From faultlines to resilience:
The 2024 energy shock does not require an LNG response

An independent report for
Rewiring Aotearoa

June 2, 2026

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About the authors

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David specialises in electricity market analysis, power system operation and analysis, generation investment, energy market risk management, the role of electrification in decarbonisation, and new technology. David has worked in distribution and in major energy companies in New Zealand and has consulted in New Zealand, Australia, Philippines, Singapore, and Tonga. He is also an educator to the electricity industry through Whiteboard Energy.

Stephen Batstone

Stephen has held a variety of senior positions in the electricity industry and other infrastructure sectors across network development, technological innovation, risk, portfolio management, regulatory and commercial operations. He has participated in a range of industry and regulatory working groups as the market has evolved over the past 10 years, and has been at the forefront of many of the major regulatory and technological changes. He is also an educator to the electricity industry through Whiteboard Energy.

Corina Comendant

Corina Comendant is an environmental economist with over a decade of experience in policy design and economic analysis for the low-carbon transition of the energy sector. Her work spans carbon market reform, infrastructure planning, and investment strategy for low-emissions technologies. She has led projects evaluating renewable energy procurement options, modelling decarbonisation pathways, and assessing policy frameworks for distributed energy resources, battery storage, and bioenergy.

Conflict of interest declaration

Sapere operates a conflict of interest policy and management framework. No conflicts exist for this project.

The authors have advised most entities in the energy sector including electricity generators, generator retailers, retailers, consumer bodies, Transpower, electricity distribution companies, regulators, officials, Ministers, and other groups (including the client).

Stephen Batstone provides advice to Rewiring Aotearoa, and this is in compliance with the policy.

Executive summary

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An immediate package of measures is needed:

Manage gas down. Contract renewables for dry-year firming. Avoid LNG lock-in.

The 2024 energy shock exposed three faultlines in the system

- Soon gas will no longer be able to reliably flex for dry years
- Process heat remains too dependent on declining gas
- Missing contract market led to undersupply for firm energy and left businesses exposed to wholesale prices.

LNG is a rushed response

- LNG appears premature and costlier than short-term diesel-based bridging and long-term renewable options.

An immediate package of measures is urgently required

- Significantly accelerate industrial process heat fuel switching so it tracks the rate of decline in existing gas reserves
- Remove barriers to renewables for dry-year firming with diesel as a bridge
- Create firm-energy contracts that unlock dry-year investment.

A dedicated team should be set up

- The team could sit within the DPMC Office
- It would build on existing workstreams underway (EA, MBIE, EECA, Transpower)
- The programme of work will be ascribed a high-level of urgency.

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The 2024 energy shock exposed three faultlines in our energy system

1. The 2024 energy shock saw rapidly declining gas reserves in a low-inflows year, which drove power prices to levels not seen previously in the electricity market
2. This shock exposed three faultlines in the energy system:
   - **Faultline #1 (reduced gas for dry year):** Declining gas reserves and production capacity means that in the near future existing domestic gas will not be able to reliably flex to cater for all the needs of a dry year.
   - **Faultline #2 (industrial gas shortfall):** New domestic gas is unlikely, and LNG cannot be an affordable long-term fuel for process heat users. Slow fuel switching risks exhausting gas reserves by 2040, leaving businesses exposed.
   - **Faultline #3 (missing dry-year contract market).** A missing electricity contract market that will continue to leave businesses exposed to wholesale prices and delay investments in a dry-year solution.
3. The government's
   - LNG response to the dry-year faultline is premature as it has ignored credible alternatives.
   - Response to the industrial gas decline faultline is missing.
   - Response to the missing contract market faultline is yet to be published.

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LNG is premature: diesel + renewables for dry-year is preferrable

4. In our view, importing LNG to solve the dry-year problem was not adequately compared to a feasible and competitive alternative of diesel (in the short term) and renewables (in the long term). Our analysis shows that **using diesel as a bridge to around 2039 could be lower cost than the government's LNG proposal**:
    - Diesel capacity could be created quickly by converting existing OCGT gas plant to dual-fuel capability. In parallel, discussions should be commenced with Channel Infrastructure regarding recommissioning diesel storage at Marsden before any commitment to LNG is made. **This option could be delivered before winter 2028.**
    - Diesel also offers a number of strategic benefits over LNG, such as providing **resilience for the domestic transport fleet**, should disruptions to our diesel import arrangements occur again, and a lower-cost ability to respond to uncertainty in the timing of a renewable solution to the dry year problem
    - Therefore, we believe diesel is preferable to LNG and offers resilience benefits to transport**. Rushing into an LNG commitment is unwise.**
    - Documents sourced under OIA show that diesel appears to have been dismissed on questionable grounds.
5. There is also value in quantifying how much flexibility exists in current gas use and reserves that could be drawn on in a dry year:
    - When combined with electricity demand flexibility, contingent hydro storage and Huntly, this may substantially reduce or even remove the need for a new dedicated dry-year fuel.
    - Having **multiple tools to manage a dry year** may be more transactionally complex, but can deliver greater resilience and avoids single points of failure; by contrast, relying on LNG (even alongside Huntly) concentrates risk in a small number of vulnerable supply chains.
    - We have not yet finalised the assessment of the flexibility option in time for this report, but strongly recommend that any major commitment to a new fuel is paused until it is complete.

