NATURAL GAS · INTEGRATED VIEW

Building a consolidated view of options to manage NZ’s energy shortage

A system-wide assessment of options to manage the risks related to the natural gas shortfall

A systems-wide view of the impacts from the gas shortfall and options

EXECUTIVE SUMMARY

What this report found, and why it changes how urgent this is

- This report brings together a single view across the whole system of the options to manage the energy shortage. It is based on a project-by-project assessment of industrial gas conversion (the largest demand-side lever) looking at what is required to enable industrial gas users to switch to electricity or biomass. It sets that alongside what the remaining demand-side options can offer, and what new supply could add. The report finds that New Zealand's gas shortage is real, it is already under way, and it is growing. This is an energy shortage that reaches industrial users, households and businesses directly. An electricity dry year makes it worse without being the cause of it.
- This is a challenge that can be managed, **provided we recognise how time-constrained the response is.** The workforce able to convert industrial sites can deliver around six large projects a year. Electricity network upgrades take two to six years. New LNG supply cannot be running before 2028 at the earliest. None of these timelines shorten by waiting to decide; they set the pace regardless of when action starts. That means the range of actions still available narrows quickly as the shortfall grows. Each lever takes years to start delivering, so the actions that will matter in 2030 and beyond have to begin now, in parallel.

Managing the shortfall will require taking more actions on both supply AND demand

- Industrial conversion is the largest and fastest demand-side lever available. Up to 17.7PJ (around 4,900GWh, or 36% of forecast 2028 gas supply) is achievable by concentrating the conversion workforce on the 44 largest industrial sites, which together account for 87% of industrial demand.
- Delivering it depends on the rest of the system being ready. Electricity network investment to support conversion needs to start now, in the areas where conversion will happen. The scale and location required are already known. Biomass is expected to play a significant role in this transition, but supply chain volumes, locations and timing are largely unknown.

A systems-wide view of the impacts from the gas shortfall and options

EXECUTIVE SUMMARY (CONTINUED)

Managing the shortfall will require taking more actions on both supply AND demand [CONT]

- Even with that support in place and industrial conversion delivered in full, it is not enough on its own. A shortfall still opens in 2028 and widens through 2035. The other demand levers help but do not close it either. Reducing gas used for electricity generation still leaves a shortfall from 2031, as does moving residential and commercial users off gas with switching at three to five times today's rate.
- As an example, combining full industrial conversion, reduced gas for electricity generation, elevated commercial and residential switching, and new LNG supply nearly closes the shortfall under the plausible supply scenario. Under the downside scenario, a shortfall still remains that requires further action, for example LPG or diesel supply additions. **More supply and demand actions are needed**. Neither demand action nor supply action is sufficient alone. Combined, they come close, but do not remove the risk entirely.

What has to be true for the switching itself to happen fast enough

- Electricity and biomass together provide enough energy to meet the demand-side actions identified. But that available energy only becomes real supply if two things happen. Clear demand signals are needed for the renewable generation pipeline to translate into build, rather than sitting as consented but undelivered capacity. The connecting infrastructure, particularly electricity networks, cannot be allowed to slow things down once that build starts.
- For residential and commercial users, the gas fitting workforce is unlikely to hold back conversion, even at a faster switching pace. The real limits are electrician availability, household cost, and network and appliance supply chains.
- Where the remaining gap is filled with imported fuel, LNG and LPG both carry geopolitical and supply chain exposure, plus their own logistics limits and the full cost of new import infrastructure once it is built into delivered prices.

A systems-wide view of the impacts from the gas shortfall and options

EXECUTIVE SUMMARY (CONTINUED)

Why this is worth treating as urgent

- If this energy shortage is not managed, the cost is large, and it does not behave like an ordinary downturn. The GDP impact could reach $320-600m in 2028, rising to $1-1.7bn a year by 2035, with an estimated 2,100 to 6,700 industrial jobs at risk in 2028, rising to 6,500 to 19,300 by 2035, concentrated in the regions around the industrial sites affected rather than spread across the country. Independent modelling commissioned by MBIE reaches a similar conclusion: Sense Partners estimates real GDP around $4.5bn (about 1%) below baseline by 2035.
- Unlike the GFC or Covid, which were sharp shocks followed by recovery, these losses are structural. The economy does not bounce back from them. The impact does not land evenly either. As users who can leave the gas network do, its fixed costs fall on a shrinking base of those left behind, not because they chose to stay, but because they have no alternative. Rising bills land on those least able to do anything about it.

Recommendation

- While MBIE provides policy direction across all elements of the energy system (gas, electricity, biomass and LNG), the regulatory layer beneath it is fragmented, split across the Commerce Commission, the Gas Industry Company, the Electricity Authority and EECA. This analysis takes full account of steps Government has already taken, including the Loan Guarantee Scheme, LNG procurement, the Gas Security Fund and EECA support. Even so, a shortfall still opens from 2028 and widens through 2035.
- Our recommendation is for Government to lead a coordinated national plan, comparable in scale to the fibre rollout or the Canterbury earthquake rebuild. Participants in the Framework, representing organisations across the energy system, are ready to work in partnership with Government to help craft and deliver it.

CONTENTS

What this paper covers

Background and context: why this work was needed

THE QUESTION

The Gas Working Group's initial report found that, while standalone studies exist for individual fuels (LNG, biomass, electricity), there is **no integrated, system-wide view of alternatives** – so it remains unclear which fuel switches best support gas-system stability and the best outcomes for New Zealand. This analysis builds that consolidated view: taking a bottom-up, project-by-project demand assessment alongside the latest supply forecasts – does demand-side action change the likelihood and timing of an energy shortage, and where a gap remains, what can fill it and what does that demand of the wider system?

BACKGROUND

- July 2025: the Gas Working Group's initial report identified critical information gaps, including the absence of a system-wide view of alternative fuels.
- November 2025: the Group's final report concluded New Zealand faces a real, growing and urgent risk of an energy shortage, that current actions are insufficient, and that action is needed on both supply and demand.
- This paper responds with an integrated, energy-system view: what demand-side conversion can deliver, the supply outlook, and the options to fill the remaining shortfall.
- A key purpose is to surface practical system limits and barriers ahead of time – such as electricity network lead times and biomass supply chain visibility – so work can start before they bind.

RELATED WORK

- **Government LNG programme:** an LNG import facility is confirmed, with Port Taranaki proposals shortlisted, a contract targeted for mid-2026 and operation as early as 2027/28 (MBIE). This sits alongside the Gas Security Fund and other policies.
- **Sense Partners (for MBIE):** economy-wide modelling of the impacts of declining gas supply; sustained high gas prices leave real GDP around $4.5bn (~1%) below baseline by 2035.
- **BCG's** Energy to Grow report and **Enerlytica** gas supply outlooks – both referenced in this report
- **Sapere / Rewiring Aotearoa:** analysis of the 2024 energy shock and dry year alternatives; compared with this report later in this pack.
- **GIC:** the 2026 Gas Supply and Demand Study (PwC, March 2026), plus a report in train from GIC's discussions with gas users, on the challenges of conversion and the role of LNG or additional supply.

The analysis completed for this report

THIS ANALYSIS

A bottom-up, project-by-project assessment of industrial demand, set against updated supply forecasts, to test the size and timing of the shortfall – then a scoping of what can fill the remaining gap, and what each option demands of the wider energy system (electricity networks, biomass supply chains, LPG and LNG infrastructure).

WHAT WE HAVE DONE

- Updated Enerlytica 10-year field forecasts from production data to May 2026, baselined to 2026 MBIE reserves data.
- Used the BCG “Energy to Grow” report as a starting point for our residential, commercial and power-generation demand.
- Layered in a project-by-project industrial view — confirmed conversions plus likelihood-categorised large-user projects (with DETA).
- Tested whether this bottom-up demand picture changes the size and timing of a shortfall, year by year.
- Scoped the range of alternatives to address the shortfall, and what conversions demand of networks and biomass.

KEY ASSUMPTIONS

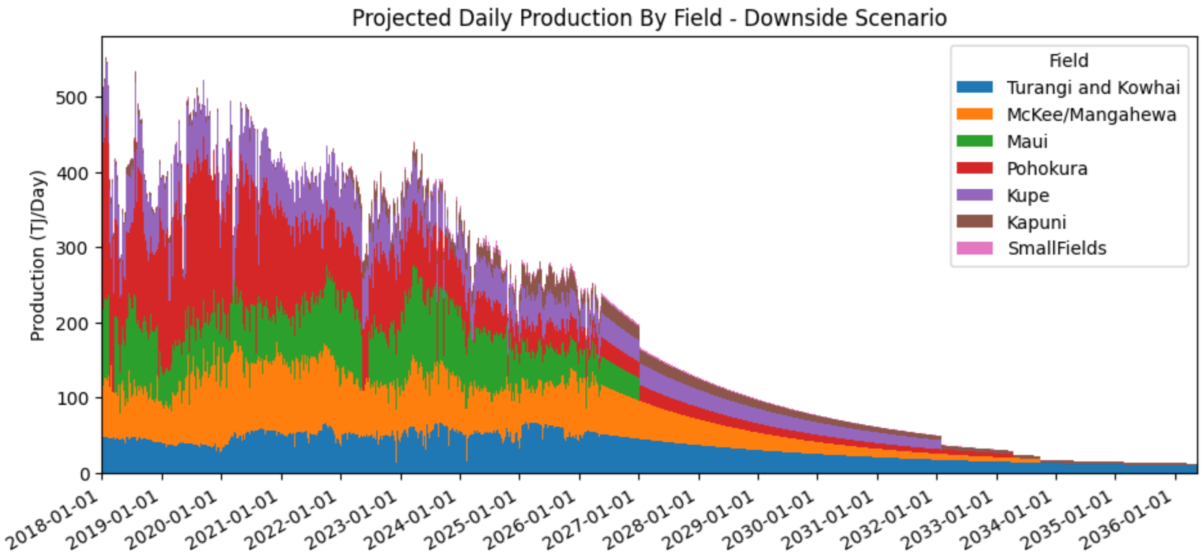
- No new gas fields; supply projected forward from existing fields (on the basis that if there is a new field discovery, it will take ~10 years for production to come to market).
- Methanex and Ballance exit by 2027.
- BCG projections used for non-industrial demand.
- Industrial sites < 0.1 PJ/yr not assessed for switching (≈ 4 PJ).
- Workforce constraints cap boiler / air-heater projects deliverable per year (≈6).
- Largest projects convert first where possible.
- No technical barrier to LPG and diesel use for industrials.
- Scope is time-bound to options that are technologically ready and commercially viable now. Hydrogen is excluded as a near-term substitute, though relevant to transport and feedstocks.

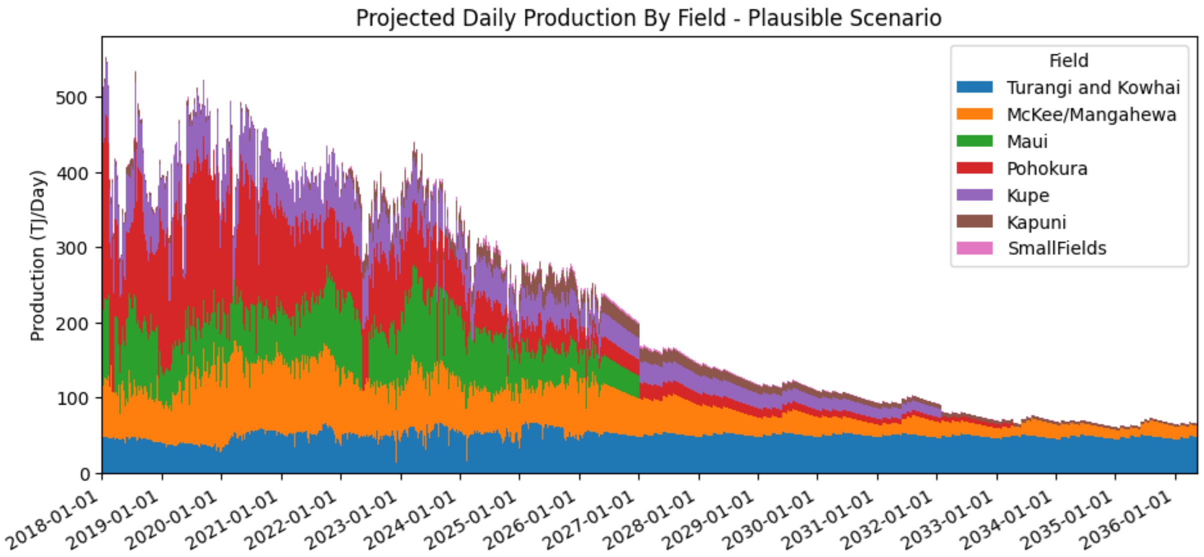
SECTION 01

Updated 10-year supply forecasts

Analysing future supply scenarios, including comparison to scenarios used by other pieces of work.

Field forecasts: two scenarios bound the decline





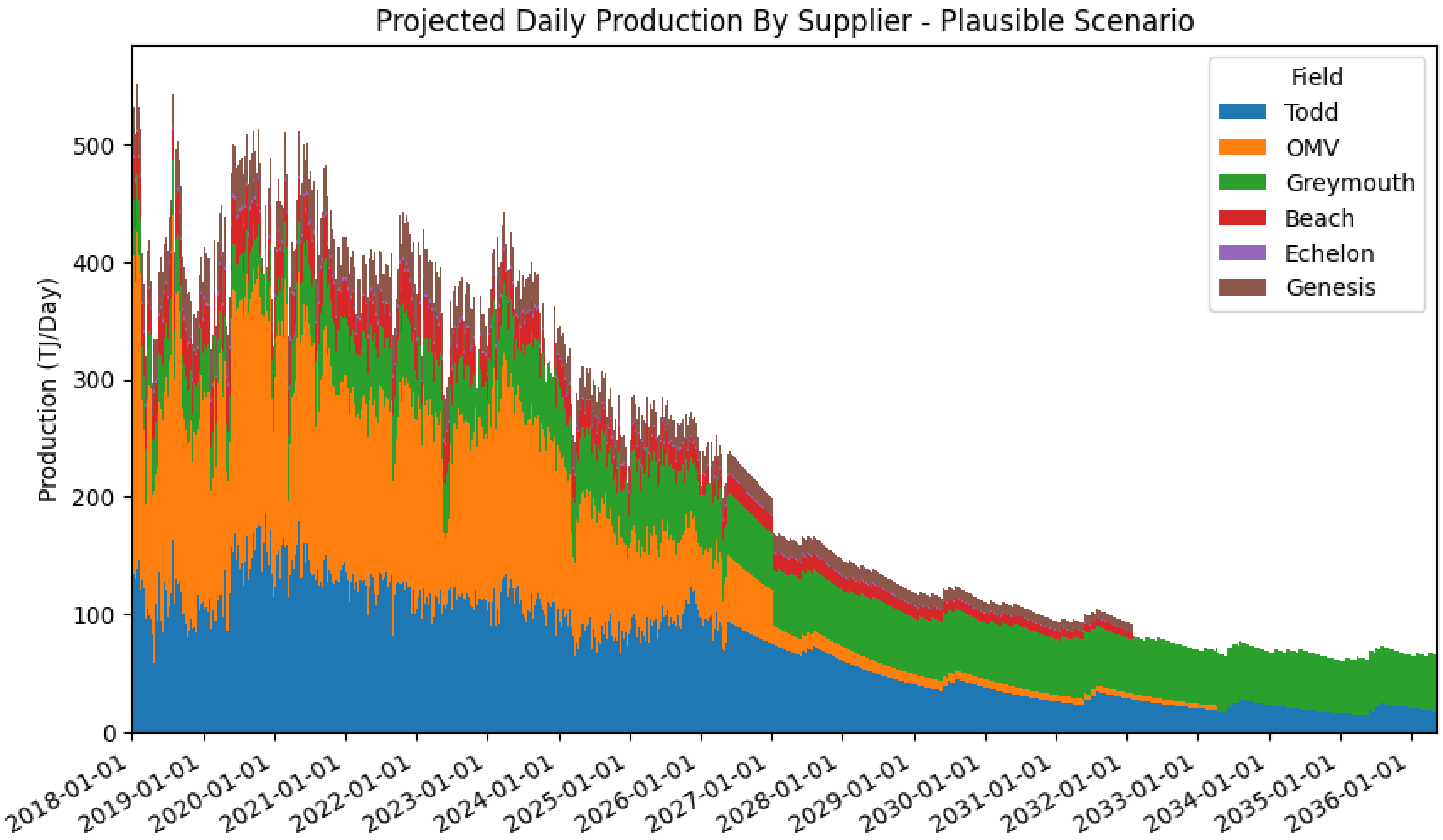
- We have looked at updated 10-year supply forecasts for the big six fields, based on daily production data to May 2026. Total volumes projected are baselined using MBIE's 2026 gas reserve estimates for each field – preventing over/undershoot when forecasting supply.
- We use two scenarios in this work:
  - Downside: this aligns with Enerlytica baseline scenario, updated so individual gas field decay curves are fitted to most recent data with no new production.
  - Plausible: this aligns with Enerlytica low scenario, viewed as a realistic case for future production (as compared to the mid case which includes drilling activity and well outcomes that are ambitious in a declining market).
- Turangi, Kapuni and Mangahewa are the only fields with material 2P reserves to supplement supply past 2035, based on minimum economic deliverability.
- Forecasted field supply accounts for behind the meter consumption.
- Maui exit (by May 2027 at the latest, on plant certification) frees only ≈3–4 PJ of Methanex gas, but Methanex exit significantly reduces gas market flexibility.

Source: Gas industry field production data to May 2026; MBIE reserves; Enerlytica low/base scenario April 2026; GWG supply modelling.

Equity supply concentrates in two players

- The following shows production projections by gas supplier for companies with equity in the big 6 fields.
- OMV is heavily depleted after Maui's 2027 exit — remaining output is its 74% share of the Pohokura JV (with Todd).
- With Kupe ramping down in Q1 2032, Genesis no longer produces its own gas. Daily volumes from Kupe have been under the required amount to fuel minimum output at Huntly Unit 5 since the start of 2026, therefore requiring Genesis to contract with other suppliers.
- Long-term, Greymouth and Todd dominate the equity-supply outlook. This is largely bolstered by Turangi and Kapuni / Mangahewa production for the two companies respectively.

Projected daily production by supplier — Plausible Scenario (TJ/day)



Source: Field production data to May 2026; equity ownership shares. GWG supply modelling under PEP (prudent expected production) scenario.

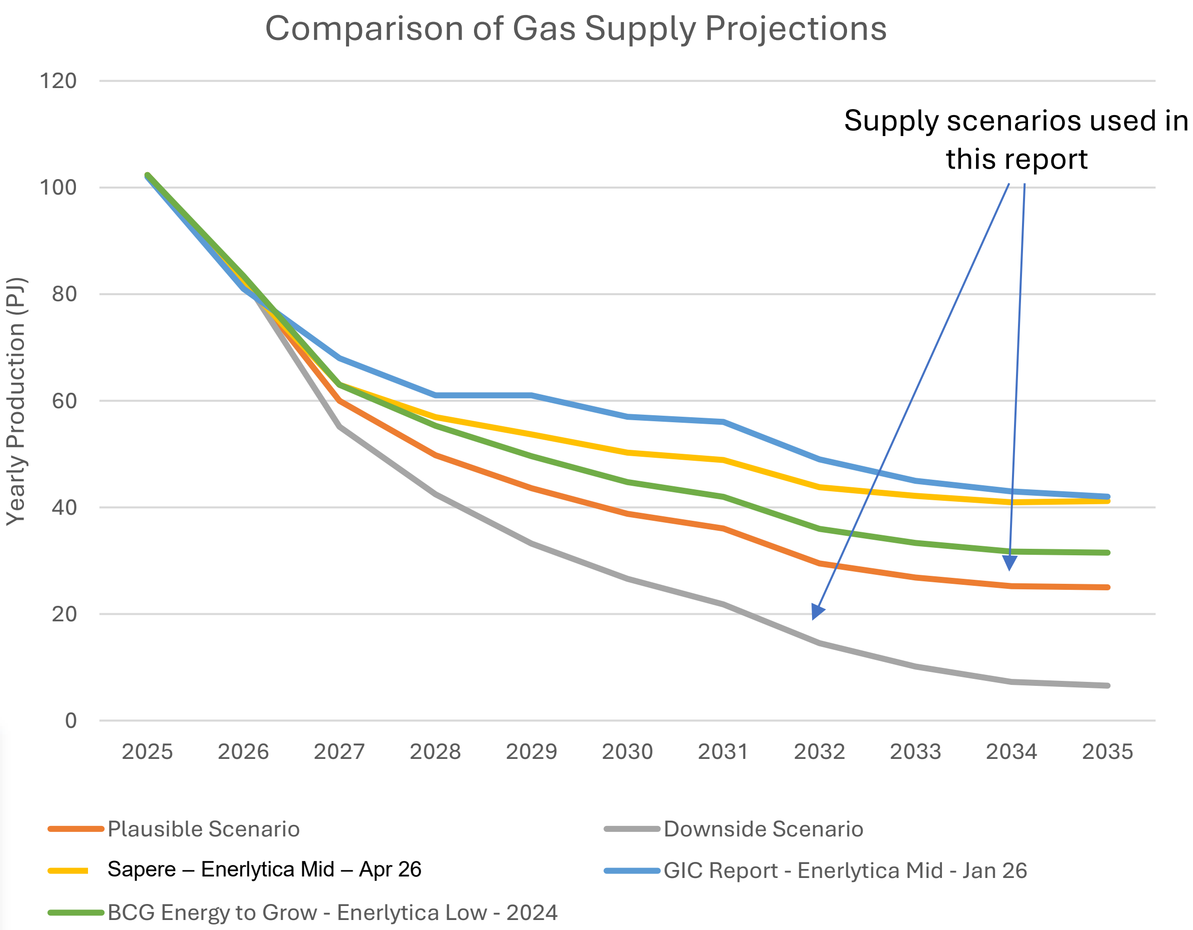
How does this outlook compare with others?

- Given the significant amount of other work in the public domain, we want to make clear how the supply forecast used in this report differs from supply forecasts in other similar reports.
- BCG's "Managed Transition" supply forecast in their 'Energy to Grow' report builds on Enerlytica's low scenario – but from 2024, adjusting up to 7 PJ per year above the base curve from 2030 — on the assumption domestic development performs. Since publication of their report, drilling performance has been mixed, which may not reach this level of upward adjustment.
- Sapere's recent report uses a version of Enerlytica's mid scenario, which was updated with MBIE's 2026 reserves data.
- GIC and PWC's Gas supply and demand report uses a now-outdated version of Enerlytica's mid scenario from 2025, which has not been adjusted to MBIE's reserves data in 2026.

WHY IT MATTERS

Different supply scenarios carry **≈30 PJ more supply in 2035**. Where you start on supply drives the size of every shortfall, and basis of the scoping of required solutions.

Supply scenario comparison — forecast (PJ/year)



Source: Gas Working Group supply modelling; Enerlytica; BCG; Sapere. Adjusted for 2026 MBIE reserves.

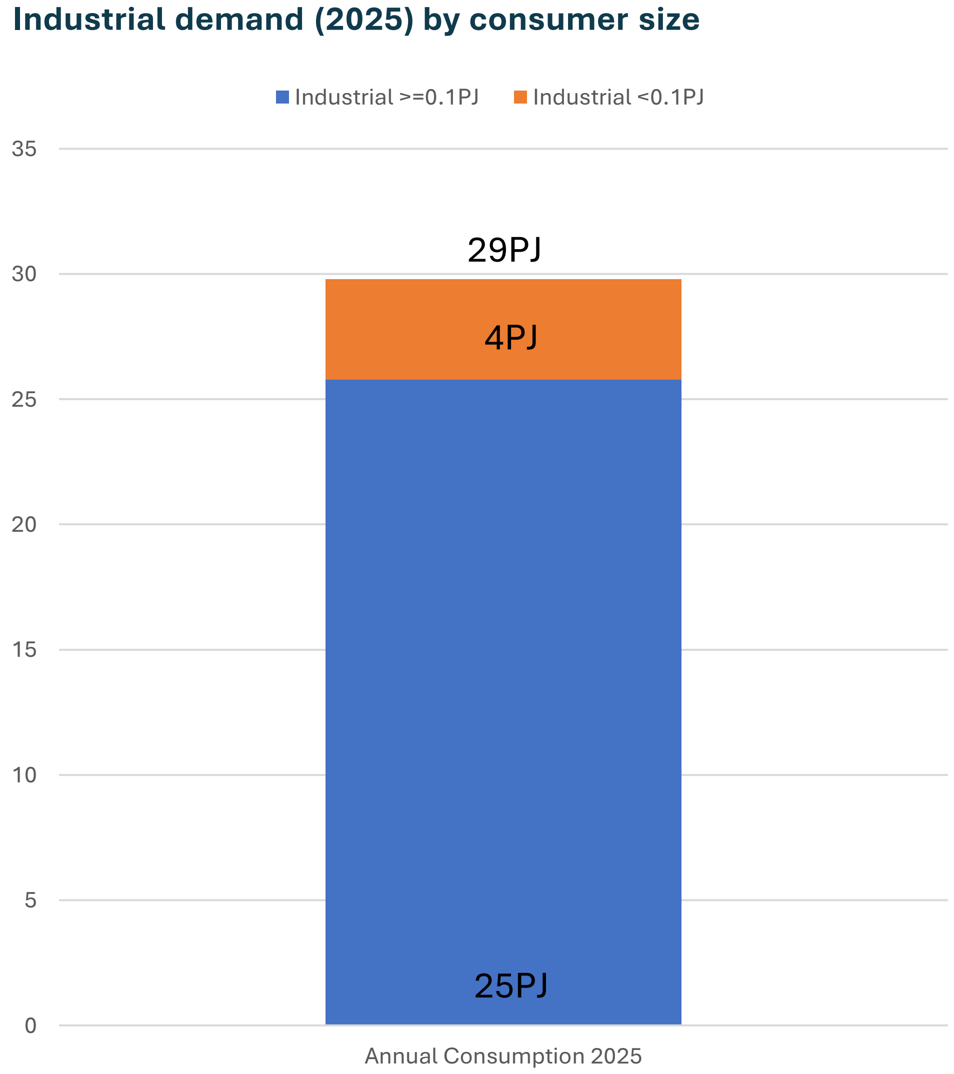
SECTION 02

Potential for large industrial users to convert

Analysing – project by project – how much industrial gas demand can plausibly switch.

