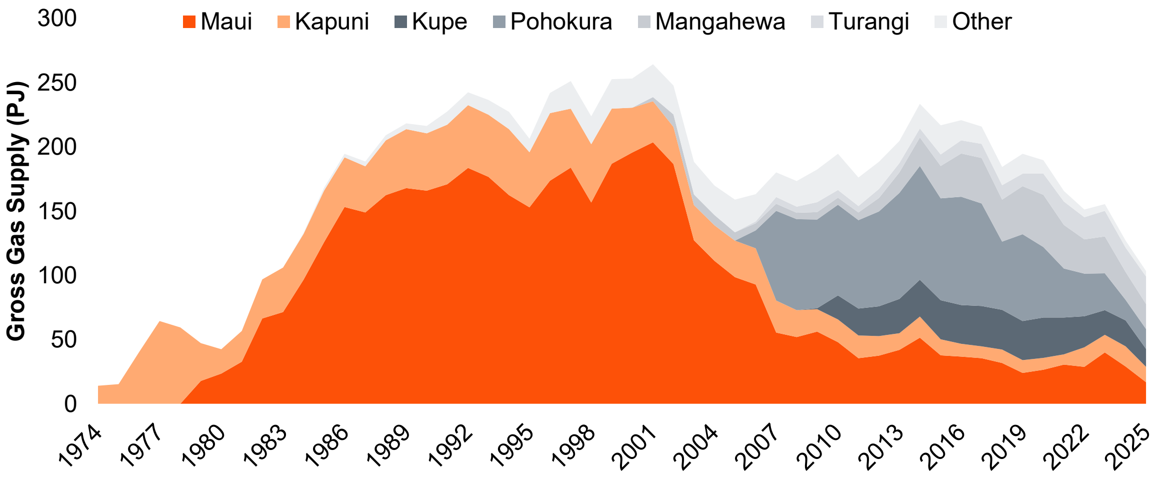
Gas production has fallen rapidly in recent years, resulting in increased market uncertainty, high prices and difficult choices for gas users

The pace of decline has been much faster than expected with increasing risk over future indigenous supply

New Zealand's gas market is entering a critical period. In the last decade, indigenous production has more than halved, returning to levels last seen in 1983. Unlike similar periods of decline (the early 2000s), there is limited new supply coming onstream to replace the maturing Taranaki gas fields and upstream activity has slowed amid market and policy uncertainty.

Exploration and production potential remain, but reduced investment activity and increasing failure rates indicate more challenging economic and technical conditions.

Gas supply by major gas field (PJ per annum)



Elevated prices and gas supply uncertainty are forcing gas users to rethink their energy choices

Demand is already falling in response to tightening supply and historically high prices. Large commercial and industrial (C&I) users are reducing gas use, accelerating decarbonisation and switching plans, and in some cases exiting their New Zealand operations altogether.

As the market contracts, uncertainty grows over the future of several major industrial users. The potential closure of Methanex and Ballance's Kapuni urea plant (Ballance) in particular would remove significant demand flexibility from our energy system and economic activity.

Residential and SMEs are more reluctant to move away from gas, valuing its convenience, reliability and controllability, especially for cooking, hot water and high-temperature heat. They generally prefer to switch when appliances reach end of life.

These market shifts also have direct consequences for our electricity market. Thermal generation remains vital in meeting daily peaks and as a backup in dry conditions, when hydro generation is low (called a 'dry year'). Tightening gas availability has constrained gas-fired generation and driven high prices and volatility into the electricity wholesale market, increasing reliance on coal and demand shedding. The loss of Methanex demand flex and Māui gas supply would compound these pressures. While wind and solar renewable power play a growing role, their output is intermittent and they cannot consistently provide firm backup when hydro and gas are tight.

A Petajoule (PJ) is a measure of energy. 1 PJ of gas is equivalent to the current annual gas use of 43,000 average New Zealand households.

Summary of approach and assumptions

Gas demand for each consumer segment is modelled to meet forecast supply, based on analysis of gas switching and generation in normal and dry years

Supply forecasts

Scenario 1 supply forecasts based on independent assessment of gas field production by Enerlytica with LNG added in Scenario 2.

Scenario 1

Indigenous Supply

Production for the 6 largest gas fields is forecast by Enerlytica based on a mid-case scenario (January 2026).

Māui assumed to exit in 2027.

Other fields are assumed to produce at proportionally the same levels.

+ **LNG**

Not available

Scenario 2

+ **LNG**

LNG is imported from 2028 for thermal electricity generation (minimum 12 PJ for dry year security) and other hard-to-transition and high-value uses.

Market balancing

Scenario 1: Demand reduces to meet indigenous supply and gas users with the lowest switching costs exit first.

Scenario 2: LNG caps local prices and increases to meet demand where switching costs exceed LNG prices.

Demand forecasts

Key demand segments modelled to meet supply based on analysis of switching, shutdowns, and thermal generation.

Segment	2025 – 2030 – 2035
Methanex & Ballance	Exit 2027
Commercial & Industrial	Energy switching & plant shutdowns assessed based on economic cost to switch and sector insights.
Electricity Generation	Gas generation demand forecast in normal & dry years assuming Huntly Rankine units run on coal with 10 Year HFOs in place.
Residential & SME	Electrification & fuel-switching rates based on analysis of mass market switching rates used by GDBs, MBIE, & Commerce Commission.

Indigenous Gas Only

As supply continues to fall, gas generation becomes constrained and consumers face a rapid and potentially turbulent gas transition

Under Indigenous Gas Only, gas production halves by 2035, requiring demand to reduce by 61 PJ.

Māui and Methanex are assumed to close in 2027 removing a large block of supply and demand and rebalancing the market at a lower level.

Other **demand (excl. Methanex) needs to fall by around 44%** over the decade, forcing commercial and industrial businesses to switch to alternative energy sources or close their operations. Consumer switching accelerates in the late 2020s as supply tightens, prices rise and suppliers rebalance gas portfolios.

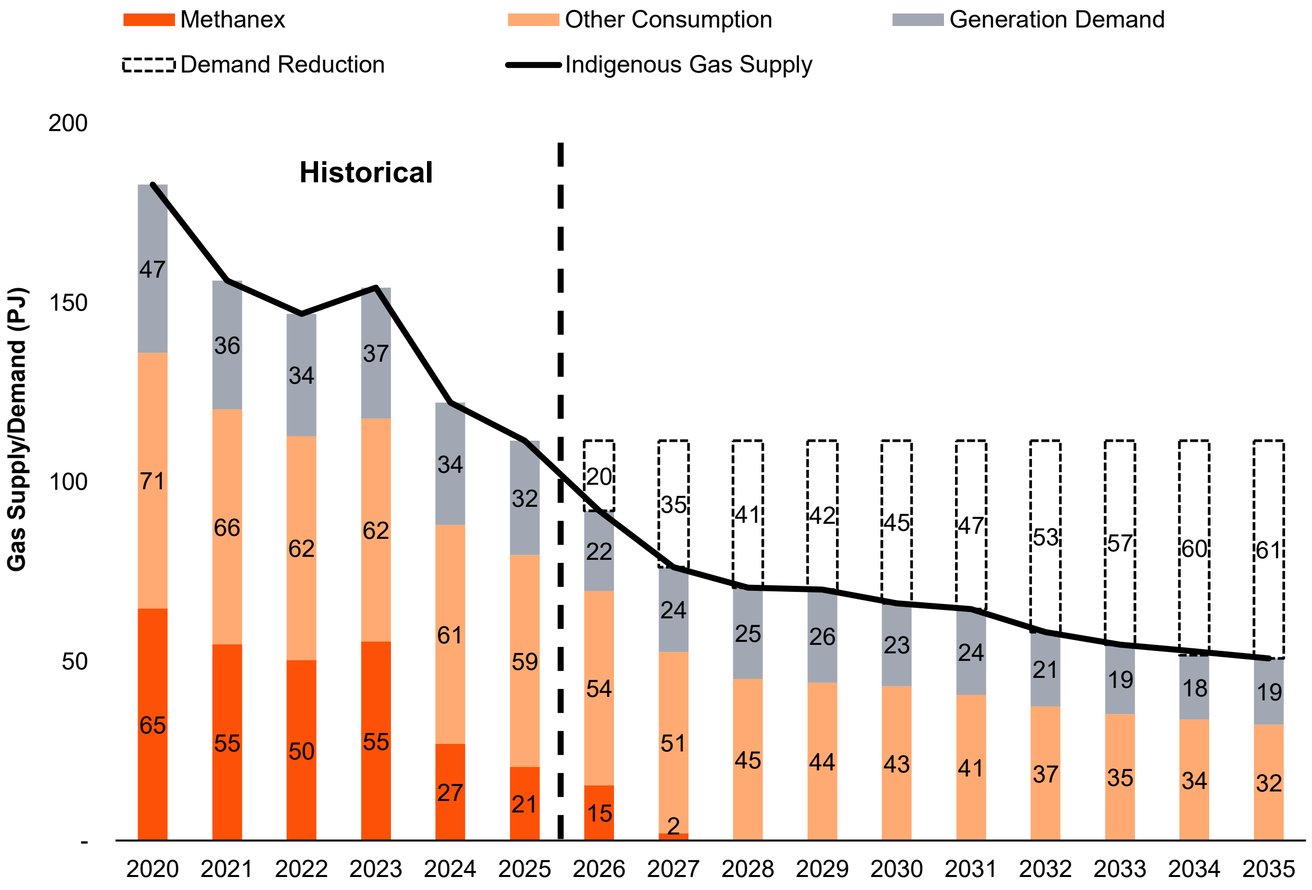
Gas-fired generation operates at constrained levels, targeting morning and evening peaks and winter security, with limited daytime or overnight running. The Huntly Rankine units run harder on coal and biofuels to meet minimum backup generation requirements. This requirement increases over the decade as electrification drives higher electricity demand.

The departure of Methanex removes up to 95 TJ per day of current contractual flexibility, leaving the Ahuroa Gas Storage (Ahuroa) facility as the primary balancing mechanism (up to 65 TJ per day). This loss contributes to sharper price swings and heightened seasonal and dry year supply constraints.

Supply forecasts reflect mid-case assumption and **significant downside risk remains for the market** in the low case, where supply falls faster.

In the absence of new supply, the core issue in Indigenous Gas Only is how quickly and how orderly the gas transition occurs and who bears the costs. **Supply and demand shifts and supporting energy infrastructure investments will need to be carefully co-ordinated and support for households and businesses will be essential to minimise disruptions.**

Gas supply and demand forecast - Indigenous Gas Only (PJ)



Indigenous Gas + LNG

Introducing LNG helps stabilise total gas supply and prices, reduces structural scarcity pressures, and restores confidence in the market to support an orderly gas transition

LNG helps stabilise total gas supply, reduces scarcity pressures, and restores confidence in the gas market. While LNG is unlikely to reverse the recent market contraction, the projected reduction in demand is half (31 PJ in 2035) of that under Indigenous Gas Only.

Based on January 2026 pricing, **LNG is projected to be a viable economic option for many gas users, which could see its use extended beyond electricity security.**

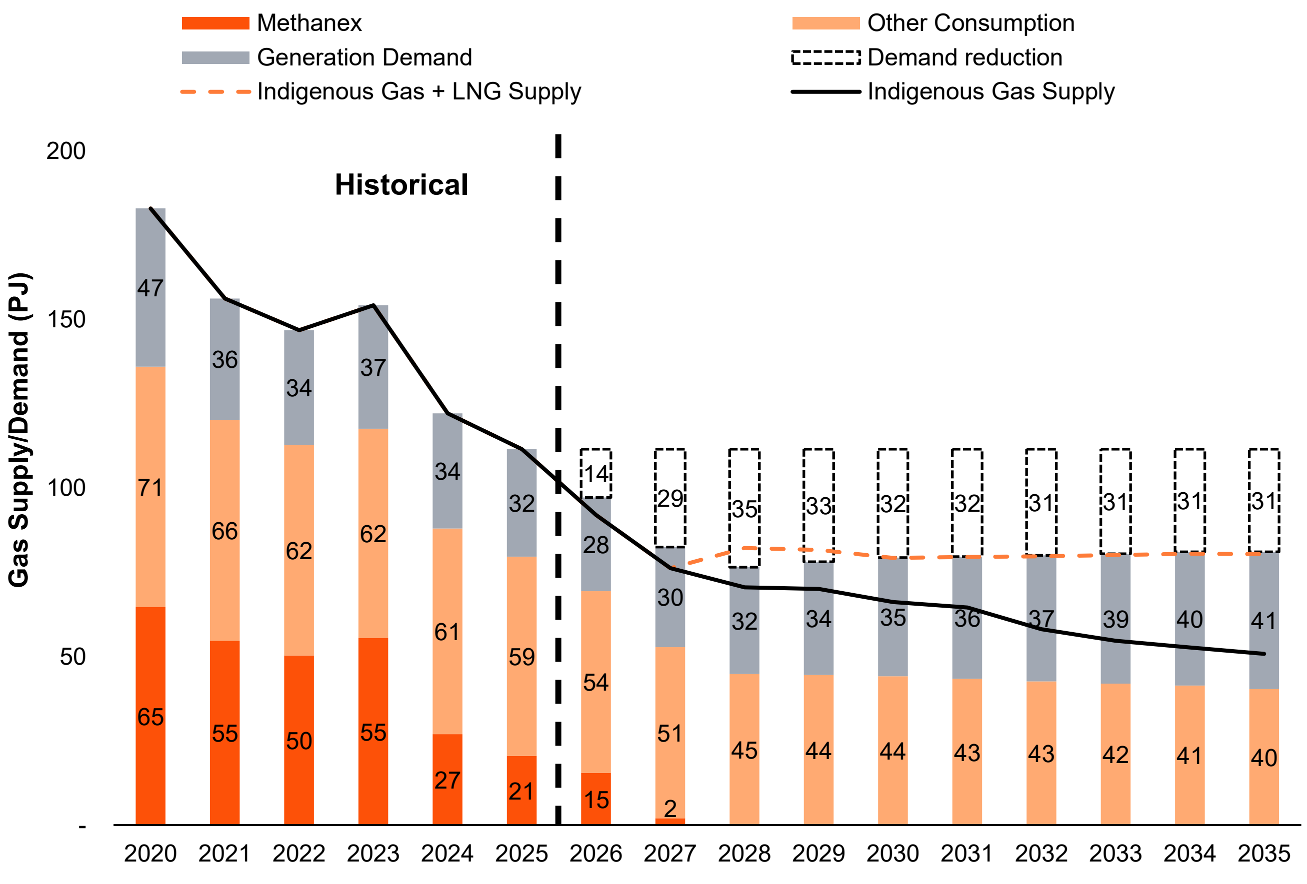
LNG provides much needed flexibility and resilience to our energy system. LNG imports can scale up in dry years and down in wet years, providing both energy insurance and system flexibility. It provides a supply cushion for seasonality and one-off market adjustments and can be throttled to support gas switching and investment decisions on indigenous gas, reducing short term supply disruptions.

LNG shifts market risk exposure from domestic gas scarcity and production economics to global markets and international competition. **Global market exposure can be managed through long-term contracts and deep hedging markets.**

LNG does not alter New Zealand's gas transition end point or Net Zero ambition. Total gas supply forecast under the Study falls below all of the Climate Change Commission's 2021 gas supply scenarios. It can **support an orderly energy transition**, providing optionality and breathing space for the energy sector to build new renewables and network capacity, and transition consumers off gas.

While modelling shows a relatively steady demand decline, **the energy transition will be much more dynamic in practice. LNG supports this** and can be turned off quickly if renewable energy takes over. It can also be scaled to support firming of new renewables or new industrial demand (data centres, green industry).

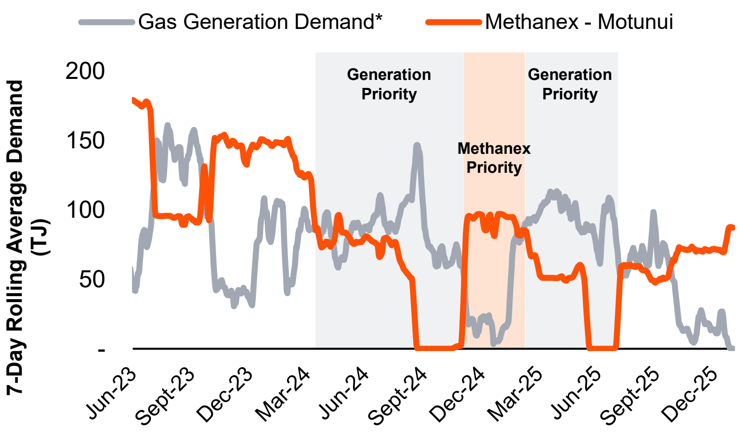
Gas supply and demand forecast - Indigenous Gas + LNG (PJ)



Dry year risk

Gas supply and system flexibility remain critical to maintaining electricity security in dry years over the next decade

Methanex versus gas generation demand



** Huntly + Junction Road + TCC + Stratford Peakers + McKee*

Methanex's departure exposes dry year risk

Methanex plays a vital role in our energy system, currently providing up to 95 TJ per day of demand response and recontracting flexibility. During periods of energy system stress (i.e. gas outages and dry periods) it can temporarily reduce production, redirecting contracted gas to generators. This role was critical in 2024 when Methanex diverted gas to gentailers for generation in a particularly dry period. August 2024 electricity spot prices spiked to $488 per MWh but could have been higher without Methanex.

Having large, flexible demand as a balancing mechanism for the wider energy system is critical for dry years and seasonality. If Methanex shuts down, Ahuroa becomes a primary balancing mechanism. Alternative options will need exploring for demand flex and storage in Indigenous Gas Only.

Thermal generation remains the primary dry year solution over the next decade, until renewable firming can be deployed

Energy security requires reliable and readily dispatchable capacity and sustained generation volumes from stored fuels (water, coal, gas).

Wind and solar can support but not reliably meet dry year risk. Both are intermittent and weather-dependent, and output can be low during dry winters. Wind generation is partially correlated with hydro inflows, increasing the likelihood that dry years may coincide with low wind. Batteries can help firm wind and solar over short intra-day periods by shifting energy from periods of surplus to periods of constraint, but are not practical for long-term duration seasonal storage.

The sector is exploring various renewable alternatives for winter security, including biomass, pumped hydro, and flexible geothermal. Each option faces technical, cost, and delivery hurdles and may not be available at scale in the next decade.

To bridge the gap, Genesis implemented its **10-year Strategic Energy Reserve Huntly Firming Options (HFOs).** This makes three Huntly Rankine units available through to 2035, providing about 720 MW of firm capacity. However, gas (domestic or imported) will continue to be vital in covering dry year risk, in providing both capacity and fast generation response.

Demand response and operational flexibility from major industrials, like Methanex (in gas), and Tiwai Point aluminium smelter and Glenbrook (in electricity) are an increasingly important balancing mechanism.

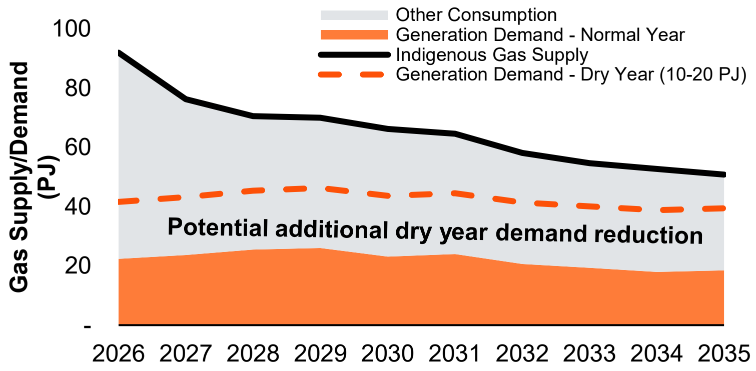
Dry year risk without LNG

New Zealand needs 10-20 PJ of gas supply, demand flexibility and/or storage otherwise further demand destruction is expected

10-20 PJ

Additional gas required for dry years to 2035

Dry year generation demand vs total supply - Indigenous Gas Only



Winter 2027 risk

While it is too soon to know whether 2027 will be a dry year, significant security of supply risk hangs over this year. If Methanex demand flexibility and Māui production are both unavailable from early 2027 and LNG imports start from 2028, then indigenous gas supply will likely be insufficient to meet dry year requirements. Transpower is already monitoring this, but careful management of energy system resources is needed.

In the absence of LNG and system flexibility, additional gas is needed for dry years in Indigenous Gas Only

Gas generation is assumed to be constrained in normal years in this scenario. The system also lacks demand flexibility and sufficient gas storage to meet a dry year supply gap. While the HFOs provide up to 720 MW of coal-fired generation, an extra 10–20 PJ of gas is estimated to be required in a dry year.

Under Indigenous Gas Only, dry years lead to price spikes that may rival August 2024, higher coal use, and potential demand curtailment in gas and electricity markets. Retailers may be forced to adjust their portfolios for acute dry year risk and exposure to gas, which could accelerate gas switching beyond what is modelled.