There is no credible plan for dwindling gas: industrial fuel switch cannot be avoided

6. The government has not proposed a plan for how process heat gas demand (55PJ pa in 2025) could be managed, given the low probability of significant new gas supply. This suggests the government is relying on:

   - The market driving a sufficient level of fuel switching, and/or
   - New significant gas discoveries occurring and being brought to market at an affordable price, in time to arrest the decline in domestic gas supply for remaining users, and/or
   - LNG being a long-term affordable fuel source for New Zealand, which - given the price is entirely determined by factors outside New Zealand's control - may require future governments to subsidise an unknown LNG price.

7. Our analysis shows that:

   - Market-led fuel switching of industrial process heat cannot occur without a strong carbon price signal, and therefore a significant ETS reform
   - A future of significant new domestic gas discoveries is unlikely.
   - Process heat fuel switching could be accelerated at relatively low cost to a point where remaining gas reserves could be adequate until the 2040s. Acceleration grants - totaling much less than the cost of an LNG terminal - would extend the life of current gas reserves.
   - There are sufficient resources in-country (biomass and electricity) to meet the demand for these alternative resources.
   - The new network connections required for the accelerated electrification of industrials (only 12% of all electrification projects) is achievable with a concerted policy focus.

Long-term contracts are needed for dry-year firming investments

8. A firm energy contract market is required to ensure large consumers have access to long-term affordable contracts that protect them from wholesale prices, while at the same time incentivising investment in firm energy.

9. A policy direction for a long-term firm-energy contract market is urgently needed to set the electricity market up to deliver security of supply in the long term – in the post-Huntly world, and enabling renewables to provide firming.

   - Government and regulatory work is under way to address this issue, but this is yet to be completed. However, we emphasise the need for long-term contracts.

10. We outline the principles on which a contract market solution can be based, and examples of the types of arrangements that can deliver these principles.

An immediate package of measures is urgently needed

11. In summary, New Zealand's pathway to a resilience does not require immediate reliance on LNG, but does require an immediate package of measures that unlocks investment while preserving flexibility under uncertainty.

12. The package of measures must be directed to achieve:

Intended outcome	Policy measure
Diesel (short-term) + renewables (long-term) for dry year	• Implement the diesel option as a bridging dry-year fuel while barriers affecting the speed of renewable deployment are being addressed • Accelerate deployment of renewables for dry-year by amplifying the impact of fast-track consenting with accelerated transmission connections.
Electricity contract market reform	• Develop long-term contracts that drive investment in dry-year firm energy and provide affordable protection for industrial electricity consumers through

Accelerated transition of industrials away from gas	• Address upfront cost barriers by setting up a targeted public co-investment of up to $958M that scales with the pace of industrial process heat transition.
	• Accelerate electrification:
	  • Develop power purchase agreements and sleeves between renewable electricity generation investors and process heat customers
	  • Remove barriers to rapid upgrades of networks to accommodate electrification of process heat.
	  • Address workforce constraints affecting the pace of industrial electrification (*)
	• Accelerate the biomass market in line with expected demand to ensure reliable and sustainable supply.

(*) We have not investigated the workforce question as part of this report

A dedicated team is required to deliver the package

13. This package does not start from scratch. It builds on work already underway across the system
    - Transpower's work on connections pipeline
    - MBIE's work on Action 2.5 dry year
    - Electricity Authority work on contract markets, security of supply, EDB connections
    - EECA RETA and $5.9M budget appropriate for gas transition

14. A dedicated team in the DPMC Office could coordinate these existing workstreams, bring them together into a single urgent programme, and drive delivery at pace.

Energy system faultlines reveal the path to resilience

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In 2024, New Zealand's energy system experienced an unprecedented shock

In 2024, an unexpectedly rapid decline in gas reserves collided with low hydro inflows, leaving generators short of dependable fuel and pushing wholesale prices to unprecedented levels. A relatively modest dry year was enough to send winter prices to around $400/MWh and a week in August to $800/MWh, signaling deep uncertainty about how much firm fuel was available and at what cost. That price shock, combined with some firms' lack of contracts, contributed to permanent closures for businesses exposed to the spot market.

This should not be how our energy system works, and any response now needs to be carefully designed so that fixing today's problem does not create new faultlines in the economy.

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The shock exposed three major faultlines in the energy system

The 2024 energy shock exposed three major faultlines in our energy system:

- Declining gas reserves and production capacity means that in the near future **existing domestic gas can no longer reliably flex to cater for all the needs of a dry year**.
- There is still no plan for industries facing an inevitable gas shortfall due to declining gas and low chance of new finds. **Slow fuel switching risks exhausting gas reserves by 2040**, leaving businesses exposed**.**
- A **deficient electricity contract market** will continue to leave businesses exposed to wholesale prices and delay investments in a dry-year solution.

The faultlines point the way to building energy resilience

Building energy resilience requires three shifts:

1. **Remove barriers to renewables being the long-term solution to dry-year firming**, providing a clear policy signal to investors. In the near term, consider a short-term bridging thermal fuel as a buffer for unplanned delays in the deployment of firming renewable projects.
2. **Acceleration of fuel switch in industrial process heat** to enable a sustainable management of existing gas reserves for the users that need it most.
3. **Development of a firm-energy contract market** to accelerate investment in firming renewables, and mitigate the business exposure to wholesale market prices.