Context on the size of industrial demand

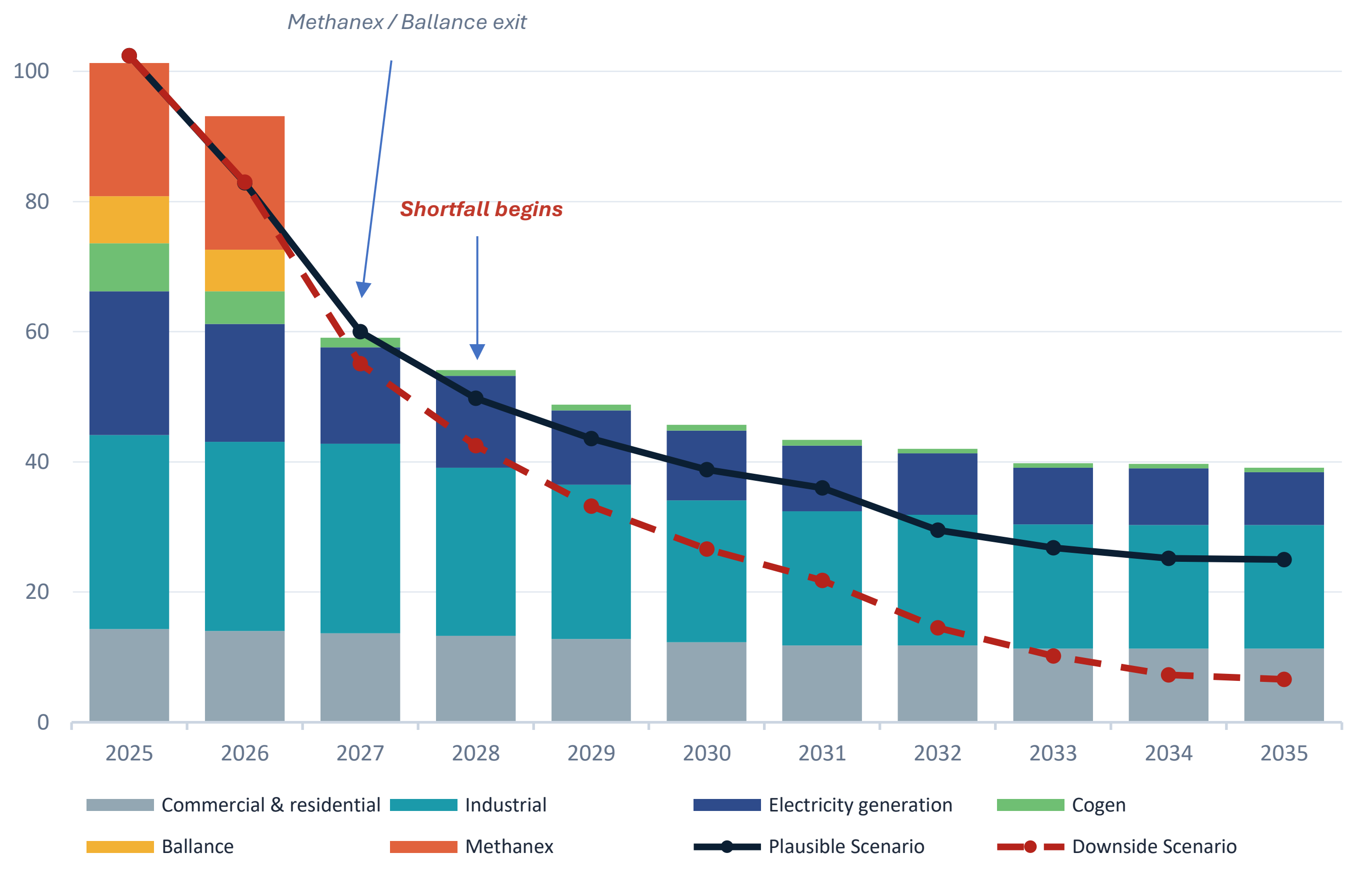
- Industrial users make up the largest portion of gas users, but the industrial consumer group is comprised of a wide variety of different-sized consumers.
- Excluding Methanex and Ballance there are 44 industrial sites (30 companies) which used more than 0.1PJ of gas in 2025 – however these sites account for 87% of all consumed industrial gas.
- There are 200+ industrial sites (across 89 companies) which use less than 0.1PJ of gas per year. They account for only 13% of industrial gas.
- Given, for the most part, the workforce which carries out switching projects for all industrial sites is broadly the same, this calls out the value of prioritising the largest projects.
- The following modelling from DETA only considers sites at or above 0.1PJ per year – due to a lack of visibility, and therefore a lack of certainty around the likelihood of these smaller switching projects occurring.



Updated industrial demand modelling

- To develop a more granular view of industrial gas demand, we have worked with DETA to identify potential conversion projects.
- From this analysis, we have identified **11.2PJ** (or 37% reduction) of industrial gas and **6.5PJ** (or 88%) of cogen gas. This is from 60 confirmed, probable and possible industrial projects on 42 sites and 26 companies. A significant number of these projects are Fonterra.
- Some notes on the analysis:
    - This only covers sites who use more than 0.1PJ pa, under the broad assumption that these larger use sites are easier to convert.
    - Our analysis attempts to illustrate the size of what may switch as opposed to what can switch
    - A deliverability of 6 projects per year is assumed – based on the size of existing conversion workforce
- Fonterra's electrification projects at Whareroa and Edgecumbe this year are significant short-term wins, accounting for a 6PJ reduction in gas
- We have included Ballance leaving in our modelling, however they have announced a temporary deal with Genesis to be supplied with gas for the remainder of the year.
- Since Genesis has no form of gas storage, if Methanex leaves the market, they may use Ballance to manage the risk of being long gas in a wet electricity system in 2027.
- This is under the assumption that the proposed Tariki storage project does not go ahead – which would allow Genesis to store gas – removing their need for Ballance

Demand (DETA industrial) vs supply (PJ/yr)

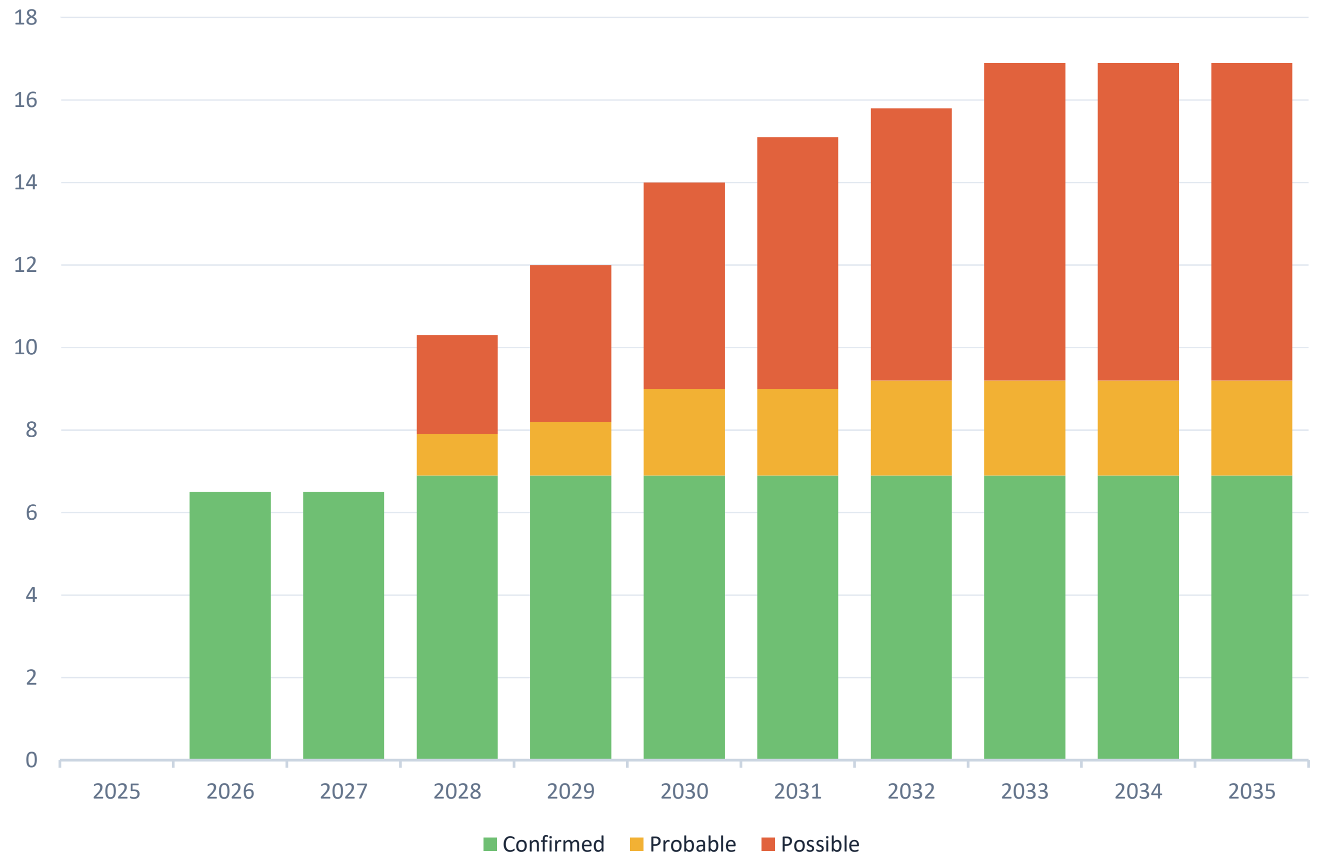


Source: DETA industrial demand modelling (60 projects); BCG for non-industrial; Gas Working Group supply.

Almost half the demand reduction relies on “possible” projects

- DETA has classified projects into the following categories, based on site/project knowledge:
  - Confirmed — publicly announced.
  - Probable — likely economic, but potentially capital-constrained.
  - Possible — feasible, not economic based on current gas prices, but the lowest-cost option for the site. Some of these sites may not be able to handle a significant increase in ongoing energy cost and will be forced to close.
- This reflects current gas prices and current policy settings, including the Gas Transition Loan Guarantee Scheme, which addresses financing cost, not the underlying operating economics.
- If the largest “possible” projects are not prioritised under current workforce constraints, the shortfall grows by up to 8PJ out to 2035.
- Sites < 0.1 PJ sum to ≈4 PJ — DETA believes the viability of these projects is too uncertain to assume any of them occur.
- These sites may also be constrained by the same workforce delivering the largest projects.
- REAL-WORLD PACE: Fonterra's own Whareroa and Edgecumbe gas conversions (this report's 2026 short-term wins) were announced Jan 2025. Stage one cut Whareroa's gas use 25% within a year, but full conversion of both sites will take several years.[1]

Cumulative PJ avoided, by project likelihood



Source: DETA project-by-project industrial modelling. Bands above each show individual sites. [1] RNZ, "Fonterra announces plans to slash fossil gas use by 38%" (28 Jan 2025); NZ Herald, same (29 Jan 2025).

SECTION 03

Wider energy impacts of industrial switching

Switching industrials at scale requires significant support from electricity network and biomass supply chains.

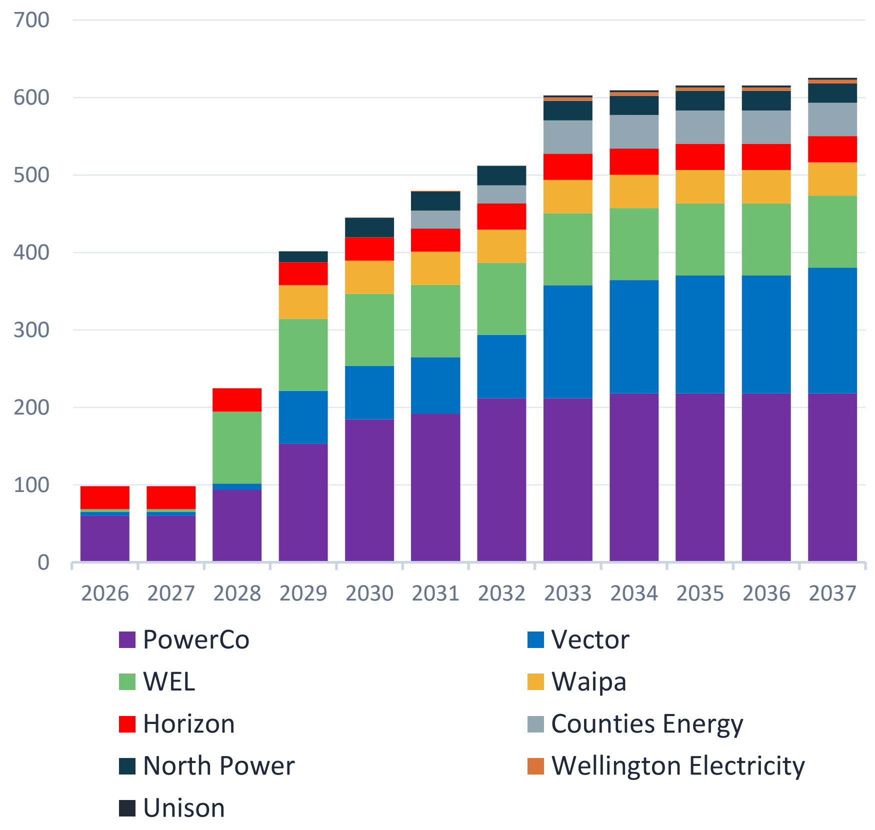
Industrial electrification requires supporting work on network capacity

- DETA has estimated the future capacity required for each confirmed, probable and possible projects – we have calculated the total network capacity increase by EDB.

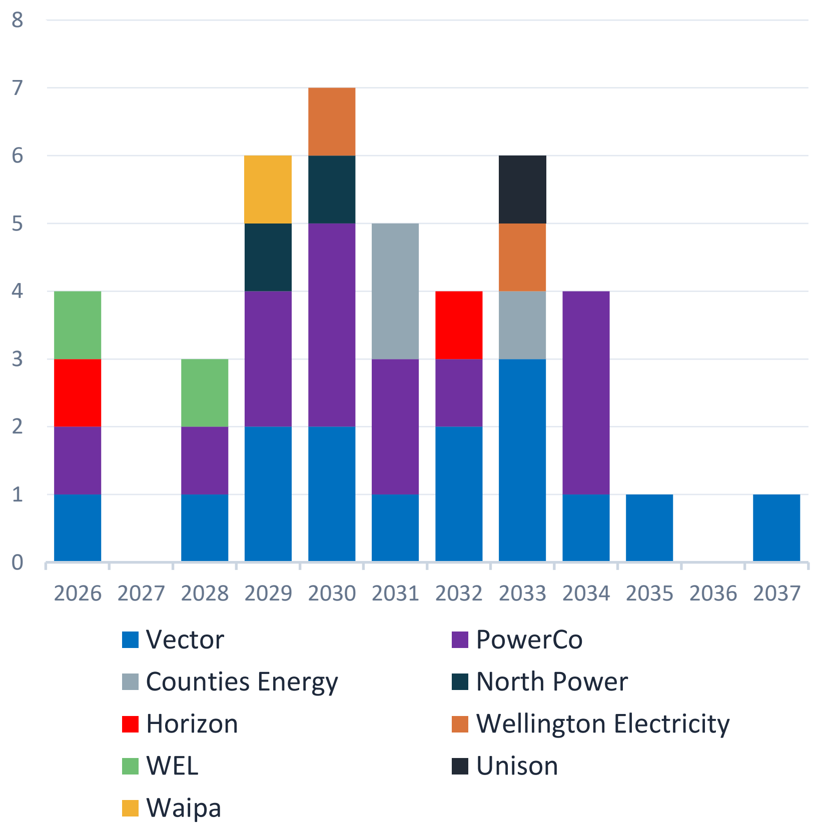
- Note that as Fonterra Lichfield sits on Vector's network (though physically located in the Waikato) — we have counted it under Vector.

- Case shown is electrification-biased on 50:50 projects (where the alternative is biomass) making these figures a worst case for network load under this level of industrial switching.

Cumulative forecast capacity increase (MW) by EDB



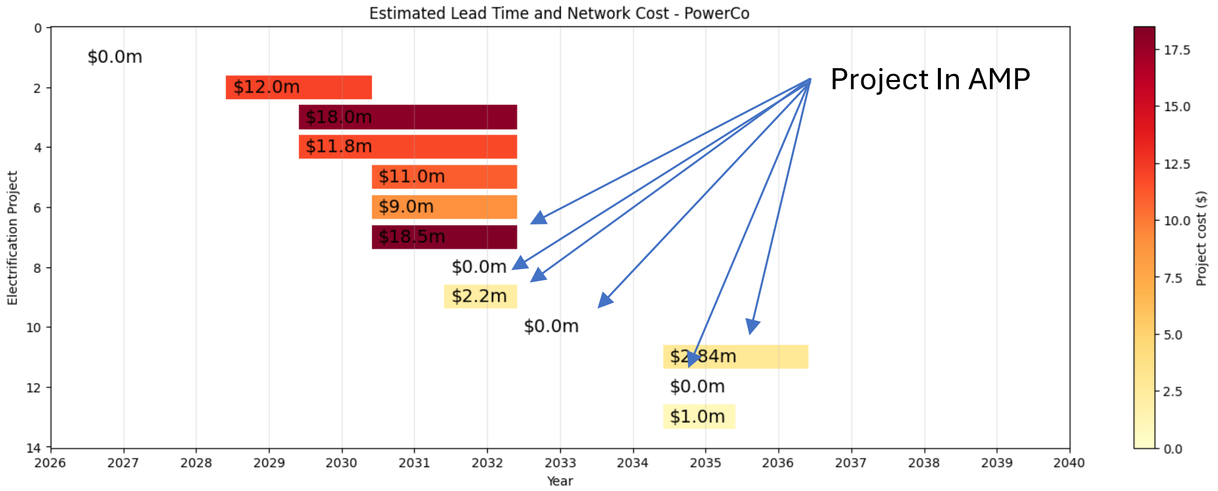
Number of electrification projects by EDB

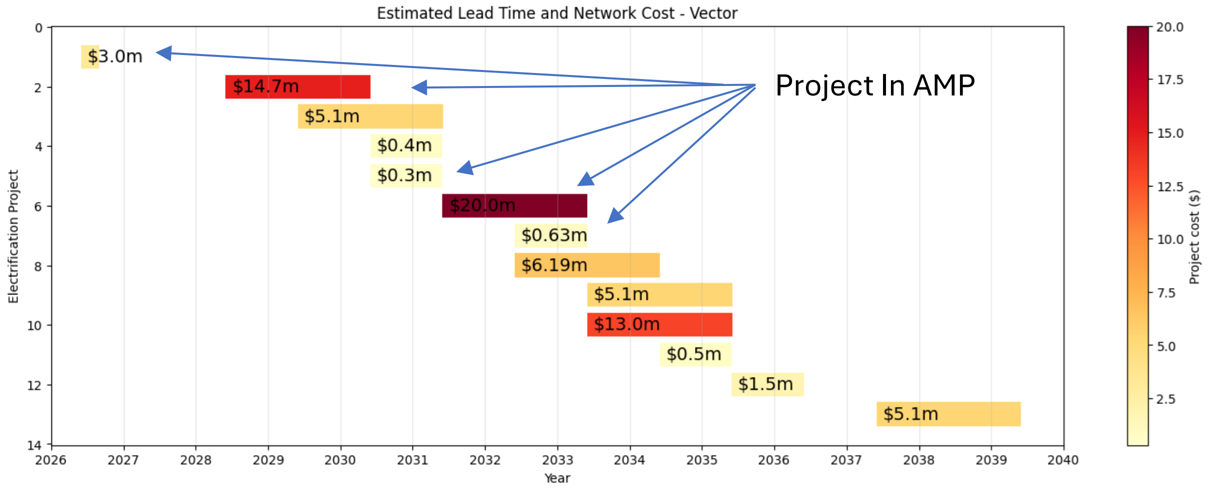


Source: DETA updated analysis; Electrification-biased base case.

Getting ahead of the connection pipeline

Estimated lead time & network cost, by project





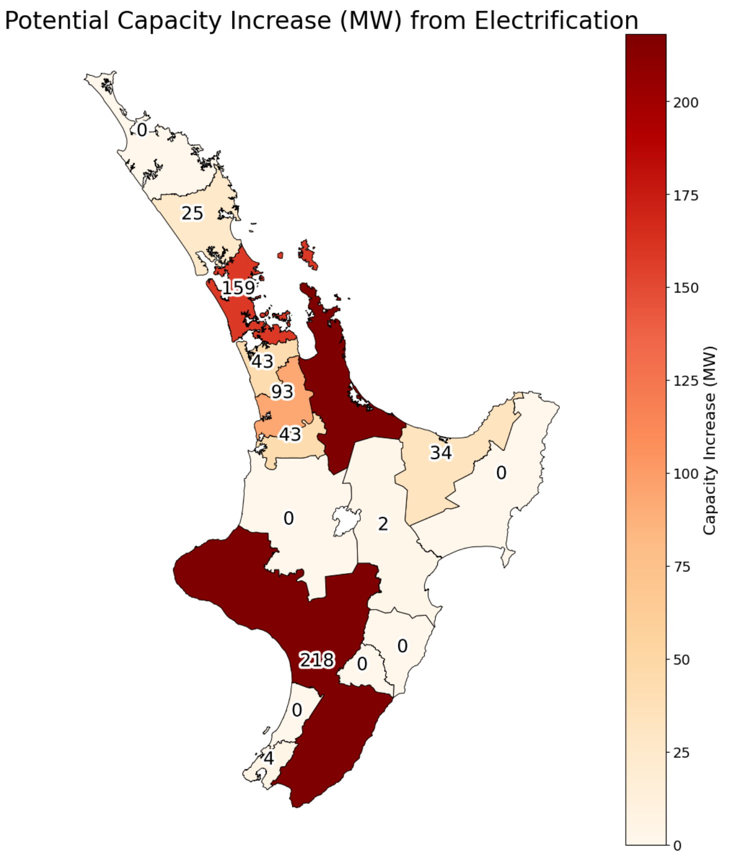
- These network charts show the cost and lead time required for each network project supporting the conversions. Each bar is one project — its lead time and network cost, taken from the RETA work (Ergo estimates, where $0 project cost represents transmission-only capex), projects are treated as independent unless staged by the same company on the same asset.
    - Project timing follows DETA estimates and may vary widely.
    - If an announced network upgrade impacts project cost (i.e. where new capacity is added, thus reducing the cost of electrification as the project no longer causes an upgrade), this is taken into account.
- The density of capital and resource needed in a short window is significant — it demands a strategic, coordinated approach to network planning to deliver this scale of electrification. The costs on this chart represent sub transmission cost, including customer contributions.

Source: Ergo/RETA cost & lead-time estimates; DETA project dates; EDB AMPs.