Dry year risk could drive further demand destruction in Indigenous Gas Only

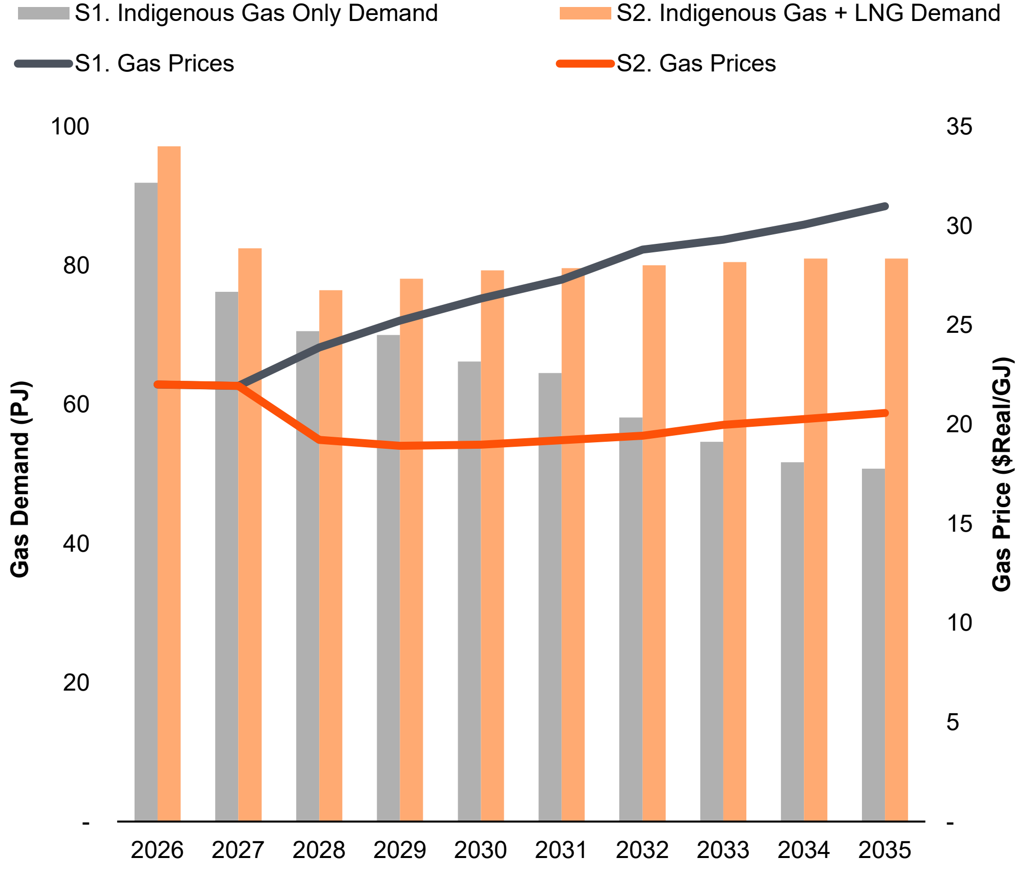
Under Indigenous Gas Only, **any additional gas required for generation due to a dry year will require further consumer demand curtailment.** A proportion of this will come from temporary demand response and storage, but significant additional permanent demand destruction beyond what is modelled is likely in a dry year. Retailers are unlikely to accept this dry year risk and may act early to derisk their gas portfolios, such as by accelerating electrification and gas switching.

By contrast, LNG restores fuel storage availability and enables gas generation to operate closer to normal running levels, reducing demand destruction and strengthening dry year resilience. It provides confidence to an already fragile market which may help to reduce current elevated wholesale prices.

Pricing outcomes

Gas prices are above historical levels in both scenarios, but LNG could deliver lower prices and lower pricing volatility if appropriately managed

Demand and gas price outcomes under each scenario



LNG may deliver cheaper gas than under Indigenous Gas Only

In the Indigenous Gas Only scenario, sustained upward pressure on prices is expected as consumer demand exceeds supply.

Delivered gas prices are projected to rise to around $31 per GJ (real, including wholesale prices, carbon and transmission) by 2035 in Indigenous Gas Only. This is compared to average industrial gas pricing over the last decade of $10 per GJ. Significant price volatility is expected in this scenario as prices respond to gas scarcity and seasonal periods of excess and tight supply.

With LNG, imports can be scaled to respond to supply imbalances and high prices. Global LNG markets are large, and imports can significantly reduce domestic gas scarcity, subject to management of global market risk.

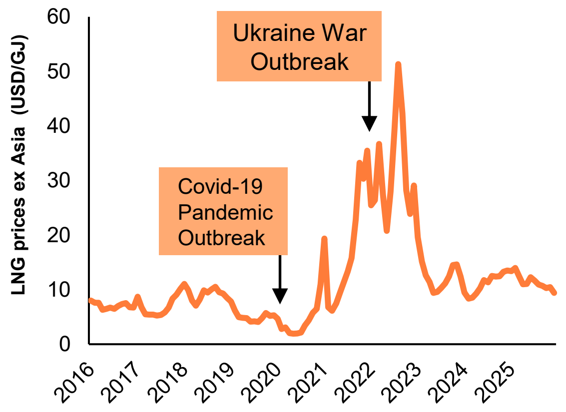
Within a global market, **LNG would effectively cap local prices at international levels.** Based on January 2026 LNG forward price curves, **delivered gas prices are projected to fall between $19 to $22 per GJ** (real, including landed LNG import price, carbon, regasification, and transmission) over the decade.

Exposure to global markets can be managed through contracts

LNG prices in Asia rose from around USD 2 per GJ in early 2021 during Covid to USD 51 per GJ in mid-2022 at the start of the Ukraine War. Prices returned to normal levels of around USD 10 per GJ but have again been disrupted by conflict in Iran. The most recent forward price curves are up USD 9 per GJ in 2026 but return to more normal levels by 2028.

Conditions like these are extreme but demonstrate that LNG could transmit global price instability to the domestic market. This risk can be managed through long-term supply contracts and access to deep global hedge markets.

LNG prices ex. Asia (USD per GJ)



Source: US FED

C&I impacts

Demand destruction and switching is concentrated in petrochemicals and food production, with economic consequences for our industrial base, jobs and exports

LNG could retain about 5 PJ of C&I demand, primarily due to lower prices and supply availability

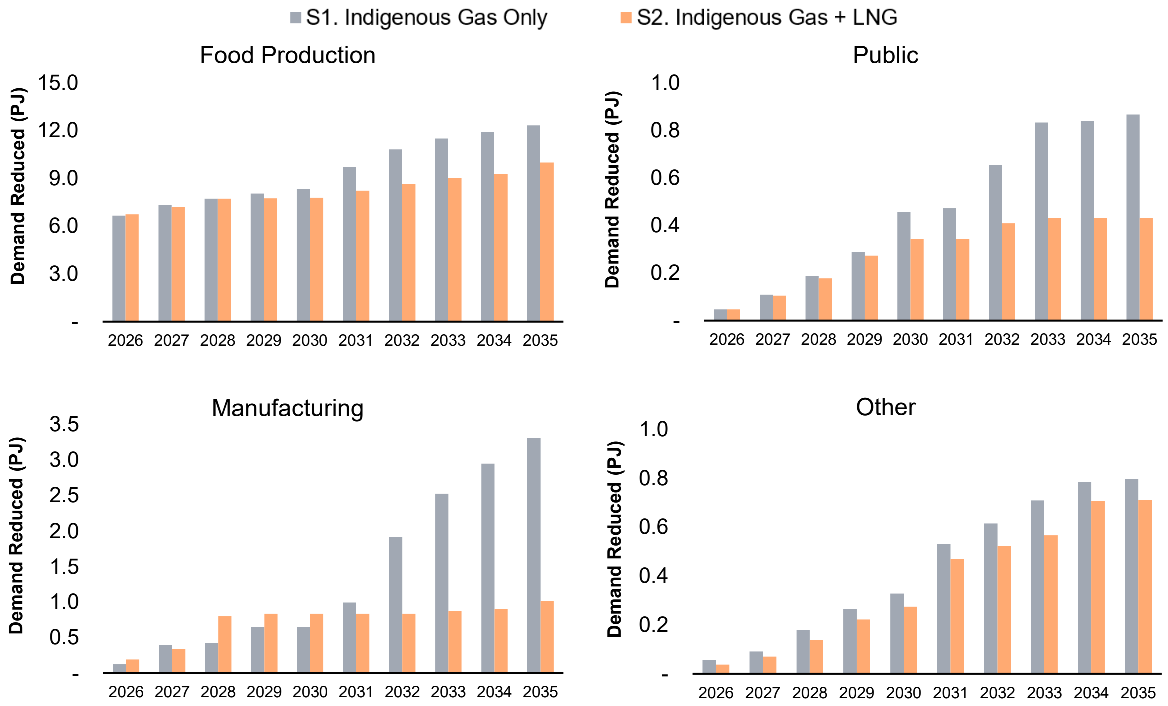
Under the Indigenous Gas Only scenario, demand destruction and switching are concentrated in petrochemicals and food production, driven by their relatively low cost of switching from gas. These sectors form part of New Zealand's export base and regional industrial economy.

LNG does not prevent the assumed closure of Methanex and Ballance as both face international competition, but it could support retention of manufacturing and food production.

LNG helps to retain 5.2 PJ of C&I demand across remaining sector groups compared to Indigenous Gas Only. This is mainly due to the sensitivity of many C&I customers to changes in gas price. Some customers are willing to pay more and some less. LNG is priced relatively below the cost of switching from gas, compared to Indigenous Gas Only.

PwC have not modelled economic impacts, but Sense Partners' has for MBIE under broadly similar scenarios. They estimated that without an LNG terminal (analogous to Indigenous Gas Only), New Zealand's real GDP is around 0.96% lower by 2035 and employment drops by about 9,500 FTEs in the early 2030s. With LNG, the impacts are smaller, with GDP around 0.71% lower by 2035 and employment dropping by about 4,600 FTEs.

Cumulative demand reduction by sector under each scenario (PJ)



Higher gas prices under Indigenous Gas Only result in higher demand destruction across C&I, compared to under Indigenous Gas + LNG

Residential and SME impacts

Residential and SME users may reluctantly be forced to switch where gas supply continues to fall

Residential and small business customers (SMEs) make up the majority of gas connections but only represent a small share of total gas demand (about 8%). Their gas use is typically tied to cooking, hot water and space heating (both) and low to medium temperature process heat (SMEs).

Evidence from consumer research suggests these customers are generally reluctant to switch proactively, valuing gas for convenience, controllability and reliability, and preferring change to occur gradually.

Switching decisions are also shaped by upfront cost, such as appliance replacement and electricity connection upgrade costs, business disruption, and the availability and affordability of alternatives (LPG, electricity connection capacity, and biogas).

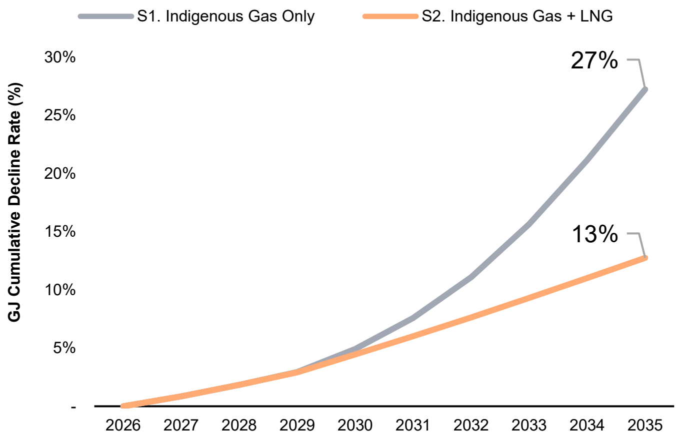
Mass-market switching is expected to be gradual due to these factors, accelerating only if rising prices or supply constraints begin to force consumers off.

Residential switching halves with LNG

Under **Indigenous Gas Only**, residential switching accelerates once supply constraints bind in 2028, with residential gas demand reducing by 27% by 2035.

Under **Indigenous Gas + LNG**, switching is more gradual, with demand reducing by 13% by 2035. This reflects reduced supply constraints and pricing pressures in this scenario.

Residential cumulative demand reduction

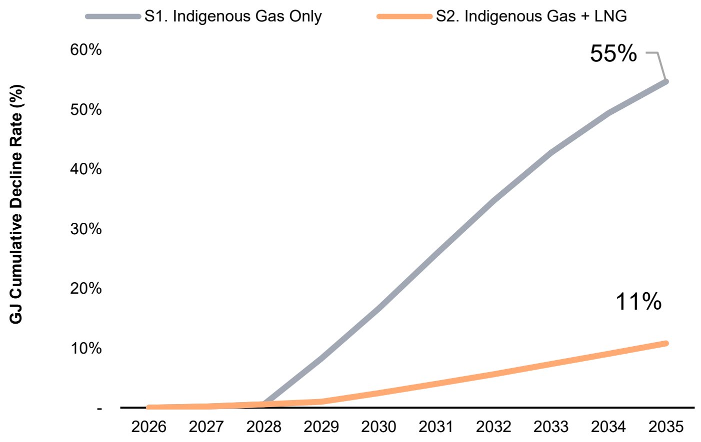


Price sensitive SMEs will respond more quickly in a supply squeeze

Under **Indigenous Gas Only**, SMEs act quickly to mitigate the business impacts of supply constraints and high prices, which accelerates switching, downsizing, and business closure for the most price sensitive businesses.

Under **Indigenous Gas + LNG**, improved supply certainty and lower prices supports a more measured transition aligned with equipment replacement cycles.

SME cumulative demand reduction



2050 market outlook

Balancing supply and demand is increasingly complex beyond 2035 as indigenous gas supply and consumption falls and as generation plant retires

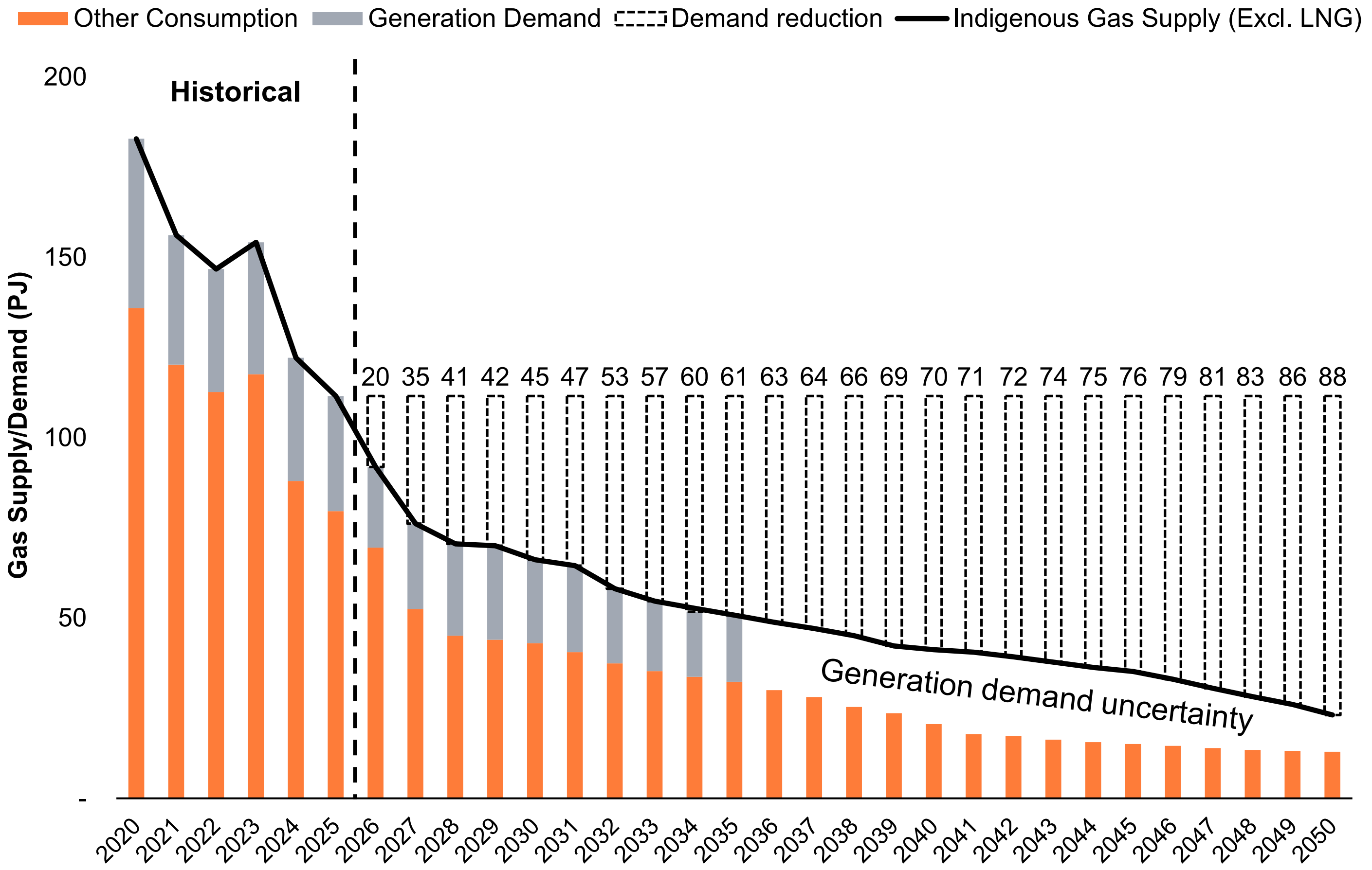
Indigenous gas supply is expected to reduce to around 23 PJ by 2050, a reduction of 79% (88 PJ per annum)

Projecting forward our demand modelling beyond 2035, sees the market contract to a small core of hard-to-abate uses. C&I users are assumed to switch at accelerated rates in later years as supply tightens, making it increasingly difficult to sustain major commercial operations. Residential and SME user switching rates accelerate in the 2040s and comprise only about 2% of demand by 2050.

The 2030s emerge as a critical inflection point for gas generation. Genesis' HFOs are assumed to end in 2035, gas-fired generation plants approach end of life, and the Kupe and Pohokura gas fields are assumed to be decommissioned. Available supply for generation tightens further in the late 2040s to about 10 PJ by 2050, which may support a few gas peaking units.

The future role of LNG beyond 2035 remains uncertain and is not modelled. If international prices remain stable, LNG could continue to supply hard-to-abate users, with import volumes flexing to manage seasonal and one-off demand shifts. However, as gas-fired generation retires and New Zealand advances toward Net Zero 2050, overall LNG volumes are likely to decline, and its role may shift from providing bulk volume to targeted flexibility. That said, if policy and economics allow, LNG could support expanded or new industrial demand where gas remains a competitive input.

Gas supply and demand forecast to 2050 (PJ) – Indigenous Gas Only – normal hydrology



Other Market Implications

Balancing decarbonisation and entrenchment risk

LNG will likely reduce reliance on higher-emitting coal and diesel-fired generation, but if used as a long-term substitute rather than energy insurance, it risks slowing decarbonisation (albeit at levels lower than all Climate Change Commission scenarios). Over-reliance may also weaken investment signals for renewable firming solutions.

At the same time, LNG may reduce transition shock and support new renewables. By stabilising supply and moderating price spikes, it provides confidence for consumers to electrify and invest in renewables. Its role in firming intermittent solar and wind generation, may support wider decarbonisation in transport, our largest source of energy related emissions.

Because LNG import volumes can be throttled, it preserves optionality and avoids entrenching new long-life domestic gas production assets.

Flexibility and storage is critical in Indigenous Gas Only

Without a replacement recontracting mechanism of about 10 PJ to 20 PJ, from Methanex leaving, there is high price volatility and supply risk under Indigenous Gas Only.

The inflexibility in the system could lead to cannibalisation of gas supply. For example, gentailers can outbid C&I users to secure dry year fuel, being able to pass these energy security costs on in wholesale electricity markets. While gas may return to the market when dry year risk subsides, the dynamic is unsustainable for most C&I businesses.

Additional flex or storage is vital in this scenario to smooth short-term seasonality and dry year variations.

By contrast, LNG imports open up supply to a global market, reducing scarcity buying behaviours and the need for 10 PJ to 20 PJ of flexibility and/or storage.

There is significant downside risk for indigenous supply

Enerlytica's Mid-case forecasts show indigenous gas supply declining to around a quarter of current levels by 2050.

However, the downside risk is materially more severe. In their Low-case, inaction triggers cascading supply failures, erodes confidence in gas investments and market contracting, and drives premature exits of major users. This, in turn, could hasten the retirement of thermal generation, with implications for energy security.

Enerlytica's high and low cases are asymmetric, with upside supply only marginally above the mid case, while downside risks are significant.

Decisions taken to restore market confidence in an orderly gas transition will be vital to avoiding this downside risk.

Delays to LNG could create short term dry year stress

Even small delays to LNG (or any equivalent dry year insurance) can materially increase near-term risk, as gas availability is already tightening and dry years can occur with little warning.

Without LNG in place, a dry year would rely on constrained domestic gas, higher coal-fired Huntly Rankine units' output, and demand curtailment. This would drive price spikes, volatility, and higher emissions.

Affordability and energy security pressures can cascade by accelerating industrial curtailment or closure, weakening confidence in contracting, and increasing the risk that thermal plant retires before replacement firming options are ready.

2

Introduction

Introduction

The 2026 Gas Supply and Demand Study explores how New Zealand's gas market may respond to declining indigenous supply, major demand shifts, and the introduction of LNG

Purpose and Scope

This report presents the analysis and findings of Gas Industry Co's 2026 Gas Supply and Demand Study (the Study), undertaken by PricewaterhouseCoopers (PwC).

Gas Industry Co oversees the efficient operation of New Zealand's gas sector under a co-regulatory framework involving government and industry participants. As part of its role, Gas Industry Co commissions annual supply and demand studies to examine emerging challenges and opportunities in the gas market, to support industry dialogue and planning.

The Study aims to advance national discussion on the future of New Zealand's gas sector by examining how the market will respond to conditions of declining indigenous gas supply and rapid shifts in major supply and demand segments.

This year's Study has a narrower and more targeted focus than previous editions. It concentrates on exploring several critical market risks, to better understand gas transition pathways, key decision points, and uncertainties. The immediate focus is on the next decade to 2035, but the longer-term outlook to 2050 is also considered to better understand risks and uncertainties.

The intent is for the Study to reach a wide audience to improve understanding of the key challenges and opportunities facing the gas sector.

The Study comes at a critical period for the gas sector as New Zealand debates the role of gas in balancing energy security and affordability, while moving towards a Net Zero 2050 decarbonisation target.

To evaluate future gas market outcomes, two supply scenarios have been developed reflecting plausible supply outcomes:

1 Indigenous Gas Only:

Continued reliance on declining indigenous gas supply

2 Indigenous Gas + LNG:

Indigenous supply supplemented by LNG imports from 2028

Three critical uncertainties for the gas transition are considered in each scenario:

- **Consumer demand transition:** Due to uncertain gas availability and high prices**,** large users are actively considering their choices of reducing gas use, switching to alternative energy sources, or ceasing production. The Study considers the scale, timing, and distribution of demand reduction required by different customer segments to balance the market.
- **Methanex and Māui exit:** Methanex is particularly exposed to declining gas supply availability and is finding itself competing for scarce supply with other major users, particularly electricity generation. Methanex is supplied mainly from the Māui gas field and the future of both is closely linked, with coincidental closure a distinct possibility. Such an outcome would result in a rapid contraction of the gas market.
- **Electricity security of supply:** Gas-fired generation plays a critical role in electricity security and system flexibility, particularly in dry years. Gas scarcity has contributed to elevated electricity prices and increased volatility in wholesale markets. The potential loss of Methanex intensifies this risk by removing a key source of demand flexibility that has been vital in redirecting gas to electricity generation during dry periods.

These critical uncertainties are discussed in more detail in Section 3 – Current Market Context.