Shift #1 towards building energy resilience:

Enable renewables for dry-year firming, with diesel as bridging fuel

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Summary of key points

- Declining number of production fields means domestic gas can no longer reliably flex to cater for all the needs of a dry year.
- Gas wells that have been refurbished or newly drilled have failed to restore previous production levels, while reserves and overall production capacity have steadily declined. This decline will deepen as major fields such as Maui, Mangahewa, Kupe, Kapuni, and Pohukura shut down over the coming decade.
- The most likely future is one without significant new domestic gas [see section 1.1]
- Renewables for dry-year firming are an economically attractive solution, which can be met with generation in the pipeline even under an aggressive demand scenario[see section 1.2].
- A bridging fuel is likely to be required until the necessary renewable generation for dry-year firming is built.
- Diesel as a bridging fuel is an implementable solution that is lower cost than LNG for scenarios where renewable solutions can be advanced before 2039 [see section 1.3].

1.1 The most likely future is one without significant new domestic gas

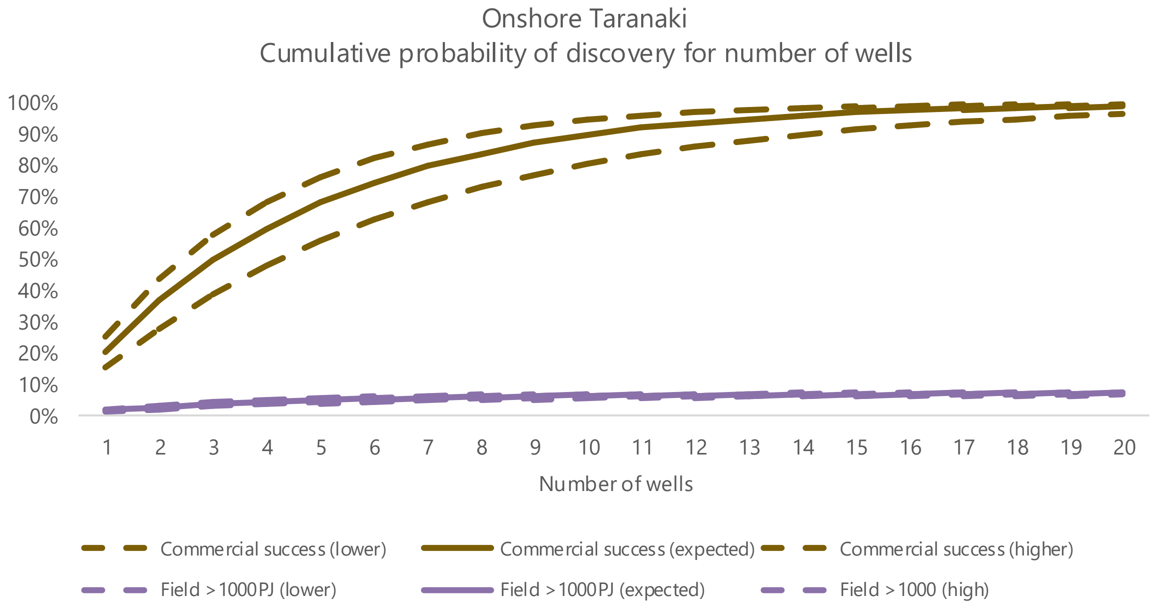
The necessary conditions for new gas discoveries are significant and uncertain