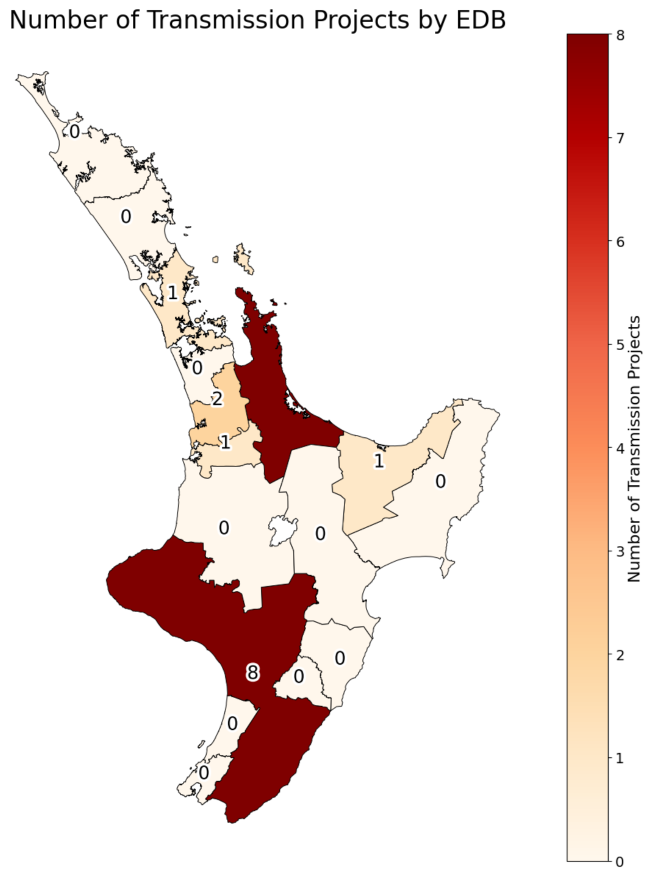
Potential network capacity increases are in known areas

- We aggregate, by EDB, the total potential increase in capacity from the projects modelled by DETA.
- **For many networks – the increase is at least 10% of their current peak demand. PowerCo has the most significant capacity increase at 218MW.**
- A significant number of gas-consuming industrial plants are in the Taranaki region, hence the capacity concentration on PowerCo's network.
- Based on Ergo estimates from the RETA, we show the number of electrification projects, by EDB, which are expected to require transmission level upgrades.
- These are reflective of favouring electrification over biomass, when to DETA's best knowledge, they are equally likely.

Capacity increase by EDB



Transmission-level projects by EDB

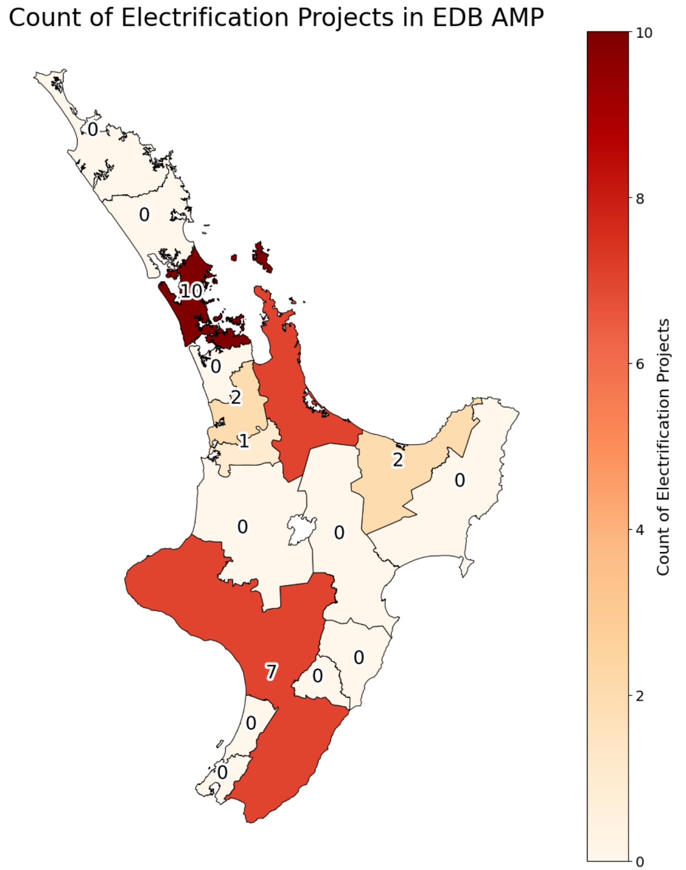


Source: DETA analysis; EDB Asset Management Plans; Ergo RETA estimates.

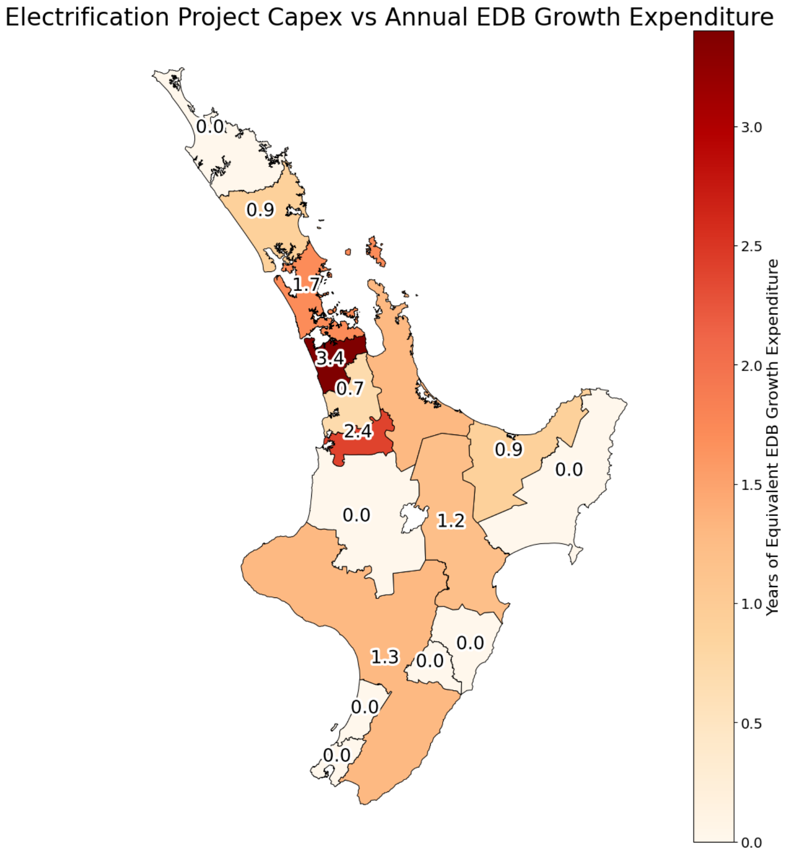
Network capex is significant compared to current projections

- Building on the previous slide, we project electrification capex compared to each EDB's disclosed annual growth spend (5-yr average, incl. capital contributions).
- This allows network upgrades from electrification to be compared to normal EDB network spend.
- We have examined EDB AMPs (Asset Management Plans) for each of our electrification projects, scoring 2 points for a project which is directly mentioned, 1 point for mention of process heat electrification at the corresponding asset and 0 otherwise.
- This explains the variation in projected network spend by EDBs, as many AMPs mention "industrial electrification" but exclude specific project spend and demand from forecasts.

Number of Electrification Projects in AMPs



Capex vs annual EDB growth spend



Source: EDB Asset Management Plans; Ergo RETA estimates. North Island shown; "years of equivalent growth expenditure" normalises for network size.

Why our network conclusion differs from Sapere

Sapere View

- The recently published report by Sapere, includes a slide which notes that transmission & distribution upgrades for industrial electrification are achievable — they cite the RETA, saying:
    - Of 615 optimal RETA identified projects, only 12% (72) need a network upgrade.
    - Of these 72 optimal projects requiring a network upgrade, only 10 are considered major by EECA/Ergo, and could take somewhere between 2 and 6 years to complete. Major upgrades only occur in 5 EDBs.
- Several non-Major projects still require capex north of $10m, and at least 12-18 months to deliver. Our previous analysis shows the timing and investment for networks to get these projects delivered.

Our View

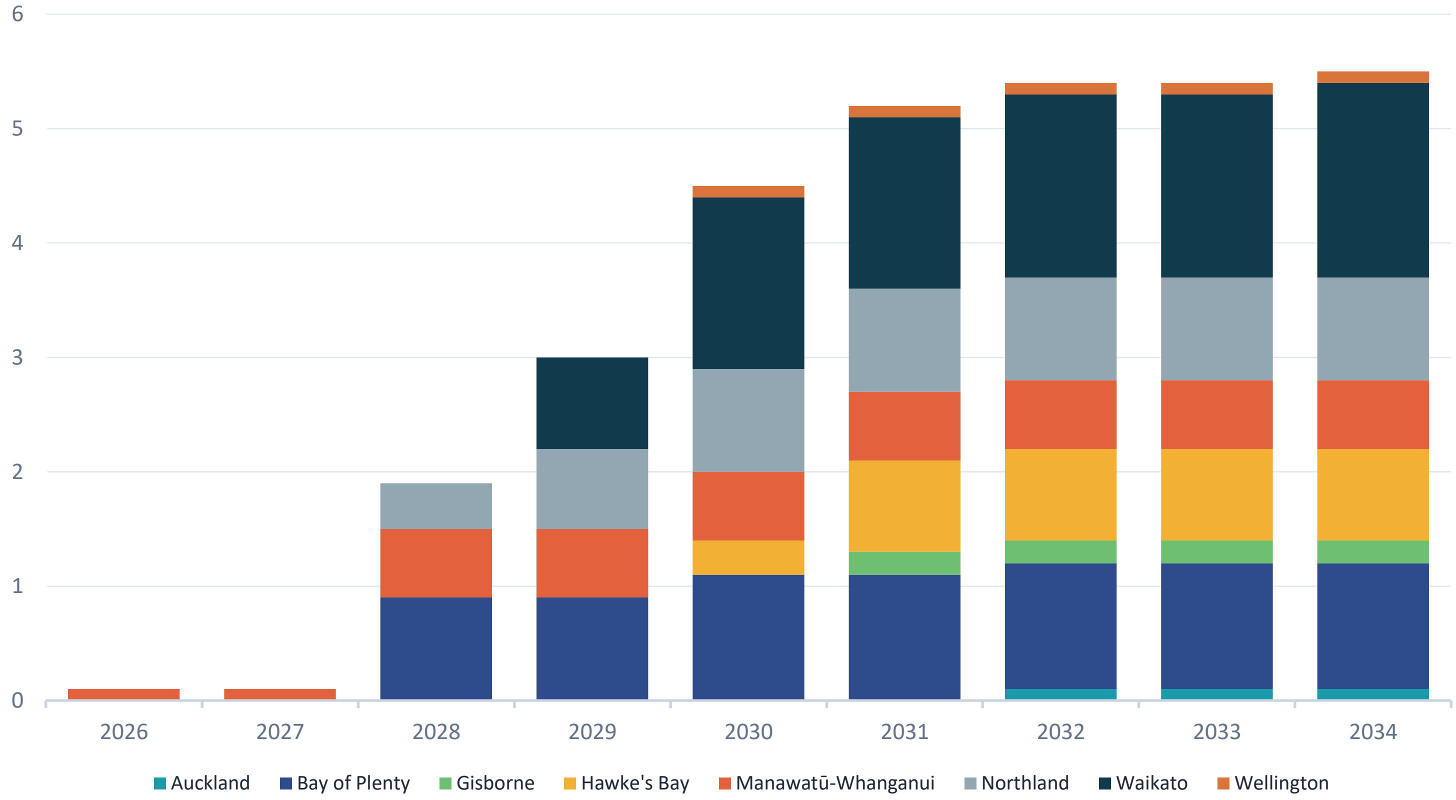
- We estimate the network impact for 44 electrification projects, in the higher electrification scenario where electrification is favoured over biomass. The total potential network spend across transmission and distribution for these 44 projects alone is estimated to be north of $630m. On the distribution side, much of this spend is not included in EDB asset management plans.
- These points are not a criticism of the Sapere report or its analysis. That report provides helpful insights on questions and information different to those in this report. Its analysis complements this work, particularly its economic analysis, and it also covers alternatives for electricity dry year risk, which this report does not.
- To help build clarity and coherence during this period, future reports should help readers understand differences in questions and outcomes. For example, any future analysis of the challenges facing gas users looking to convert is most useful when paired with equivalent information about the challenges of alternatives available to them – including the full cost of continued gas use once LNG infrastructure costs are incorporated.
- A link to the Sapere and Rewiring report is here: From faultlines to resilience: The 2024 energy shock does not require an LNG response

Source: Sapere/Rewiring report; EECA RETA; Gas Working Group analysis.

Projected biomass demand by region

- The industrial conversion projects switch partly to biomass and partly to electricity.
- We have quantified cumulative regional biomass demand from DETA's modelled switching, by year and region.
- Several projects are 50:50 electricity/biomass, and the visual shown on the slide favours biomass for these projects.
- This includes all confirmed, probable and possible projects.
- We note that the feasibility of using biomass for conversion (and therefore these demand levels) depends on cost, which is significantly dependent on diesel cost for transport.

Cumulative regional biomass demand (PJ)

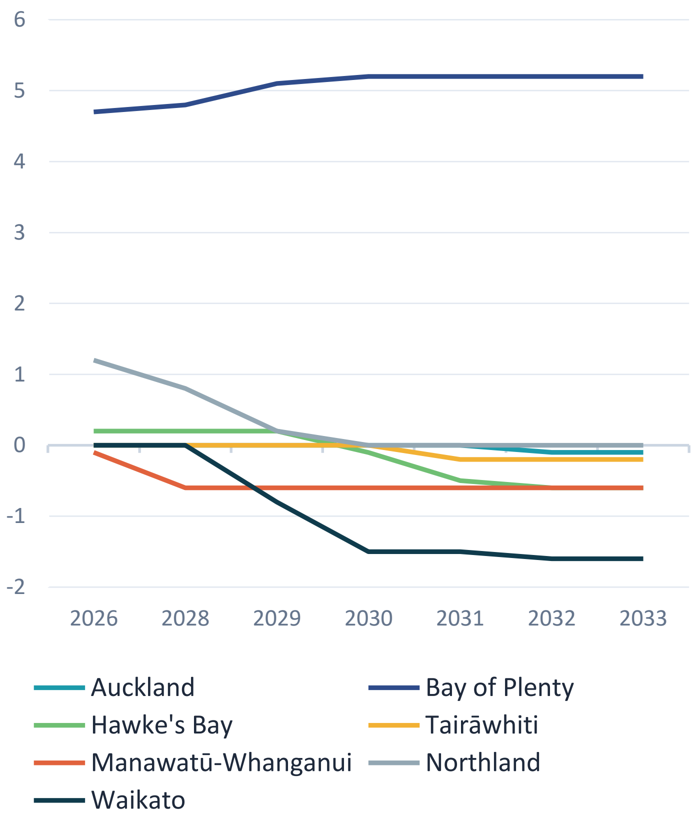


Source: EECA RETA regional residue volumes; DETA project list. Biomass-biased (high) case.

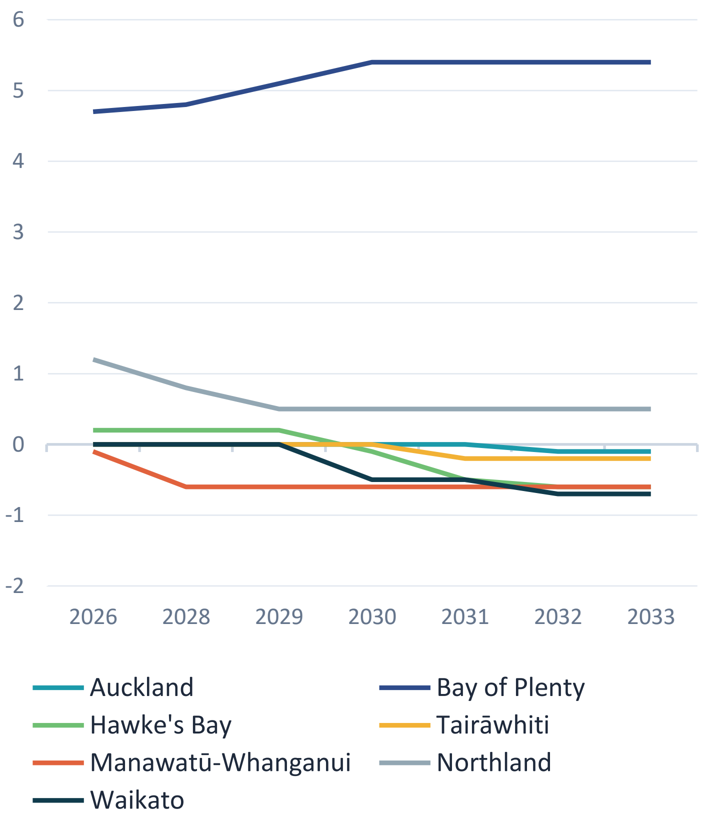
Regional biomass demand vs estimated deliverable supply

- Using the previously quantified PJ of biomass demand from potential projects, along with the numbers reported in the RETA on available wood processing residue volumes, we can get a high-level picture of the theoretical biomass supply chain.
- Above zero = surplus residue; below zero = regional deficit needing imports or transport.
- Bay of Plenty stays in strong surplus; all other regions move into or near deficit.
- A key limitation on this analysis is the lack of available biomass data. We use wood processor residues minus existing demand for bioenergy as a proxy for truly available volumes.
- **However, we have no visibility on the actual available biomass supply chain for these conversion projects. This is a significant gap that could be prioritised to fill to help manage the energy shortage.**

High scenario (Supply – Demand, PJ)



Base scenario (Supply – Demand, PJ)



Source: EECA RETA regional residue volumes; DETA project list. Positive = regional surplus, negative = deficit.

SECTION 04

Options to address the remaining shortfall

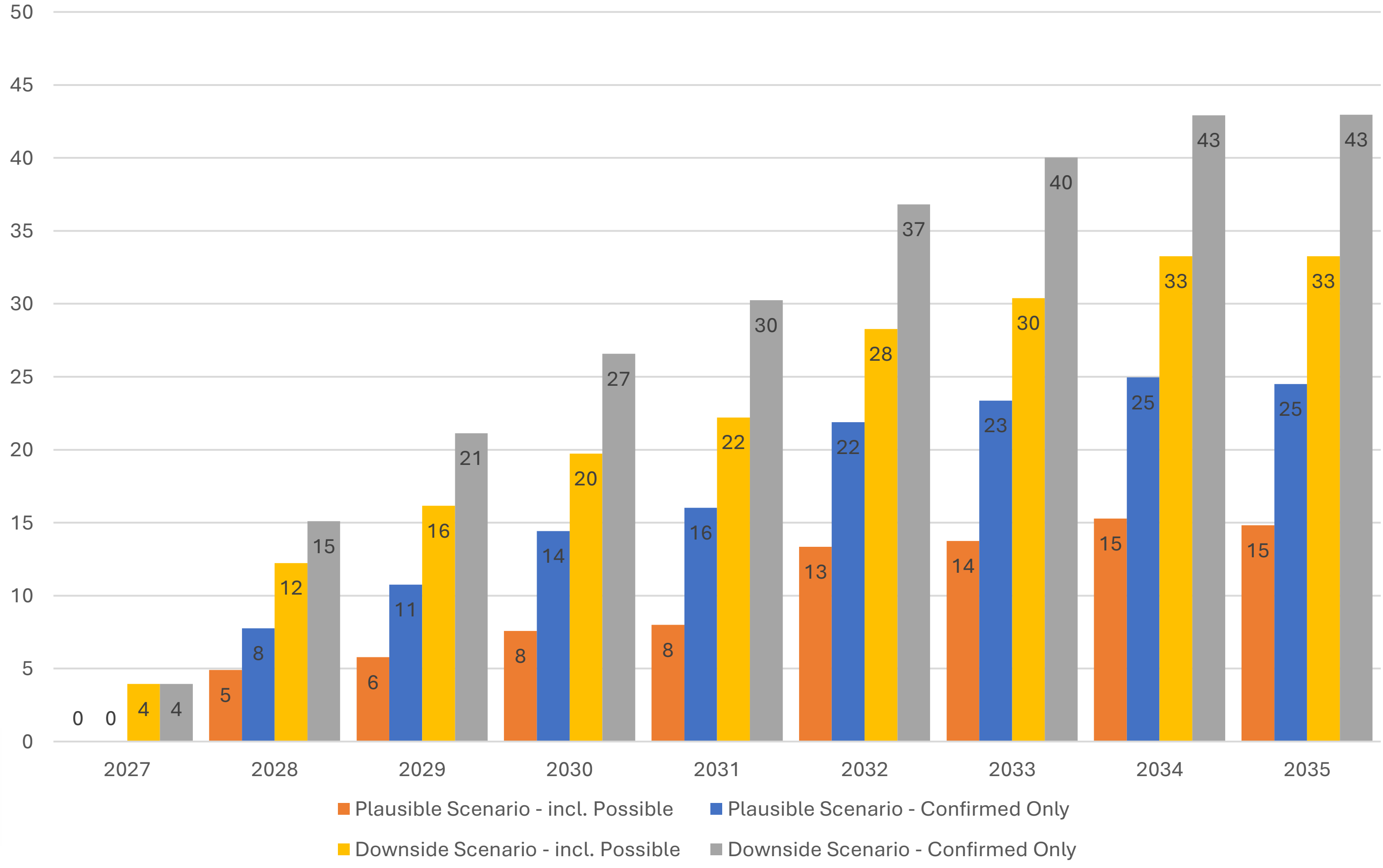
Even with significant industrial conversion, a structural gas shortfall remains. We explore the impacts of other demand-side switching.

A shortfall opens from 2028 and widens through 2035

- Even with significant industrial conversion, the energy shortage persists.
- Depending on the price and volumes required for electricity generation, along with residential price inelasticity – with no other actions taken, deindustrialisation will likely follow once the shortfall materialises, as industrial users tend to be the group most sensitive to price.
- The shortfall size if only confirmed conversion projects occur is between 8-15PJ in 2028 and 25-43 in 2035 – at an average of $40m GDP loss per PJ, this is ~$320m-600m loss in 2028 and $1b-$1.7bn loss in 2035 using the GDP numbers on the following slide.
- The next set of slides look at options to close this shortfall. No single lever provides the solution - multiple demand and supply-side levers must be pulled.

FOR SCALE
20 PJ ≈ all of Methanex, or all gas-fired electricity in 2025.

Annual gas shortfall by supply scenario (PJ)



Source: Gas Working Group supply/demand modelling. Range = PEP (expected) to NNP (no new production).

Deindustrialisation has far-reaching socioeconomic impacts

- Food processing generates the highest economic value from gas, contributing $45-75m GDP, $70-100m exports and supporting 30-500 jobs per PJ consumed.
- Methanex consumes the largest volume of gas (27 PJ) but generates comparatively low economic value ($6-8m GDP and 6-7 jobs per PJ), however it provides valuable demand flexibility to manage gas for electricity.
- GDP and employment impacts vary by more than an order of magnitude across industrial sectors, highlighting the importance of where gas shortages occur.
- This is a factor that decision-makers will need to weigh in formulating actions to manage shortage risks.