We have applied a range of qualitative and quantitative research and analytical approaches to assess gas market outcomes. Scenario analysis, existing studies and stakeholder interviews have been drawn on to strengthen our assessment and confirm findings. Our approach is described in Section 4.

Our analysis of gas market outcomes to 2035 and 2050 is summarised in Section 5 and 6, with discussion of key market implications in Section 7.

Limitations and acknowledgements

The Study reflects defined supply scenarios involving declining indigenous supply and LNG, however alternative pathways are possible

Limitations

The gas market is dynamic and complex, influenced by changing supply conditions, the investment decisions of numerous businesses, and shifting consumer behaviour. Actual market outcomes may differ materially from those described in the Study, and alternative assumptions or unforeseen market news (e.g. a large gas find, unforeseen plant closures) could lead to outcomes that are more or less significant. Other stakeholders may also hold different but equally valid views.

Our focus is on the gas market and while wider energy system dynamics are assessed and considered the entire energy system has not been modelled, which would be a far larger scope of work.

The scenarios focus on a future involving rapidly declining indigenous supply and LNG imports. This is not the only possible pathway for our wider energy system needs.

We have attempted to compile accurate information on the market within the scope and budget of the Study and have made various assumptions to simplify the analysis and address data gaps.

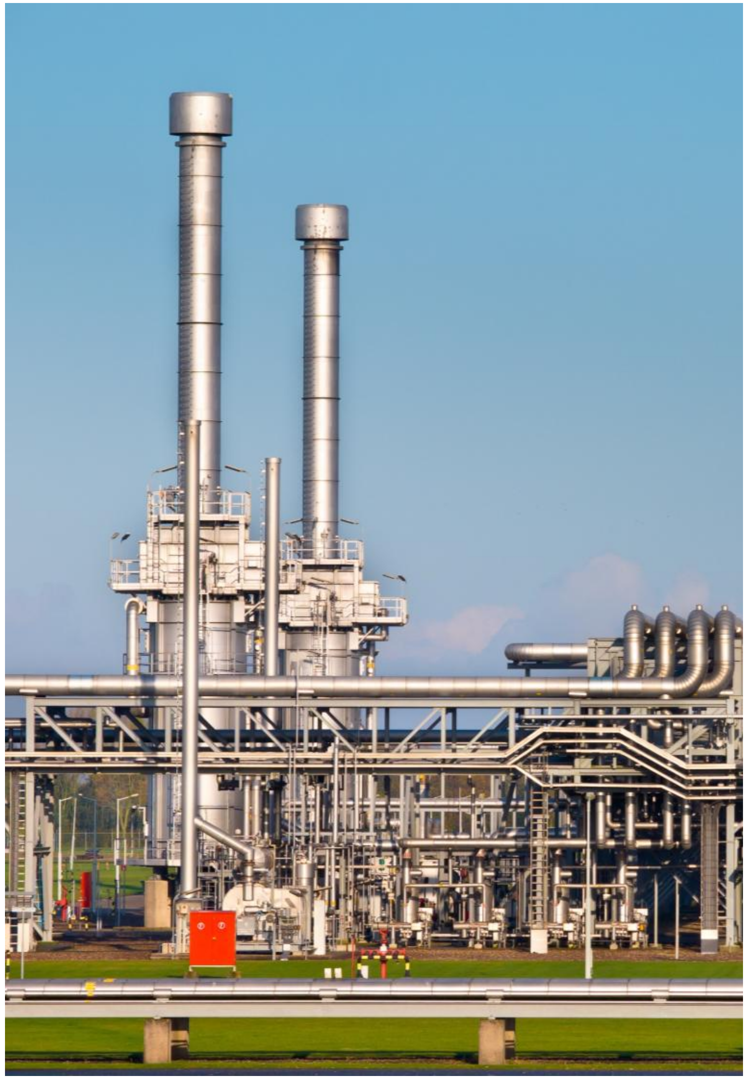
This Study discusses the market implications of each scenario but does not prescribe or evaluate specific policy or commercial solutions.

Acknowledgements

We would like to thank Gas Industry Co and other stakeholders that contributed with data, analysis and insights. We specifically acknowledge:

- Enerlytica, for providing gas field production forecasts.
- The Energy Efficiency & Conservation Authority (EECA) for providing access to anonymised information on North Island large C&I gas users from its Regional Energy Transition Accelerator (RETA) database.
- A number of large industrial users that we interviewed to test our assumptions.

Our conclusions and analysis are not necessarily intended to reflect the views of these stakeholders.



Current market context

3

The New Zealand Gas Sector

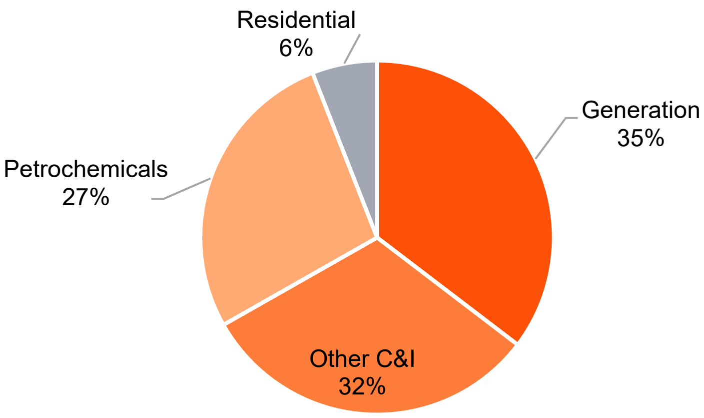
The key users of gas

There are approximately 304,000 gas consumers across the North Island; around 98% are households and small businesses. Active connections peaked at about 309,000 in November 2023 and have since declined.

There are about 5,700 C&I and petrochemicals users, which represent around 59% of total gas demand. This consumer segment is dominated by the five largest industrial users including Methanex, Ballance , Fonterra, Oji, and New Zealand Steel, representing about 40% of total demand in 2024.

Electricity generation is another major source of gas demand, though use is highly variable, driven by hydro conditions and electricity system needs.

Gas use by consumer segment (2024)



2P (proven and probable) reserves are the estimated volumes of natural gas that field operators assess as recoverable from known accumulations

Where gas comes from

Around 10%-15% of New Zealand's energy comes from natural gas.

Our gas fields are in the Taranaki region with production concentrated in six large fields:

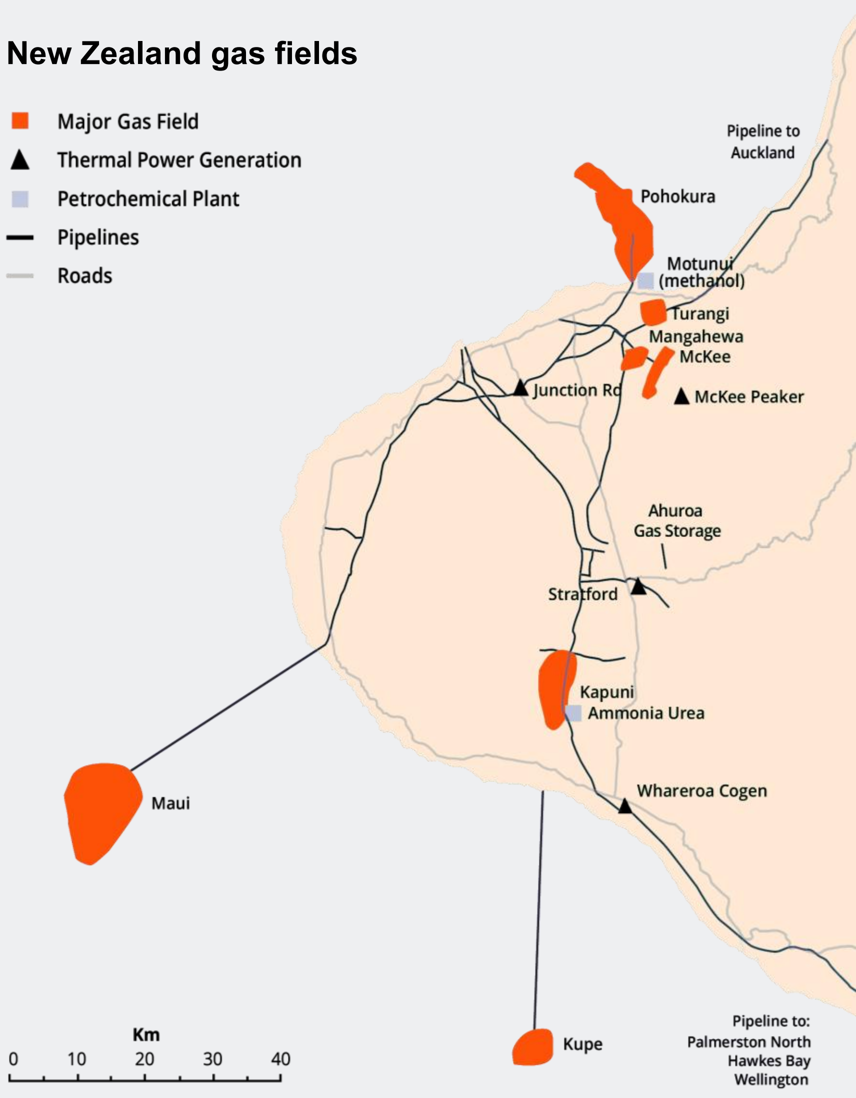
- **Offshore:** Māui, Pohokura and Kupe
- **Onshore:** Mangahewa, Turangi, and Kapuni.

A number of other smaller onshore fields provide additional supply.

Together, these fields supply the North Island gas transmission network, which connects generators, major users, gas storage, and local gas distribution networks.

In January 2025, operator estimates of proven and probable (2P) gas reserves reduced from 1,300 PJ to 948 PJ. This decline was mainly driven by upstream field operators reducing their estimates by 234 PJ (the reasons for which are not disclosed). The remaining 119 PJ reduction reflects the gas reserves that were used during the year.

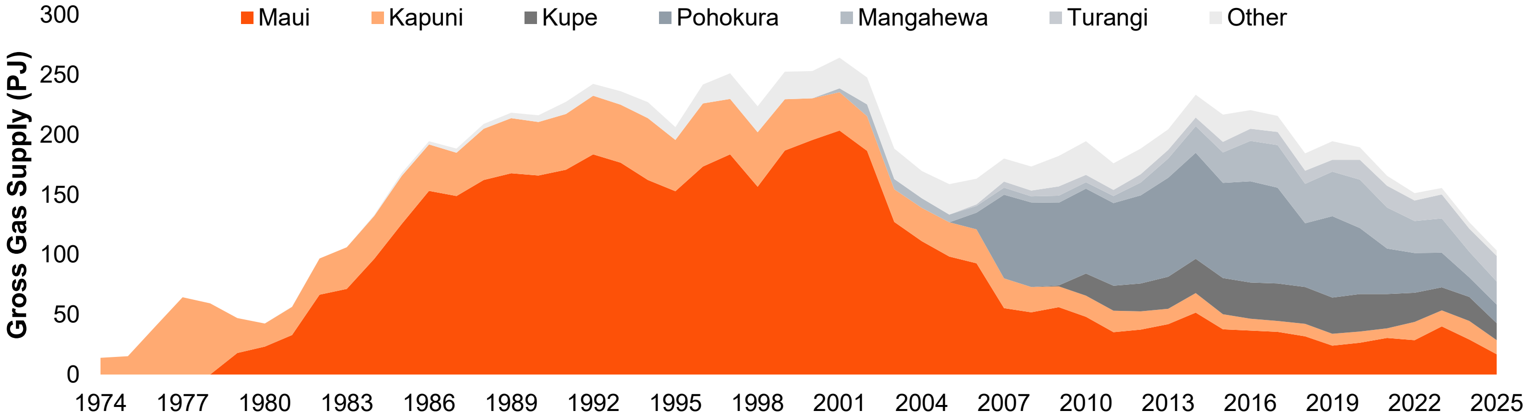
New Zealand gas fields



Supply snapshot

New Zealand's gas supply has fallen to critical levels last seen in the 1980s, with significant uncertainty over future supply

Annual gas production by major gas field (PJ)



When discovered in 1969, Māui was one of the largest gas finds in the world. Together with the previously discovered Kapuni, it underpinned the development of New Zealand's gas sector through the 'Think Big' era, providing the bulk of our gas supply for the next three decades.

Maui's production started to decline rapidly in the early 2000s. New supplies came in to replace the decline, mainly from the Pohokura, Mangahewa, Kupe, and Turangi gas fields in Taranaki. New production from these fields helped to sustain supply at similar levels until the mid 2010s.

Since 2016, production has more than halved, with a 34% reduction observed in the last 2 years alone. The last time gas production was this low was in 1983.

Unlike the situation in the early 2000s, we are not seeing new indigenous gas coming to market. A key reason is many of Taranaki's gas fields are relatively mature. Māui, in particular, is reaching the end of its productive life. Exploration and production opportunities still exist to extend the life of the Taranaki gas fields (e.g. infill wells) but declining activity and increasing failure rates over the last decade indicate challenging economic and technical conditions.

Uncertainty over the future role of gas in our national energy transition is another driver of declining gas investment. The 2019 commitment to Net-Zero emissions by 2050, the 2018 oil and gas exploration ban, and ongoing political debate on the pace of the gas transition have created uncertainty for investors and many consumers.

With uncertainty over indigenous gas availability, alternative options are being explored to provide affordable and secure energy while supporting a credible net-zero transition

Support for indigenous production: Incentivise ongoing upstream exploration to slow the pace of decline, potentially using carbon capture, utilisation and storage (CCUS), where economic and technically feasible. This prioritises energy security and affordability, mitigating carbon where possible.

LNG imports: Develop LNG import facilities to provide insurance against dry year electricity generation risk and a more balanced gas transition. LNG is thought of as backup 'insurance' that would improve supply stability, flexibility and resilience, as well as price transparency.

Green gases: Development of biogas and hydrogen substitutes and reuse of existing infrastructure. A Blunomy report (2023) estimated up to 23 PJ of biogas could be produced annually. While attractive from a transition perspective, supply, cost, and timing constraints mean these options are unlikely to offset declining gas in the near term.

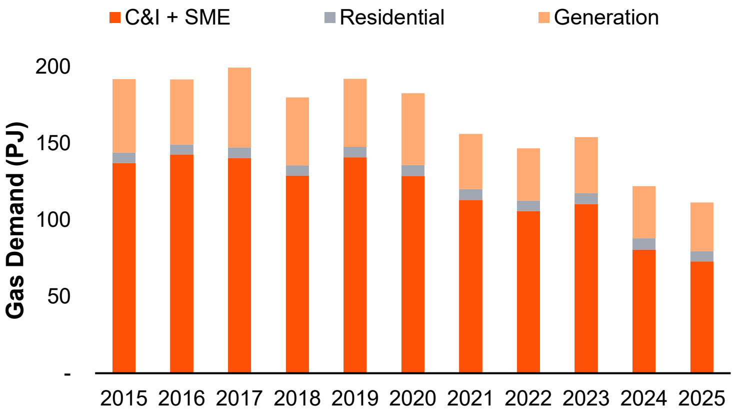
Managed transition: Signal a clear transition away from natural gas within defined timeframes, prioritising remaining gas for electricity security and hard-to-abate users, while providing incentives to accelerate switching.

In practice, a combination of several of the above may be pursued.

Demand snapshot

C&I users are already exiting gas due to high prices and gas scarcity, with several major industrials at risk of closure

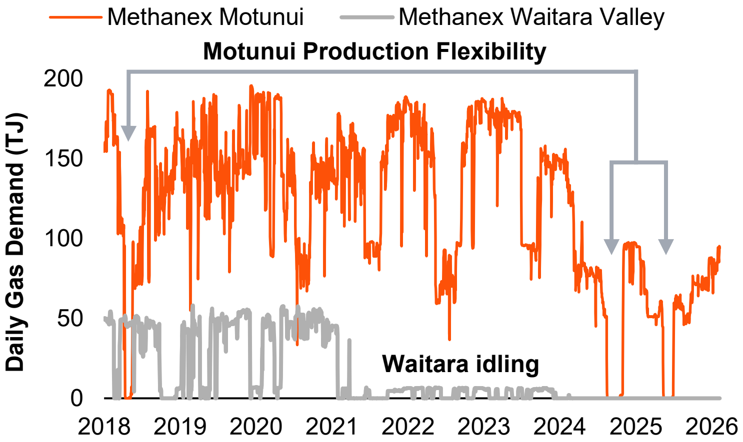
Historical gas use by consumer segment



45 PJ

Reduction in petrochemicals related gas use in last 5 years

Methanex production response to gas constraints



C&I demand is already falling

Businesses have been quick to respond to tight gas supply and historically high prices by reducing gas use and bringing forward decarbonisation and switching plans. A 2025 survey of this group by the Business New Zealand Energy Council (BEC) indicated half of respondents had reduced operations, increased prices, or cut staff in response to these conditions. Several large C&I users have recently decided to close, citing high gas prices as a key driver; notably Oji Fibre Solutions' paper mill.

This trend accelerated under the Government Investment in Decarbonising Industry (GIDI) fund, with $18.6 million of co-funding provided to support gas plant replacement and upgrade initiatives.

Petrochemicals sector at risk

Methanex and Ballance are among New Zealand's largest gas users, together consuming up to 270 TJ per day. They are particularly vulnerable to the current supply squeeze as gas is a primary feedstock to production, accounting for about 75%–85% of operating costs. While still profitable, Methanex recently wrote down the value of its New Zealand business to zero, warning that suppliers may not be able to deliver beyond 2029. Ballance has also struggled in obtain viable gas supply.

Methanex is an anchor user and underpins upstream production activity at Māui, Pohokura, and Mangahewa gas fields, as well as other fields indirectly. Its future is closely linked to the Māui gas field, and both could close coincidentally if tight conditions persist.

Loss of Methanex's demand response role

Methanex often temporarily reduces production during periods of system stress (e.g. gas outages and dry winters), reselling contracted gas to electricity generators to support energy security. Its Waitara Valley plant stopped producing in 2021 due to gas scarcity. The Motunui plant temporarily reduced production in 2024 and 2025 to divert gas to gentailers for dry year thermal generation.

Having large, flexible demand as a balancing mechanism for the wider energy system is critical in tight supply conditions and to address demand seasonality. If Methanex closes, other options will need exploring to balance supply such as storage, LNG or more disaggregated demand response and flexibility.

Dry year electricity security

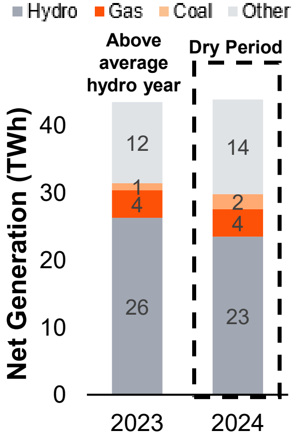
What is a 'dry year'?

Hydro generation represents 52% to 60% of New Zealand's annual electricity supply but national hydro storage is only about 10% of total supply (4,500 GWh per year). If there was no inflows from rain or snow melt into our storage lakes, full hydro storage would only last about three months.

A 'dry year', or more accurately, a dry period occurs when hydro inflows are significantly below average for an extended period, causing storage levels to fall to critical levels (typically defined as less than the lowest 10 percent of historical records). As hydro generation becomes constrained, the system must currently fill the shortfall from thermal backup (primarily gas, coal, and diesel) or demand response (turning consumers off).

Dry periods are most acute in winter, when electricity demand is high and snowmelt has not yet replenished storage.

Dry year with gas scarcity



Dry years may require 10 PJ - 20 PJ of additional gas over the next decade

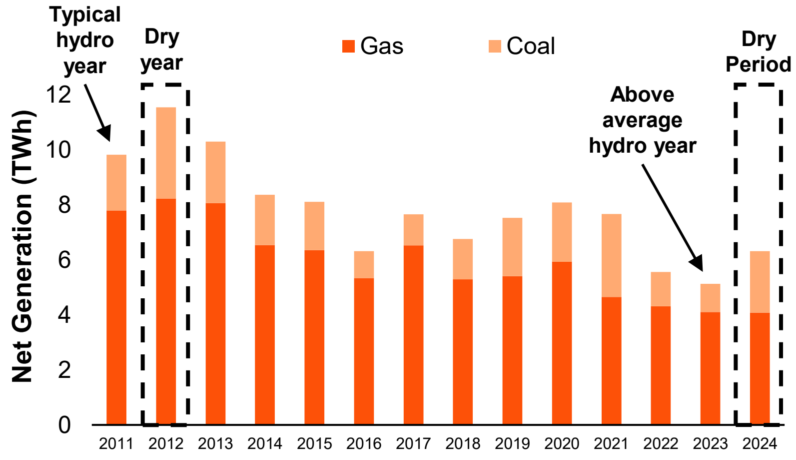
Over the past 15 years, there have been two notable dry periods; 2012 and 2024. The hydro shortfall compared to the 30 year historical average was 1.7 TWh and 0.8 TWh in each year, respectively. This is equivalent to around 15 PJ and 8 PJ of additional gas if this shortfall was covered by gas-fired generation.

2024 had a winter dry period with highly constrained gas supply. Hydro generation in 2024 was 2.8 TWh lower than in 2023 (an above average year). More than a third of this hydro shortfall was met by increased thermal generation, mainly coal (13 PJ) due to gas supply constraints. If this had been supplied by gas-fired generation instead of coal, around 11 PJ of additional gas would have been required that year.

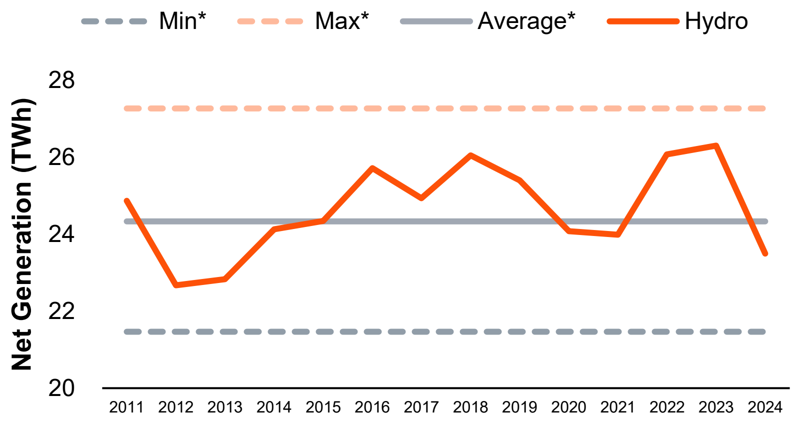
Both dry year requirements and our reliance on coal-fired Huntly Rankine units in normal years is expected to increase as electrification drives demand growth and as intermittent renewables increase the need for thermal firming.