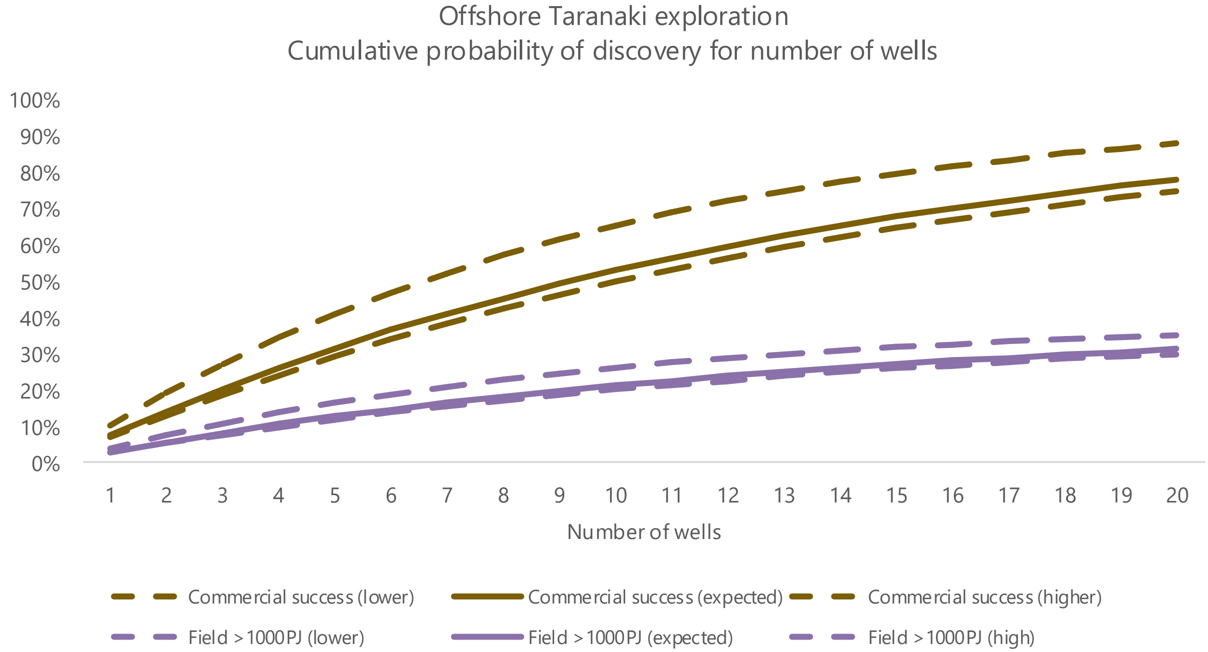
- International exploration firms will only deploy capital to NZ to look for oil. Exploring for gas is very risky, because the local market is small.
- "A lot of gas out there" slogans conflate the Taranaki basin (which is in the late stages of field decline) with greenfield potential in other basins (e.g. Great Southern Basin, Great Southern Canterbury and East Coast), which are a long way from any delivery infrastructure for the current gas market.
- Our view is that developing major new gas resources is unlikely:
  - Finding a major new oil field in the Taranaki basin is possible but unlikely: first, operators are unlikely to commit to an off-shore drilling programme because strike rates have been low since the initial large field discoveries; second, onshore discoveries are unlikely to be large.
  - Even if oil discoveries are made, finding significant gas is a second-order objective
  - Gas field discoveries in a greenfields area (i.e. Great Southern, Canterbury, or East Coast basins) have little existing infrastructure to leverage, requiring significant investment in oil services, port facilities, transmission, and compressor stations.
  - If in searching for oil they find a field that also delivers gas, they will only invest the significant capital to bring the gas ashore if there are long-term (20 year) commitments from a sufficient volume of gas users (or the government).
  - The improving economics of fuel-switching means that, as time passes between now and (uncertain) discoveries, there is a diminishing chance that sufficient gas users will remain that will commit to the long-term contracts required to underpin this investment.

New onshore discoveries are possible, but are likely to be small. New offshore discoveries are unlikely

Onshore Taranaki has a good strike rate but tends to only have small gas reserves, although strike rates are low compared to mature basins internationally. Stock includes Kapuni plus 14+ smaller fields (average size 120PJ). Kapuni was a rare find and could be the only large onshore field in New Zealand. This assessment is based on historical drilling; as the Taranaki basin is expended then strike rates will decrease.

Onshore drilling is cheaper. With existing onshore operations, small operators will continue to drill but the chance of large discovery is small.





Offshore Taranaki has low strike rates by international standards (even for frontier drilling let alone mature basins). Commercial success tends to deliver larger gas finds, but there is the same probability of finding a majority oil or oil only field as a large gas field. The Tui oilfield failed early and has become a liability for the New Zealand Government. Another Maui is unlikely.

Offshore drilling is very expensive, especially as the rigs have left New Zealand. It is unlikely anyone will commit to the portfolio of wells that would be necessary to make a commercial discovery.

Future gas reliance should be phased out, not bridged

- The combined probabilities of ending up with significant new gas for the NZ economy mean that **believing that LNG is a bridge to an abundant gas future is – at best – a risky bet.**

- If domestic gas discoveries and infrastructure take a long time to prove, parts of the economy could end up dependent on imported LNG if significant fuel switch doesn't occur. Because LNG prices are set offshore and shaped by geopolitics, future governments may be forced to subsidise those costs, with the scale of any subsidy largely outside New Zealand's control.

- The reality of this future means that the most rational response is to transition current gas users to an alternative fuel as quickly as (affordably) possible.

1.2 Renewables for dry-year firming are an economically attractive solution, and can be met with generation in the pipeline

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Renewables can be used for firming dry years

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- The dry-year 'problem' arises from weather conditions which see lower inflows into hydro lakes than would be expected in a 'normal' year. For this exercise, we have assumed a conservative estimate of dry year requirements: a 2.3TWh increase in non-hydro generation is required in the worst inflow scenarios.
- This problem does not emerge overnight, but rather gradually appears over days, weeks and sometimes months. It is an **energy** shortfall, much more than a **capacity** shortfall.
- As a result, renewables can be used to 'firm' dry years, despite some of them (wind and solar) being intermittent. There is no technological reason that prevents renewables providing dry year support.
- The requirement is simply that a sufficient amount of renewables are kept out of the market during non-dry years, and only released into the market when a dry year is starting to emerge. This is precisely the same role that gas and coal plays today.
- The perceived challenge with renewables is that that vast majority of their cost is up-front capital, with little or no 'fuel' cost. Thermal plant has lower capital cost, but much higher fuel costs. Having committed hundreds of millions to constructing a wind farm or solar farm, it appears counterintuitive to withhold that generation from the market in most dry years.
- However, this paradigm – common in the sector - often fails to recognise that:
  - Renewables as a dry-year solution is a question of **economic attractiveness**, not **technological feasibility**.
  - It is essentially the same challenge faced by LNG or diesel, where up front capital is required ("north of a billion" for LNG), despite the risk that LNG may only rarely be needed to solve the dry year problem.
- In many ways, renewables are a better way to solve the dry year problem:
  - As a result of the high variable cost of LNG, diesel or coal in dry years (reflecting its scarcity), the incentive is to delay incurring these costs until it is clearer that hydro inflows are trending towards a 'dry year'.
  - As a result of the near-zero variable cost of renewables, more precautionary use (i.e. releasing it into the market earlier) has little or no opportunity cost. Hence the price effect of dry years could be reduced, particularly in the early period of a dry year.