GDP and employment impacts of deindustrialisation by sector

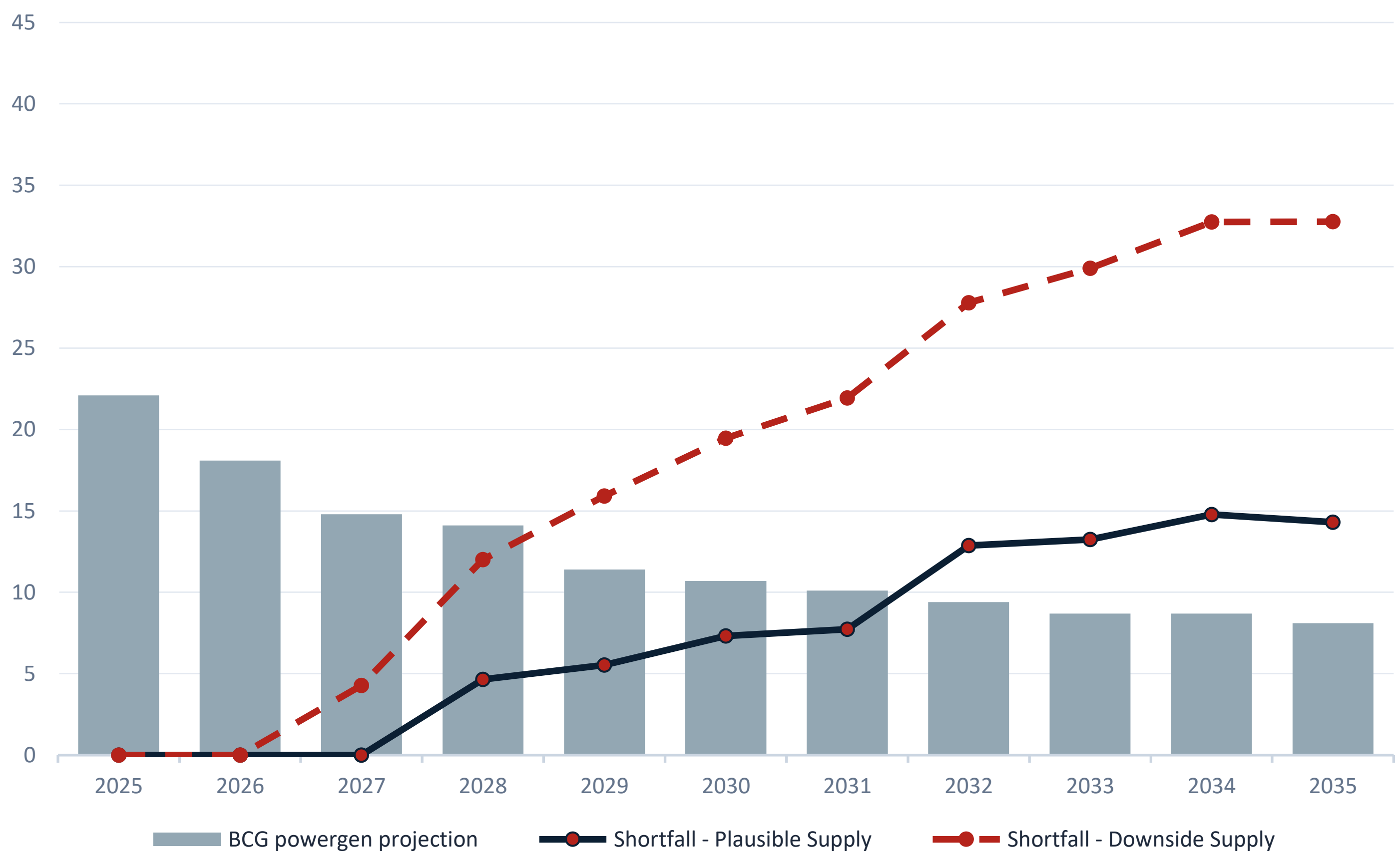
	2025 gas (PJ)	Gas % of opex	GDP $m / PJ	Exports $m / PJ	Jobs / PJ	Alternative?
Electricity generation + cogen	29	–	–	–	–	Renewables / coal / diesel
Industrial — food processing	20	3–5%	45–75	70–100	300–500	Biomass / e-boilers, HT heat pumps
Industrial — wood	3	1–2%	15–30	10–20	150–300	Biomass / e-boilers
Commercial & residential	15	–	–	–	–	Yes — sticky preferences
Industrial — other	3	1–2%	30–60	20–40	200–400	Heat pumps
Industrial — chemicals	1	1–2%	20–40	15–30	150–300	Partial — biomass / e-boilers
Industrial — basic metals	2	1–2%	15–30	15–30	150–300	Limited — high process heat
Methanex	21	75–85%	6–8	6–8	6–7	No — gas-dependent
Ballance (Kapuni)	7	75–85%	3–4	no exports	14–16	No — gas-dependent

Source: Boston Consulting Group analysis.

Power generation: a significant lever, but not enough alone

- Of the three big gas-user groups, electricity generation is the next largest single use group in the short-term, after industrials.
- The chart compares projected gas-for-generation (from the BCG Energy to Grow report) against the shortfall. The gas use here reflects an average hydro year, noting that the size of required gas for dry year generation will also reduce in line with new renewable build.
- Lines represent shortfall, after optimistic industrial switching (all confirmed, probable and possible projects converted), taken from last slide. On top of that, **if all gas use for electricity generation was removed, we would still have a gas shortfall after 2031 in both supply scenarios**.

Gas shortfall vs electricity-generation gas use (PJ)

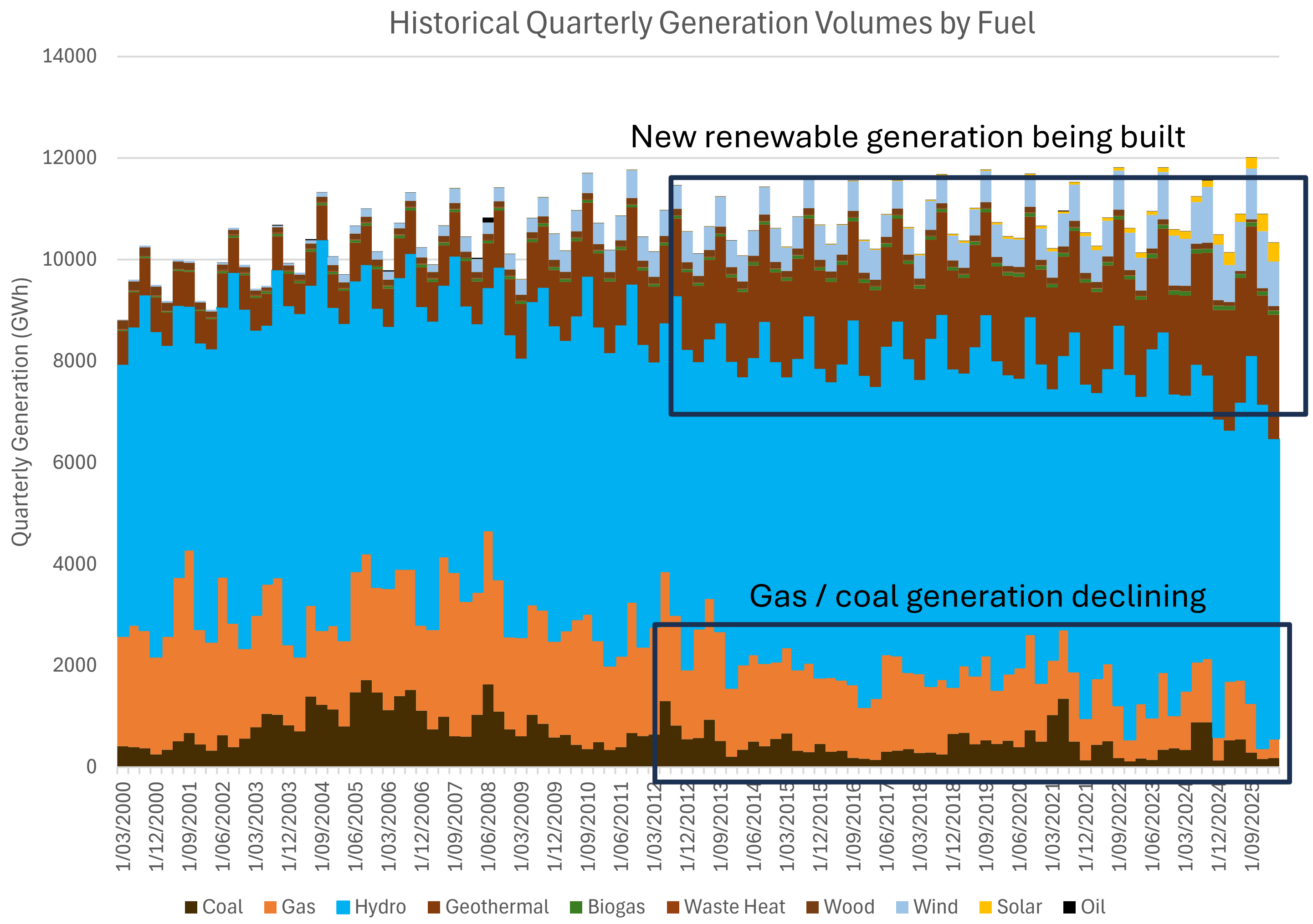


Shortfall (lines) exceeds projected power-generation gas use (bars) from the early 2030s.

Source: BCG generation gas use (average hydro); Gas Working Group shortfall modelling.

The changing role of gas for electricity generation

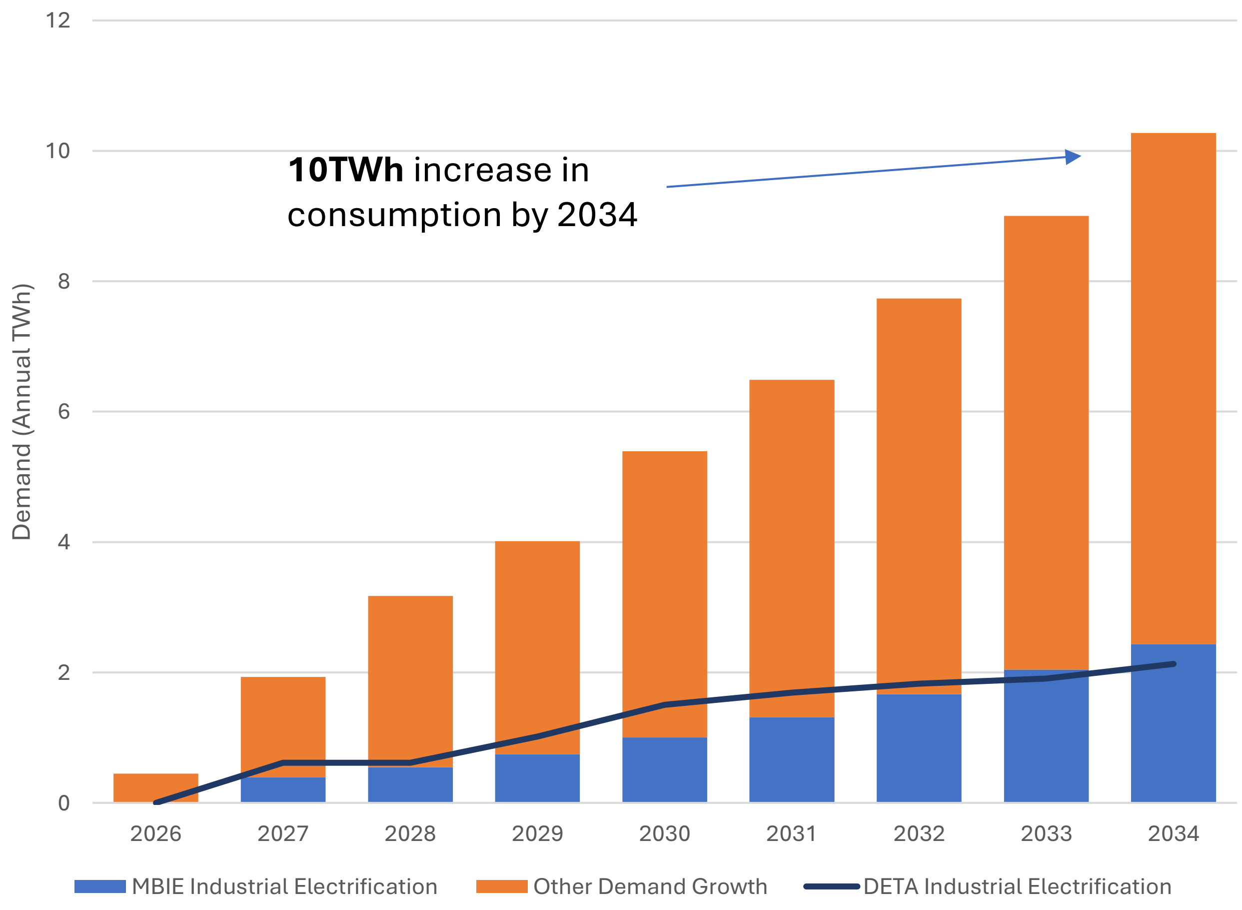
- Historically, our abundant domestic gas existed as a low-cost source of dispatchable baseload and firming generation, complementing our hydro-dominated system and reducing reliance on coal.
- As domestic gas production has declined, and prices have increased, gas-fired generation increasingly sits on the margin of dispatched electricity.
- Outside periods of hydro spill, additional renewable generation is assumed to reduce dispatched gas roughly one-for-one on an annual energy basis, as it results in preserved quantities of hydro storage.
- This is shown on the graph by the orange bars reducing over time – in line with the increase in cheaper geothermal, wind and solar.



Projecting future demand for electricity

- To understand whether there is sufficient electricity generation available to support the conversion options contained in this report we first looked at total demand through to 2034, including the demand from the conversions we have identified.
- The chart shows how the underlying industrial electrification from gas in MBIE's Growth demand scenario roughly aligns with the industrial conversion we have identified. The MBIE demand aligns in the short-term but is higher in the longer term.
- Because of this alignment, we have adopted the MBIE Growth demand scenario to assess whether electricity generation available can meet this demand into the future.
- Since MBIE's forecast, distributed solar uptake has significantly outpaced their assumptions. We update only their distributed solar assumption to reflect the current rate of uptake visible in the Electricity Authority's dataset. For more detail, see the appendices, where compare our projection to theirs.

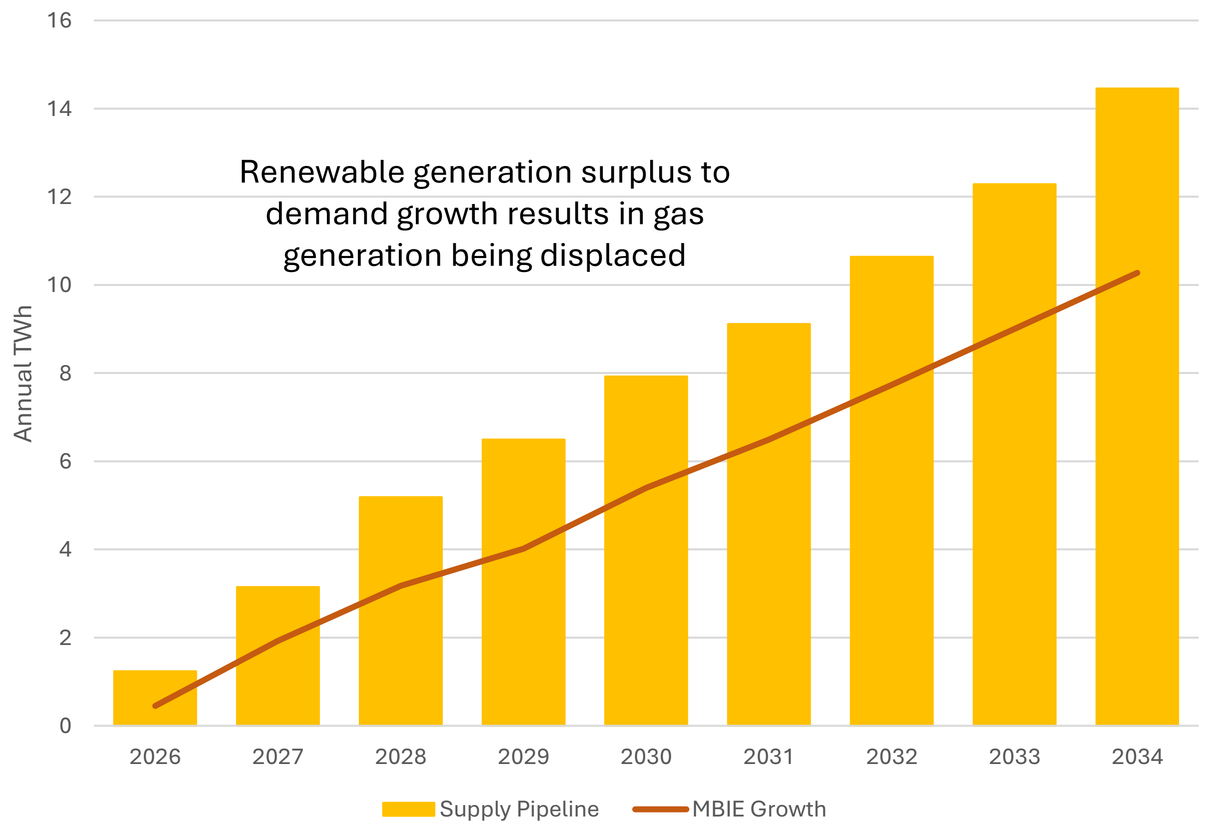
Cumulative annual demand under MBIE Growth scenario



Source: MBIE Growth scenario; DETA industrial electrification; EA distributed solar installation data.

Generation pipeline sufficient to meet demand growth

- Using 2025 supply and demand as a baseline – we overlay (shown in red) the demand increase from MBIE's Growth scenario, (adjusted for observed uptake in distributed solar).
- The yellow bars show a likelihood-adjusted renewable generation pipeline from Transpower. To adjust the pipeline, we have removed projects on hold or without a consent application.
- Under our set of supply assumptions, even with the aggressive MBIE Growth scenario, by 2034 **the pipeline of renewable generation is enough to both meet demand (including industrial conversions) AND displace the quantity of gas used for electricity generation in an average year**.
- Displaced gas in the visual refers to the volume of renewable generation surplus to meeting projected demand, which we have assumed to displace gas - either directly or implicitly via hydro generation saved.
- **Important caveats on this view:** this is pipeline, not build rate, and intermittent generation is not separated from firm. For the pipeline to translate into build, signals are needed to sustain investment – including clarity on demand and forward price. Further, focus is needed on ensuring that the mix of generation provide necessary security and affordability.



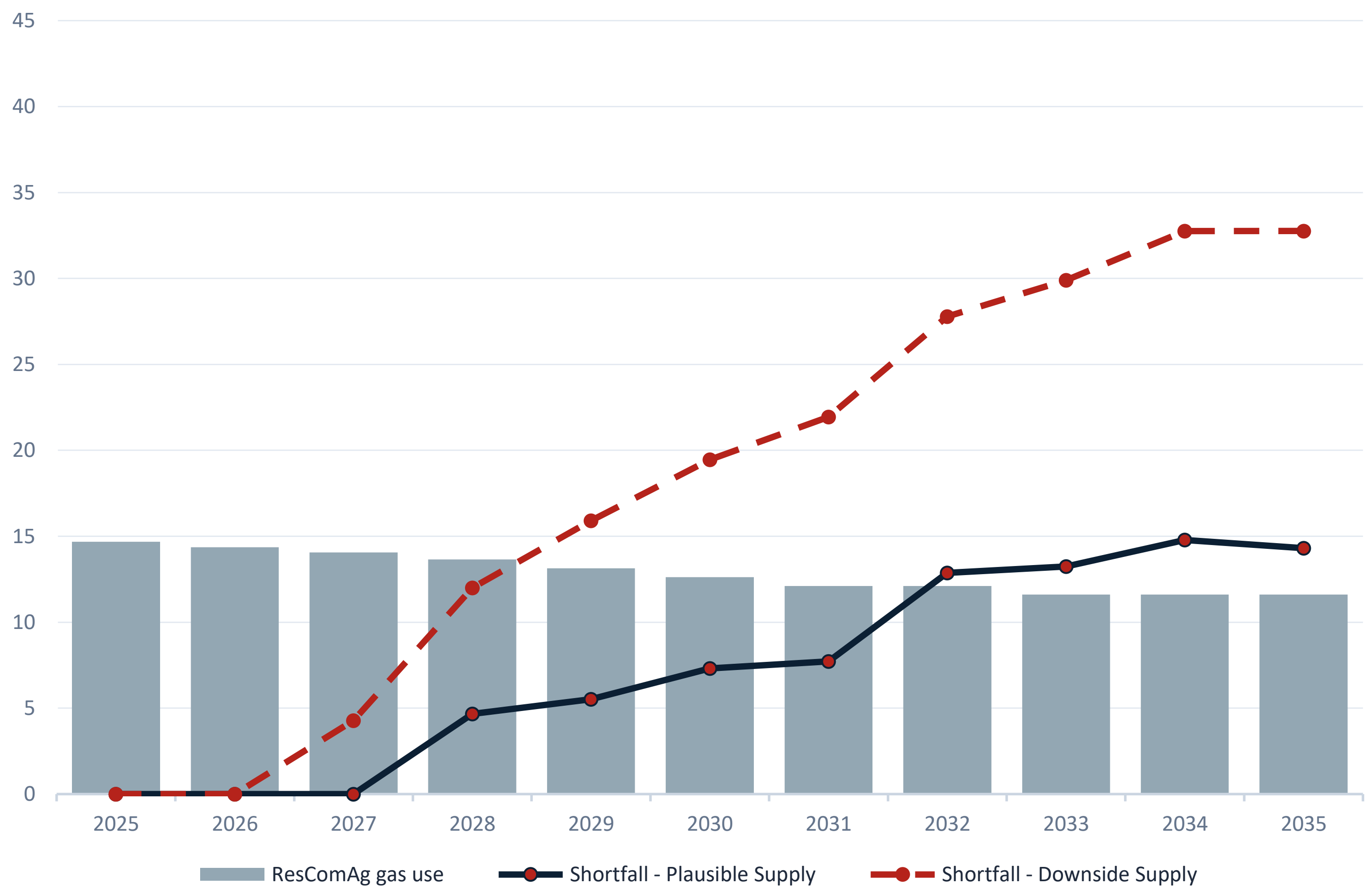
	2026	2027	2028	2029	2030	2031	2032	2033	2034
Gas Generation Displaced (TWh)	0.79	1.22	2.01	2.48	2.53	2.62	2.90	3.28	3.54

Source: Transpower; MBIE; GWG analysis.

Residential & commercial: a coordination-heavy lever

- Switching residential and small commercial gas users is feasible to further reduce gas demand, but needs significant coordination at scale, which may be difficult.
- It is noted that some users are relatively price-inelastic and will be reluctant to switch on changes in price signal alone.
- Similar to electricity generation, solely eliminating all residential and commercial consumption, combined with optimistic industrial switching is **still** not enough to prevent a shortfall past 2028 in the downside supply scenario and 2032 in the plausible scenario.

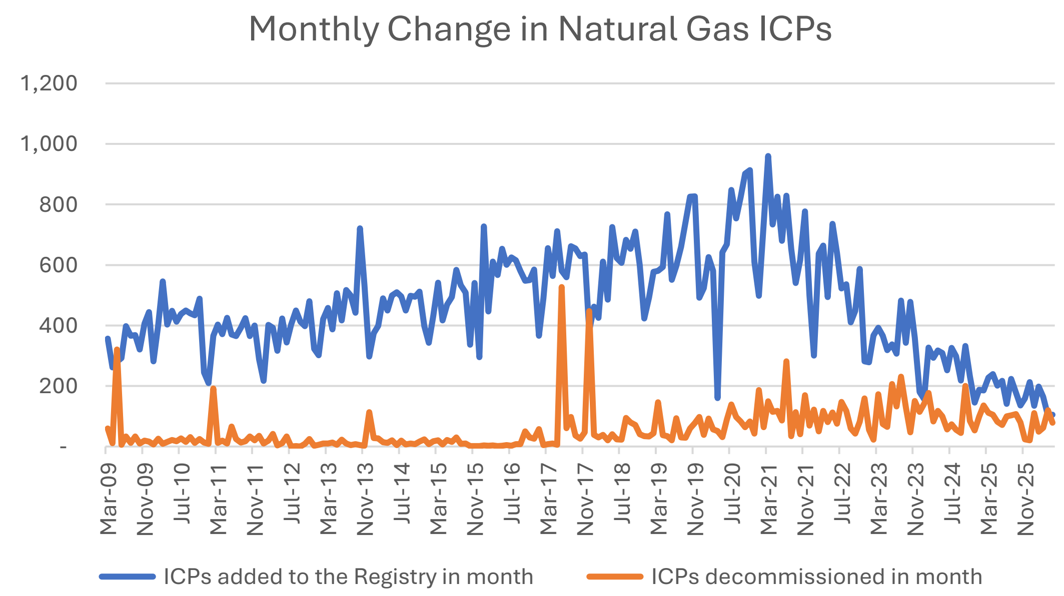
Gas shortfall vs residential/commercial/ag gas use (PJ)



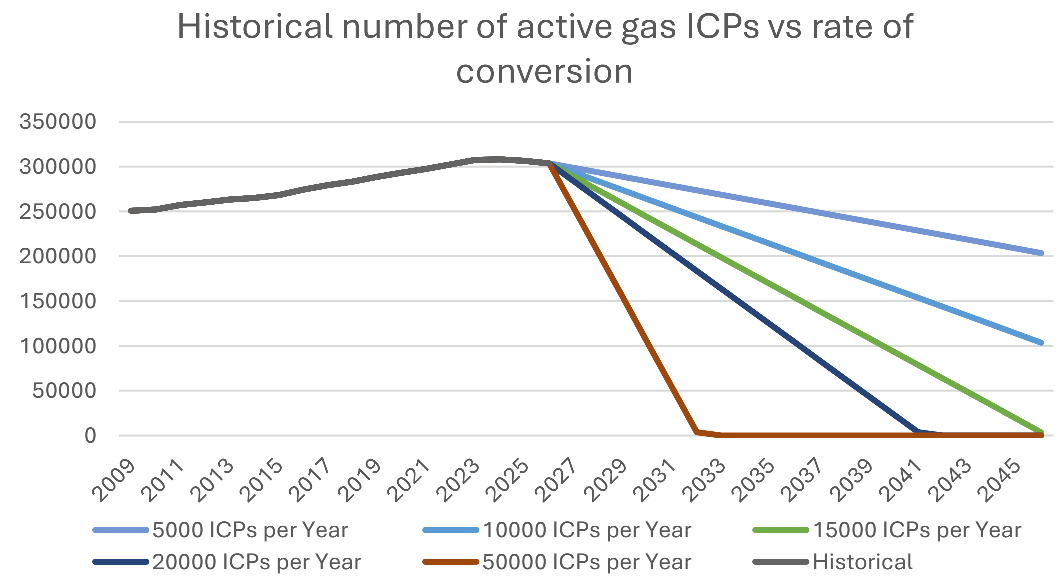
Source: BCG residential/commercial gas use; Gas Working Group shortfall modelling.