We estimate ~10-20 PJ of additional gas-fired generation may be required over the next decade to provide volumes and peaking capacity to manage dry year risk.

Historical gas and coal generation



Hydro generation versus historical average

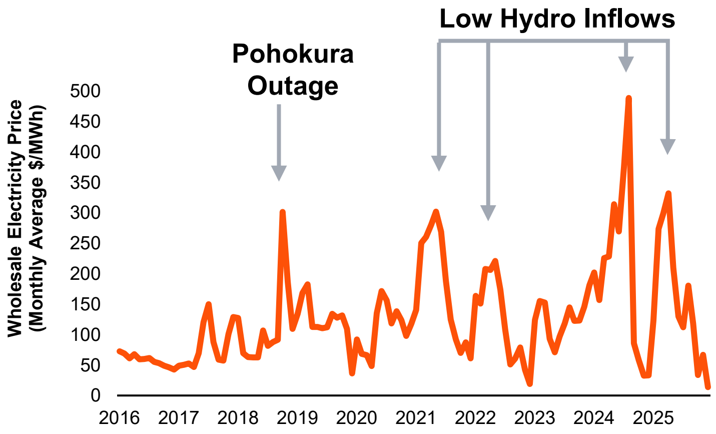


** Note: 30 years historical data from 1995-2024*

Role of gas in electricity security of supply

Gas remains critical to electricity security and affordability over the next decade

Electricity prices during supply constraints



Importance of gas in electricity security

Gas-fired thermal generation plays a critical role in New Zealand's electricity system in providing flexible, readily dispatchable capacity as backup supply for renewables.

Over the last 5 years, 32 PJ to 47 PJ of gas has been used each year as fuel for generation. Its role becomes vital in dry year periods when hydro generation is constrained and in winter when demand is high.

In dry periods, we now see electricity prices spiking to record levels where there is insufficient gas for generation. In August 2024, one of New Zealand's driest hydrology periods, monthly wholesale electricity spot prices reached $488 per MWh in Auckland; the highest in market history.

LNG	Pumped Hydro Storage	Renewables Overbuild
Biomass Peakers	Flexible Geothermal	Grid-Scale Batteries
Indigenous Gas with CCUS	Coal Fired Generation	Hydrogen Fuel Cells

Alternative dry year firming options

The energy sector is considering alternatives to indigenous gas that can provide winter security. Renewable options include pumped hydro schemes, biomass and hydrogen fuelled generation, and flexible geothermal, each of which faces technical and economic challenges. Grid-scale batteries are being installed now and provide short term flexibility but do not provide inter-seasonal or long-term energy storage.

In 2025, the four largest gentailers agreed on option contracts to keep three of Genesis' Huntly Rankine units available until 2035, running on coal and eventually biofuels. This provides up to 720 MW of generation capacity but may not be an enduring solution given the age of these plant. The Rankine units also do not provide fast start flexibility that modern gas-fired plant provide.

LNG imports scheme

In February 2026, the Government committed to developing an LNG import terminal to support electricity security. LNG is natural gas that is cooled to a liquid so it can be transported efficiently. It is traded extensively on global markets, including by Australia, our nearest trading partner. For context, New Zealand's total 2024 gas demand represents around 0.6% of global LNG trade.

The LNG import facility will need to be capable of receiving, storing, regasifying, and injecting gas into the existing transmission network. A minimum of 12 PJ would be made available on an as-needed basis to fuel gas fired generation for dry year security. LNG could also be economic for high value and hard-to-transition industrial, commercial, and residential users.

Accelerated delivery solutions are being progressed through a procurement process, with the first shipments potentially available as early as 2027 or 2028. All shortlisted proposals are located in Taranaki, reflecting its proximity to existing gas infrastructure and generation assets.

The Government has characterised the facility as an "insurance policy" against gas supply shortfalls, high electricity prices and energy insecurity, with analysis suggesting it could reduce electricity prices by at least $10 per MWh. Funding for the LNG infrastructure itself would be socialised via a levy on electricity, with indicative estimates around $2 – $4 per MWh. The ongoing cost of physical LNG would be borne by users when gas is drawn from the facility.

Case Study: The Netherlands Gas Transition

The Netherlands provides a real-world example of how quickly the gas transition can accelerate due to supply scarcity — and the energy system pressures that follow.

After Russia's invasion of Ukraine disrupted gas supplies and drove significant price increases, Dutch households and businesses rapidly moved away from natural gas.

The Dutch government moved quickly to stabilise supply. As Russian pipeline flows declined, **the Netherlands rapidly expanded LNG import capacity to stabilise supply**, including through floating regasification units at Eemshaven and increased throughput at Rotterdam. LNG imports allowed storage to be refilled ahead of winter, which brought down wholesale prices from their August 2022 peak, even though price volatility remained.

Gas-fired generation came under pressure. High fuel prices squeezed margins, while rapid renewables growth reduced running hours. Several operators warned that gas plants, critical for backup during low wind and solar output, were becoming uneconomic without stronger market signals. The result was a tension between decarbonisation and reliability. Even as gas demand fell, the power system remained dependent on flexible gas capacity to manage supply shocks and grid stability.

For Stedin, the regional network operator serving Rotterdam and surrounding areas, gas volumes fell by more than 25% from 2021, and **gas disconnections and electrification surged**. Requests for higher-capacity electricity connections rose sharply as households installed heat pumps, solar panels, and electric appliances. Electricity demand growth outpaced network capacity, creating grid congestion and connection delays. Despite investing over €1 billion in 2024 to expand cables and substations, bottlenecks remain. Stedin plan to spend a further €8 billion by 2030 on electricity network expansion and upgrades.

While New Zealand's circumstances differ, the lesson is clear: rapid supply decline creates costly and disruptive network pressures with real costs for the sector and consumers.

Coordinating indigenous gas supply decline with alternative fuels (LNG, biogas, LPG) and electricity system readiness will be critical to avoiding a turbulent and inefficient gas transition.

4

Approach

Scenarios and critical assumptions

Gas demand is modelled to balance available supply in each scenario, through analysis of consumer switching and generation production in normal and dry years

<table>
<tr><th></th><th colspan="2">Supply forecasting</th><th>Market balancing</th><th colspan="4">Demand forecasting</th></tr>
<tr><th></th><th>Indigenous Gas</th><th>LNG</th><th>Gas Price</th><th>Petrochemicals</th><th>Electricity Generation</th><th>Large C&I</th><th>Mass Market</th></tr>
<tr><td>Scenario 1:

Indigenous Gas Only</td><td rowspan="2">Supply is forecast based on Enerlytica’s Mid case gas production forecasts for the six largest fields (as at Jan 2026).

Key assumptions:
• Māui exits 2027
• Kupe exits 2032
• Pohokura exits 2039.

Other minor fields produce at same proportion of total supply, declining over time.

Forecasts shown overleaf.</td><td>No LNG</td><td>Gas prices rise from current levels to balance supply and demand based on the rank-order economic cost of switching for large C&I customers, sourced from EECA.

Assumes consumers with the lower cost of switching exit market first to clear demand.</td><td rowspan="2">Methanex and Ballance are assumed to close in 2027.</td><td>Gas Prioritised for Peaking and Daytime Running: Existing thermal plants run at levels sufficient to provide basic daily peaking. Huntly Unit 5 runs at minimal levels in between peaks and only provides winter strategic cover from 2032.

High Coal/Biofuels: 3 Huntly Rankine units available to 2035 running only on coal / biofuels.</td><td>Accelerated transition with more aggressive switching / shutdowns forced through higher prices and gas supply constraints. Switching behaviour shaped to accelerate in early 2030s to force transition due to gas unavailability.</td><td>Accelerated transition with gas switching accelerating sharply (peaking at 9% demand reduction in 2034). Based on estimates adopted under Commerce Commission draft GDB price quality path (DPP) decision.</td></tr>
<tr><td>Scenario 2:

Indigenous Gas + LNG</td><td>Minimum 12 PJ of LNG delivered per annum from 2028 to meet electricity security and demand growth. Additional LNG allowed where economic, to provide for more balanced demand transition for hard to transition customer segments.</td><td>Prices calculated under the above mechanism are capped at the landed price of LNG. Imports increase where consumers willing to pay.

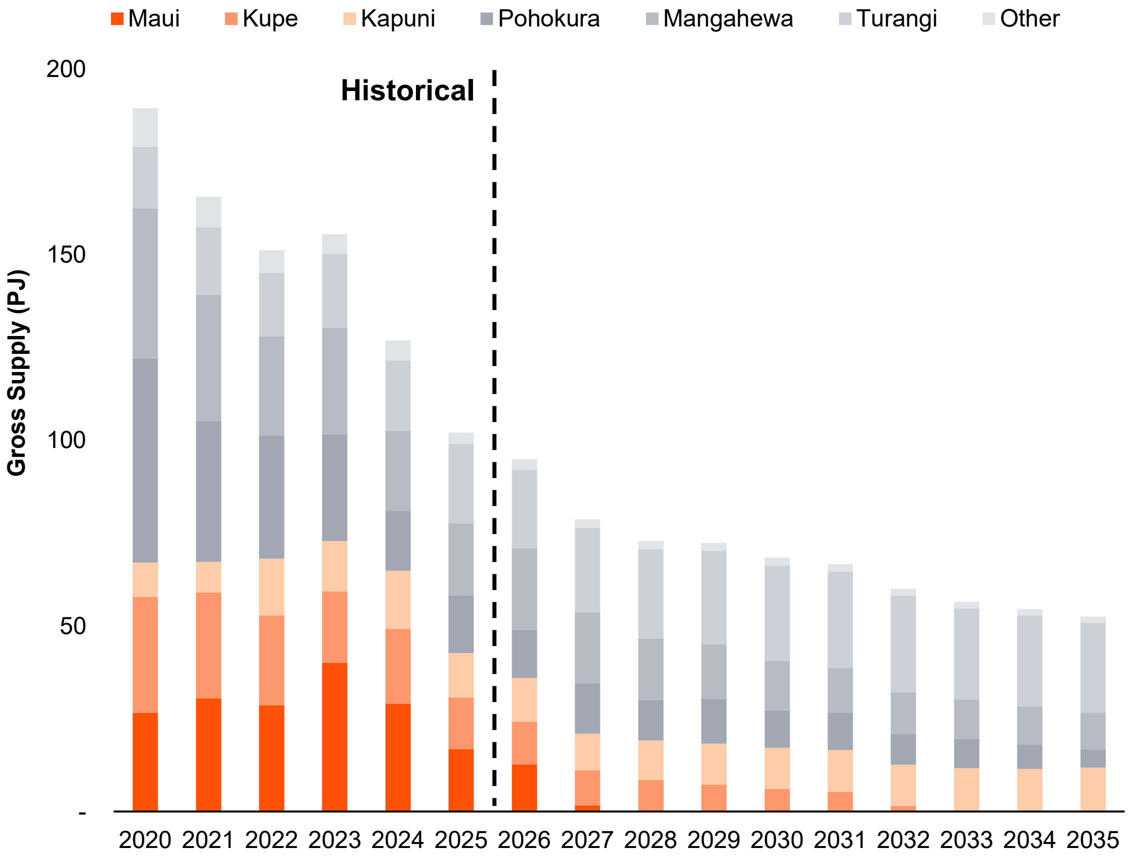
Fixed LNG terminal costs are socialised as energy security insurance.</td><td>Normal Gas Running: Existing thermal peaking plants run at normal operating levels to provide daily peaking and dry year security. Huntly Unit 5 operates normally.

Low Coal/Biofuels: 3 Huntly Rankine units available to 2035 running on coal / biofuels or excess gas / LNG.</td><td>Balanced transition with LNG providing a price cap and alternative supply options for hard to transition and high value uses. Transition shaped to accelerate in late 2030s to allow planning and supply to catchup.</td><td>Balanced transition with lower average annual gas reduction (averaging 1.5% demand up to 2035) with LNG to supplement supply, as necessary. Based on GDB forecasts and MBIE EDGS modelling.</td></tr>
</table>

Indigenous gas production forecasts

Māui is assumed to exit in 2027, Kupe in 2032, and Pohokura in 2039 with other fields maintaining production

Gas field production forecasts (PJ)



Source: Enerlytica (Mid January 2026), MBIE, PwC

Māui

Māui production continues to decline through 2026 and ceases in early 2027 as deliverability falls below economic thresholds. After exit, Māui is assumed to provide no ongoing residual production.

This outcome is supported by OMV's 2024 financial year decision to write down EUR 222 million of New Zealand gas assets, an 85% reduction.

Kupe

Kupe is forecast to continue producing into the early 2030s at progressively declining levels. The field is assumed to become uneconomic and cease producing in 2032.

Kapuni

The forecasts assume Kapuni continues producing at relatively consistent volumes across the forecast period.

Pohokura

Pohokura production is forecast to progressively decline after Maui's exit, and is projected to cease in 2039, beyond the 2035 forecast period.

Mangahewa

Mangahewa production is assumed to decline from the 2030s but to continue to make sizeable contribution to supply.

Turangi

Turangi production is projected to increase in the late 2020s due to planned drilling campaigns, which will make it the largest source of indigenous gas.

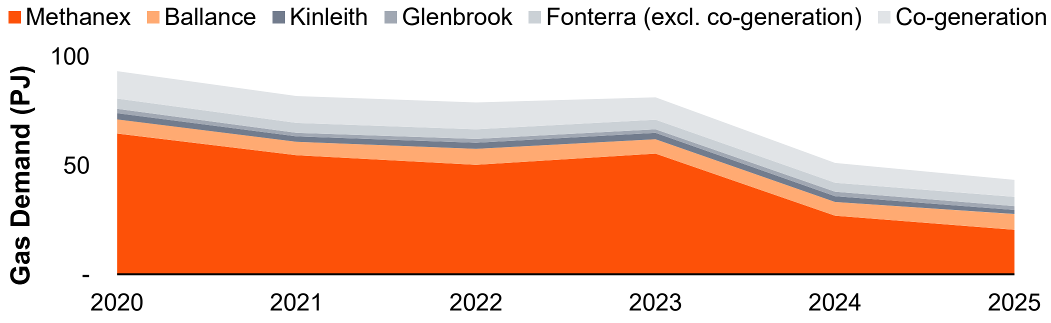
Other

Other smaller fields are assumed to contribute at a similar proportions to historical levels.

Approach to forecasting demand

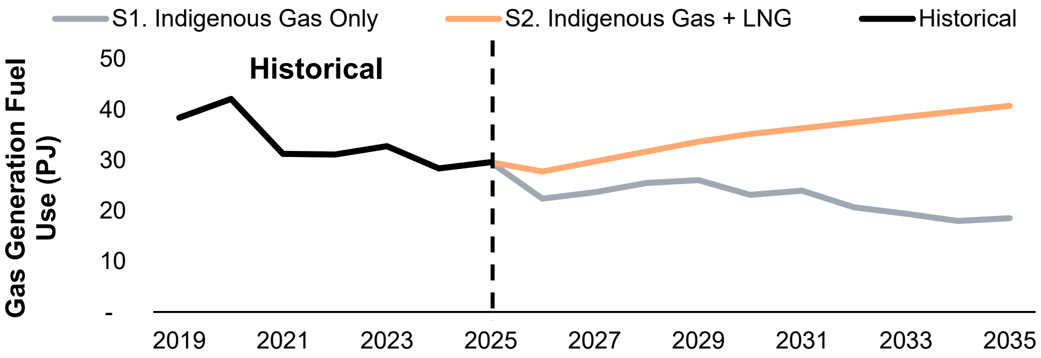
Industrial and generation comprise two-thirds of total demand; forecasts are based on analysis of gas switching plans and generation in normal and dry years

Gas usage by major industrial (PJ)



** Note: Excludes Marsden Point and Fonterra plant not directly connected to gas gates*

Annual gas generation fuel use in a normal year (PJ)



Note: Excludes TCC

Major Industrials

Major industrial gas users include Methanex, Ballance, Oji, NZ Steel, Fonterra, and related co-generation, which together accounted for 39% of 2025 gas demand.

Methanex and Ballance are assumed to exit in 2027 in both scenarios. This outcome is uncertain but is based on an assessment of the current economic stress these plants face due to high gas prices, gas unavailability, and international competition for production outputs.

Demand forecasts for the remaining industrials are based on EECA switching cost data, market disclosures and selective interviews to clarify plans and expected responses to gas shortages and high prices. Where gas is unavailable, transition timelines are accelerated, considering economic viability of alternative energy sources, practical timing constraints, and each company's supply chain exposure. This is a key uncertainty given the complexity of production economics and supply chains, and the limited information available on gas supply contracts and transition plans.

Generation

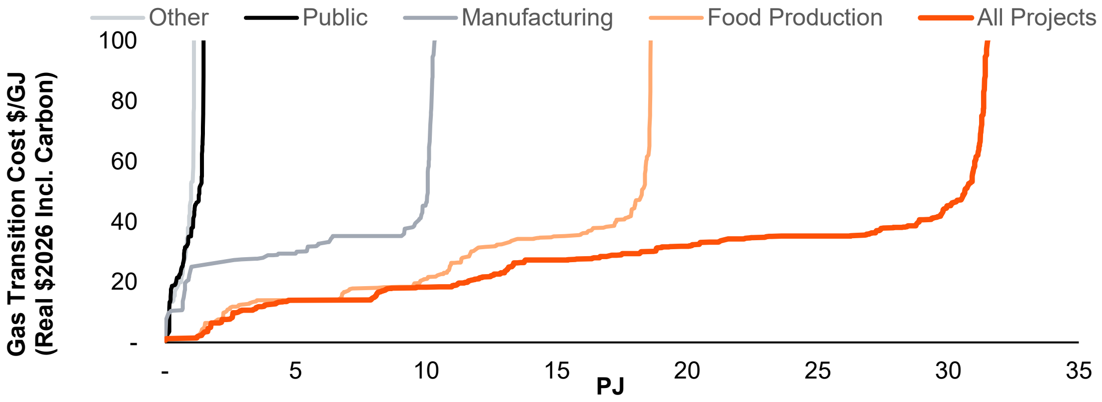
Thermal generation gas use is forecast out to 2035 in both normal and dry years based on PwC's price path model. Key assumptions are:

- **Thermal plant closures:** Genesis' Huntly Unit 5 reverts to winter security in 2032 in Indigenous Gas Only, consistent with Kupe gas field shutdown expectations. Other gas plant remain open until at least 2035, but no new plants are built.
- **Electricity demand growth** increases the thermal gas peaking requirement to firm intermittent renewables, resulting in higher generation gas use with LNG. In Indigenous Gas Only, this demand is absorbed by other generation (e.g. coal).
- **Three Huntly Rankine units** available until 2035 running on coal / biomass, but only two are in the market at a time.
- **Gas generation running** is constrained to minimal levels in Indigenous Gas Only, with more coal use. In Indigenous Gas + LNG, gas generation returns to normal running levels with less use of coal.

Approach to forecasting demand

Demand forecasts for commercial, SME and residential segments reflect analysis of switching costs and preferences

Ranked marginal cost of gas transition curves by sector



Large commercial

For large commercial users and other industrials, **we have used EECA's RETA database to assess the economics of gas switching and plant closures**. The database of over 470 North Island C&I gas users outlines the most economic alternatives to gas and provides a marginal cost of gas transition (MC) curve to switch to alternative energy sources. It shows that C&I users have different willingness to pay for gas, with some being able to pay more and some less.

MC data is ranked from the smallest to largest cost per GJ to determine the switching profile (see above). As gas prices increase above MC, consumers exit, thereby providing a market-clearing mechanism. Steeper MC lines indicate switching is economic at higher prices.

The volume of gas demand (in GJ) that can be switched or reduced each year is constrained to reflect practical technical limits, such as the availability of contractors, biofuel supply chains and electricity network capacity.

Each sector's ability to switch accelerates following an "S-curve" profile to reflect expected gas transition dynamics. This is characterised by **slow at first, then fast, then tapering off**.

Mass market

Residential and SME customers are assumed to transition from reticulated gas to electricity and LPG, based on assumed switching rates.

This group represents a small share of gas demand (i.e. 8%) and recent studies (Castalia 2025; Concept 2025; Pinstriped Leopard 2025) show a low willingness to leave gas. Residential customers in particular value gas' performance and convenience while SMEs face operational and cost barriers to switching. Research suggests a slower pace of electrification, with LPG preferred due to continuity of service, despite its higher cost. Electrification generally requires new appliances and, for many, electrical capacity upgrades, meaning cost and delays.

In Indigenous Gas Only, we assume switching rates accelerate quickly from 2028 as retailers seek to reduce their gas portfolios and support electrification. This is based on modelling undertaken for the Commerce Commission's draft DPP decision for GDBs.

In Indigenous Gas + LNG, a more balanced transition is assumed reflecting that LNG may be more economic than other energy sources. This is based on

Market balancing mechanism

Demand and supply is balanced primarily by the actions of C&I consumers in response to gas availability and prices

C&I users are assumed to switch to other forms of energy when gas prices exceed the cost of switching

Gas generation is assumed to be able to pass on gas prices through wholesale electricity markets. This reflects the importance of gas generation in daily peaking and dry year security of supply.

Residential and SME customers are assumed to be price takers and do not materially influence gas prices. This is considered reasonable given the small size of this group, relatively high willingness to pay and cost of switching, and low propensity to switch.

Under **Indigenous Gas Only**, we assume sustained upward pressure on gas prices as indigenous supply declines, resulting in persistent excess demand. This pressure is only relieved as demand exits to balance the market, with electricity generation absorbing any available supply.

Under **Indigenous Gas + LNG**, New Zealand's LNG requirements are small relative to global demand and we can import as much as we need. LNG is therefore assumed to cap domestic gas prices at the delivered price of LNG. This slows the pace of C&I switching and demand reduction as LNG prices fall below the MC of some customers that switch under Indigenous Gas Only**.**

Limitations in analysis

In practice, gas pricing is likely to be more volatile than assumed in the modelling under Indigenous Gas Only. Periods of tight supply and high prices may alternate with periods of lower prices as major demand segments exit, creating temporary excess supply.