An example arrangement for renewables in a dry year

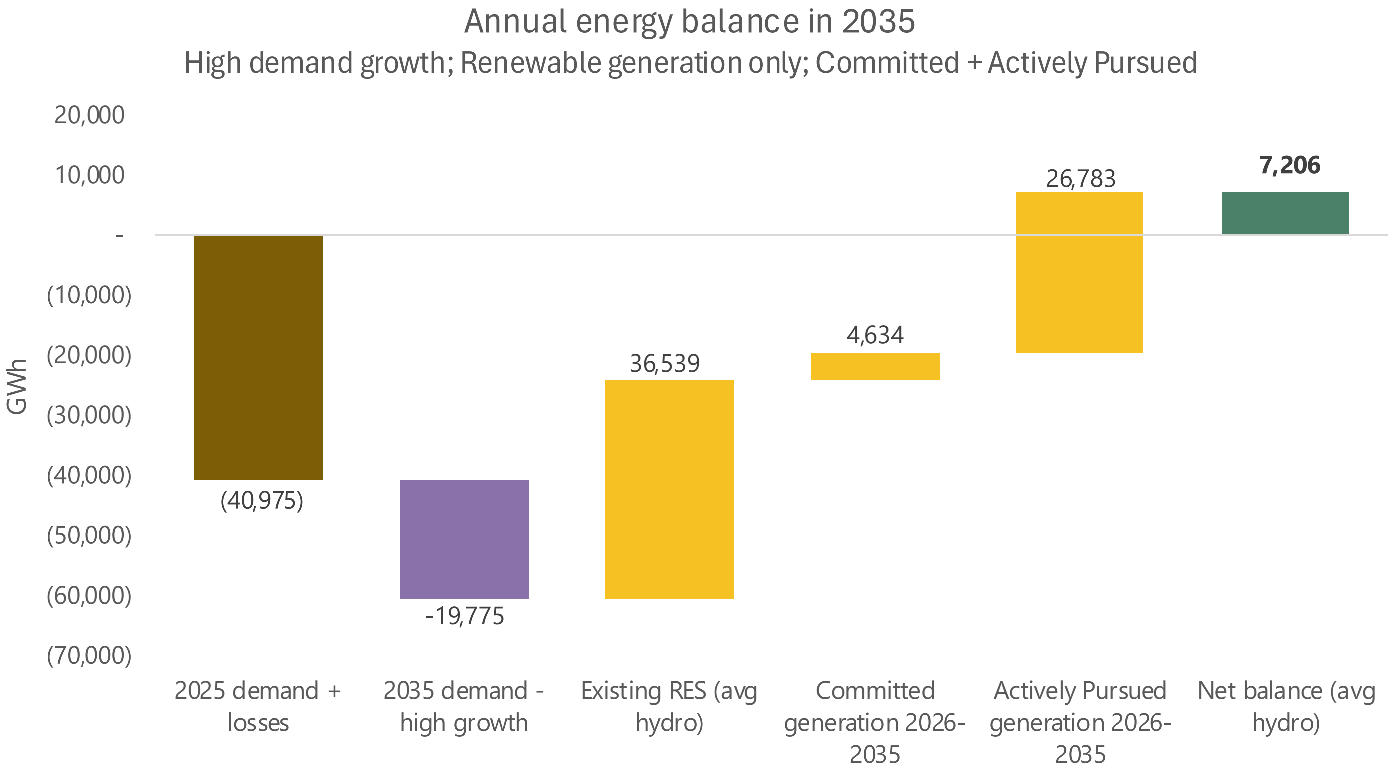
- A renewable plant could deliver this dry year support as follows:
  - A 800MW wind farm*, at 40% capacity factor, costing ~$2.6B (using MBIE figures from EDGS 2024)
  - In normal years, the wind farm would remain idle. Commencing operation would be triggered based on a combination of the deviation of recent inflows and storage from average, but as discussed on the previous slide, introduced earlier than an equivalent thermal power station
  - Operating for 10 months, this wind farm could deliver 2.3TWh, meeting most conservative estimates of inflow deviations from average (and allowing for contingent storage utilisation as currently enabled) over this period.

- We assume that the windfarm could contract for this role under a 25-year swaption-style arrangement as follows:
  - When its operation was triggered, the counterparty/s would enter into a contract for difference which would remunerate the windfarm at $310/MWh for its output in the dry year. This price approximates what an open-cycle gas plant would offer in using LNG (at a fuel cost of $28/GJ including carbon). If it operated for the full 10 months, the windfarm would earn around $690M from market revenues in the dry year.
  - Assuming this arrangement was triggered once every 7 years, the residual revenue the wind farm owner would require in order to earn an 8% return on capital would be $1.7B. This could be spread over 25 years as an option fee of $160M per annum.
  - If this is spread across all current electricity consumption (40TWh), **this equates to $3.90/MWh, or $29 per household.**
  - **The government has stated that the cost of the LNG infrastructure alone (i.e., not including the cost of the fuel, paid for by electricity consumers) would be $2-$4 per MWh.** It is not clear what assumptions about the capital cost of the infrastructure underpinned this assessment; we expect that early indicative estimates would have been used.
  - Notwithstanding, our illustrative numbers (using MBIE figures for the cost of the wind farm) are at the high end of the government's range. **However, unlike the LNG terminal, the fuel for the renewable solution is domestically sourced, unaffected by international markets**.