Residential & commercial: what rate of switching is required?

Gas shortfall vs residential/commercial/ag gas use (PJ)



Illustrating required rate of ICP switching (ICPs / year)



- According to the Gas Industry Company, there are currently around 300,000 active piped natural gas connections in the North Island.
- Active ICP count has just started to trend downwards over the last couple of years; we estimate the current rate at 5,000 per year. However new ICPs are still being added.
- The rate of switching required to eliminate residential and commercial gas usage by 2040 is just over 20,000 ICPs per year – to eliminate it by 2030, it is over 50,000 ICPs per year. Rates this high would require a significant shift in both policy and consumer behaviour.
- We explore the costs of this switching in the following slides, the two most feasible options for these consumer groups as being either electrification or LPG. It is worth calling out that costs may vary significantly case-by-case, particularly with remaining appliance life.

Source: BCG residential/commercial gas use; Centre for Sustainable Finance; Gas Industry Company; Gas Working Group shortfall modelling.

Residential & commercial: electrification benefits outweigh costs

Electrification upfront costs

- Households and small businesses are typically reliant on natural gas for either cooking, space heating, hot water or any combo of all three.
- To electrify, there are no upfront connection costs, as most homes will already be connected to the grid. However, the gas appliances will need to be replaced with electric equivalents.
- The average upfront costs of electrifying gas technologies are:
  - Cooking; induction upfront = $2k, resistive upfront = $2k
  - Space heating; heat pump = $4k, resistive = $2.3k
  - Water heating; hot water heat pump = $7.5k, resistive = $5k
- Assuming 290,000 of the 300,000 ICPs are residential and small business, electrifying all of them would require **average upfront costs between $600m (cooking only) and $3.3b (all).**
- Gas appliances also face costs comparable to these when being replaced – therefore for the most part this is not an increased spend – just a change in timing for spend for most customers.

Electrification benefits

- Although up front costs are high, replacing gas machines with new electric machines contributes to significant efficiency gains and bill cost savings for consumers.
- When compared with gas, the potential differences in yearly bills and lifetime savings (upfront cost + 15-year machine lifespan) are:
  - Cooking; $70/yr vs $120/yr, $3k/lifetime vs $3.6k/lifetime
  - Space heating; between $260/yr (heat pump) and $1040/yr (resistive) vs between $1.2k (flued) and $1.3k (fire), $8k (heat pump) - $18k (resistive) vs $24k (flued) - $26k (fire)
  - Water heating; between $130/yr (heat pump) and $53/yr (resistive) vs $890/yr (gas avg), or $9k-$13k vs $18k lifetime.
- An increased amount of demand flexibility through appropriately-managed hot water and other flex assets has **significant benefits for reduced network costs through improved utilisation and deferral of investment in network assets**.

Source: Rewiring Aotearoa; Centre for Sustainable Finance; Orion analysis on electric hot water; Gas Industry Company; Gas Working Group shortfall modelling.

Residential & commercial: LPG is a case-by-case alternative

LPG costs

- The average upfront costs of converting or replacing associated technologies are below:
  - Cooking – converting: $400, replacing: $2,000
  - Hot water – converting: $600, replacing: $5,500
  - Space heating – converting: $700, replacing: $7,700
  - Note if the home is not already on LPG, cylinders and regulatory checks are required as an upfront "connection cost".
- This leaves the conversion range at between $200 and $10,000, dependent on the switching required. Across 200,000 residential customers this is **between $40m and $2b**.
- Most of the energy cost of LPG is volumetric, not fixed. For high energy users, it is not a great alternative.
- Similar to electrification, significant upstream distribution and supply investment would also be required to support new volumes of LPG consumption.
- As domestically produced LPG is also declining, this consumption would require increasingly imported volumes.

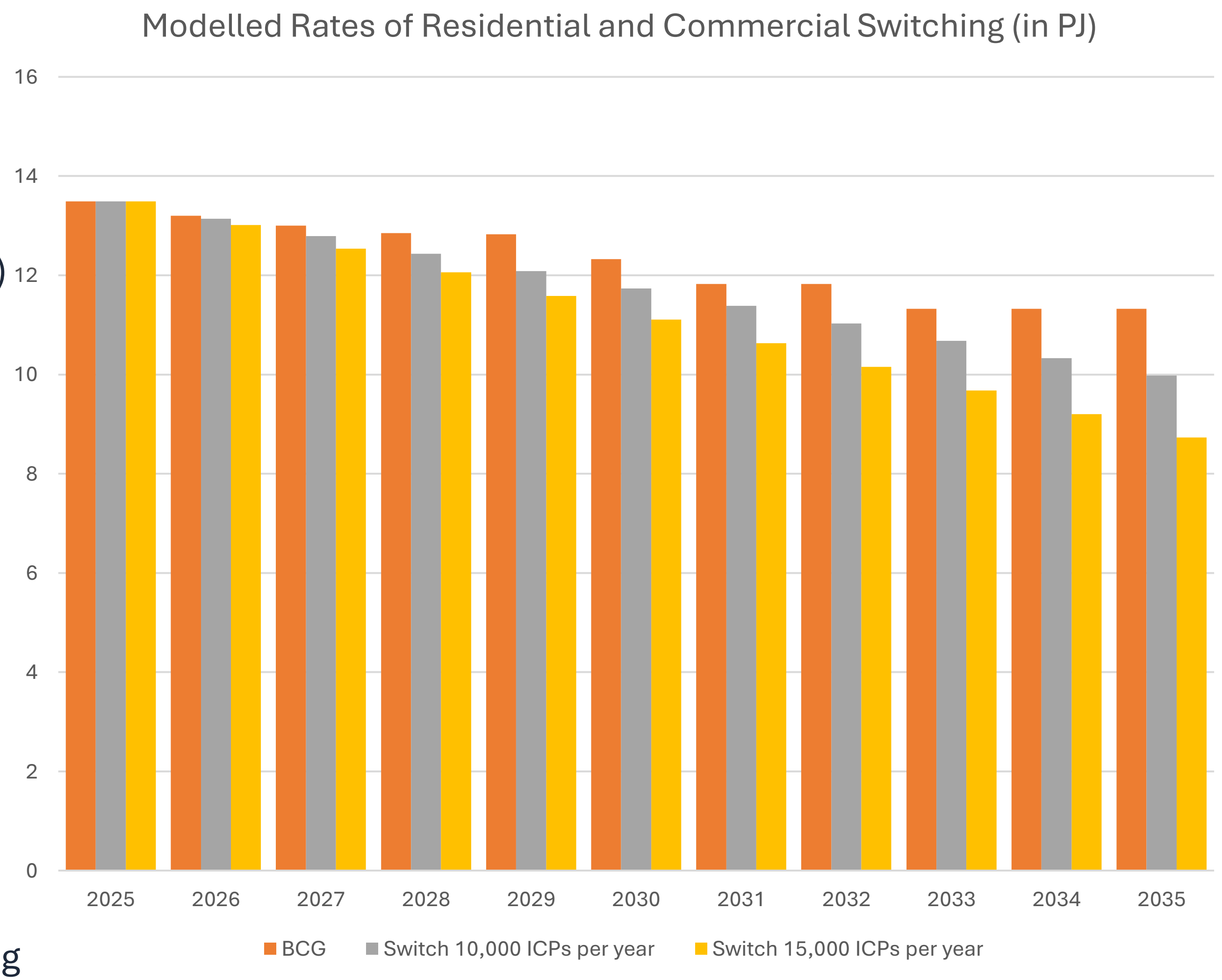
LPG benefits

- Other than space heating, for which electricity and gas are cheaper on average in both upfront cost and energy costs, LPG appliances are typically the cheapest upfront replacement cost. Considering conversions as opposed to replacements, LPG can be even cheaper upfront.
- The energy savings are significantly smaller than electricity, particularly as most homes are already grid-connected (so customers cannot avoid the fixed daily cost of electricity) and variable electricity costs are significantly lower than LPG.
- It is worth noting that some customers may desire to cook with a flame (particularly restaurants). LPG is an attractive alternative to gas in that case. However, this is likely a small constituent of consumers – hence LPG is mainly a case-by-case option.
- There may also be practical limits on LPG volumes: moving LPG at volume has flow-on impacts across import, storage and distribution infrastructure (we understand MBIE may have more detail on where this binds). Use is location specific, depending on volumes needed and storage, and as an imported fuel LPG carries supply chain and geopolitical risk.

Source: Rinnai NZ; Elgas NZ; Hot Water Cylinders NZ; Consumer NZ; Centre for Sustainable Finance; Orion analysis on electric hot water; Gas Industry Company; Gas Working Group shortfall modelling.

Residential & commercial: projecting potential switching

- Taking the underlying switching rate at 5,000 ICPs per year identified earlier, we model two scenarios of additional switching:
- at 5,000 ICPs (total 10,000 ICPs per year / 833 a month) delivering 3.5PJ reduced demand; and
- at 10,000 ICPs (total 15,000 ICPs per year / 1,250 a month) delivering 4.76PJ reduced demand.
- According to MBIE's numbers, residential and commercial gas consumption is just under 14PJ, equally split between the two groups.
- However, most of the ICPs are residential and small business consumers (290,000 of the 300,000 total) who consume around 25GJ/year on average.
- There are around 7,000 business and small commercial ICPs, which consume around 340GJ/year on average.
- Medium and large commercial have 2,000 ICPs who consume 1950GJ/year on average.
- We include business and commercial consumers switching at proportional rates to residentials.



Source: MBIE fuel consumption 2026; Commerce Commission gas pipeline business report 2025; Gas Working Group shortfall modelling.

Integrated network planning must support the transition

Electricity networks

- As discussed in the previous slide on the costs and benefits of residential gas electrification, there is a significant opportunity for EDBs to increase the amount of available demand flexibility.
- However, if poorly managed, residential electrification at this scale can impose significant costs on networks – and the customers that networks recover their revenue from. Resistive electric hot water cylinders alone account on average for:
    - Around 30% of residential household energy consumption – just over 2MWh per year.
    - 0.5kW contribution to peak demand (when not controlled by ripple, retailers or consumer smart devices).
    - Multiply this across many consumers, and the impacts can scale very quickly, particularly on low voltage networks.
    - Across 100,000 ICPs, this is a 50MW increase peak demand, and a 200GWh increase in network volume.
- Heat pump hot water cannot be controlled by networks – although the contribution to peak demand is far smaller.

Existing gas networks

- Fixed charges represent (among several other things) the cost of investing in and maintaining the network which delivers gas. Currently, they make up a significant portion of consumer gas bills, around a third in 2026.
- As many residential and commercial customers disconnect, this could push up the share of fixed costs that must be recovered by a shrinking pool of consumers remaining on the network.
- This further improves the economics of switching but raises affordability concerns for those unable to switch.
- Current regulation and pricing is suitable for managing a growing network, but these must change when the network begins to shrink, to enable an orderly decline.
- As a significant number of the customers are connected to gas distributors who are also electricity distributors (Vector and Powerco), coordinated planning and regulation for a single integrated system will help facilitate an orderly transition.

Source: Orion hot water analysis; Grattan Institute.

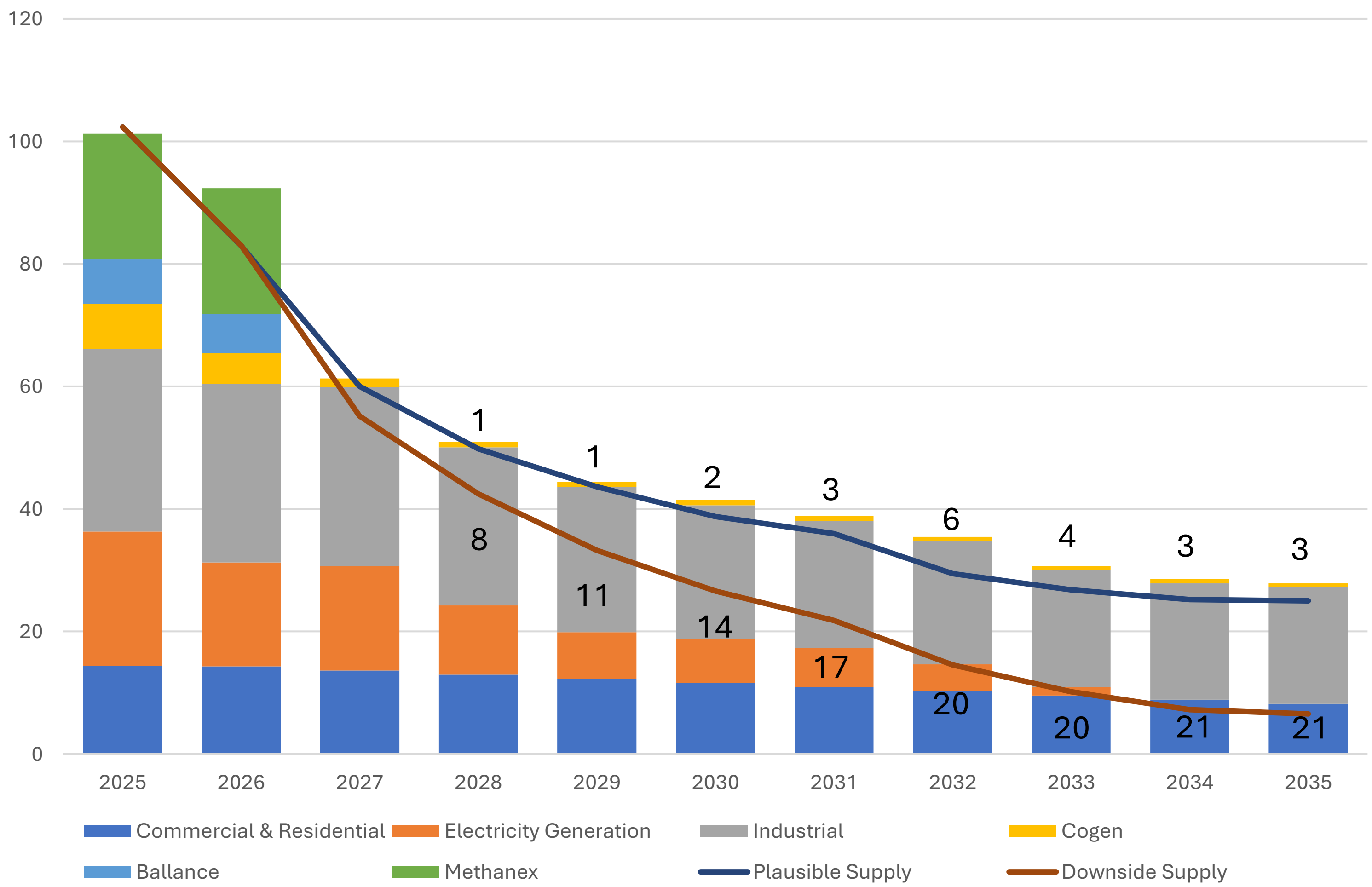
SECTION 05

Consolidated scenarios to manage the energy shortfall

How do the combinations of the previously covered actions manage the risk of energy shortage.

Pulling demand levers hard leave a shortfall risk to manage

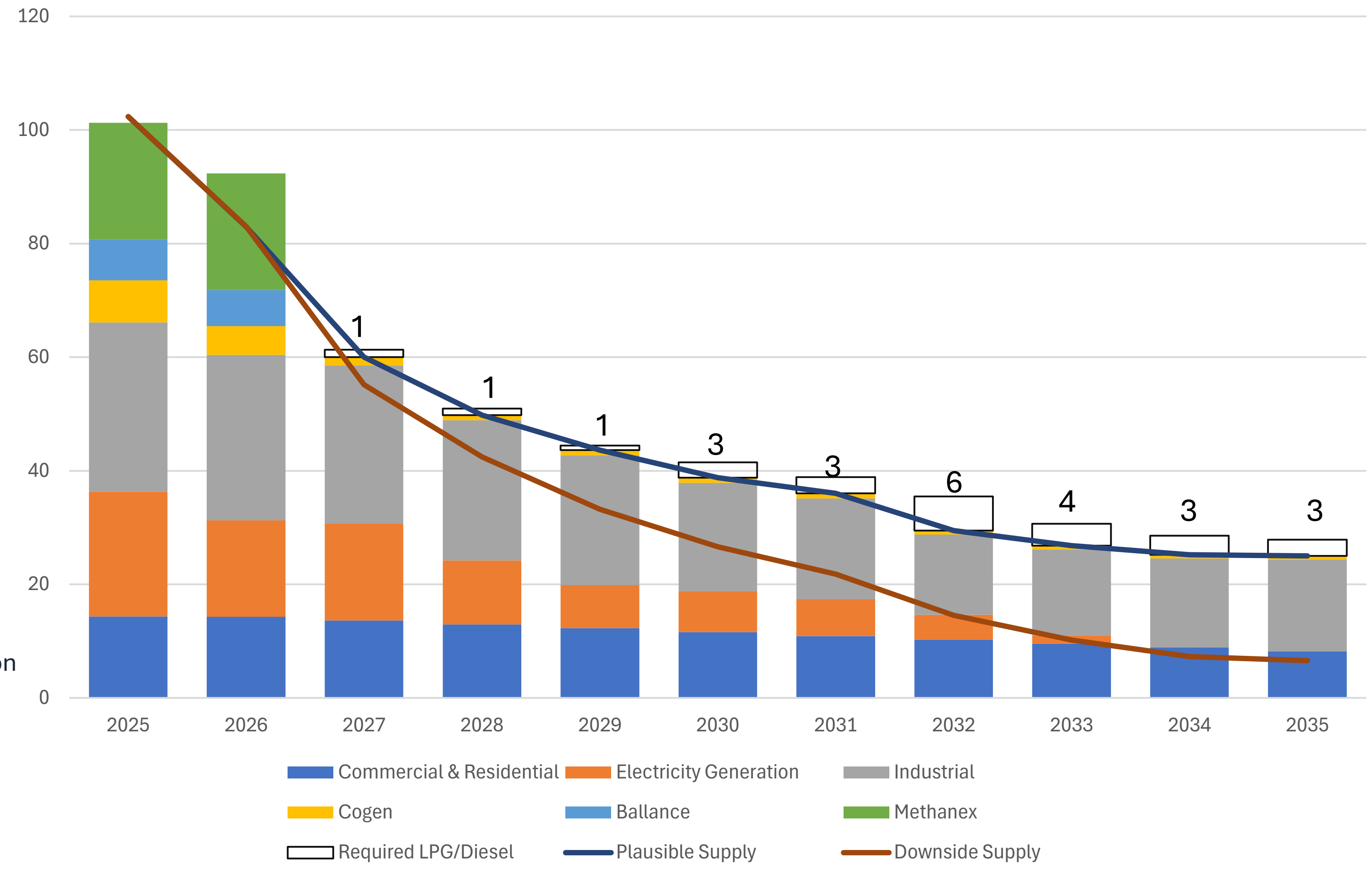
- When we combine the actions of:
  - Completing the confirmed, probable and possible industrial fuel switching; and
  - Reducing the requirement for gas for electricity generation through greater renewable generation (assuming a repeat of 2025 hydro generation) and
  - Implementing a campaign for elevated residential and commercial gas switching at a rate of 15,000 ICPs per year.
- There is still a shortfall as big as 6PJ in 2032 under a plausible supply scenario ($240m GDP). In the downside scenario, the shortfall is up to 21PJ by 2035 ($840m GDP).
- The plausible supply scenario shortfall begins to narrow from 2032, as rapid renewable build displaces all gas for electricity, but remains at 3PJ in 2035.



Source: BCG generation gas use (average hydro); Gas Working Group shortfall modelling.

Pulling demand levers hard AND using LPG to fill the shortfall

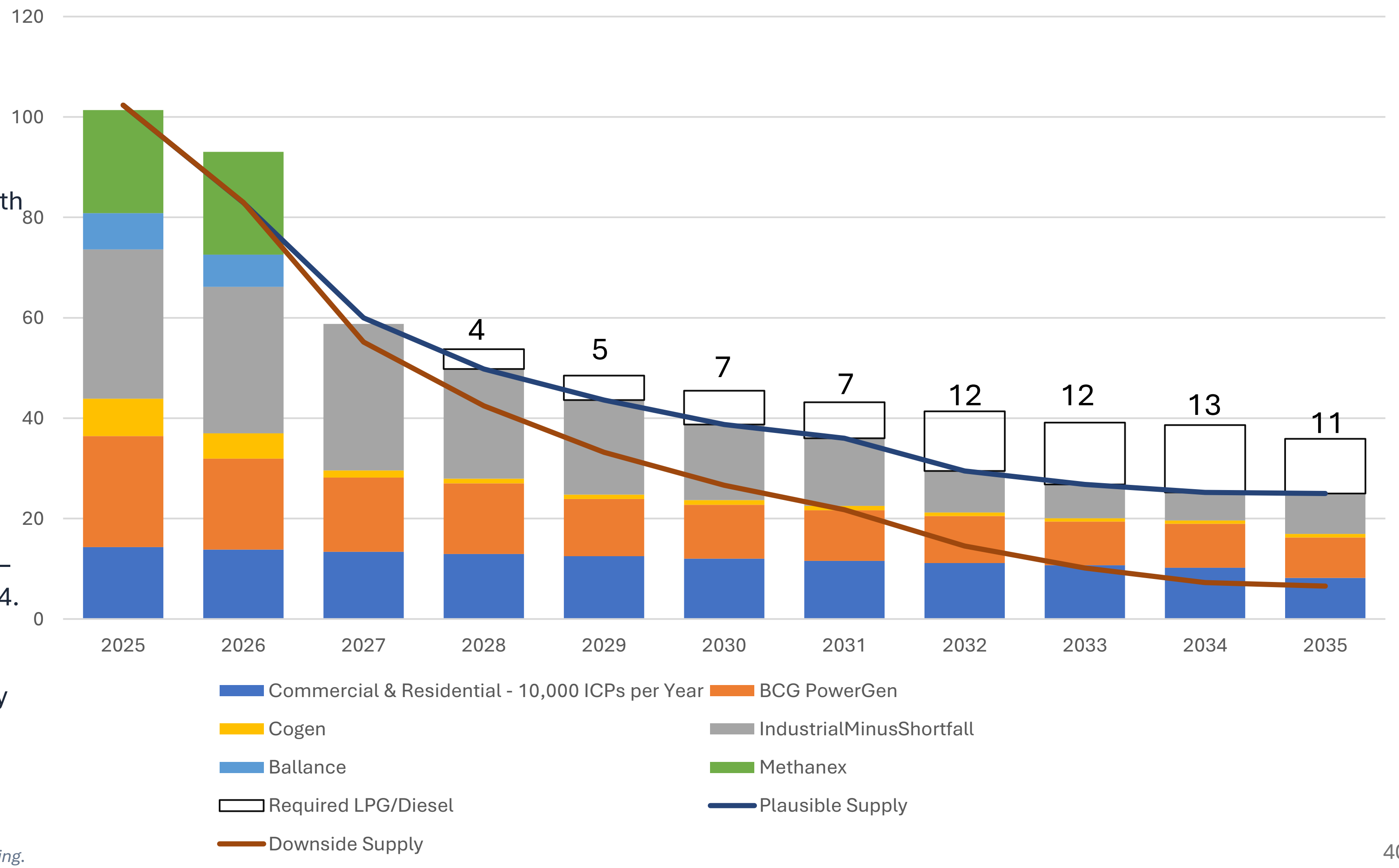
- This chart shows the demand actions from the previous slide:
  - Industrial fuel switching; and
  - Reduce the requirement for gas for electricity generation; and
  - Elevated residential and commercial gas switching (15,000 ICPs per year).
- Then the shortfall of domestic gas is managed through using additional LPG (potentially by small industrial users). Another example alternative fuel for these users may be diesel.
- LPG at this scale (an increase of around 50%) would likely require additional storage, port facilities, fire systems and consenting – around $160m (or $2 to 3 per GJ) and taking 1-2 years.
- The cost to users of meeting the shortfall with imported LPG could be $25m to $300m a year, depending on the size of the shortfall (1 to 6 PJ) and the delivered price ($25-50/GJ, which reflects current market price and the cost of new import facilities).
- Under the downside scenario, the shortfall grows further – from around 9PJ in 2026 to around 21PJ by 2034-35.
- LPG at these volumes may face practical limits: moving LPG at volume has flow-on impacts across import, storage and distribution infrastructure, and suitability is location specific. We understand MBIE may hold more detail on the volumes at which this binds. As an imported fuel, LPG also exposes users to global supply chain and geopolitical disruption.



Source: BCG generation gas use (average hydro); Gas Working Group shortfall modelling.