Seasonal dynamics are also important. Generators are expected to contract gas volumes to cover dry year risk and release surplus gas as the forward hydrology curve improves. These behaviours are likely to contribute to price volatility and episodic price shocks, which could drive faster-than-modelled demand reduction in Indigenous Gas Only. As the analysis assumes a normal or dry year, these dynamics are not explicitly modelled. In effect we assume foresight of future market conditions.

The economics of several large industrial users is uncertain, as information is not reliably available in the EECA RETA database for all plant. Interviews with three large industrials on their gas transition plans under different pricing assumptions have informed the Study. Assumptions have been required where information is unavailable or unable to be published.

5

2035 Pathway

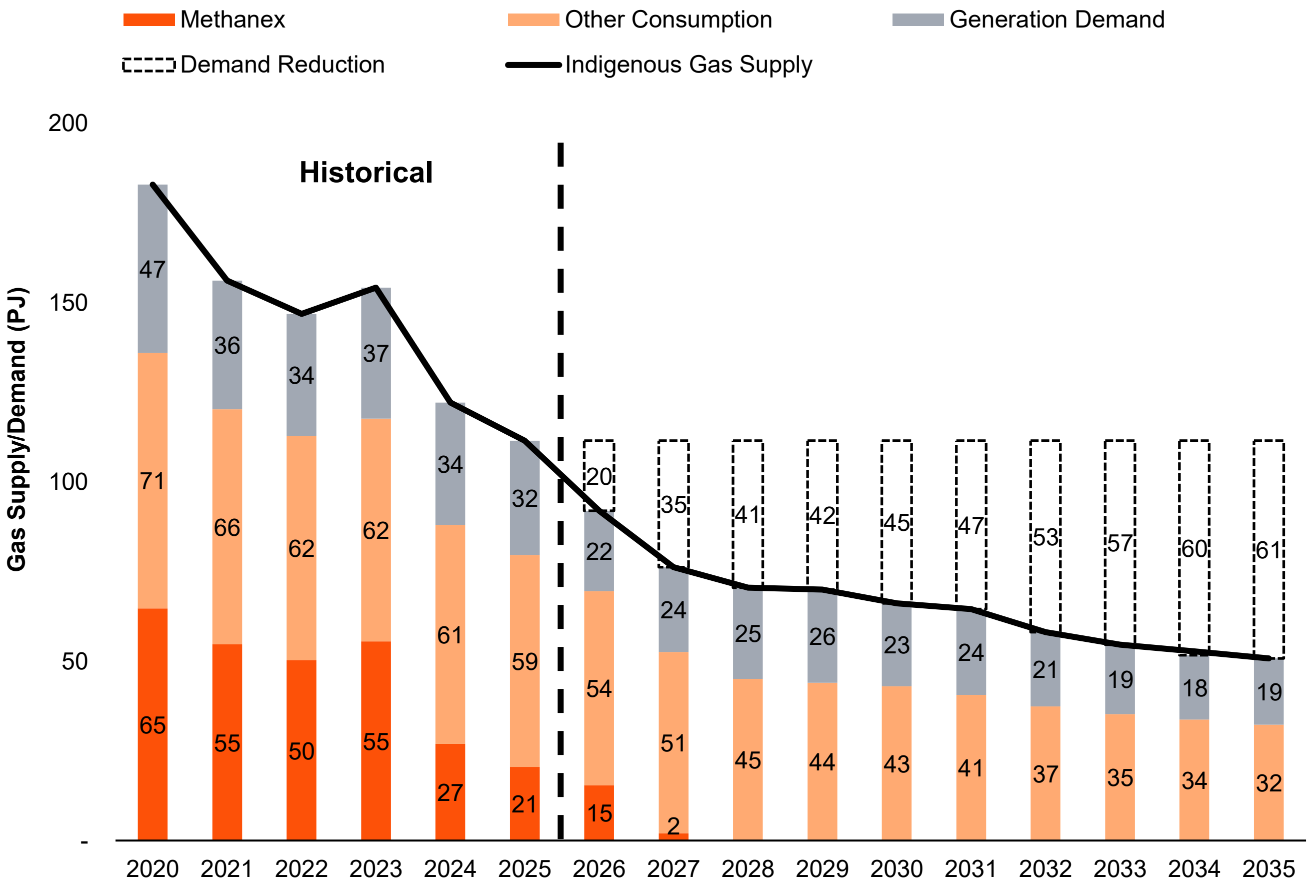
Scenario 1 - Indigenous Gas Only: Summary

As supply continues to fall, consumers face a rapid and potentially turbulent gas transition while gas generation will be constrained

Key observations

- Indigenous gas production halves by 2035 forcing annual demand to reduce by 61 PJ.
- The first few years see large industrial loads exiting including Methanex, Ballance, and previously announced closures of co-generation plants.
- Other consumer demand (excluding Methanex), reduces at an accelerating pace from 2028 in the face of rising gas prices and supply shortages, halving by 2035.
- Thermal gas generation is constrained in normal hydrology years and prioritises winter running and morning and evening peaks, with limited day time running. Rising electricity demand in later years, compounded by higher gas switching, requires coal-fired generation to run longer and puts pressure on the availability of gas-fired peakers to firm renewables.
- Around 10–20 PJ of additional gas is required for generation to manage dry year risk. Alternatively, a combination of additional demand reduction, energy demand response, and gas storage is required to balance the system.
- Ahuroa storage and new sources of energy demand flex will become increasingly important to support winter security, as major petrochemical demand flex is no longer available.

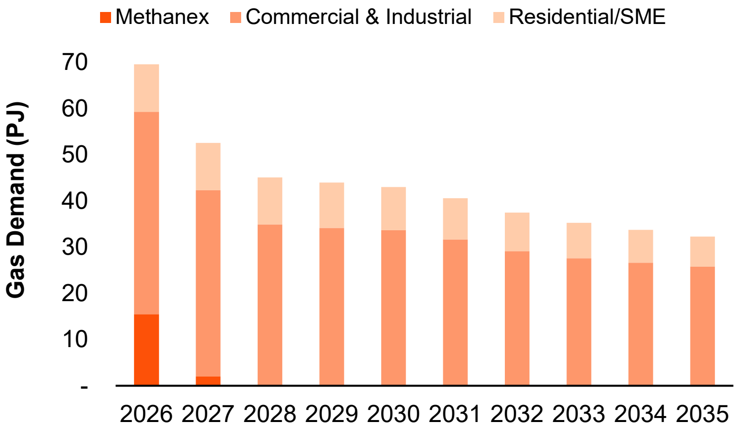
Gas supply and demand forecast (PJ) – Indigenous Gas Only – normal hydrology



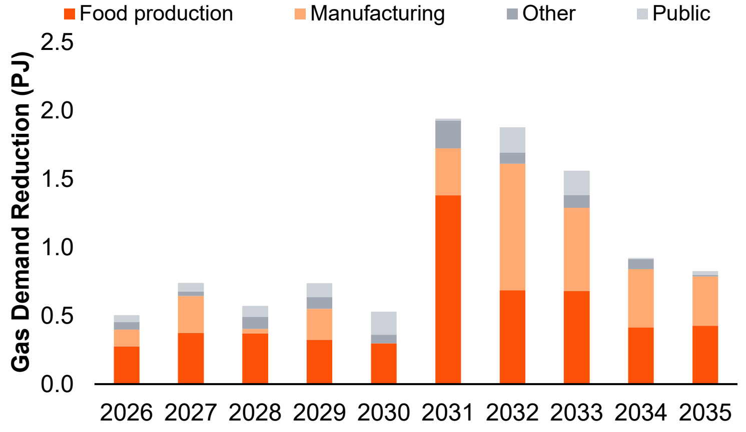
Scenario 1 - Indigenous Gas Only: Demand

Petrochemicals and food production account for most of the reduction in demand due to sensitivity to prices and supply constraints

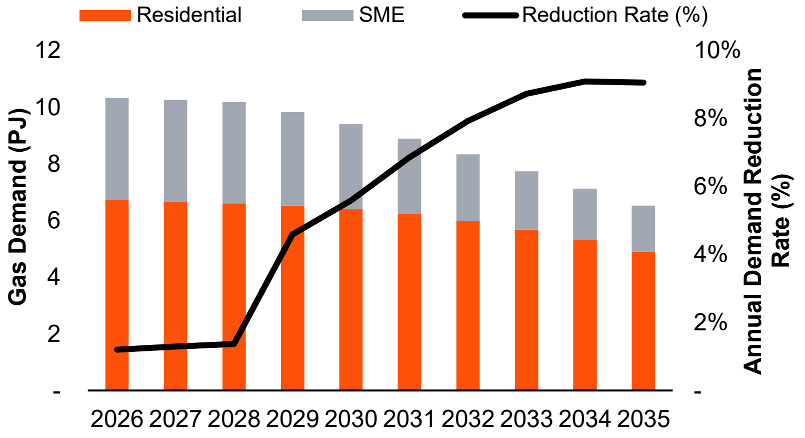
Forecast consumer gas demand



C&I annual demand reduction by sector (excl. petrochemicals and co-generation)



Mass market demand and switching



Demand contracts across all segments

- 27.7 PJ of **petrochemicals** demand (2025 equivalent) is removed with the exit of Methanex and Ballance in 2027
- **Remaining C&I demand** (excluding the petrochemical customers above) reduces 17.3 PJ (40%) between 2026 and 2035. This includes **co-generation plant** closures of 7.1 PJ, mainly from existing commitments to close plant by 2028.
- **Residential / SME** demand reduces 3.8 PJ (37%).

Food production demand reduces the most

- **Food production** (dairy, horticulture, food and beverage etc) make the largest contribution to demand reduction totalling 5.2 PJ by 2035, a 30% reduction. **Manufacturing** demand (other industrial, manufacturing, processing etc) reduces 3.3 PJ (25%) by 2035. **Public** sector (e.g. government, military, education, councils) and **Other** segments reduce by less than 1 PJ each.
- Switching gathers pace from 2031 as switching projects are completed and following an initial planning phase.

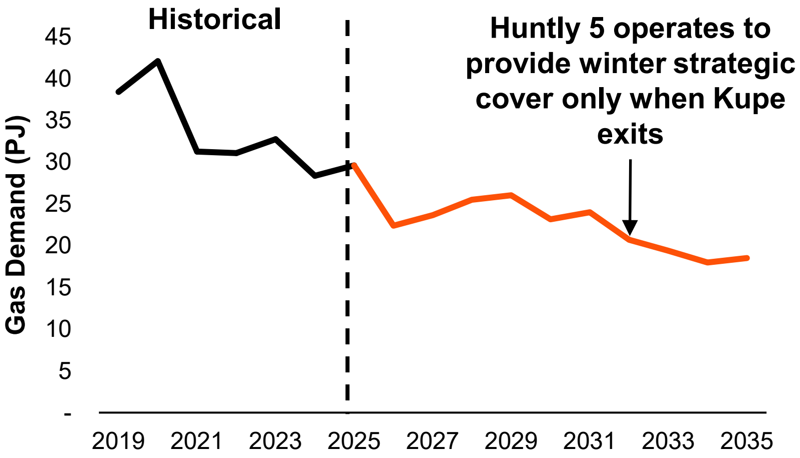
Mass market switching accelerates from 2028 as retailers reduce portfolio risk

- Mass market switching accelerates after Māui / Methanex close as retailers ramp up electrification and gas switching offerings to reduce portfolio exposure.
- Demand reduction peaks in 2034 at 9% before falling away.
- SME demand reduces by 2 PJ (55%) as high gas prices and supply uncertainty force businesses to switch.
- Residential demand reduces by 1.8 PJ (27%), reflecting their lower willingness to switch than other sectors.

Scenario 1 - Indigenous Gas Only: Generation

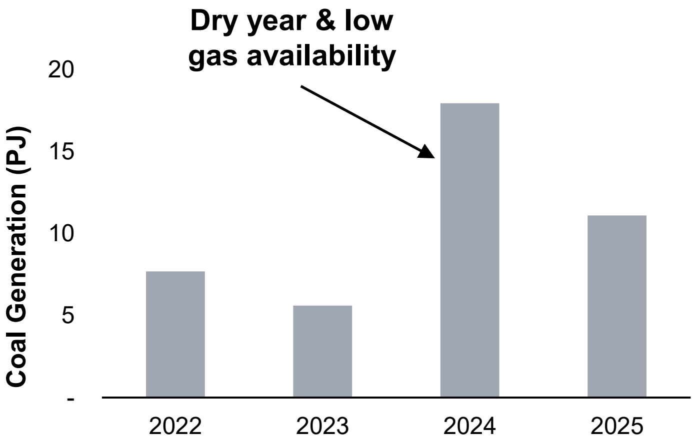
Gas scarcity constrains gas generation, with greater reliance on coal-fired generation

Annual gas generation demand

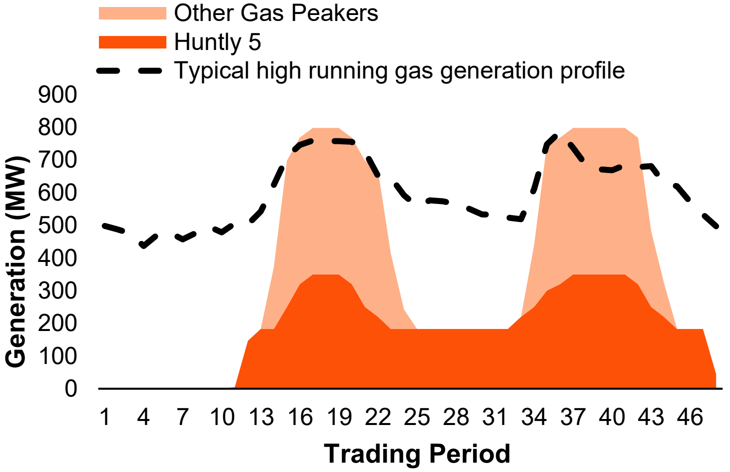


Note: Excludes TCC

Coal used for Huntly Rankine units generation



Assumed typical daily gas generation profile



Gas-fired generation operates at constrained gas levels due to fuel scarcity

- Gas generation fuel use declines to 19 PJ in 2035, reflecting lower operating levels seen during gas supply shortages.
- Accelerated electrification from gas switching compounds electricity demand growth pressures out to 2035 and market requirements for gas firming.
- Huntly Unit 5 reverts to a strategic winter cover role once Kupe ceases producing in 2032, similar to how TCC has been running in recent years.

Greater reliance on coal generation

- In 2024, a dry period with gas supply constraints, 17.9 PJ of coal was used by the Huntly Rankine units. This is notably more than prior years and highlights the role coal may play in dry years where gas is scarce.
- In a normal hydro year in the Indigenous Gas Only scenario, the two available Huntly Rankine units are expected to run longer and will burn up to around 40% more fuel per year than in 2024.

Gas-fired generation operates at constrained running levels

- It is expected that Huntly Unit 5 and other peaker generation will be prioritised towards morning and evening peaks with limited day time and overnight running.
- Peakers are also expected to prioritise the higher demand months i.e. winter and parts of the shoulder months.
- The figure above highlights the typical running profile under Indigenous Gas Only. This is compared to gas generation under a typical high running profile, highlighting the constraints placed on gas generation in this scenario.

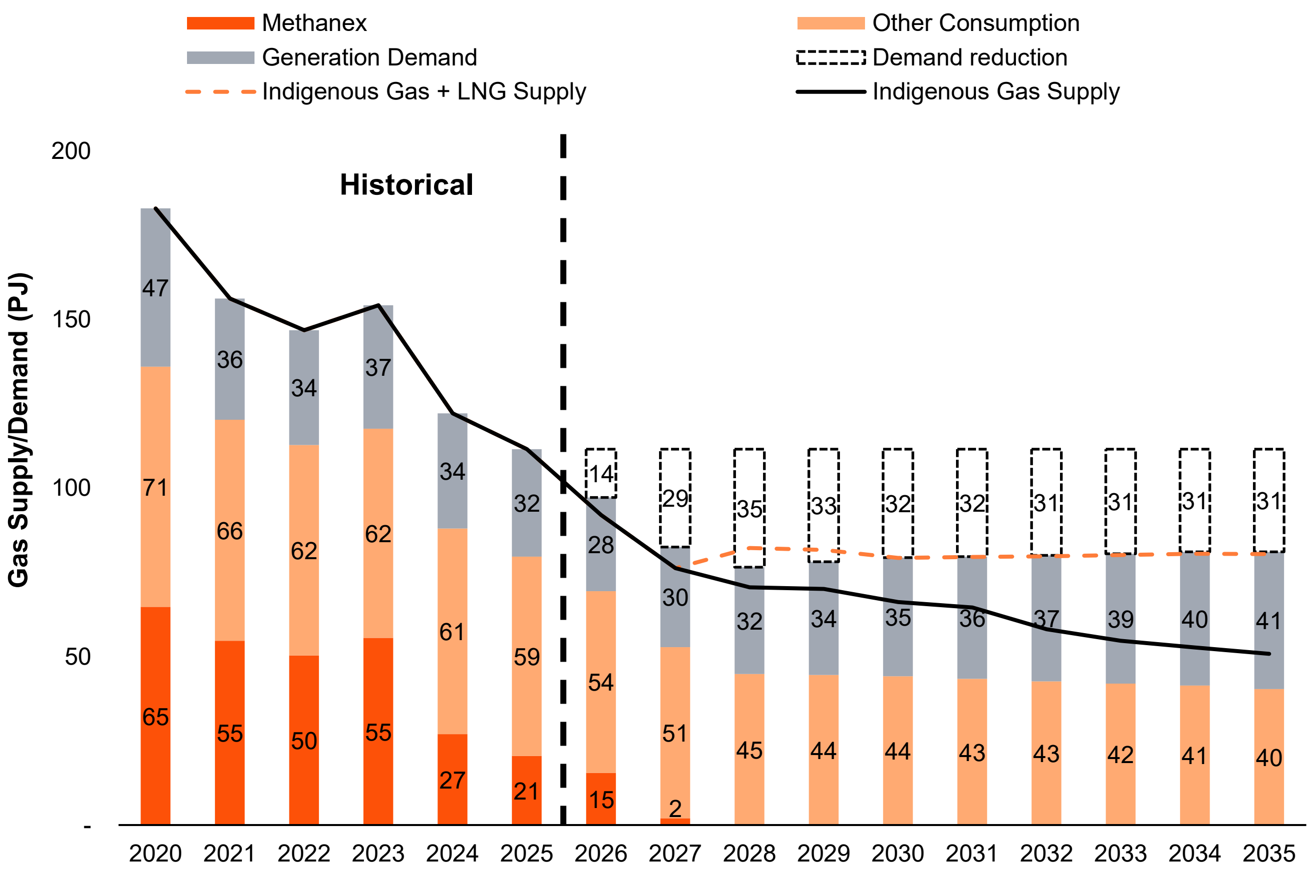
Scenario 2 - Indigenous gas + LNG: Summary

LNG supports a more orderly gas transition across all consumer segments and provides fuel certainty and flexibility for gas generation

Key observations

- Annual demand reduces by 31 PJ by 2035 relative to 2025 levels, around half of the reduction in the Indigenous Gas Only scenario.
- Petrochemicals (i.e. Methanex and Ballance) remain uneconomic with LNG and close as under the previous scenario.
- LNG supply increases from a minimum of 12 PJ in 2028 to 30 PJ by 2035, stabilising overall gas supply. LNG imports are critical to meet security of supply and to provide confidence for a managed gas transition.
- Māui's exit from the market ahead of LNG entering in 2028 results in a period of undersupply out to 2027 and demand holds to anticipate the new supply. In 2028 and 2029, there is an oversupply as minimum levels of LNG are assumed to be physically delivered. Tight supply conditions are anticipated for 2027 before LNG shipments arrive, which if a dry year could see acute pricing and constraints.
- LNG improves supply confidence and allows for a more planned and moderately paced transition across consumer segments. Demand reductions in C&I are around two-thirds of the Indigenous Gas Only scenario, and a half as much for Residential / SME. Cumulatively this reflects a 28% and 12% reduction by 2035, respectively.
- LNG fills the supply gap for thermal gas generators as indigenous gas declines, supporting a return to normal generation running in a normal hydro year and for growth in electricity demand and renewable generation firming.
- Overall, LNG increases flexibility in managing the gas transition, enabling more consumer led energy switching, and allowing time for the electricity and alternative fuel sectors to absorb demand.