* There is no reason a geothermal power station or solar farm couldn't perform the same role. We chose wind due to is dependability year-round and relatively favourable economics to geothermal. We have not investigated whether the fact solar produces significantly less in winter would compromise its ability to provide the requisite level of dry year support in different inflow sequences.

There are sufficient renewables in the pipeline to provide firm energy

- Because the renewable firming option is reserved for periods of low-inflows, it is needed in addition to renewables to meet general demand growth and retirement of baseload thermal (coal and gas).
- Electricity Authority generation pipeline data shows that there is sufficient known investment* to meet this requirement over the next 10 years.



The figure illustrates an electricity market that includes:

- A high demand growth scenario (60TWh in 2035 compared to 41TWh today)
- All 'committed'* generation projects are constructed
- All 'actively pursued'* generation projects constructed per timing in EA pipeline
- All current thermal plant removed from the system

In this scenario, **there is 7.2TWh more generation projects available than needed to meet annual electricity demand in an average hydro year. Less than 40% of these surplus projects would be required to provide the 2.3TWh dry year firming service.**

* Using the Authority's vernacular, "a project is 'committed' once a final investment decision has been made. If a final investment decision hasn't been made, but other significant milestones have been reached (a location being secured in addition to a consent application being submitted or contracts to finance the project executed) then the project is 'actively pursued'." Source: https://www.ea.govt.nz/data-and-insights/charts-and-dashboards/generation-investment-pipeline/

1.3 Diesel is an implementable solution that is more economic than LNG as a bridging fuel

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MBIE's assessment of diesel

MBIE assessed LNG for dry-year generation against several alternatives, including diesel. Diesel was evaluated as shown in the MBIE extract to the right, however, as noted:

This is not a technological constraint. There is no limit to the use of diesel as a high duty cycle fuel. It is often described as a peaking fuel as it has high variable costs and low capex (preferable for lower duty). However, when compared to other high variable cost and higher capex fuels, it can be preferable

Taranaki based peakers (Stratford – 200MW, McKee – 100MW, and Junction Road – 100MW) could be converted to dual fuel (liquid fuel and gas with a local storage buffer) in around 12 months. Subject to cost all Huntly machines could also be converted to dual fuel (another 1,150MW)

Even just converting the Taranaki peakers to dual fuel, diesel could offset as much gas consumption as LNG

By converting the Taranaki peakers (six separate machines) to dual fuel risk of 'kit failure' would be reduced. Gas has a greater single point failure risk thought the transmission pipeline and critical compressor stations. LNG introduces new single points of failure at the docking and transmission tie-in points

No arrangement is needed for Whirinaki, it only runs on diesel. Diesel is more transactionally complex than LNG for the other plant, but the same outcomes are achievable through the mandatory contracts that would also be required to ensure LNG use

MBIE ANALYSIS (released under OIA)

Description:

- Increase diesel-based generation to release gas to other users (note diesel peakers only suited to short duration peaking)
- Would use diesel for generation in existing plant, including Whirinaki and Huntly unit 6

Potential gas added/released:

- 1.6 PJ (if existing 192MW capacity is used intensively to displace gas peaking)

Risks/Considerations:

- Gas storage required as gas released is seasonal and variable (most other users need a steady flow of gas)
- Risk of 'kit' failure
- Requires heavy-handed regulatory intervention to require generators to use a more expensive fuel ahead of cheaper gas

Infrastructure costs:

- Minimal

Indicative cost per GJ added/released

- $70-79/GJ

Electricity generation cost: $510-$570/MWh

Timing: Commence 2026 (subject to regulatory intervention)

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Diesel is a practical and implementable solution to the dry year problem

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Convert 400MW existing gas plant to 'dual-fuel' capability:

- GE offer standard dual-fuel 'kits' that enable existing gas generation plant run on either diesel (or any liquid fuel) or gas. One 50MW NZ gas peaker is already dual-fuel capable.
- These conversion kits would cost $100M-$170M to convert 400MW of existing gas peakers, and kit delivery could take 12 months. Installation would require a plant outage of 10-20 days.

Expand domestic diesel storage by 28 days (of baseload generation needs):

- We estimate that existing domestic diesel storage facilities could be expanded to allow for storage of 28 days of diesel generation, costing between $270 and $580M. Outside dry years, this additional storage would equate to around 9 days of diesel for the trucking fleet.
- This storage could be located at either:
  - existing diesel storage facilities at NZ ports and generation stations, costing between $270 and $580M and taking up to 3 years to consent and build; or
  - By reactivating existing Marsden refinery storage, which may be **lower cost and faster,** and shipped to domestic ports near existing generation plant (New Plymouth and Napier) as necessary in a dry year.