Medium demand levers with higher LPG to fill the shortfall

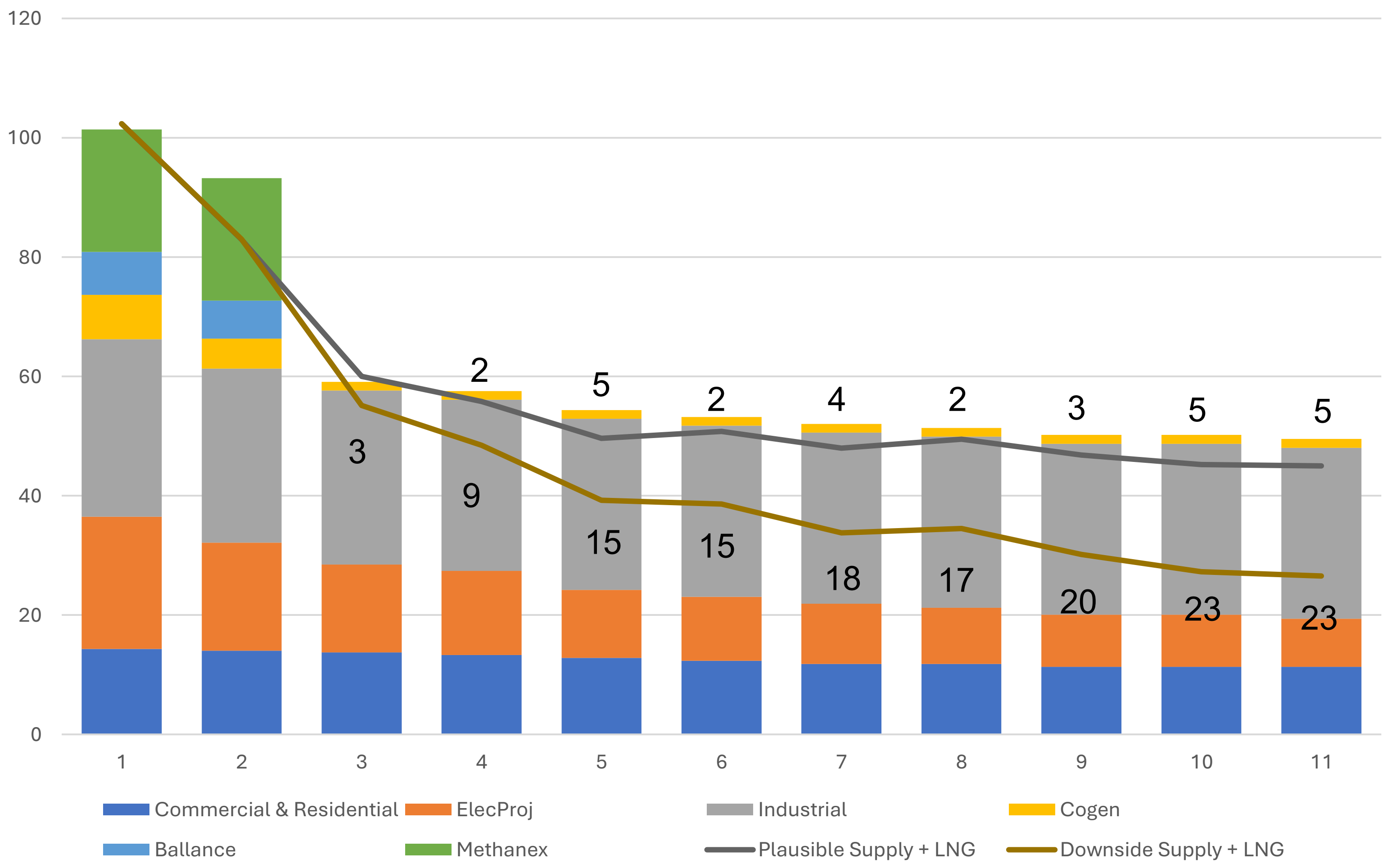
- This chart shows a different series of demand actions from the previous slide:
  - Industrial fuel switching; and
  - No elevated reduction of gas for electricity generation; and
  - Residential and commercial gas switching at 10,000 ICPs per year.
- As in the prior example, the remaining shortfall is filled with LPG with small industrial users
- LPG at this scale (more than double current capacity) would likely require a new import facility, updating of the satellite facilities, road tankers and filling facilities.
- The cost of the LPG for users (including new import facilities) could be $25-50GJ or $120m to $300m for the shortfall of 4 to 13PJ
- Under the downside scenario, the shortfall grows further – from around 10PJ in 2026 to a peak of around 31PJ in 2034.
- At this higher volume the practical limits above bind harder: the flow-on impacts of moving LPG at volume across ports, storage and road distribution are more likely to constrain delivery, and reliance on imports increases exposure to global supply chain and geopolitical disruption.



Source: BCG generation gas use (average hydro); Gas Working Group shortfall modelling.

Increasing supply (LNG) and taking minor action on demand

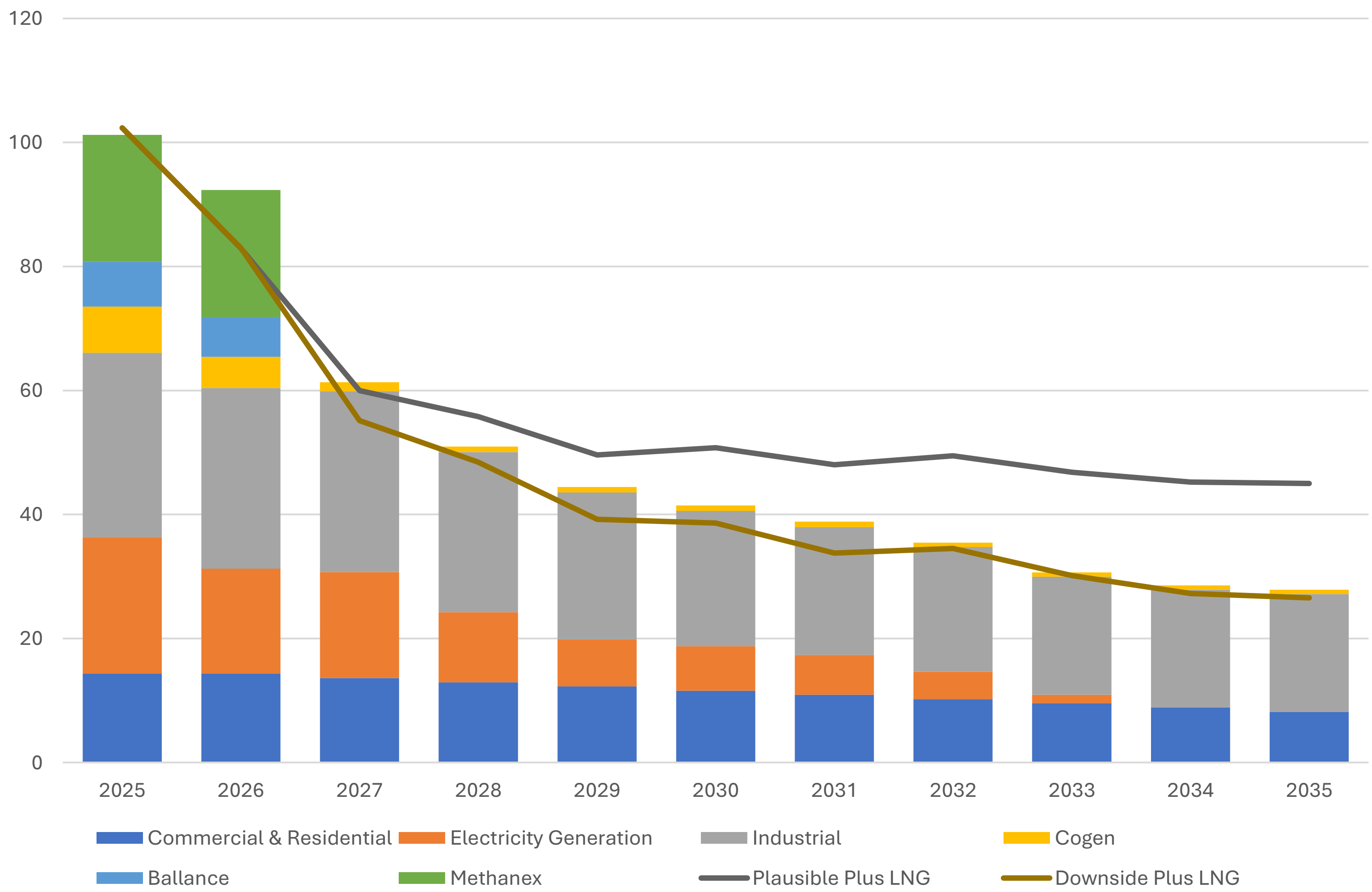
- When we combine the actions of:
  - Completing the confirmed industrial fuel switching (not the probable and possible); and
  - No elevated reduction of gas for electricity generation (assuming a repeat of 2025 hydro generation); and
  - Maintain residential and commercial gas switching at a rate of 5,000 ICPs per year; and
  - Add in additional supply through LNG of +6PJ of LNG in 2028, +12PJ in 2030 and +20PJ in 2032
- **This scenario is largely aligned with the current state policy mix of LNG with an industrial loan guarantee.**
- There is a shortfall under the plausible supply of 2-5PJ and under the downside scenario of 3-23PJ.
- Note that the ‘probable’ industrial conversion projects provide ~2.3PJ.
- Whether gas users can absorb LNG (or LPG) pricing at this scale, and how those costs flow through to other prices, still needs testing. Sapere’s economic analysis and MBIE's LNG price analysis provide some insights on this.



Source: BCG generation gas use (average hydro); Gas Working Group shortfall modelling.

A combination of supply and demand-side intervention

- When we combine the actions of:
    - Completing the confirmed, probable and possible industrial fuel switching; and
    - Reduce the requirement for gas for electricity generation through greater renewable generation (assuming a repeat of 2025 hydro generation); and
    - Implement a campaign for elevated residential and commercial gas switching at a rate of 15,000 ICPs per year; and
    - Include +6PJ of LNG in 2028, +12PJ in 2030 and +20PJ in 2032.
- Under the plausible supply scenario there is no shortfall. Under the downside scenario there is a shortfall of ~5PJ to manage in 2027, 2029 and 2031.



Source: BCG generation gas use (average hydro); Gas Working Group shortfall modelling.

SECTION 06

Conclusions and Recommendations

A whole of energy system issue - not just about dry year or gas

CONCLUSIONS FROM THIS REPORT

- **New Zealand's gas supply is shrinking, and even with the actions already under way, there will not be enough by 2028.** This is not only an electricity problem that shows up in dry years, it is a broader energy shortage that affects industrial users, households and businesses directly. Closing that gap is not a choice between finding more gas or using less of it: this report shows that more action is needed on both supply and demand together.
- **Industrial conversion is the single biggest and fastest lever on the demand side.** It could remove up to 17.7PJ of gas demand, more than a third of forecast 2028 supply. But close to half of that depends on conversions that do not yet make commercial sense. These projects are technically feasible, but only become worthwhile with greater policy support, and some of the businesses involved may close rather than absorb materially higher energy costs.
- **Conversion also depends on two other systems being ready.** Electricity network companies know where new capacity is needed and how much, in some cases more than their usual five years of growth investment, but building it takes two to six years. Current settings do not support investing ahead of this demand. As users leave the gas network, infrastructure owners and the regulator need to agree how the fixed costs of pipelines, depreciation and decommissioning get recovered.
- **No single action gets New Zealand out of this shortfall.** Even combining full industrial conversion, using less gas for electricity generation, faster switching by households and businesses, and new imported LNG supply, only nearly closes the gap, and that is under the more optimistic of the two supply scenarios modelled. Under the more pessimistic scenario, a shortfall remains even if every one of these actions happens.
- **Every one of these actions takes years to deliver, so the constraint is time, not choice.** A network upgrade takes two to six years. A conversion project takes multiple years once committed to. New LNG supply cannot arrive before 2028. None of these timeframes get shorter by waiting to decide, they simply push further out whatever depends on them.
- **Doing nothing has a large and lasting cost, and it does not fall evenly.** Modelling puts the economic cost at $320-600 million in 2028, rising to $1-1.7 billion a year by 2035, with 2,100 to 6,700 industrial jobs at risk in 2028, rising to as many as 19,300 by 2035, concentrated in the regions around the industrial sites affected. Unlike a typical economic downturn, this does not reverse once conditions improve.
- **Different parts of the system are each working on their own piece of this problem.** Electricity companies are investing in their networks. MBIE sets policy direction. Some industrial users are already converting. But oversight of gas, electricity, biomass and LNG is split across MBIE, the Commerce Commission, the Gas Industry Company, the Electricity Authority and EECA.
- **This is a problem New Zealand can manage.** The scale of investment and coordination required is significant, comparable to the fibre rollout or the Canterbury earthquake rebuild, but it is not without precedent. What will determine the outcome is not whether the right tools exist, but whether the years still available before the shortfall widens are used to act on them.

The remainder of this section sets out what is already under way and why it is not enough on its own, our recommendation for what Government needs to do, and how the Framework proposes to help deliver it.

Current actions are a start. More is needed

Actions Government is taking:

- **Gas Transition Loan Guarantee Scheme:** Up to $1.2bn of Crown-guaranteed (80%) bank lending, live from August 2026 for three years, for businesses using 1,000GJ+ of gas a year.
- **LNG import facility procurement:** Port Taranaki proposals shortlisted, contract targeted mid-2026, operation as early as 2027/28.
- **Gas Transparency Bill:** New Gas Act disclosure requirements for better supply and demand information.
- **EECA wraparound support:** $5.9m for tailored advice and feasibility studies to build a pipeline of investment-ready projects.
- **$200m Gas Security Fund:** Co-investment to accelerate or increase domestic gas supply and storage.
- **Home Energy Fund (proposed):** Crown/council financing for residential electrification, supporting the residential switching lever.

Actions other parts of the system are taking:

- **Renewable generation investment:** Increased investment in renewable generation development and pipeline creation.
- **Ahead-of-demand network investment:** Electricity network companies have developed proposals for targeted investment ahead of demand, to reduce the risk that network capacity becomes the constraint on conversion timing.
- **Engagement with EECA:** Active engagement on support and access to expertise for organisations looking to convert.
- **Commercial partnership options:** Commercial engagement with customers seeking to convert on partnership options.
- **Information for gas users:** Analysis and information for gas users on their conversion options.
- **Renewable gas development:** development of and investment in alternative options such as biogas, hydrogen and other longer-term supply options.

These actions are real and are helping. This report has taken into account these actions and the impact that they will have as part of this analysis. Taken together, they do not close the gap this report identifies, and nothing here coordinates them into a single response. That is the gap our recommendation addresses

Our recommendation: Government must lead a coordinated national plan

A COORDINATION ROLE, NOT A PLANNING DOCUMENT

- This report recommends that Government (working in partnership with system participants) convene and lead a coordinated national plan to manage New Zealand's gas shortage. This report is not that plan, it is a whole-of-system analysis showing why a plan is needed and what it would need to weigh. Government's current settings already cover some of the supply, financing and information gaps. What is missing is additional actions and the coordinating function: the piece that connects these settings, sequences them against the timeframes each lever actually needs, and closes what remains.
- A plan of this kind coordinates rather than dictates. Its job is to keep enabling decisions and actions. Given how time-constrained the response already is, it cannot wait for the rounds of consultation that would normally accompany work of this scale. It needs a body with the mandate to manage it centrally and see it through.
- This is properly a Government role because several of the decisions ahead are trade-offs only Government can make. For example:
  - How the costs of gas and electricity infrastructure are allocated.
  - How the shortage is managed without leaving behind those who cannot access the capital to switch.
  - Whether funding obligations placed on supply-side actions could unintentionally weaken the commercial case for industrial conversion, the single lever most able to ease this shortage at the scale and pace required.
- The investment required here is for replacement and recovery, not growth, and it is necessary to protect New Zealand's economic position. Individual investment cases within the plan should be judged on that basis, not against a growth case. A well-delivered plan will also leave New Zealand with a stronger energy system to support growth in future. That is a welcome outcome, but it is not the purpose. The purpose is recovery.
- Some of this work has already been done. The Gas Working Group's earlier recommendations, including the coordinated use of existing gas infrastructure between users, remain valuable and could form part of this plan alongside the actions set out in this report.
- **The Framework is ready to help deliver this. The next page sets out how.**

Working with Government on a coordinated plan

AN OFFER OF ENGAGEMENT, NOT A WORKING GROUP

- **This is not a request for another working group:** The Framework's objective is a coordinated national plan, developed and implemented through a cross-government delivery taskforce with real authority, accountability and a whole-of-system perspective, not a group producing further advice.
- **This report is offered as a starting point:** Whole-of-system analysis of this kind can help Government move quickly and with good information as a plan takes shape, including on the further, targeted cost analysis this appendix identifies.
- **This is not Government's problem to solve alone:** The market alone will deliver a transition through price signals. There are risks that households will be hit hardest, unable to afford the upfront capital cost, and industrial businesses in the regions will close. Government and industry have shared responsibility for managing this well. The Framework is asking to take joint ownership: bringing cross-system expertise, delivery relationships, and the ability to move fast on further analysis as the plan takes shape.
- **A logical next step, not a departure:** A delivery taskforce and ministerial energy partnership would build on steps already under way, including the Gas Transition Loan Guarantee Scheme, LNG procurement, the Gas Security Fund and the Home Energy Fund, rather than replace them.
- **At minimum:** The Framework is seeking agreement that officials begin developing the mandate, membership and implementation pathway for such a mechanism, for consideration by Government.

What a coordinated plan needs to consider

WHOEVER LEADS THIS, HERE IS WHAT THE PLAN ITSELF WILL NEED TO COVER

Based on the analysis in this report, there are four things any coordinated plan would need to consider:

- **Clear, consistent communication to every gas user -** If higher rates of residential and commercial switching are needed, that involves decisions and actions across a very large number of users. Such an effort would likely require a national-level communications effort, not just individual conversations. Any element of conversion and this plan should provide gas users clear, consistent information on the supply trajectory and their options.
- **Network and regulatory settings on both networks:**
  - Electricity: the scale and location of investment required is already known. Engaging EDBs and the regulator now would help ensure connection costs and lead times do not become the constraint on conversion.
  - Gas: infrastructure owners and the regulator need to agree the changes needed to gas infrastructure cost recovery. Current settings suit a growing network, not a shrinking one.
- **Clarity on biomass supply -** Biomass is expected to carry real weight in this transition, but its supply chain is largely unknown and increasingly contested by other uses. Establishing deliverable regional volumes and constraints would need to happen before it can be relied on with confidence.
- **Flexibility in every new conversion -** Industrial, commercial and residential conversions are all opportunities to incorporate flexibility (including reducing energy use and optimisation). A more flexible energy system can help lower generation peaks, seasonal resource adequacy and reduce network costs, providing a more reliable and efficient overall system. The plan would need to consider how to ensure there are incentives that reflect the value that flexibility could provide to the system.

SECTION 07

Appendix 1 – Key Assumptions and cost analysis

Key assumptions

WHAT HAS BEEN INCLUDED IN THIS REPORT AND WHAT ARE KEY DECISION LEVERS

- **Supply**
  - Big-six field forecasts to May 2026, baselined to 2026 MBIE reserves. Plausible and Downside scenarios used throughout.
  - No new gas fields assumed.
- **Industrial demand and conversion**
  - Methanex and Ballance exit by 2027 (noting that in 2026 Genesis provided supply to Ballance)
  - Only industrial users at or above 0.1PJ/yr have been assessed for conversion; 200+ smaller users have been excluded on the basis they are too uncertain to model.
  - Workforce constraints cap deliverable conversions at around 6 large projects a year with the largest conversions occurring. This, and limits on smaller scale conversions (e.g. electricians) could be actively targeted to remove these as barriers.
  - "Possible" projects are assessed as uneconomic under current gas prices and current policy settings, including the Loan Guarantee Scheme, which addresses some elements of financing cost, but does not reduce overall capital or improve operating economics.
- **Wider system**
  - Network and biomass chapters each model their own worst case: electricity assumes every project that is 50:50 between converting to biomass or electricity electrifies; biomass assumes they all go to biomass. Both are conservative about how much supporting infrastructure will be used.
  - Biomass availability is largely unknown, and increasingly contested by other uses, including sustainable aviation fuel.
- **Scope**
  - Options assessed are technologically ready and viable now. Hydrogen is excluded as a near-term substitute, though relevant to transport and feedstocks.

Costs – what is included and what is not

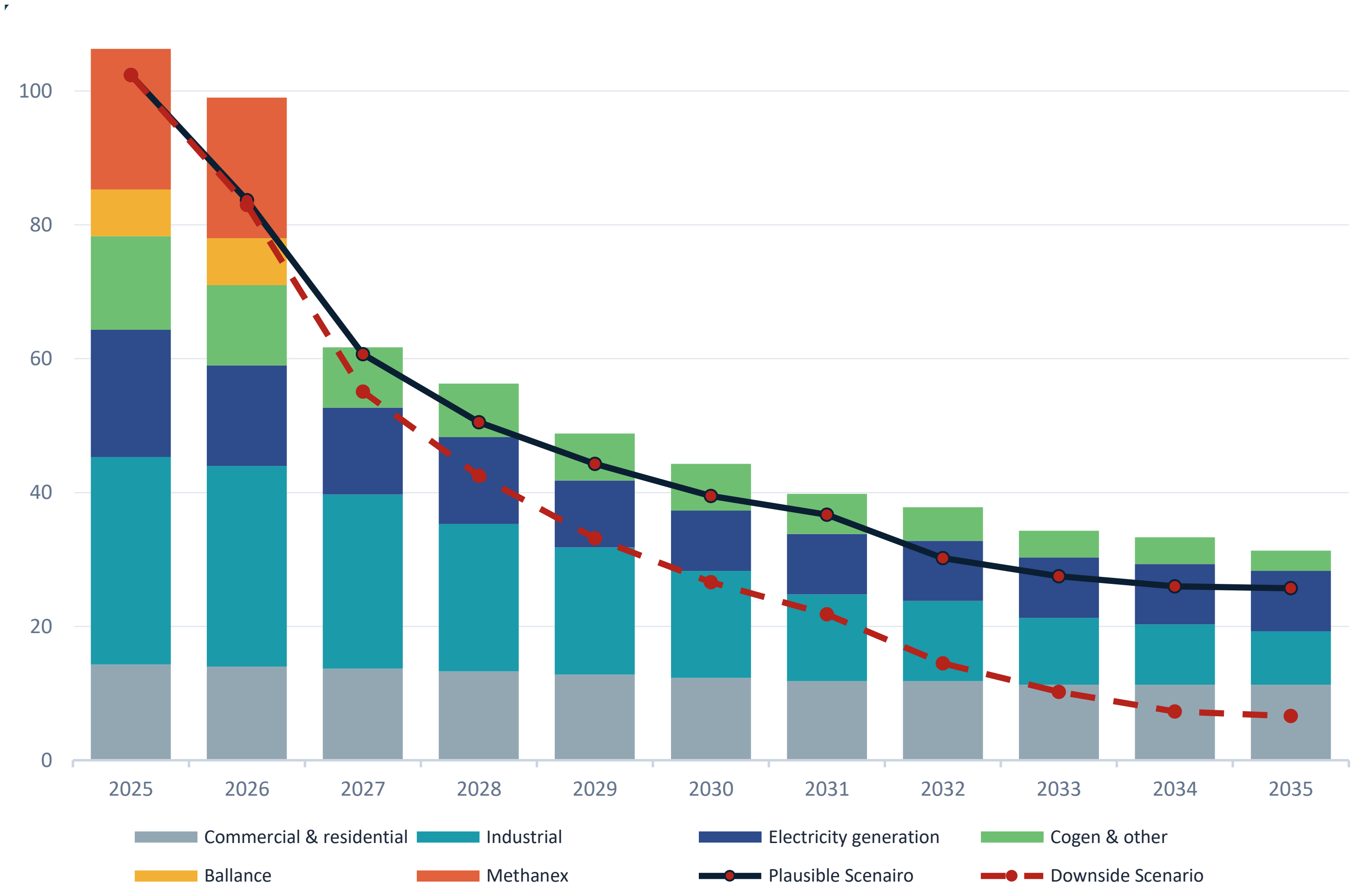
- **What this report costs**
  - Electricity network capital expenditure (RETA/Ergo estimates).
  - GDP and employment impact of not acting, cross-checked against Sense Partners/MBIE.
  - High level information on LPG costs, based on publicly available prices and estimates of infrastructure costs.
  - Residential and commercial switching costs for users.
- **What this report does not cost**
  - A full options cost-benefit analysis across every lever.
  - Site-level industrial conversion capital expenditure – while this has been taken into account in background analysis to determine ‘possible’ and ‘probable’ projects, this is not included in this report.
  - LNG landed cost and its flow-through to end-user prices, particularly long-tail residential and commercial users on a shrinking network base.
  - Biomass supply chain infrastructure cost, and
  - The fiscal cost of the policy levers themselves - The cost of establishing and running a cross-government delivery taskforce itself. This report recommends the mechanism; scoping its cost is properly part of the mandate officials would be asked to develop
- **A suggested next step -** A targeted comparison of costs of acting versus not acting under different outcomes would sharpen decisions on timing and scale, for example weighing the cost of investing now against a scenario where supply proves sufficient anyway, versus the cost of not acting and a shortfall materialising. This is quick, targeted work that should run alongside a coordinated plan, not delay it.