Gas supply and demand forecast (PJ) – Indigenous Gas + LNG – normal hydrology

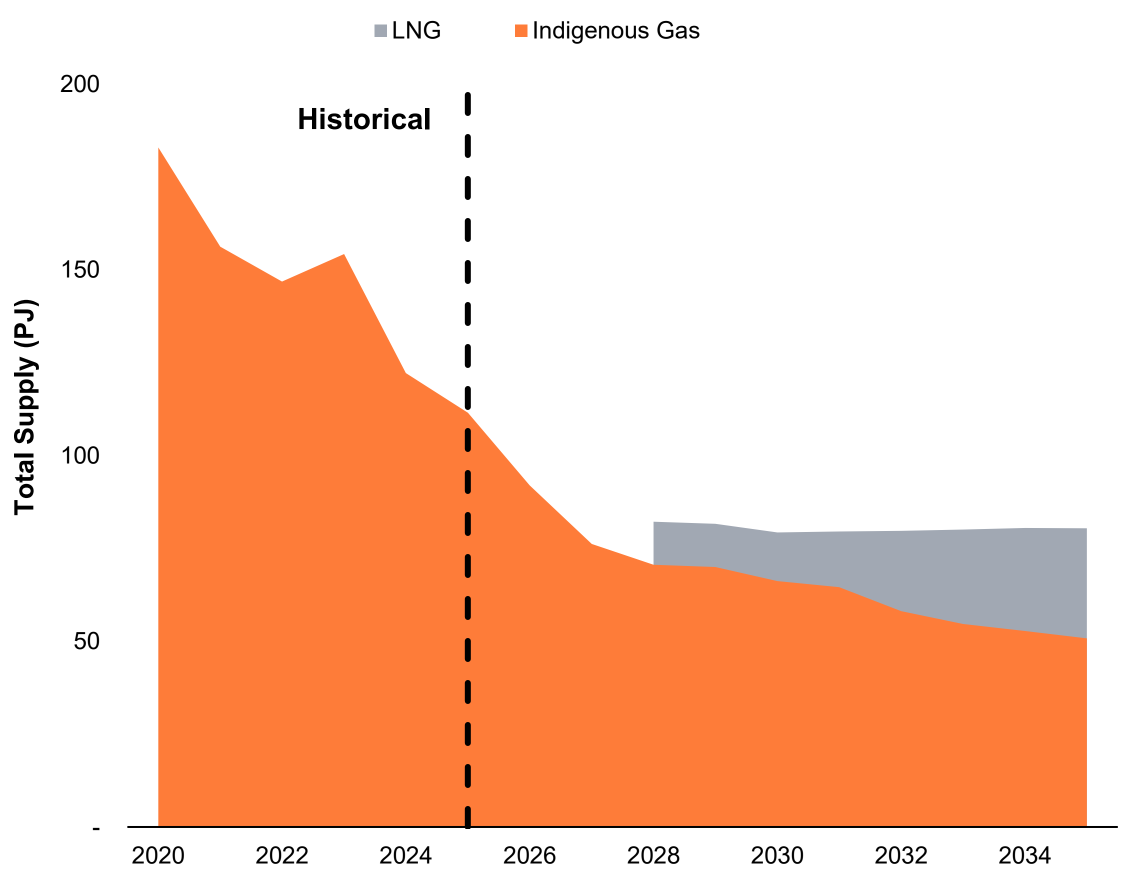


Scenario 2 - Indigenous Gas + LNG: Supply

Introducing LNG helps stabilise the gas market and provides flexibility for the energy transition and generation

- **LNG imports of 12–30 PJ per annum help stabilise the market through to 2035 at post Māui-exit levels**, equivalent to about 3–7 standard sized LNG shipments.
- **Forecast LNG prices range from $19 to $22 per GJ over the period** (real, including carbon, shipping, regasification, and transmission), which caps national gas prices. While higher than historical gas prices, LNG prices are about $10 per GJ lower than under Indigenous Gas Only.
- **LNG introduces exposure to global markets and geopolitical risk.** This could in practice introduce price volatility, but can be managed through long-term contacts, hedges, flexible purchasing arrangements and strategic storage.
- **Customer segments transition from gas at a more measured pace** due to lower pricing, allowing time to build electricity networks, generation capacity, and alternative fuel supply chains to adapt.
- **LNG could dampen signals to decarbonise and move to long-term renewable firming solutions,** particularly if used beyond dry year supply.
- **At current futures prices, LNG is a more economic option** than alternative higher cost fuels (e.g. LPG, biogas). It may also help alleviate congestion on electricity networks, as observed in the Netherlands.
- **LNG enhances gas market flexibility**, as import volumes can adjust in response to changes in supply and the pace of gas switching. Import contracting structures and scheduling will be key to enabling this flexibility.
- Supply flexibility is important for electricity generation, where hydro storage (in dry and wet years) drives demand for gas generation. **The ability to reduce LNG imports in wet years and increase imports in dry years will be important for managing energy system risk and overall costs.**
- The supply certainty provided by LNG could **stimulate indigenous gas production** by increasing confidence that sufficient demand will remain in the market to absorb indigenous gas.

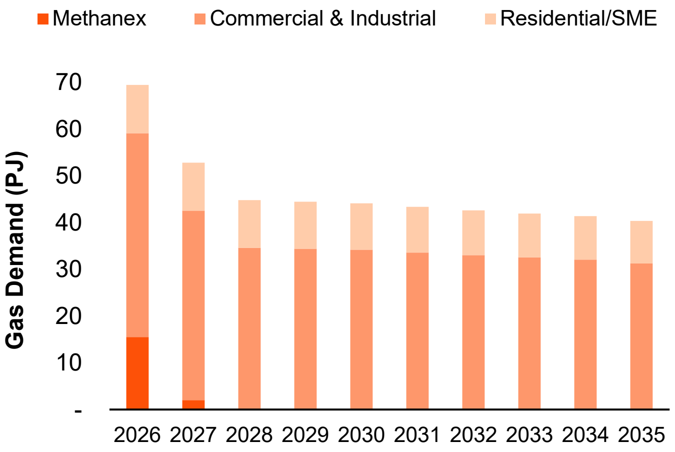
Supply forecasts - Indigenous Gas + LNG



Scenario 2 - Indigenous gas + LNG: consumption

Demand switching moderates across most consumer segments but remains concentrated in price-sensitive industrial sectors

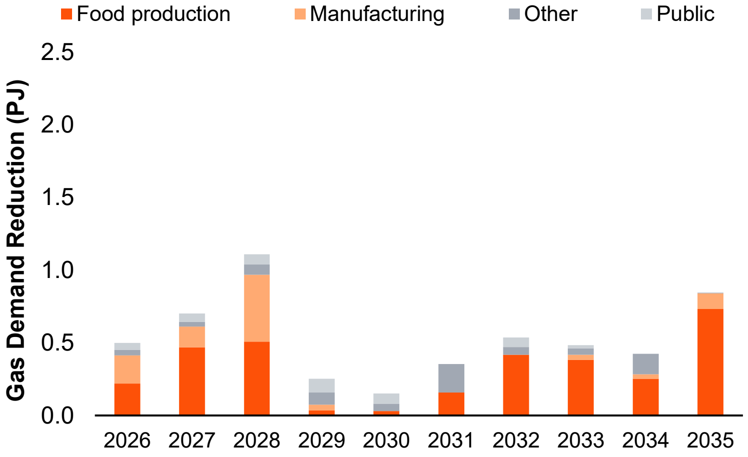
Forecast consumer gas demand



Non petrochemicals consumer demand falls at a more moderate pace

- Petrochemicals exit as under the previous scenario.
- **C&I demand** (excluding petrochemicals) reduces by 28% by 2035 (12.2 PJ), more than two-thirds of the Indigenous Gas Only scenario. **Co-generation plant** closures account for 6.8 PJ of this.
- **Residential / SME** demand reduces by 1.2 PJ (12%), less than a third of the reduction in Scenario 1.

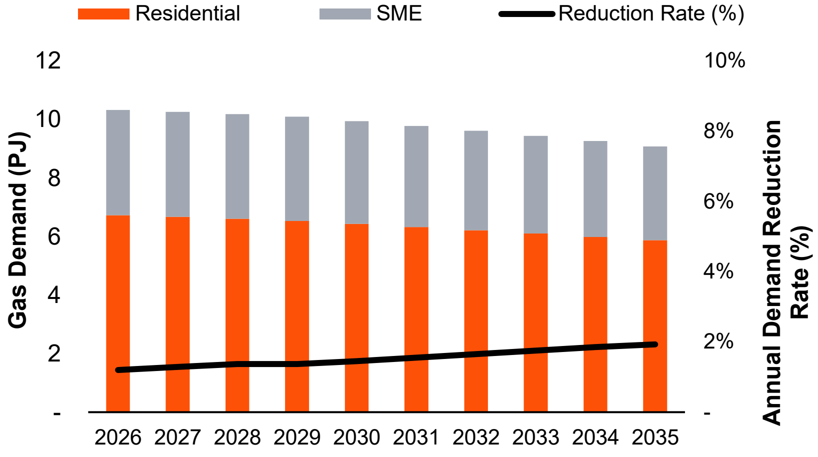
C&I annual demand reduction by sector (excl. petrochemicals and co-generation)



Food production still makes the largest contribution to demand reduction

- Food production makes a large contribution to demand reduction of 3.2 PJ (19%) by 2035.
- Manufacturing demand falls 1 PJ (7.4%), less than half as much as under the Indigenous Gas Only scenario.
- Public and Other demand reduce by 0.4 and 0.7 PJ.

Mass market demand and switching



Mass market demand reduction averages 2% per annum

- Mass market switching rates are assumed to be lower when LNG is added, reflecting more certain supply at lower prices compared to Indigenous Gas Only scenario. This may make it more economic compared to say LPG conversions or appliance upgrades.
- Overall switching rates increase to about 2% per annum by 2035.

Scenario 2 - Indigenous Gas + LNG: Generation

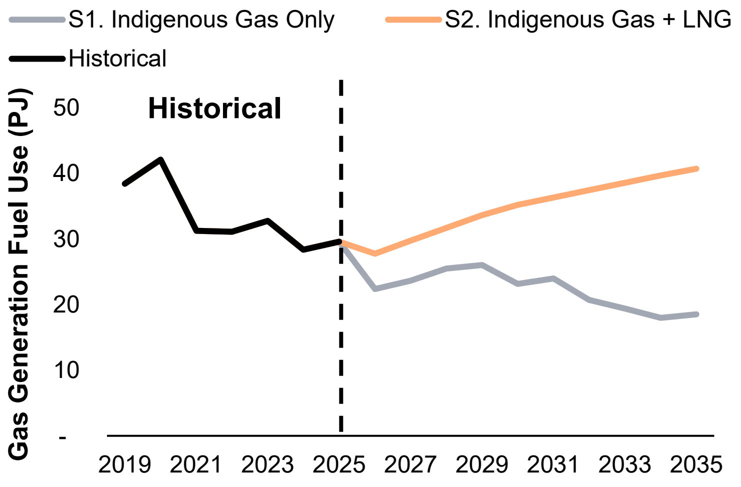
LNG meaningfully improves fuel security for gas generators, enabling gas plants to operate at normal levels to support electricity system flexibility and demand growth

Generation gas use increases to normal running levels

The stabilisation of total gas supply from 2028 restores fuel availability for thermal generation and enables a return to more typical running patterns.

Gas generation increases to 41 PJ by 2035 to support projected electricity demand growth (estimated at 6–18 TWh by 2035) and provides essential firming for increased intermittent renewable generation, strengthening overall system resilience.

Gas generation demand – normal hydrology



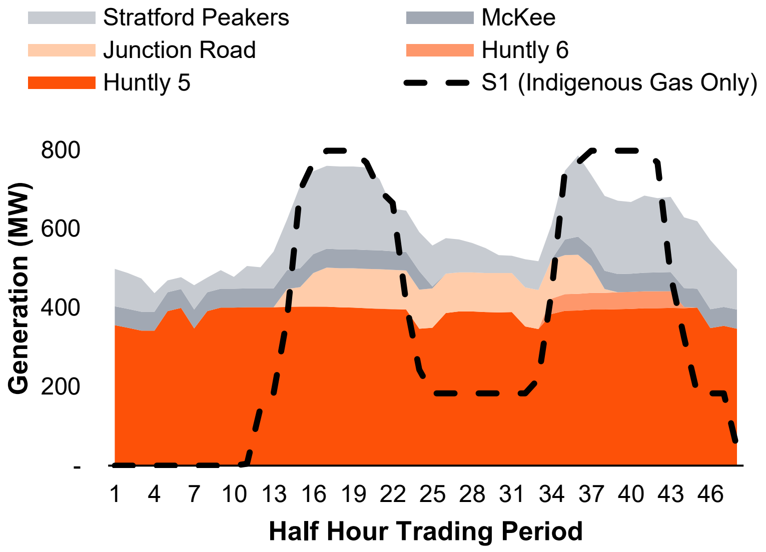
Note: Excludes TCC

Generation flexibility improved

The figure below compares gas generation under a typical high-running profile in a normal hydro year, with the Indigenous Gas Only running profile provided for comparison.

It illustrates how gas scarcity restricts the ability of thermal plant to run at efficient levels. LNG removes these restrictions and could reduce use of coal-fired generation and valuable hydro storage.

Example of typical high gas generation profile compared to S1 (Indigenous Gas Only) profile

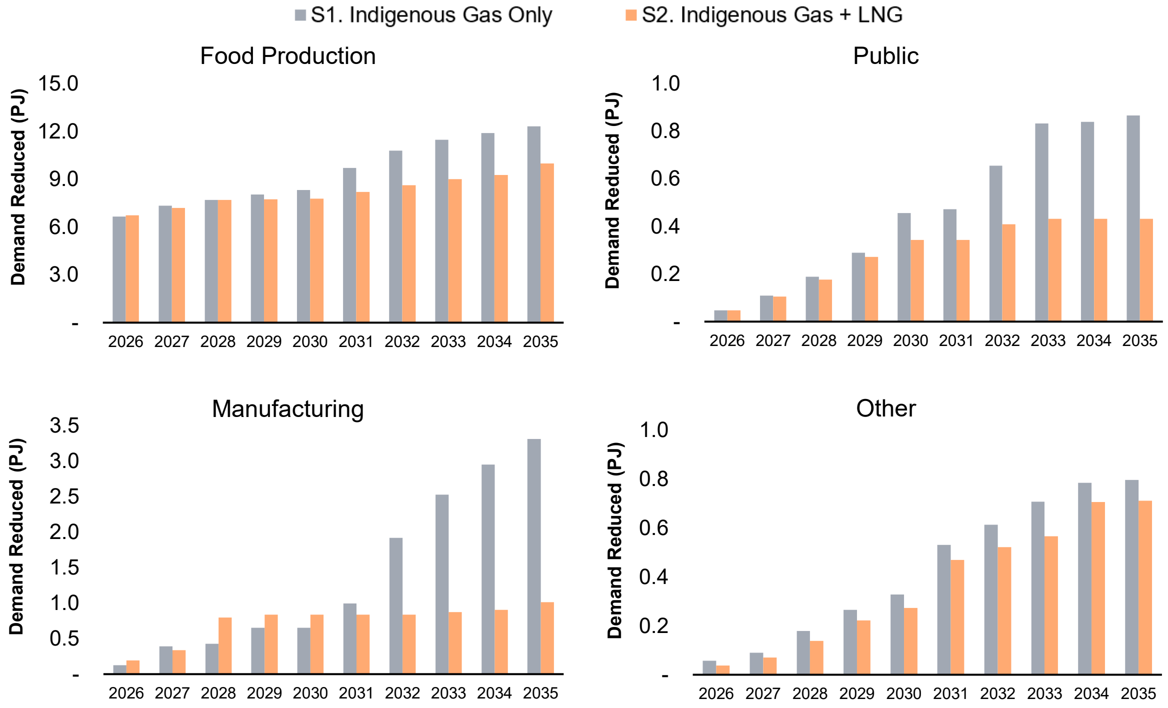


Demand comparison – commercial & industrial

Gas-intensive industries including petrochemicals and food production drive most of the projected demand contraction, with significant implications for jobs and regional economic activity

- **LNG is unlikely to support petrochemicals,** as both Methanex and Ballance face international competition from overseas producers with access to cheaper gas. The economic impact is significant and concentrated in the Taranaki region, with over 400 people are employed in these two plants
- Food Production is most sensitive to gas prices having a relatively low MC of gas transition curve. **It remains economic for many food producers to switch from gas even when lower priced LNG is available**. The cumulative demand reduction of this group reduces 2.3 PJ when LNG is added. Practically, food exports and production is critical to the economy and food security, and many food producers may decide to remain on gas if available. The demand reduction modelled with LNG imports is therefore likely to be high.
- Manufacturing and Public segments have steeper MC curves compared to Food Production and are therefore more responsive to changes in prices. The projected demand response from Manufacturing and Public segments is about 2.7 PJ lower when LNG is added, indicating that LNG may provide a good option for these segments to remain on gas.

Cumulative demand reduction by sector under each scenario



Higher gas prices in the Indigenous Gas Only scenario result in a much larger demand response across C&I, compared to Indigenous Gas + LNG scenario.

Marginal cost of gas transition (MC) is the gas price at which it is economic for demand to transition away from gas to alternative fuels, reduce demand, or shutdown**.**

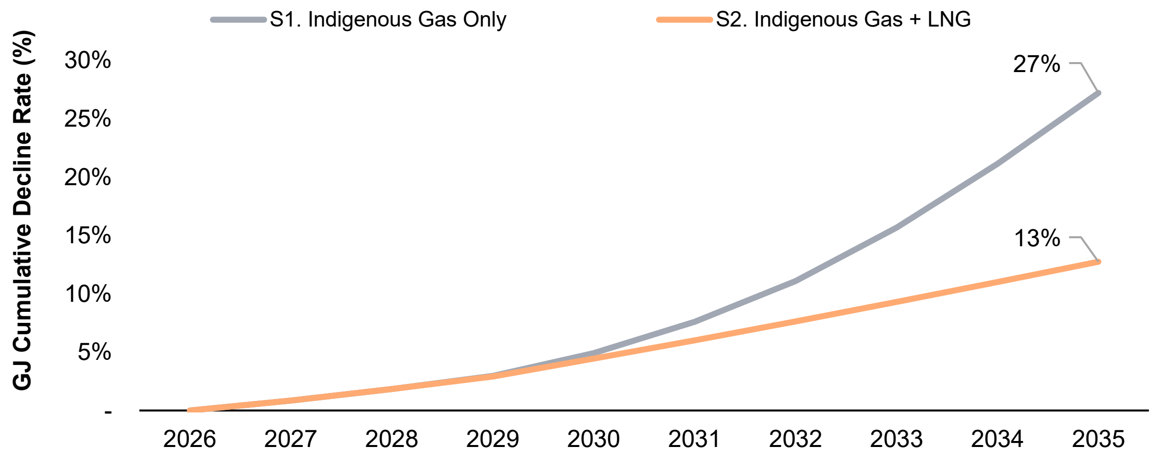
Demand comparison – residential

Residential switching is likely to be gradual in both scenarios, reflecting a preference to remain on gas and avoid switching costs

Switching accelerates from 2028 under Indigenous Gas Only as supply constraints begin to force demand off the system

- **In Indigenous Gas Only,** cumulative residential demand declines by 1.8 PJ. Many households are expected to respond to higher prices, which could rise 30% to 40% above historical levels. Retailers may seek to de-risk their gas portfolios and accelerate electrification strategies to avoid gas supply shocks in winter and dry years, that may create the need to ration gas.
- **Adding LNG in Scenario 2,** moderates the pace of residential transition as gas becomes available at relatively competitive prices compared to the alternative cost of switching. For example, LPG (excluding conversion costs) currently costs around $70 to $85 per GJ delivered, compared with an implied residential gas price of approximately $60 to $70 per GJ (based on an LNG wholesale price of $20 per GJ). Electrification adds additional costs of buying new appliances, but may be more energy efficient depending the use of gas (e.g. heat-pump space heating is generation more efficient)

Residential cumulative demand response



Consumer research supports a gradual transition profile for residential. Pinstriped Leopard (2025) found households had a strong attachment to gas and limited appetite for switching, with a preference to switch when appliances reach end-of-life.

Large-scale residential electrification is generally uneconomic. Castalia (2025) found that residential gas prices would need to increase 60%-70% relative to LPG and electricity prices for switching to be economic.

Appliance replacement, electrical upgrades, and remediation cost considerations currently outweigh energy efficiency gains and price differentials. Secondary costs may also flow through to consumers who switch, due to electricity network capacity reinforcement.

A forced transition, as in the Indigenous Gas Only scenario, is expected to impose substantial costs on households.

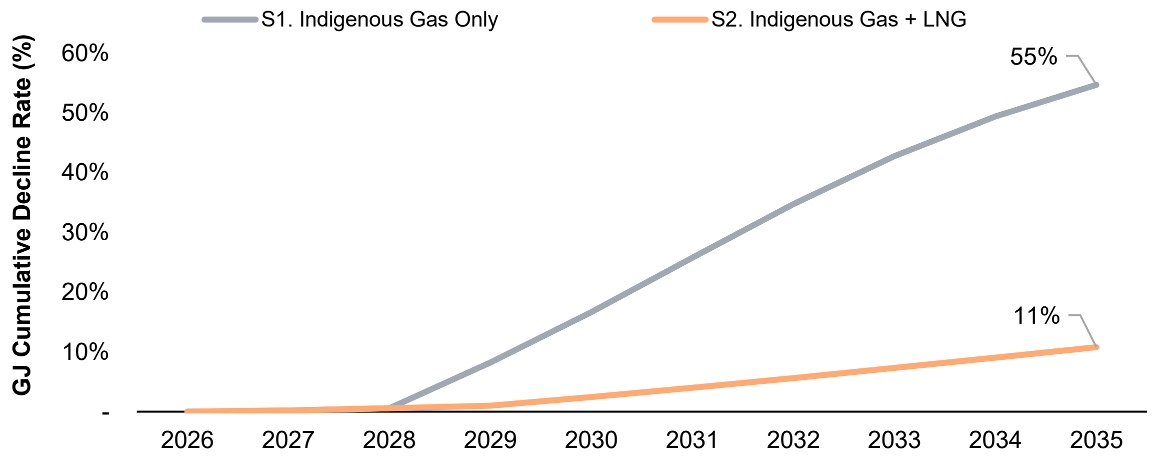
Demand comparison – SME

In Indigenous Gas Only, SMEs respond primarily to gas unavailability and uneconomic fuel prices, rather than proactively switching

LNG reduces prices to a level that may allow many SMEs to remain on gas, resulting in lower switching rates

- Under **Indigenous Gas Only**, SME demand declines sharply (55% by 2035) as higher gas prices and tightening supply force operational decisions. SMEs respond primarily when gas becomes unavailable or uneconomic, rather than switching proactively. Unlike residential users, SMEs rely on gas for process heat, where alternatives can be limited, capital-intensive, or operationally disruptive. Price increases of 50–70% above historical levels are expected to accelerate switching and contraction in sensitive segments under this scenario.
- Under **Indigenous Gas + LNG**, LNG imports moderate gas price increases to about 20%-40% above historical levels and improve supply certainty, allowing a more gradual SME transition.
- **Lower and more stable prices reduce the risk of closures and allow switching decisions to align with equipment replacement cycles and investment planning.**

SME cumulative demand response



Pinstriped Leopard (2025) found SMEs generally view gas as essential to operations, particularly where high, controllable heat is required. Switching appetite is low, with concerns focused on capital costs, downtime, and reliability of alternatives.

Castalia (2025) similarly concluded that switching SMEs to electricity is typically economic only under high gas price increases of around 70%, as appliance replacement, electrical upgrades, and disruption costs outweigh efficiency gains.

Overall, the SME transition is expected to be price-driven and uneven, with a higher risk of business exit under sustained supply constraints and high prices.

LNG is expected to limit price increases to a level that may allow many SMEs to remain on gas.