Enable full dry-year fuel requirements through contractual arrangements with diesel exporters

- The domestic storage above would allow for the 28-day shipping lead time for ordering new diesel from international suppliers (Singapore). These orders would need to be triggered as soon as a dry year looked likely (as is the case for ordering LNG). **Although, this could be offset by reactivating more storage at Marsden.**

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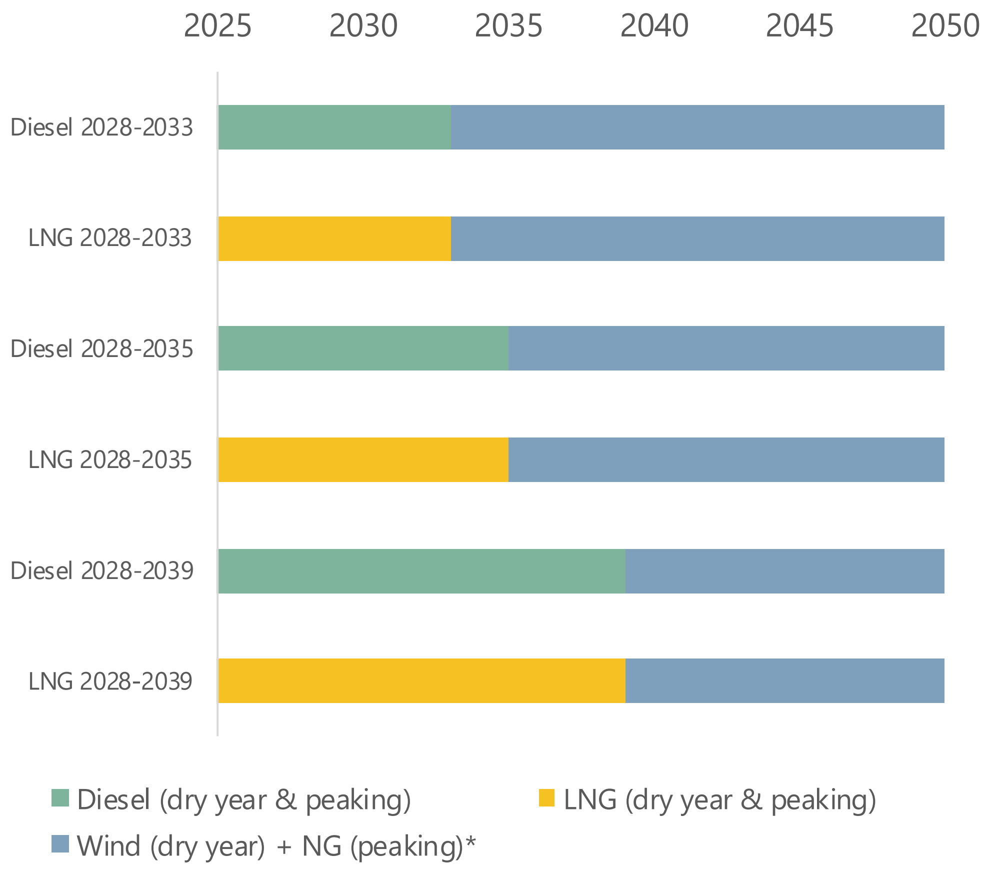
LNG is a rushed bet against diesel and renewables

Scenarios of diesel and LNG



NPV	
-$2.6B	If renewables as a dry year solution could be solved by 2033, diesel wins
-$3.5B	
-$3.0B	If a renewable dry year solution took until 2035, diesel still wins
-$3.5B	
-$3.0B	If a renewable dry year solution took until 2039, there's not much in it.
-$3.0B	

Due to its lower capital costs, **diesel is more economic than LNG when the 'bridge' period until a renewable solution to the dry-year problem comes to market by 2035.**

However, beyond 2038 our scenarios are within the margin of error, suggesting none of these options should be discounted on economics alone. In fact, these figures **strongly caution against a rushed commitment until firmer costs can be established for both.**

* Assumptions are listed on the next slide. We use the upper bound of capital costs for both diesel and LFNG. Our costs assume the peaking role after wind becomes the dry year solution is provided by gas at $25/GJ. Alternatively, it could likely be provided by a combination of demand response and BESS; for this analysis we used technologies that we were certain of (ie. gas generation). After wind enters, in all scenarios we assume domestic natural gas performs a small peaking role (2PJ per year)