SECTION 07

Appendix 2 – Additional analysis and sources

How our demand analysis differs from BCG's Energy to Grow report

- Graphed is BCG's September 2025 supply/demand analysis on fuel-switching opportunities from their Energy to Grow report – with our own supply forecasts overlayed
- The BCG analysis identified >30PJ of industrial / CoGen switching from 2025 to 2035, as compared to our 17PJ.
- The key points when comparing our two analyses are:
  - We are aligned on near-term projects that are significant and confirmed (Fonterra Whareroa / Edgecumbe)
  - BCG include estimates of smaller projects in their long-term (<0.1PJ) which we have not included for our analysis
  - BCG assumptions on transition speed (number of deliverable projects per year) may not account for the size of the available workforce, or available network capacity to deliver electrification projects at scale.
- Also, note that BCG's electricity generation forecast is based on an average hydro year, therefore a dry year would require more gas, the amount of which depends

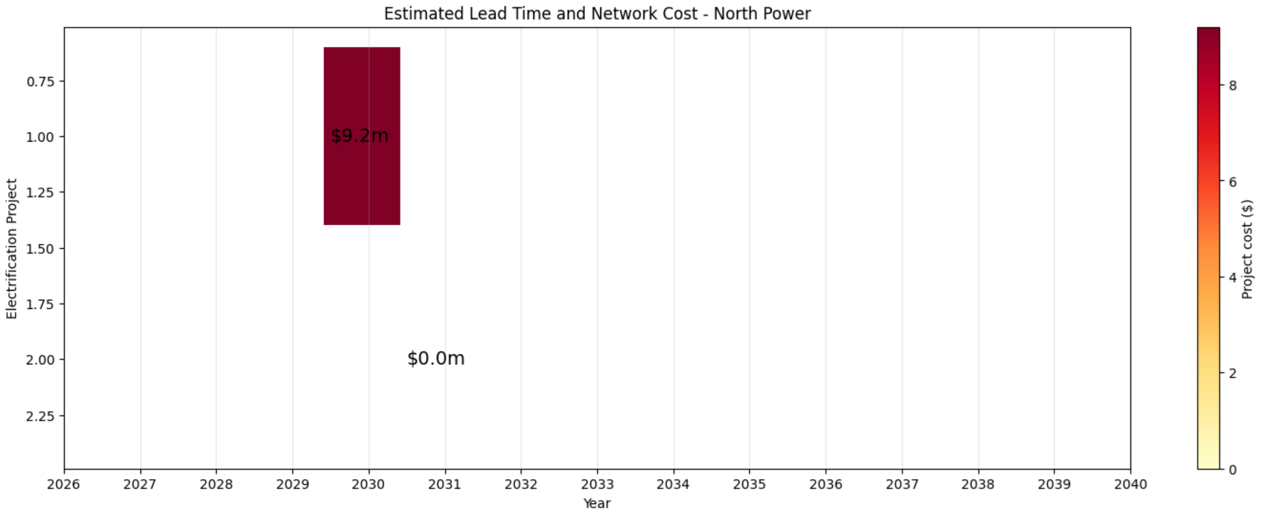


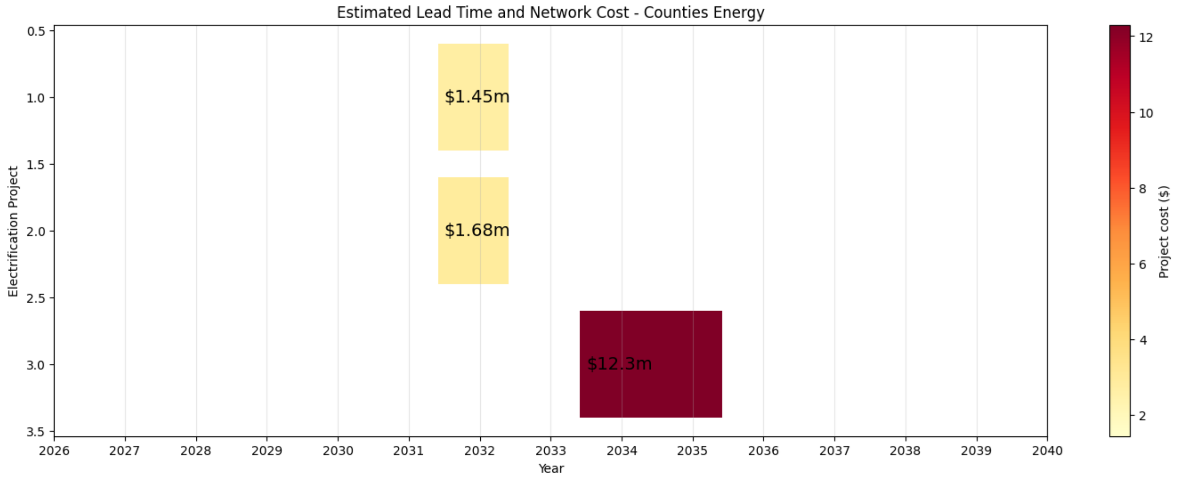
THE BOTTOM LINE

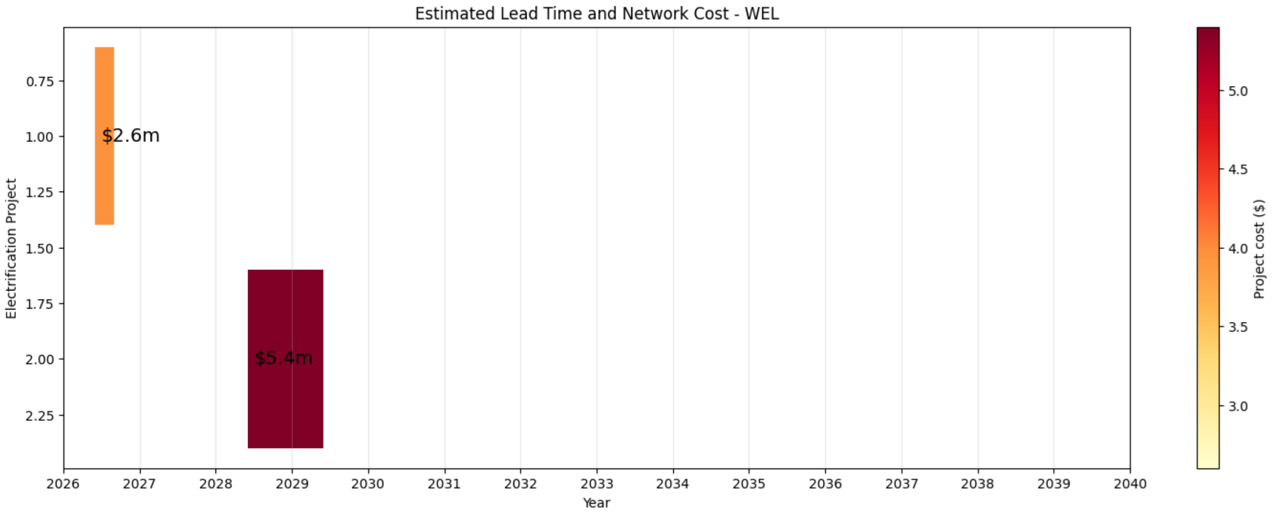
Even with a more optimistic demand conversion view, a **material shortfall exists in the modelling starting in 2028** – indicating an urgent need for action considering both supply and demand.

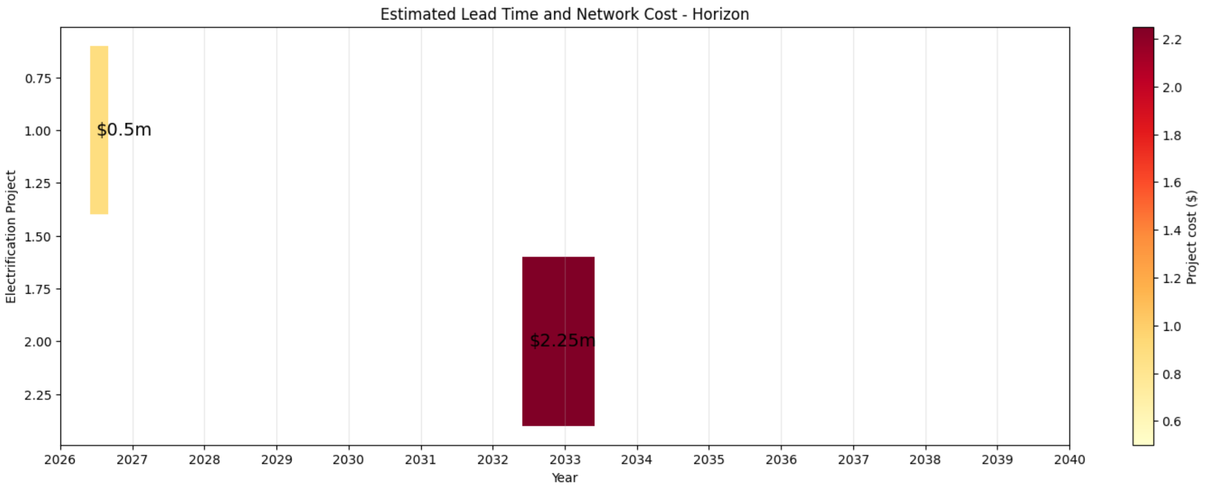
Source: BCG "Energy to Grow" (Sept 2025), RETA; Gas Working Group supply modelling.

EDB capital spend pipelines



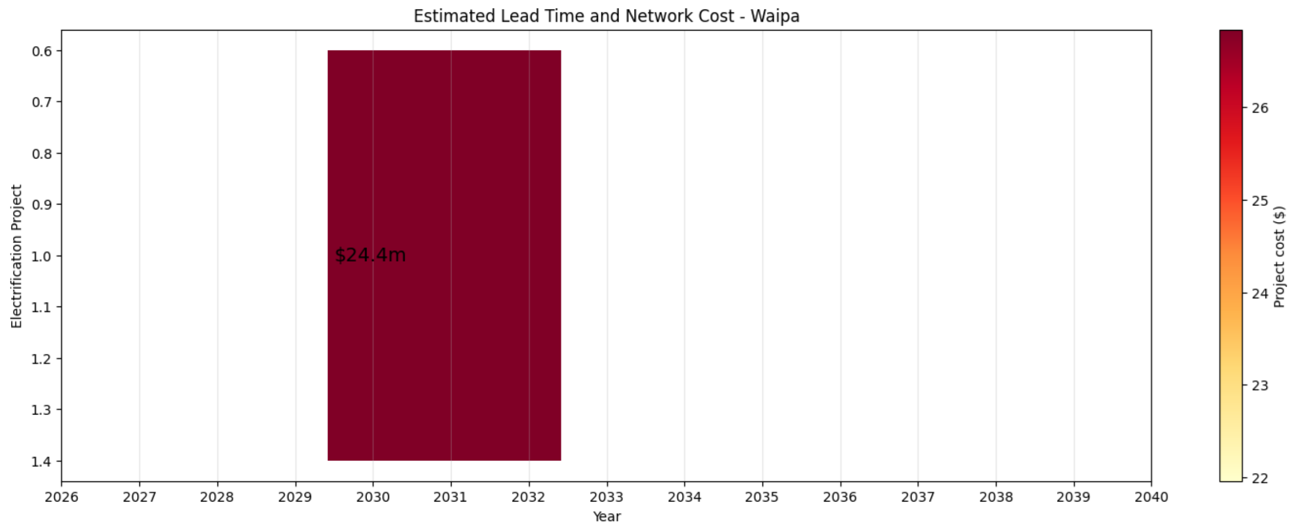


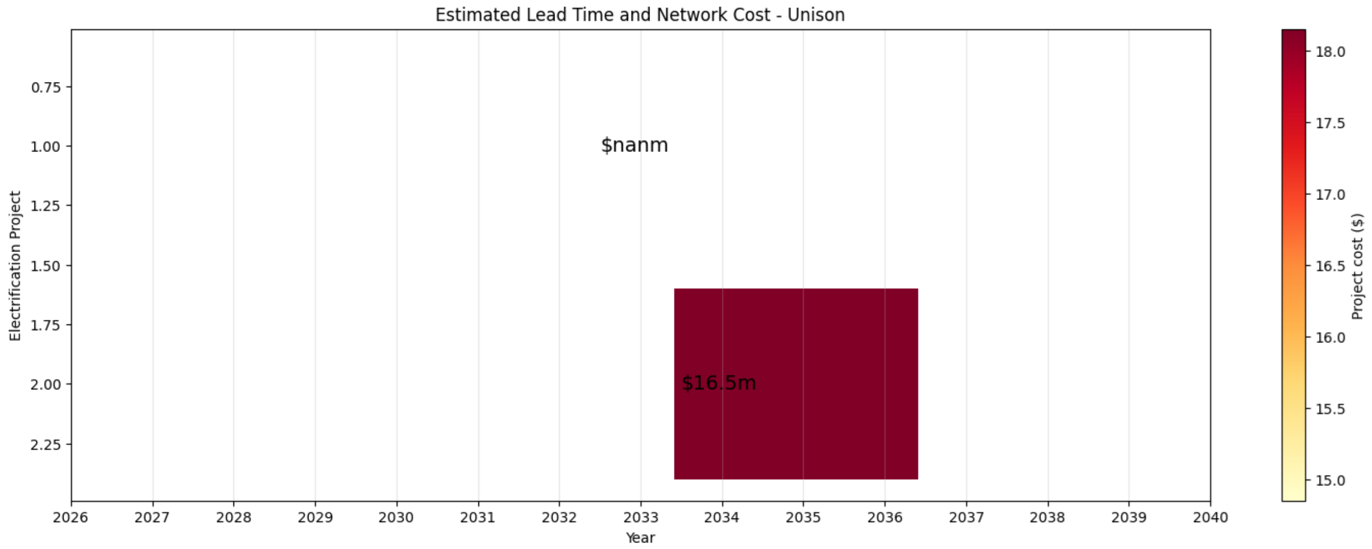




Source: RETA Electrification Cost Estimates; GWG analysis; EDB AMPs; Commerce Commission EDB disclosures.

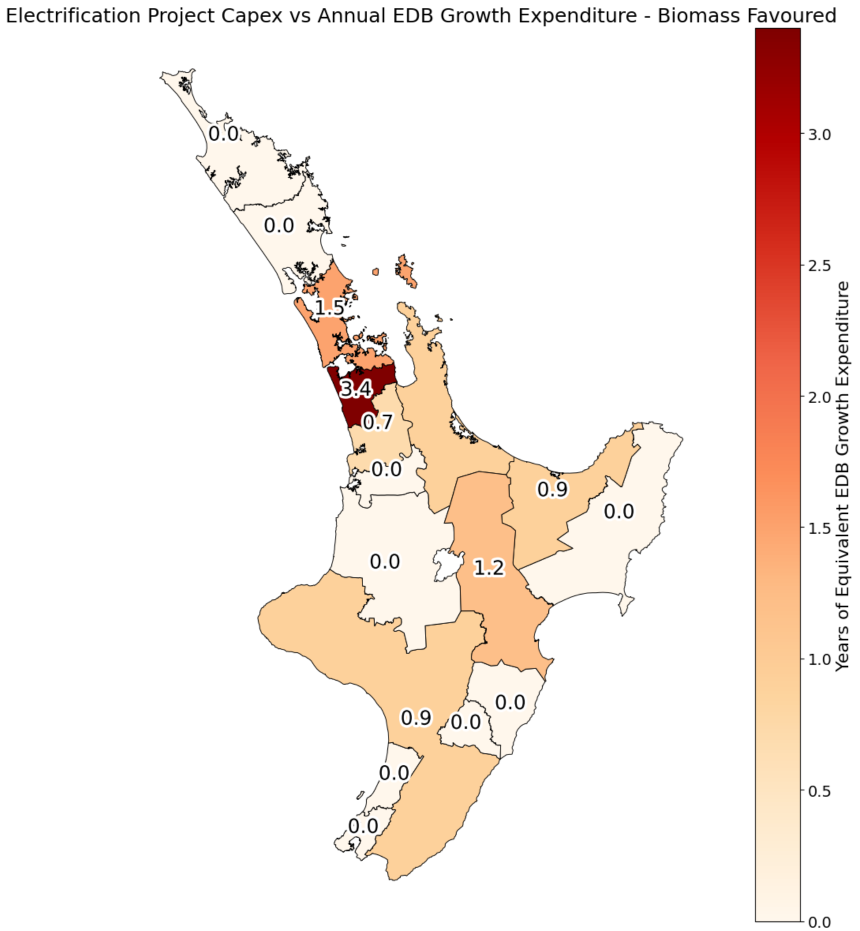
EDB capital spend pipelines

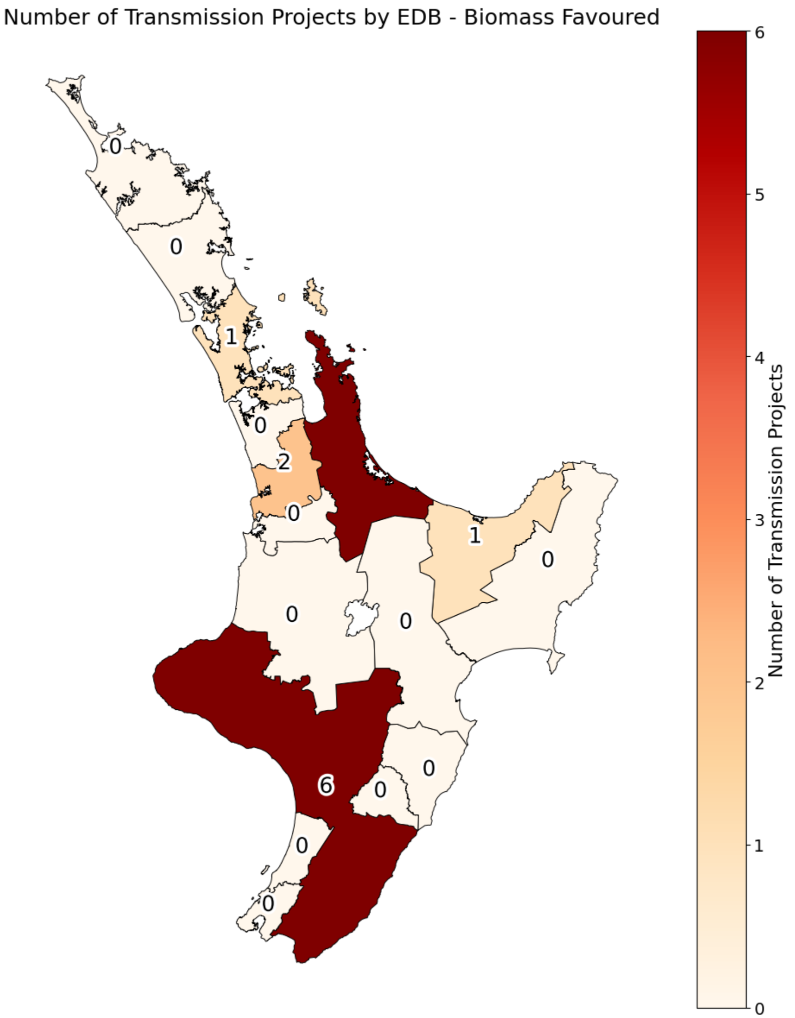


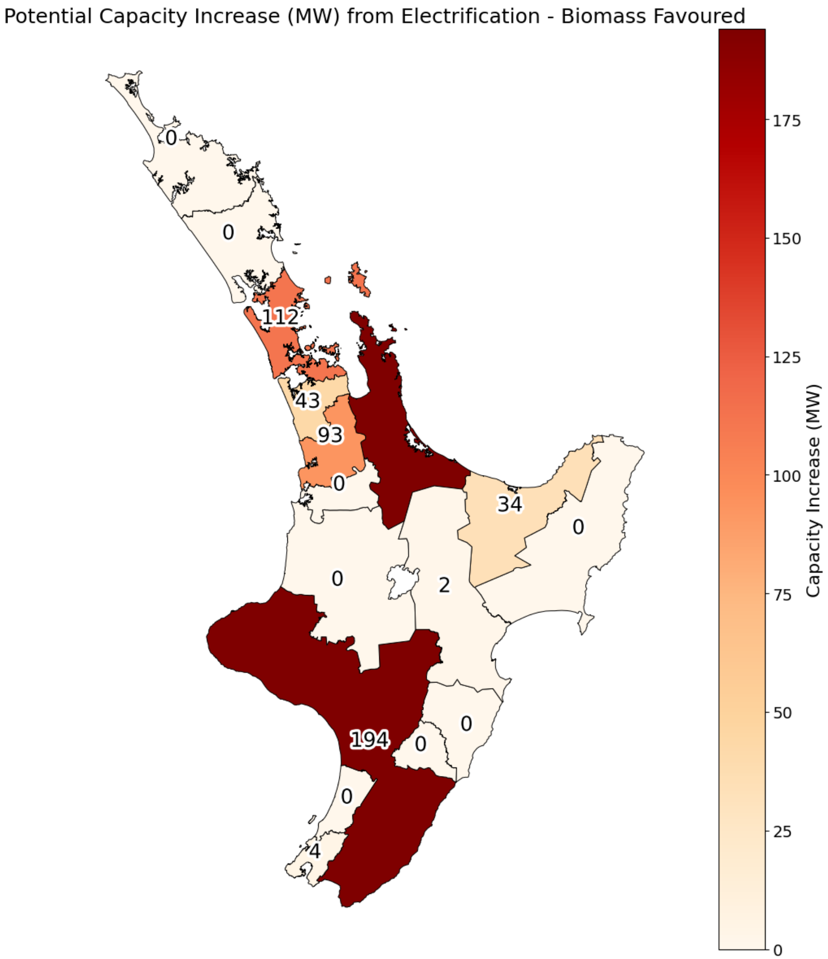


Source: RETA Electrification Cost Estimates; GWG analysis; EDB AMPs; Commerce Commission EDB disclosures.

Electrification slides – biomass favoured







Source: RETA Electrification Cost Estimates; GWG analysis; EDB AMPs; Commerce Commission EDB disclosures.

Dry year security – defining the problem

- Dry-year security is an energy adequacy problem, not just a capacity problem. Resources must be able to deliver firm, dispatchable energy over an extended period while hydro inflows remain below average.
  - We know that renewables will reduce the required energy deficit in a dry year, by allowing more dispatchable water to be preserved during times of excess wind and solar. This is likely insufficient as a security measure.
- Sapere estimates an additional 2.3 TWh of dry-year generation is required. At 40% CCGT efficiency, this is equivalent to around 21 PJ of natural gas, similar to 2025 production from the Turangi gas field.
- Given existing Huntly firming options for coal security, these volumes do not need to be met only by gas.
- Dry-year resources almost certainly will not be required every year. The economic challenge is therefore maintaining generating assets and fuel availability for infrequent, but high-consequence, events.
- The required level of dry-year security is ultimately a policy choice. The quantity of firm energy retained will depend on the level of reliability New Zealand is willing to pay for.
- Any dry-year solution must be assessed against the same functional requirements. Regardless of the fuel or technology, it must be capable of providing sufficient firm, dispatchable energy when hydro storage is under sustained pressure.