6

2050 Outlook

Supply outlook to 2050

Indigenous gas supply is projected to decline to less than a quarter of current levels by 2050

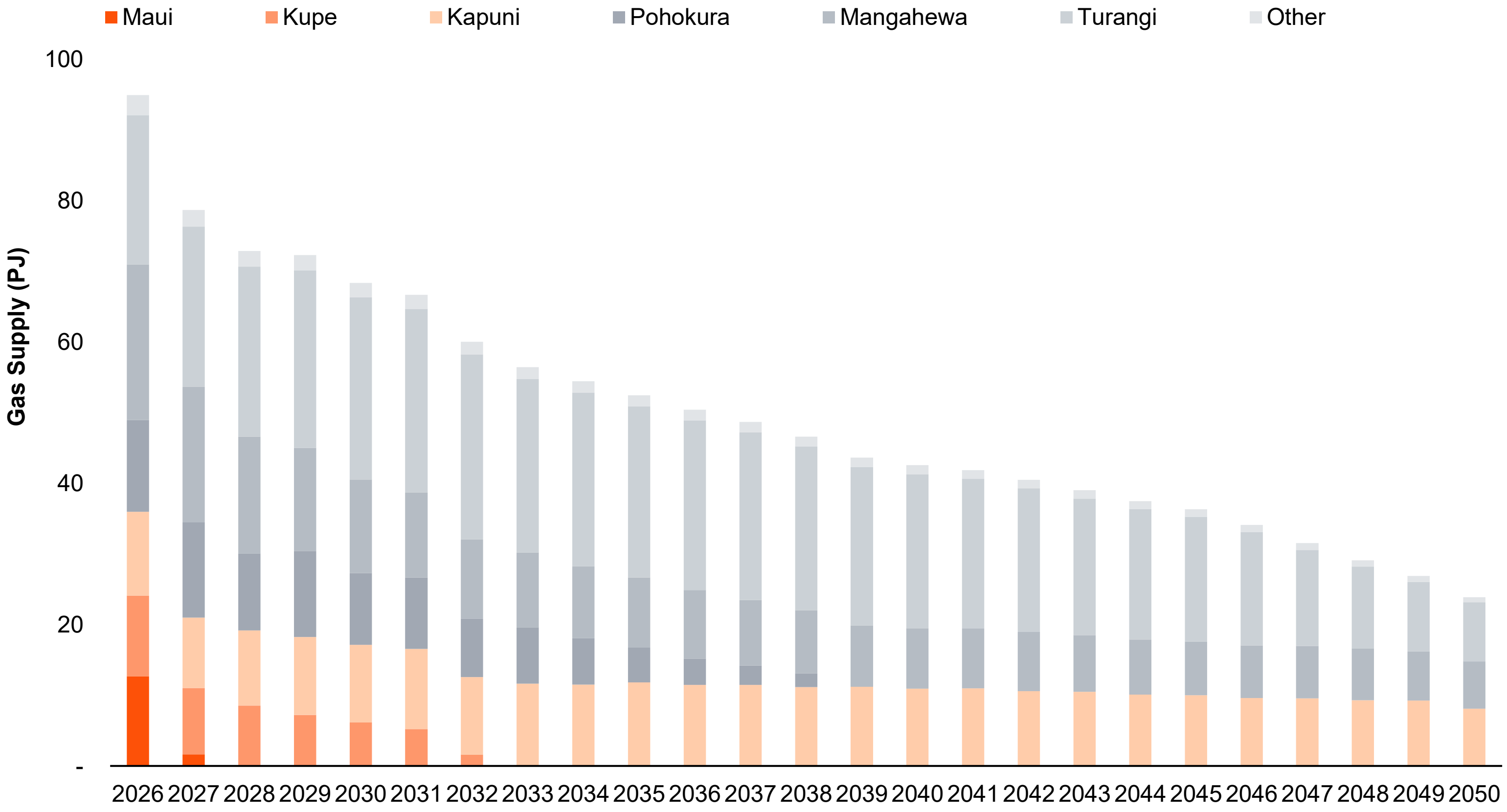
Total gas supply is forecast to halve over the next decade, falling from 112 PJ in 2025 to around 52 PJ in 2035. Long-term projections indicate supply could halve again between 2035 and 2050 to approximately 23 PJ. This is just 13% of 2020 gas supply.

The primary drivers of decline are the expected shutdown of the Māui, Kupe, and Pohokura fields over the outlook period. While production increases at Turangi out to the early 2030s, providing temporary relief, supply then falls as fields mature.

Future supply outcomes remain uncertain and could be higher or lower depending on LNG import availability, pricing, potential new gas discoveries and development timelines, and shifts in demand (including industrial use, electrification, and policy settings).

Beyond 2035, the long-term role of LNG is too uncertain to forecast with confidence, given variability in gas demand from thermal generation and broader energy transition dynamics.

Gas field production forecasts to 2050



Source: Enerlytica (January 2026), MBIE, PwC

2050 market outlook

Balancing supply and demand is increasingly complex beyond 2035 as indigenous gas supply and consumption falls and as generation plant retires

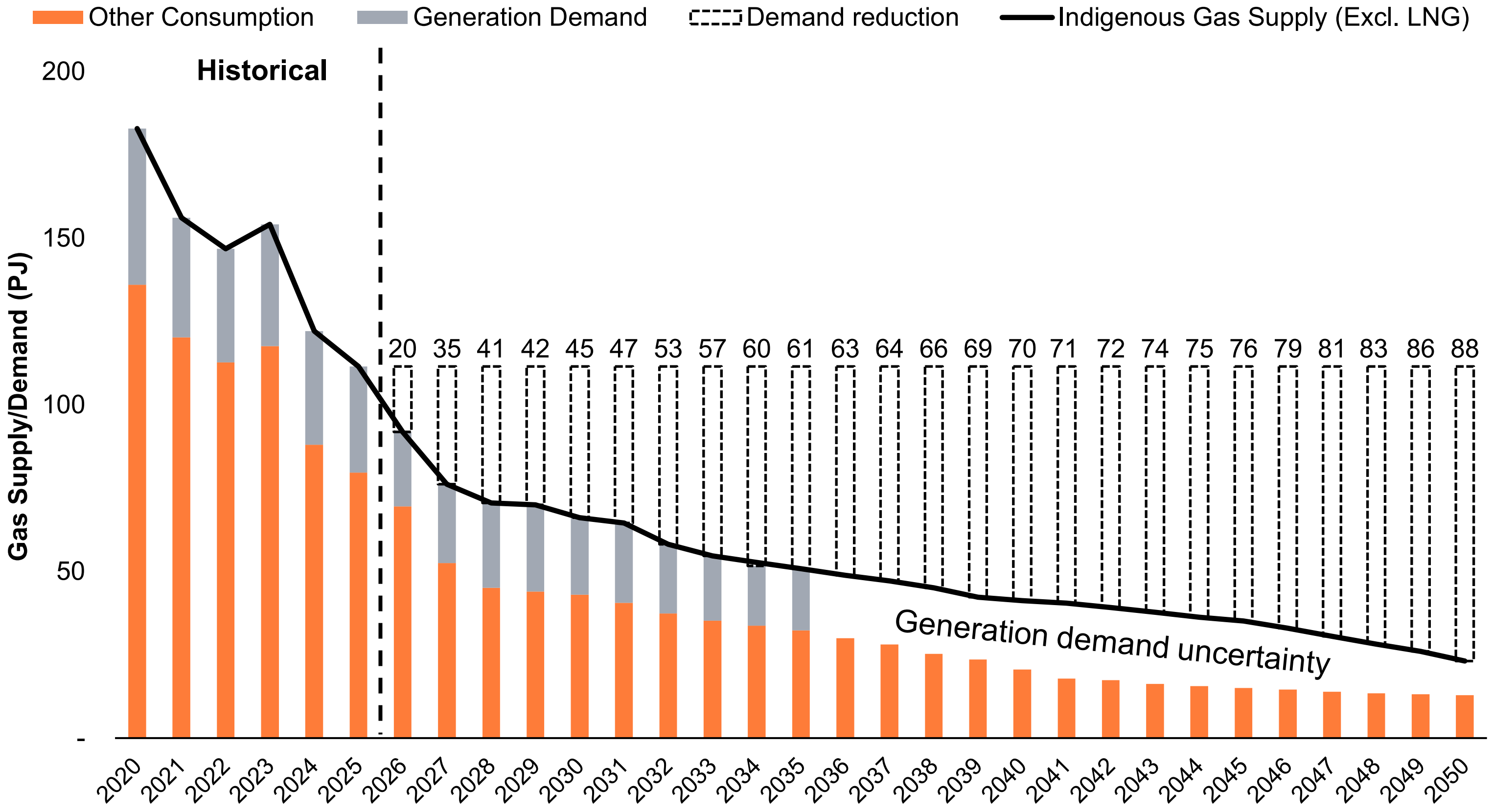
Indigenous gas supply is expected to reduce to around 23 PJ by 2050, a reduction of 79% (88 PJ per annum)

Projecting forward our demand modelling beyond 2035, sees the market contract to a small core of hard-to-abate uses. C&I users are assumed to switch at accelerated rates in later years as supply tightens, making it increasingly difficult to sustain major commercial operations. Residential and SME user switching rates accelerate in the 2040s and comprise only about 2% of demand by 2050.

The 2030s emerge as a critical inflection point for gas generation. Genesis' Strategic Energy Reserve Huntly Firming Options are assumed to end in 2035, gas-fired generation plants approach end of life, and the Kupe and Pohokura gas fields are assumed to be decommissioned. Available supply for generation tightens further in the late 2040s to about 10 PJ by 2050, which may support a few gas peaking units.

The future role of LNG beyond 2035 remains uncertain and is not modelled. If international prices remain stable, LNG could continue to supply hard-to-abate users, with import volumes flexing to manage seasonal and one-off demand shifts. However, as gas-fired generation retires and New Zealand advances toward Net Zero 2050, overall LNG volumes are likely to decline, and its role may shift from providing bulk volume to targeted flexibility. That said, if policy and economics allow, LNG could support expanded or new industrial demand where gas remains a competitive input.

Gas supply and demand forecast to 2050 (PJ) – Indigenous Gas Only – normal hydrology



Market implications

7

Gas price implications

Gas prices are higher in both scenarios but at assumed hedged LNG prices could be cheaper and less volatile

Prices will remain at elevated levels under both scenarios

Gas prices rise to $31 per GJ (real, including carbon and transmission) by 2035 under Indigenous Gas Only scenario. This is consistent with levels observed in periods of gas scarcity, such as when gas spot prices spiked to $41 per GJ in August 2024.

Pricing under this scenario is driven by the cost of switching which is assumed to clear the market. It also assumes that addressable gas demand always exceeds available indigenous supply throughout the period, creating sustained upward pressure on prices.

Projected prices are relatively lower under Indigenous Gas + LNG scenario, ranging between $19 to $22 per GJ (real, including carbon and transmission). This is estimated based on recent JKM futures prices for LNG with adjustments for shipping, regasification, carbon and transmission related costs.

LNG imports flex to meet supply based on the relative economics of domestic and global supply. LNG imports cap domestic prices at international levels.

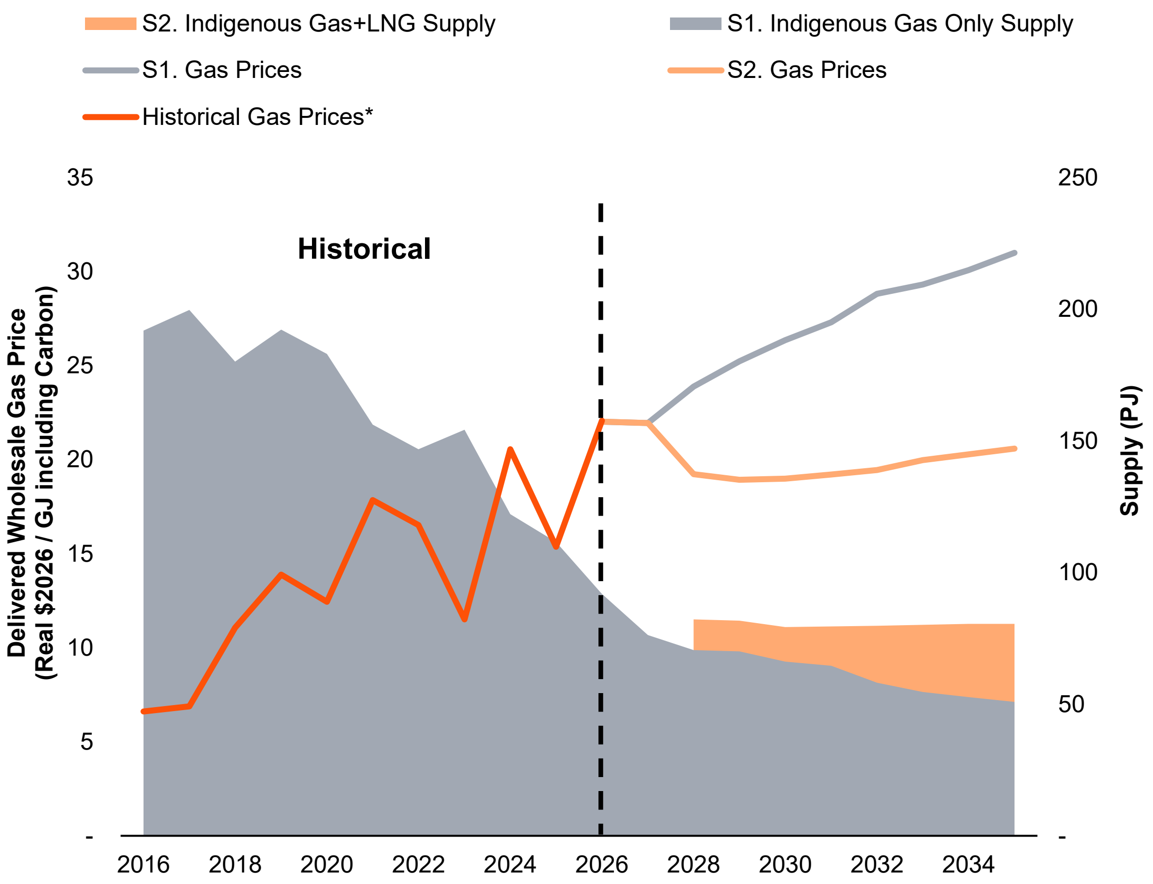
Hedged LNG could reduce price volatility

Prices volatility materialises in both scenarios for different reasons. LNG prices are exposed to global market dynamics and geopolitics, while indigenous gas prices are affected by ongoing supply risks, lack of supply flexibility, and periods of over and under supply.

Price volatility can be addressed for LNG through long-term supply contracts, hedging contacts, and flexible purchasing structures, but gas production risk and demand uncertainty remains a feature of the Indigenous Gas Only supply scenario.

Global LNG supply markets are deep and well established, and both exchange traded and over the counter hedging instruments can be used to reduce exposure to global markets, such as Platts Japan/Korea Market (JKM) futures and Chicago Mercantile Exchange (CME) JKM options contracts. Long-term supply arrangements are also common and can be negotiated to address price and volume risk.

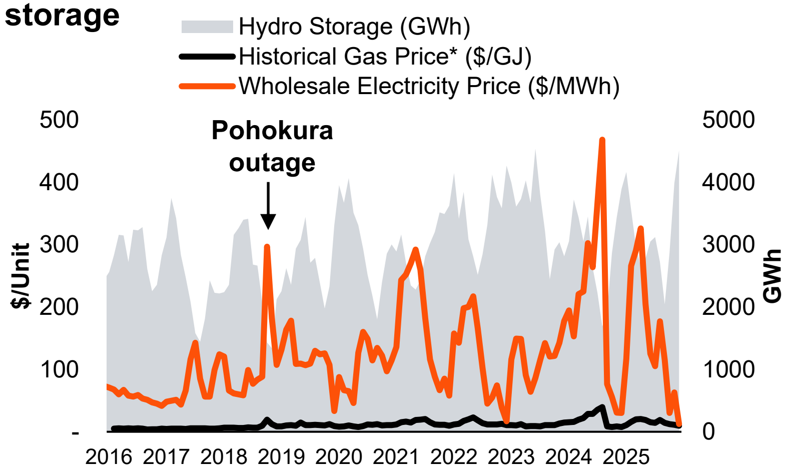
Forecast annual gas prices and supply



** Source: Gas Industry Co - EMSTradepoint*

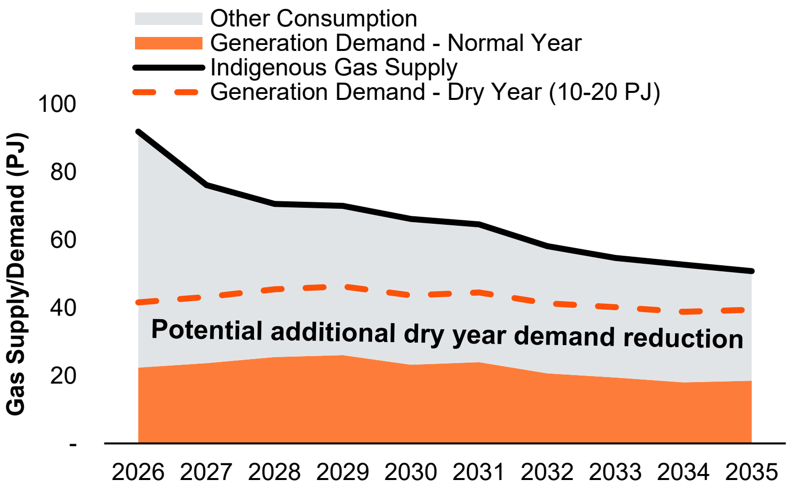
Dry year electricity generation analysis

Gas & electricity price relationship to hydro storage

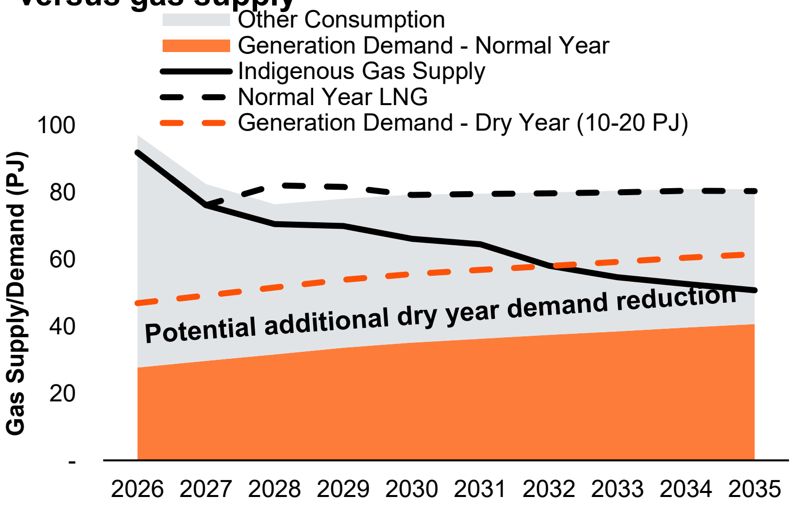


**Source: Gas Industry Co - EMSTradepoint*

Indigenous Gas Only generation demand versus gas supply



Indigenous Gas + LNG generation demand versus gas supply



Resilience during dry years

The combination of declining indigenous gas and dry hydro conditions has led to periods of high and volatile electricity and gas prices. Under Indigenous Gas Only, this risk intensifies as gas availability tightens and supply shocks become more frequent.

Under Indigenous Gas + LNG, LNG imports provide greater supply certainty and could be scaled to reduce the impact of dry years during periods of constrained indigenous gas availability.

Dry year analysis - Indigenous Gas Only

In dry years about 10-20 PJ of additional gas is required for electricity generation. Under Indigenous Gas Only, there is limited gas flex remaining in the system (i.e. due to Methanex leaving), this creates a gas supply shortage for either gas consumers or electricity generation depending on which is prioritised.

This situation becomes untenable in the late 2020s and deteriorates out to 2035. Two Huntly Rankine units may be unable to cover dry year risk, potentially requiring a third unit.

Gas and electricity demand response schemes, and flexible storage will be needed to cover dry year risk.

Dry year analysis - Indigenous Gas + LNG

LNG can scale to provide the generation fuel volumes needed during dry years as well as flexibility and fuel security. Dry years would require around 4 to 5 additional standard LNG shipments. This implies around 50 PJ of LNG is required in dry years by 2035, including to meet consumer demand. Alternatively, if lower levels of LNG are available, then further consumer demand reduction would most likely be required in normal years to mitigate dry year supply risk.

Dry year risk remains in winter 2027 and will need to be more actively managed across both the electricity and gas markets. The market will lose Methanex demand flex and Maui gas supply in early 2027. If LNG is not expected to be available until 2028 this could create tight conditions for winter 2027.

Need for additional demand flex

In the absence of 10 - 20 PJ of gas contract flexibility, alternative non-gas backup generation will be required to address dry year risk

The role petrochemicals play in providing dry year demand flex will be difficult to replace

As outlined in Section 3, Methanex has historically provided critical demand-side flexibility by freeing up gas for electricity generation during periods of tight supply and dry years.

This has included seasonal gas swap arrangements (supplying gas to generators during winter peaks and receiving volumes back in spring), as well as production shutdowns.

In 2024, Methanex reduced output early in the year and fully idled production from mid-August to late October to support electricity security (see figure opposite). Between March and October 2024, it effectively released around 22 PJ of gas which is comparable to the 20 PJ consumed by gas-fired generators over the same period. 2024 was a year with a dry period with gas supply constraints and is indicative of the size of demand response required in the future.

If petrochemical demand exits, few remaining industrial users are large enough to provide comparable dry year flexibility. Dairy would become the largest gas consumer, but its winter demand is low, and it cannot meaningfully flex within its production cycle.

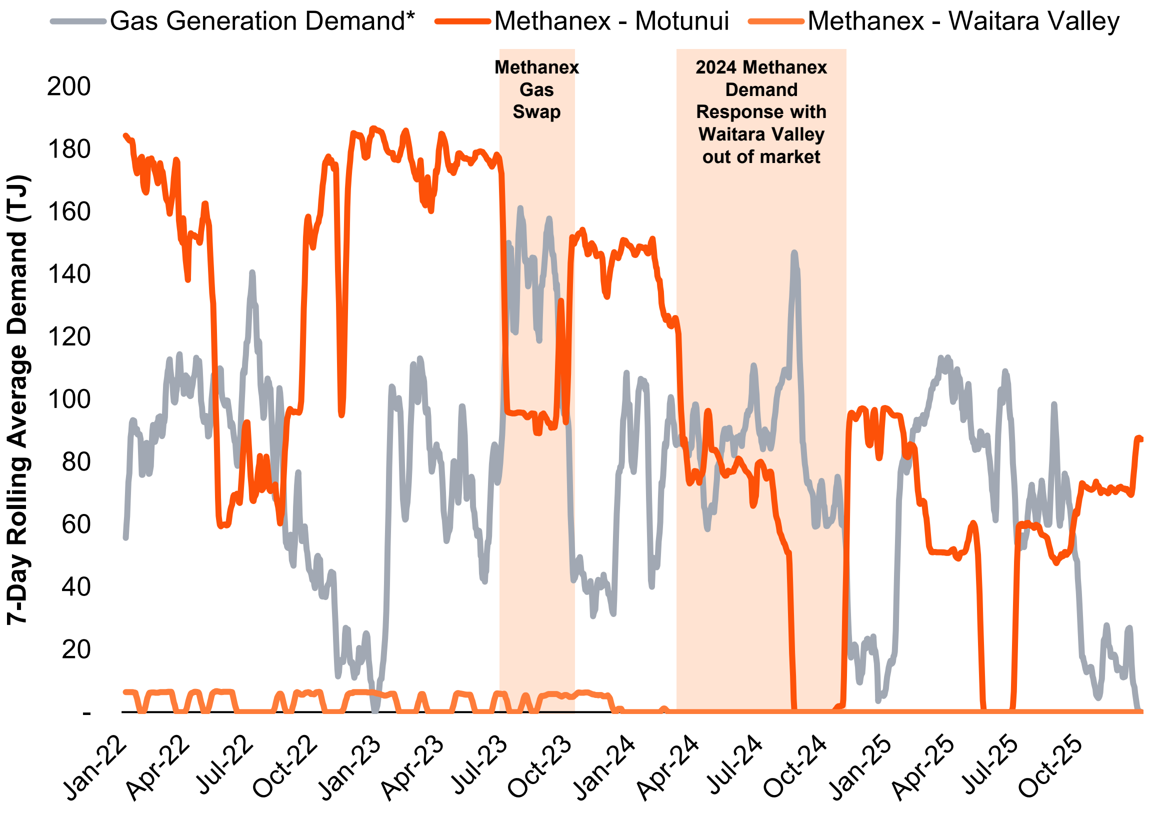
Other C&I users are individually too small to stabilise the market in a dry year.

In the absence of a major source of demand flexibility, alternative dry year storage solutions must be found

Dry year generation demand is variable and episodic. Alternative dry year options therefore need to provide a store of energy and capacity that may not be used for multiple years; otherwise, further gas demand reduction would be required to reduce system risk.

Several options are being considered and include greater reliance on the Huntly Rankine units, LNG, expanded gas storage, new dry year generation (e.g. diesel peakers), supported by enhanced demand response across both electricity and gas markets.

Methanex demand versus thermal generation



** Huntly + Junction Road + TCC + Stratford Peakers + McKee*

Role for gas storage

Gas storage will continue to support system flexibility, but will not replace large-scale demand response

Storage enhances system flexibility by shifting gas from periods of excess supply to periods of high demand (winter, dry periods). In New Zealand, the Ahuroa Gas Storage Facility provides important but limited flexibility with effective storage capacity of around 6–8 PJ (excluding ~4 PJ cushion gas required to maintain deliverability) and 65 TJ per day extraction rate.

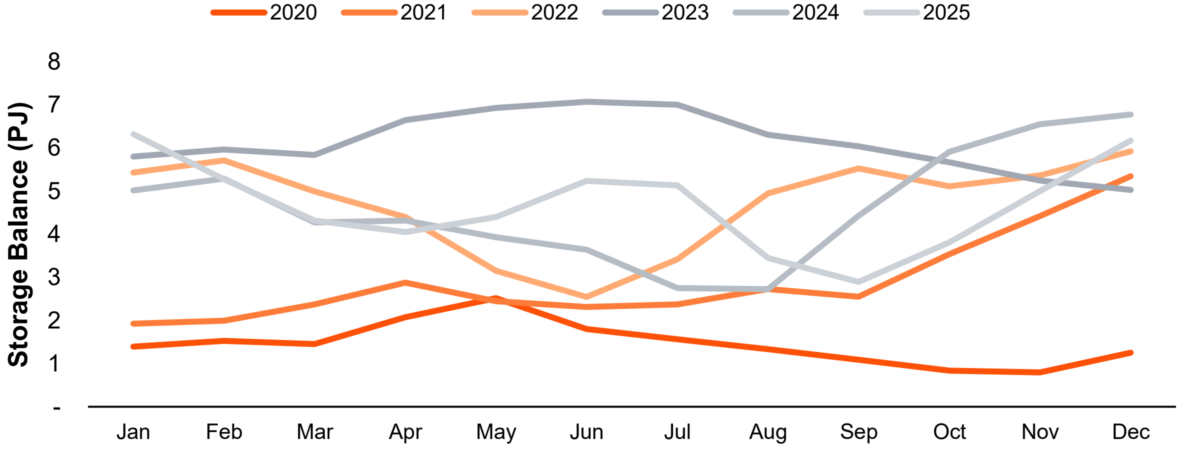
Ahuroa smooths short-term volatility and seasonal swings, with injections occurring in summer and drawdowns in winter and dry periods (see figures opposite). **However, Ahuroa's capacity is insufficient to replace large-scale contracted flexibility.** In 2024, Ahuroa drawdown during the dry hydro period totalled 3.1 PJ; around 14% of the 22 PJ of demand response provided by Methanex over the same period.

Under **Indigenous Gas Only**, with limited surplus gas available to inject, existing gas storage is unlikely to provide sufficient gas flex to make it through a dry year. It will continue to supply seasonal swing and storage.

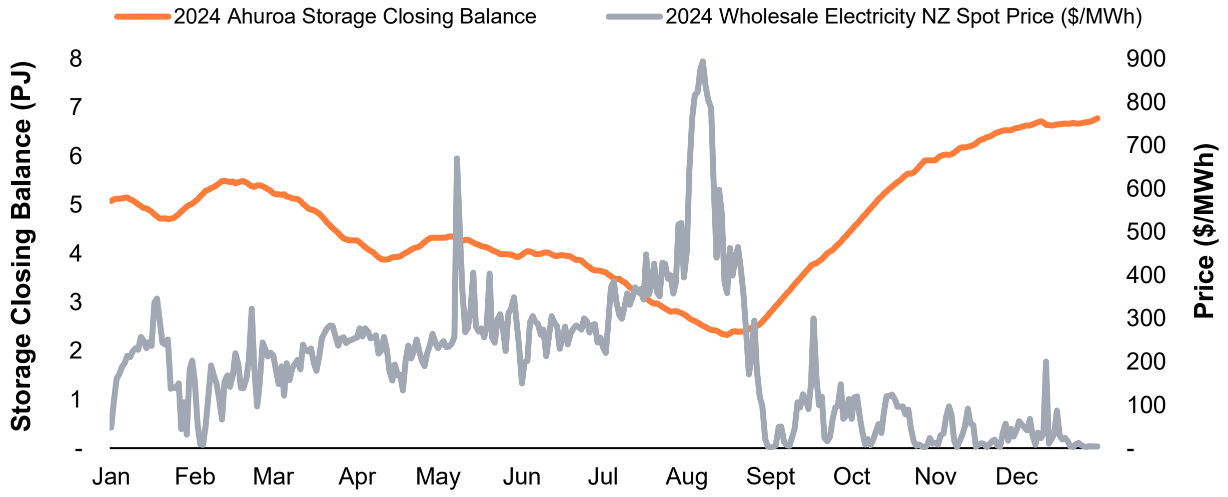
In **Indigenous Gas + LNG,** FSRU ships provide floating storage at the port. Additional onshore storage could further enhance this flexibility through stockpiling LNG-derived gas to manage LNG carrier ship scheduling, swings in indigenous gas production, and seasonal demand.

Gas storage plays an important role in managing seasonality and dry year risk, but storage is limited and insufficient to replace the flexibility previously provided by petrochemical demand.

Ahuroa monthly closing storage balances

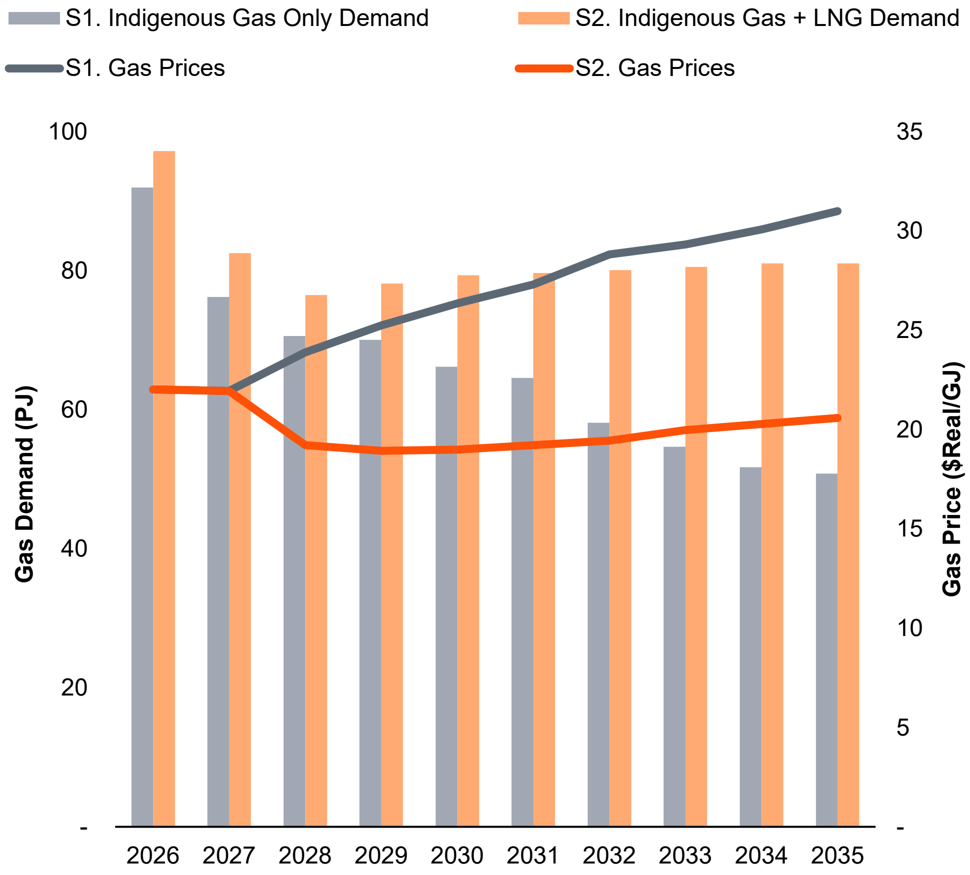


Ahuroa storage versus electricity spot prices (2024)



Benefits of LNG

Demand and gas price outcomes under each scenario



1. Dry year insurance, price stability and system flexibility

LNG provides fuel certainty for thermal generation during dry years, reducing the structural risk premium embedded in electricity prices and lowering forward prices in normal years. By capping extreme scarcity pricing, LNG stabilises both gas and electricity markets and mitigates volatility.

Flexible cargo scheduling allows imports to increase in dry years and reduce in wet years, effectively providing short-term storage and system responsiveness.

Importantly, LNG adds fuel optionality without committing to new generation capacity. This preserves incentives to build alternative firming while giving confidence that new intermittent renewable will be firmed.

2. Managed transition and demand retention

In Indigenous Gas + LNG, between 5 PJ and 30 PJ per year of demand is retained relative to Indigenous Gas Only, with three-quarters of this is from generation. LNG may not be economic for all users, but by supplementing indigenous supply it alleviates market tightness and decreases forced demand reduction.

It enables a more measured and economically efficient transition, allowing consumers to align switching decisions with equipment replacement cycles and investment plans rather than reacting to supply shocks.

3. Industrial stability and investment confidence

Improved supply certainty reduces the risk of de-industrialisation and supports higher-value C&I activity where gas remains economically justified.

A more stable gas demand outlook may encourage upstream investment in new indigenous supply.

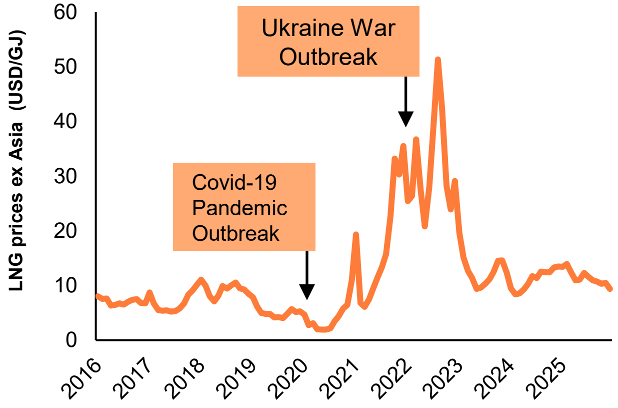
4. Emissions and substitution benefits

By reducing reliance on coal or diesel for dry year firming, LNG may lower emissions relative to alternative short-term security options. It supports renewable expansion by providing firm backup fuel while the electricity system scales low-carbon capacity.

Other considerations for LNG

Risks associated with LNG imports will need to be carefully managed, including exposures to the global market, delivery and operational risk, and impacts on market and decarbonisation outcomes.

LNG prices ex. Asia (USD per GJ)



Source: US FED

1. Exposure to global markets will need to be managed through hedges and contracts

LNG links New Zealand to international gas markets, exposing prices to global cycles, shipping constraints, and geopolitics. Supply risk can be mitigated through contracting arrangements and access to deep hedging markets.

LNG prices rose from around USD 2 per GJ in early 2021 to about USD 51/GJ in mid-2022 following Russia's invasion of Ukraine. Prices later fell back toward ~USD 10 per GJ but have since been disrupted again by conflict in Iran. The most recent forward prices (JKM) have increased by roughly USD 5 per GJ over the next two years before easing. While peace agreements in Ukraine or Iran could push prices below USD 10 per GJ, this illustrates how severe global shocks can quickly reintroduce volatility.

2. Delays to LNG increase dry year risk

Integrating LNG infrastructure by 2027-2028 is tight, depending on the solution that is adopted. Accelerated delivery depends on enabling legislation, accelerated procurement, and fast-track approvals.

Any delays would create a critical dry year risk from 2028 into the early 2030s as indigenous gas declines.

3. Decarbonisation and gas entrenchment risk

While LNG may reduce higher emitting coal or diesel use in dry years, it may slow the decarbonisation if perceived as a long-term substitute rather than short-term insurance. This risk needs to be balanced against the role gas generation will play in unlocking and firming new intermittent renewables in the electricity system

Government-backed LNG may also weaken investment signals for demand response, storage, electrification, and alternative firming technologies or solutions.

4. Operational constraints

The Taranaki coast is the expected location for an LNG facility and is located close to existing gas fields and gas transmission infrastructure. A range of operational constraints may affect practical delivery of LNG, including FSRU and LNG carrier availability, offshore weather windows, infrastructure, and availability of gas storage.

5. Market behaviour and supply incentives

LNG alters market incentives. It may cap extreme scarcity pricing, provide confidence to upstream domestic supply and C&I demand but could reduce incentives for industrial demand response. Poorly designed arrangements risk linking domestic gas prices unnecessarily to global markets.

8

Appendices

Appendix 1

Additional information

Comparison to other scenarios

The gas supply forecasts adopted in the Study are lower than the 2021 advice provided by the Climate Change Commission and consistent with other more recent scenario forecast

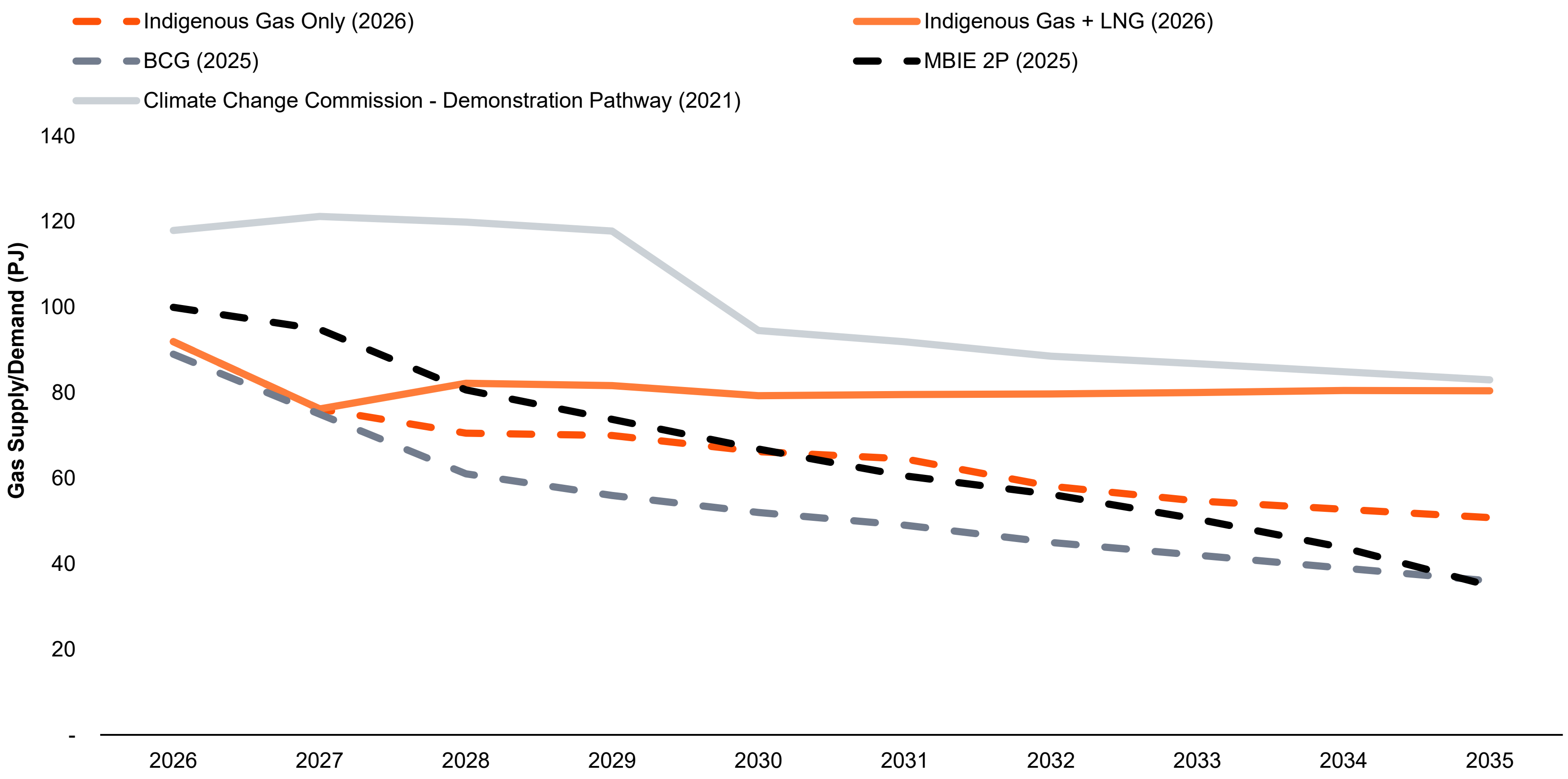
This Study uses supply forecasts sourced from Enerlytica gas field production forecasts.

BCG's 'Energy to Grow: Securing New Zealand's Future' report from November 2025 relied on Enerlytica's Low supply scenario from 2025, whereas the Study adopts the Enerlytica's 'Mid' scenario from January 2026. The mid case was chosen to reflect a conservative view of gas supply, noting that the Low scenario reflects asymmetric downside risk.

The **Climate Change Commission** projected that primary gas supply would fall to 83 PJ in 2035 under its Demonstration Pathway scenario. The Indigenous Gas + LNG scenario forecasts sit just below all of Climate Change Commission's scenario in 2035.

MBIE's 2P gas forecasts are also published regularly. The latest forecasts from January 2025 are broadly consistent with the indigenous gas supply trajectory adopted in this Study and are provided for context.

Comparison of gas industry supply forecasts



Gas supply and demand forecast

Scenario 1 – Indigenous Gas Only

PJ per annum	Historical						Forecast									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Methanex	65	55	50	55	27	21	15	2	-	-	-	-	-	-	-	-
Other Consumption	71	66	62	62	61	59	54	51	45	44	43	41	37	35	34	32
Generation Demand	47	36	34	37	34	32	22	24	25	26	23	24	21	19	18	19
Indigenous Gas Supply	183	156	147	154	122	112	92	76	71	70	66	65	58	55	53	51

Scenario 2 – Indigenous Gas + LNG

PJ per annum	Historical						Forecast									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Methanex	65	55	50	55	27	21	15	2	-	-	-	-	-	-	-	-
Other Consumption	71	66	62	62	61	59	54	51	45	44	44	43	43	42	41	40
Generation Demand	47	36	34	37	34	32	28	30	32	34	35	36	37	39	40	41
Indigenous Gas Supply	183	156	147	154	122	112	92	76	71	70	66	65	58	55	53	51
LNG Supply	-	-	-	-	-	-	-	-	12	12	13	15	22	25	28	30

Gas field production forecasts to 2050

PJ per annum	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Māui	13	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kupe	11	9	9	7	6	5	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kapuni	12	10	11	11	11	11	11	12	12	12	11	11	11	11	11	11	11	11	10	10	10	10	9	9	8
Pohokura	13	13	11	12	10	10	8	8	7	5	4	3	2	-	-	-	-	-	-	-	-	-	-	-	-
Mangahewa	22	19	17	15	13	12	11	11	10	10	10	9	9	9	9	8	8	8	8	8	7	7	7	7	7
Turangi	21	23	24	25	26	26	26	25	25	24	24	24	23	22	22	21	20	19	18	18	16	14	12	10	8
Other	3	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Forecast annual gas prices

$/GJ	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Indigenous Gas Only	22	22	24	25	26	27	29	29	30	31
Indigenous Gas + LNG	22	22	19	19	19	19	19	20	20	21

Appendix 2

Disclaimer

Disclaimer

This 2026 Gas Supply and Demand Study (the Study) has been prepared for Gas Industry Co for the purpose of documenting PwC's scenario analysis for the New Zealand gas market. It should not be relied upon for any other purpose. We accept no liability to any party should it be used for any purpose other than that for which it was prepared.

We have not independently verified the accuracy of information provided to us, and have not conducted any form of audit in respect of this information on which we have relied. Accordingly, we express no opinion on the reliability, accuracy or completeness of the information provided to us, and upon which we have relied.

Our engagement did not constitute a statutory audit (the objective of which is the expression of an opinion on financial statements) or an examination (the objective of which is the expression of an opinion on management's assertions).
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PwC reserve the right, but are under no obligation, to revise or amend the document if any additional information (particularly as regards the assumptions we have relied upon) which exists at the date of this document, but was not drawn to our attention during its preparation, subsequently comes to light.

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