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

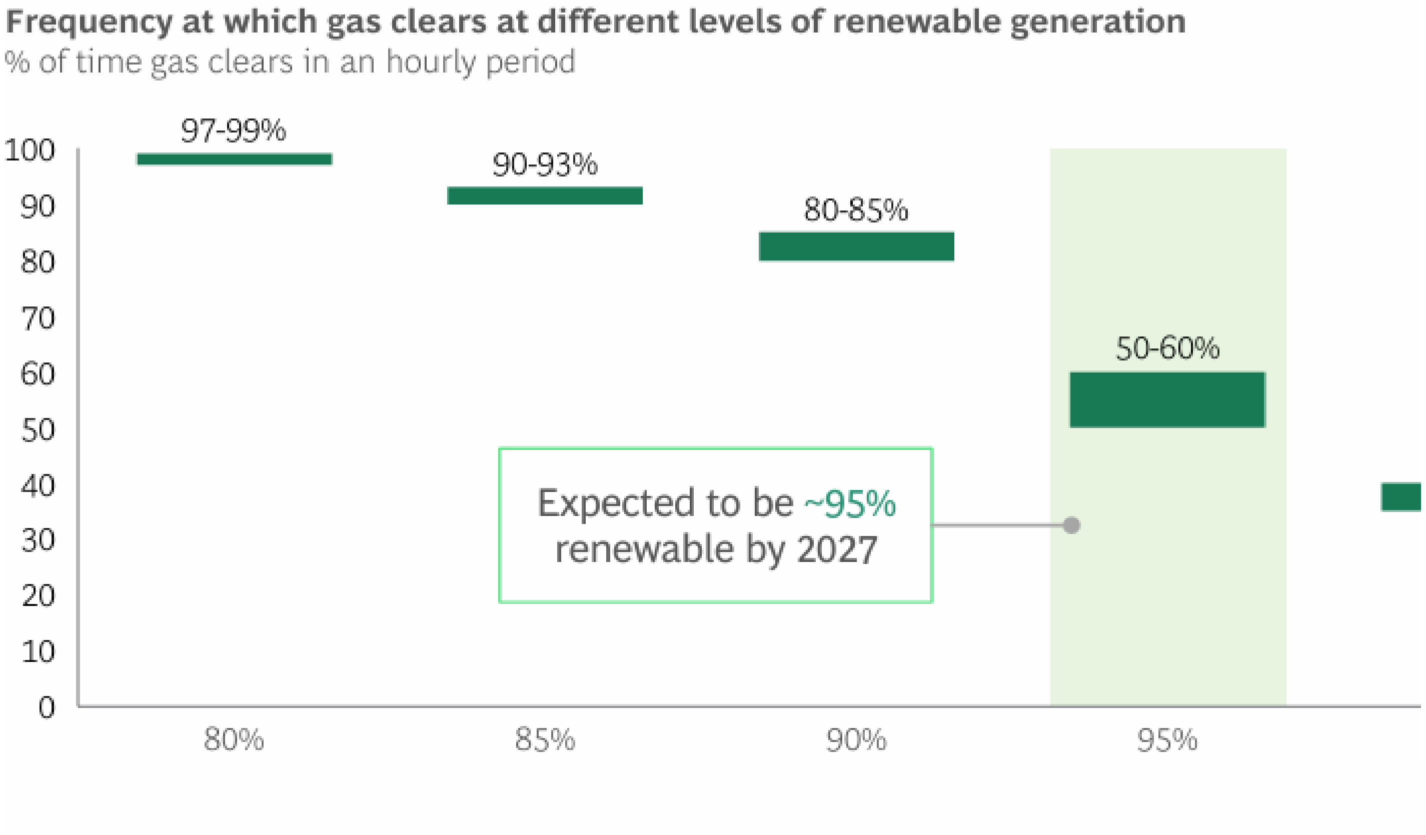
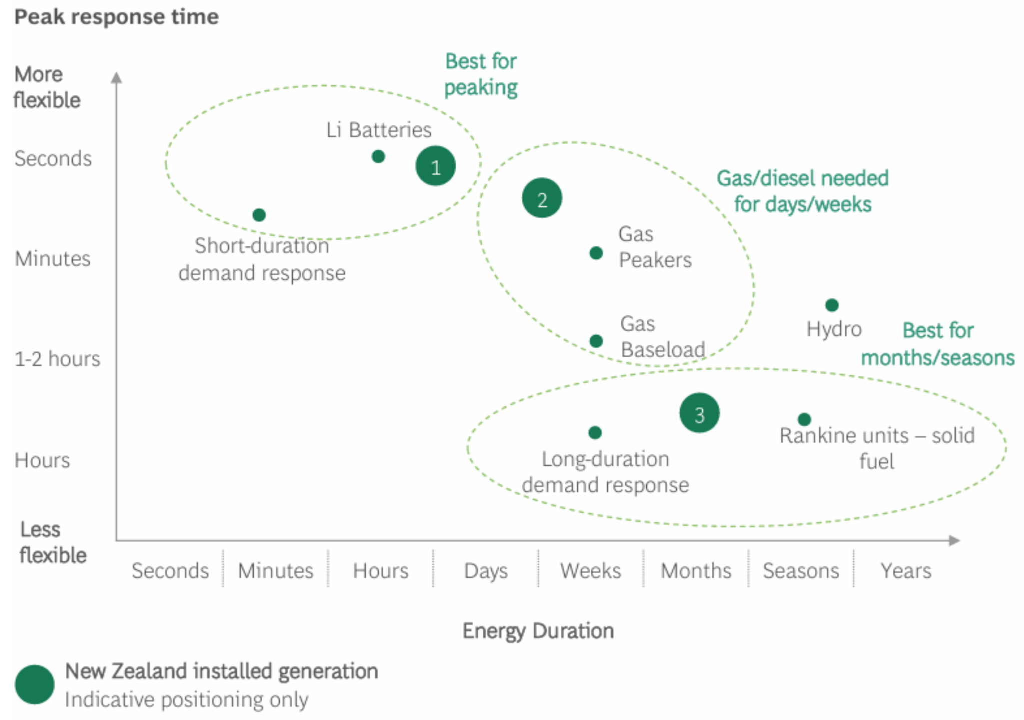


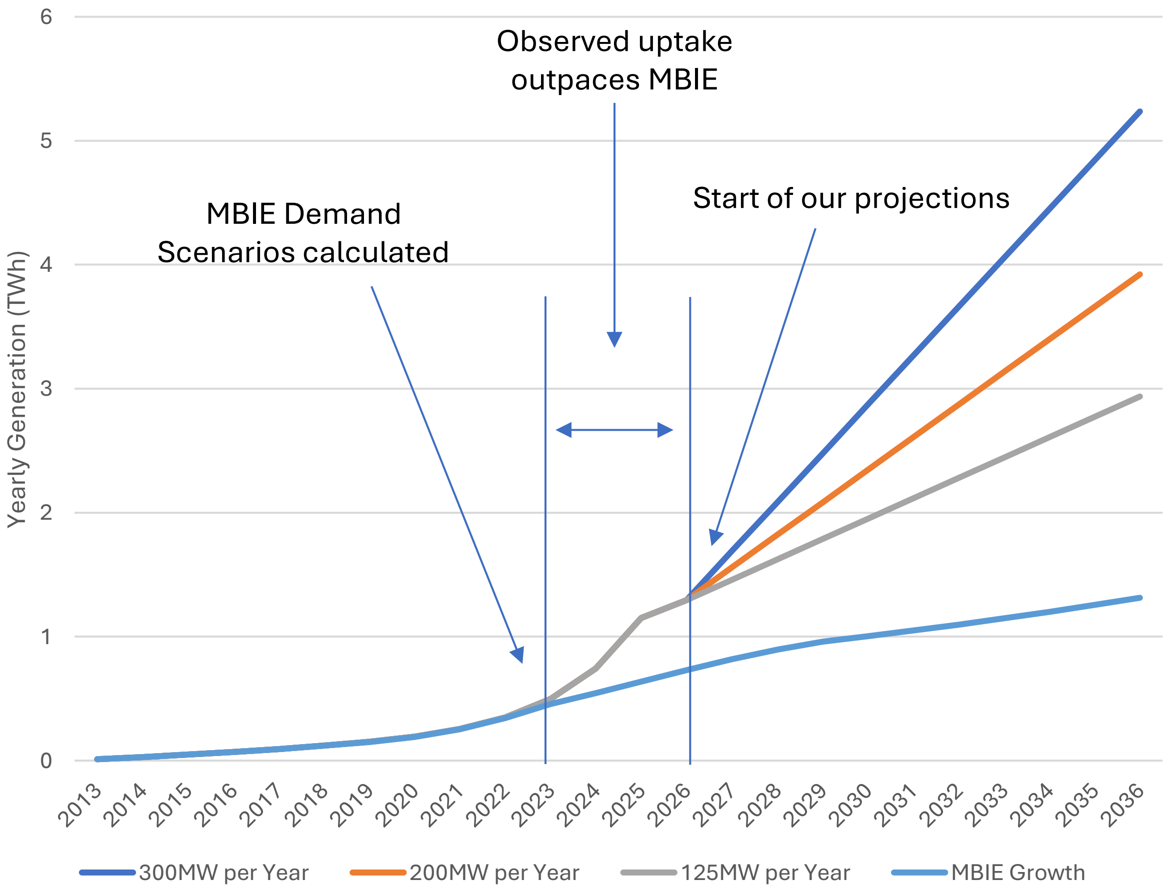
Exhibit 89: Firm energy requirements split across three time periods



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

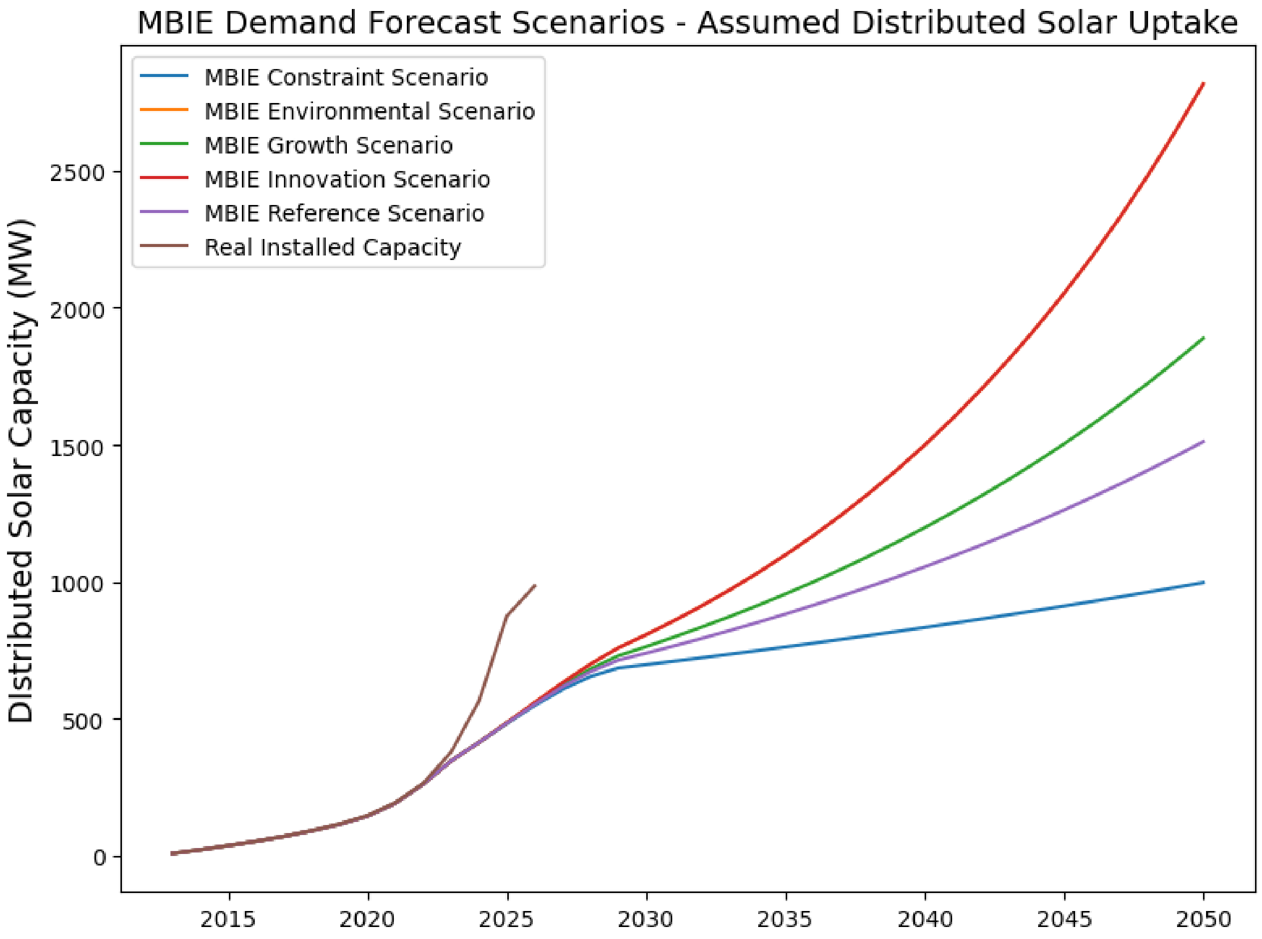
Comparing distributed solar uptake projections to MBIE

- Implicit in MBIE's demand forecast is their assumed uptake of distributed solar (residential, commercial and industrial).
- Since their forecast came out, real installed capacity has significantly outpaced their projections, so we have adjusted these projections accordingly when calculating whether future electricity supply can meet demand.
- **We use the 200MW per year scenario, which is in line with existing growth rate.**



Source: BCG "Energy to Grow" analysis, MBIE Energy Prices, Commerce Commission, Concept Consulting, Energy Link.

Electricity generation pipeline modelling assumptions



Transpower Stage	Probability
Application	0.1
Solution Proposal	0.2
Investigation	0.4
Delivery	0.9

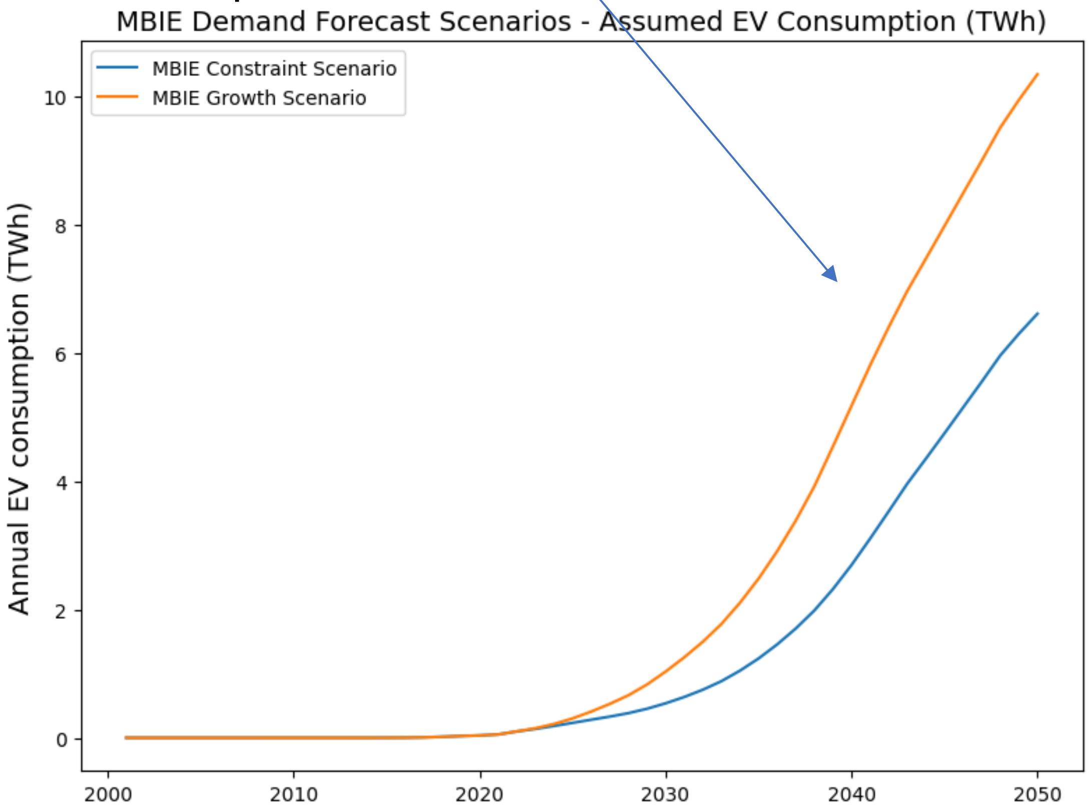
Numbers below are months spent in stage

Transpower Stage	Solar	Wind - Onshore	Wind - Offshore	Geothermal
Application	18	18	24	18
Solution Proposal	12	12	18	12
Investigation	48	60	72	60
Delivery	18	24	48	36
Commissioning	6	12	24	24

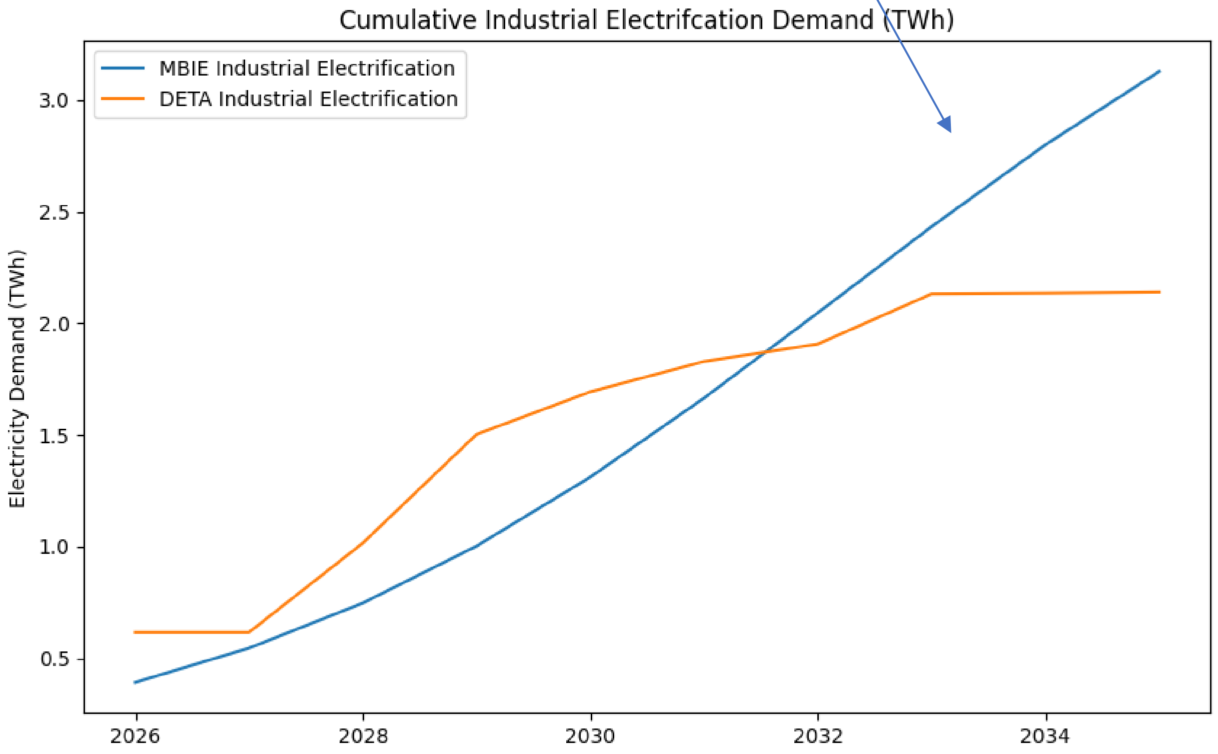
Source: RETA Electrification Cost Estimates; GWG analysis; EDB AMPs; Commerce Commission EDB disclosures.

Electricity generation pipeline modelling assumptions

Full range of MBIE's assumed EV consumption

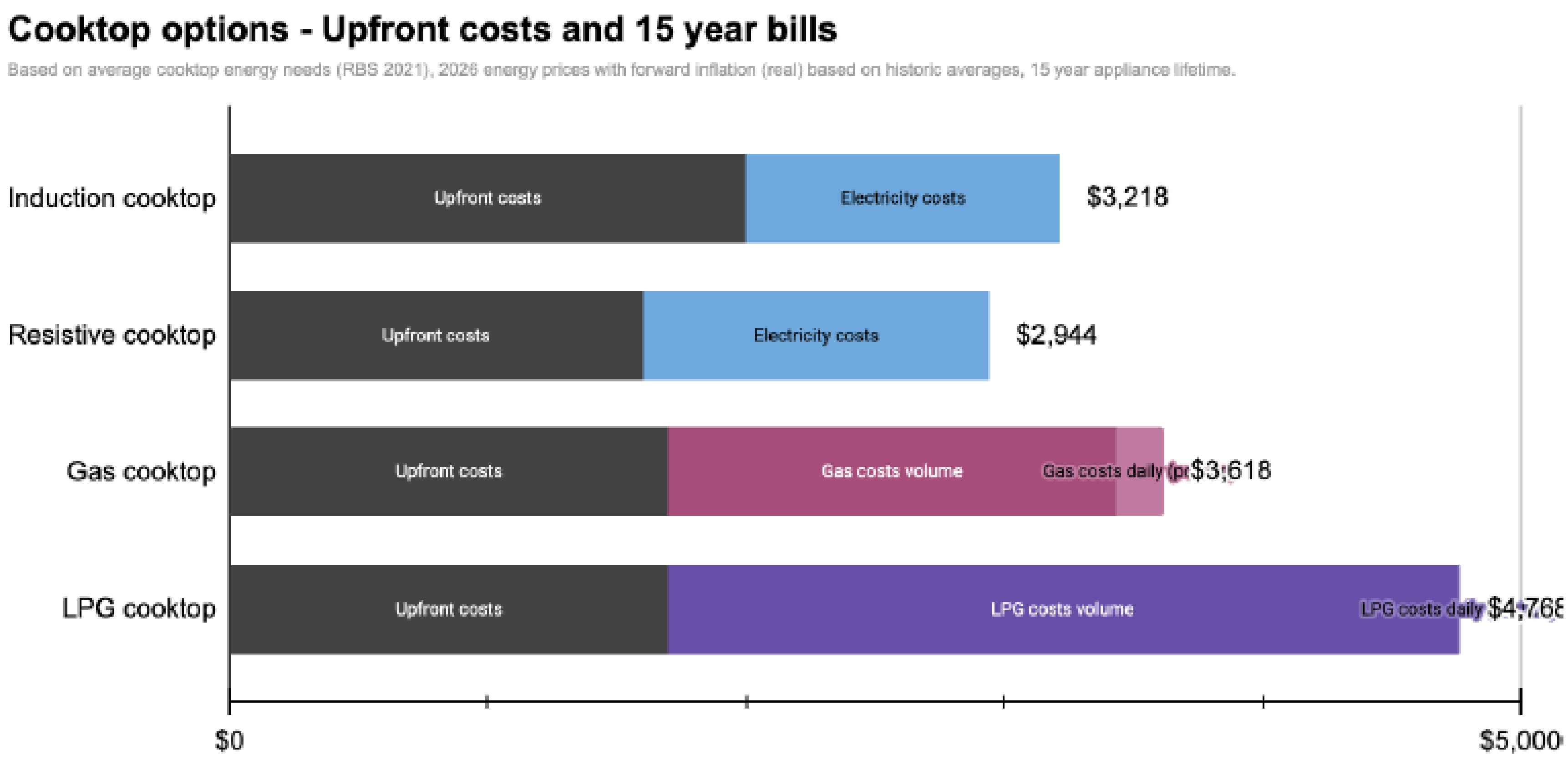


MBIE growth scenario's underlying assumption



Source: RETA Electrification Cost Estimates; GWG analysis; EDB AMPs; Commerce Commission EDB disclosures.

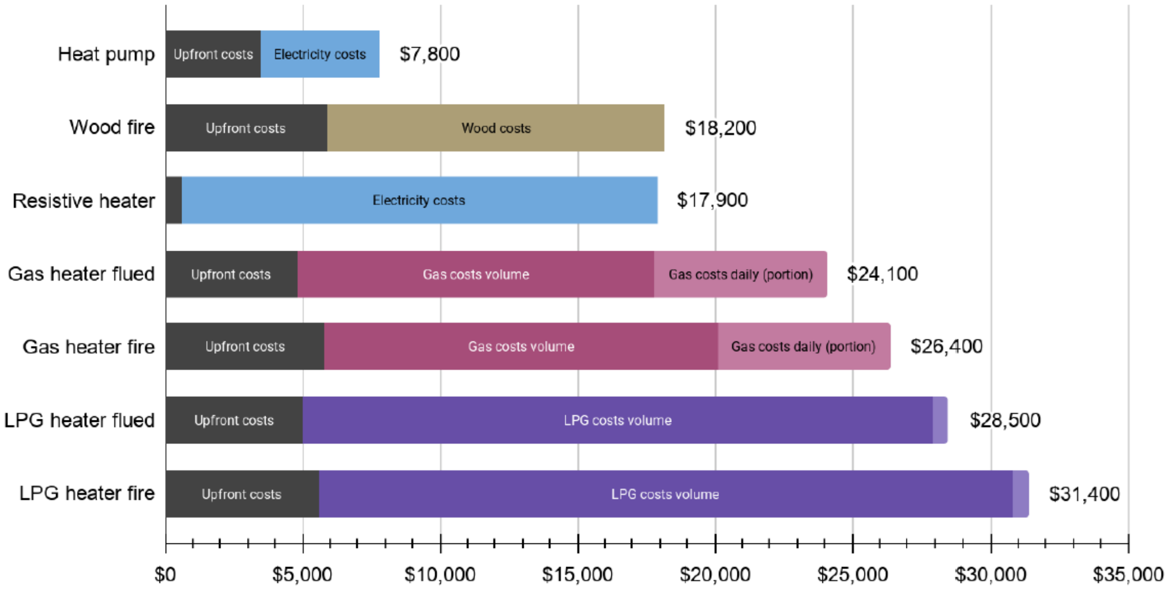
Rewiring Aotearoa: electrification and LPG economics



Rewiring Aotearoa: electrification and LPG economics

Space heating options - Upfront costs and 15 year bills

Based on average home heating needs (RBS 2021), 2026 energy prices with forward inflation (real) based on historic averages, 15 year appliance lifetime.



Water heating options - Upfront costs and 15 year bills

Based on average home water heating needs (RBS 2021), 2026 energy prices with forward inflation (real) based on historic averages, 15 year appliance lifetime.