Evaluation of diesel vs LNG

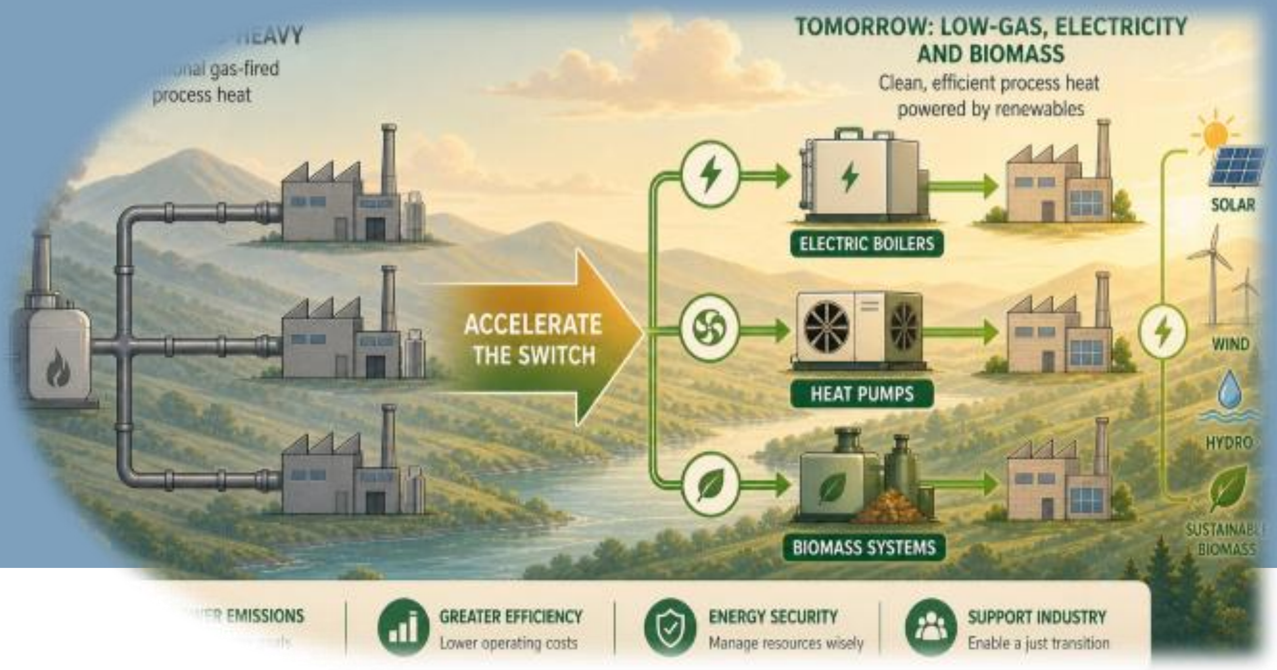
	LNG	Diesel
Capital cost	"North of $1B" for terminal; analysis uses $1.B - $1.5B	$395M - $785M (kits + storage + trucking) (likely lower cost if Marsden recommissioned)
Expected average variable cost (incl carbon)	~$28/GJ	~$46/GJ
Domestic storage	Unknown	28 days
Lead time for ordering	Unknown (est 3 months)	28 days
Exposure to international markets	Yes	Yes
Alternative resilience value	Industrial process heat	Domestic transport (esp. trucking)
Implementation complexity	Fewer parties involved (generators and production facility, possibly port facilities)	Numerous parties potentially involved (generators and ports)

In summary, which fuel is economically superior depends on how long it takes to solve the dry-year problem with a domestic fuel (renewables). Diesel is more economic than LNG up to 2039. **In the absence of certainty, the decision with the lowest up-front cost (diesel) will provide the most optionality in response to the rate of deployment of renewables**. In addition:

- Both diesel and LNG are exposed to international fuel markets
- Both diesel and LNG have a residual value in the form of resilience for other potential uses (LNG for process heat; diesel for transport). However, we believe the resilience value for diesel is much higher than LNG because transport impacts a much larger part of the economy than process heat.
- The transactional complexities are similar for both, if we assume diesel can be enabled through Marsden Point storage. If however, the diesel option is through more distributed diesel storage, the transactional costs would likely be higher than LNG.
- LNG, if used for process heat, risks a long term dependency on government-funded fuel subsidies for gas users. Diesel will just be incorporated into the electricity price (see section 2.3).

Shift #2 towards building energy resilience:

Accelerate industrial process heat fuel switch to enable a sustainable management of existing gas reserves



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Summary of key points

- MBIE has already cut domestic 2P gas reserves by 109PJ, leaving 731PJ at the start of 2026, and further downward revisions are likely. This demands a bold strategy for managing the remaining gas reserves, however this is critically missing [section 2.1].

- Limiting a long-term gas dependence on gas can be achieved by wisely managing the remaining gas reserves by pursuing the following actions:

1. Commitment to dual-fuel conversion and diesel storage to complement imminent renewable investment. This, together with a modest increase in coal generation in some years (depending on the timing of renewable investment), will eliminate 25PJ per annum of gas consumption [section 2.2]

2. Acceleration of industrials switching to a provable domestic fuel (electricity or biomass), which could reduce annual gas consumption by a further 23PJ per annum if acceleration grants of $958M were provided [section 2.3]:

   - Transmission and distribution network upgrades for the electrification of industrials are achievable.

   - There are sufficient resources in-country (biomass and electricity generation) to meet the demand for these alternative resources.

3. If the LNG path (2028-2029) was chosen, and LNG was used for process heat businesses that weren't able to economically switch at $50/t carbon prices, we estimate that an additional $10/GJ LNG subsidy would be required to ensure they were able to afford to stay operating until the end of the LNG solution. At that time, these users would still have to be switched away from gas, as reserves would be nearing end of life.

Together with the dry year solution above, we estimate the **LNG path for managing industrial process heat gas demand is $365M more expensive** than that following the diesel and accelerated industrial fuel switch path.

2.1 A strategic policy response to declining gas reserves is critically missing

The plan to manage declining gas reserves is not clear

- Recently, MBIE revised domestic 2P gas reserves downward by 109PJ. Based on this revision, there were 731PJ of 2P reserves remaining at the start of 2026.

- There is a significant chance that further downward revisions will occur as time goes by. This calls for a bold approach to managing the remaining reserves.

- The only announcements from the government have been:

  - The intention to procure LNG (at a cost of "north of a billion" for the terminal alone) to replace the use of domestic gas for the dry year problem

  - The Gas Transition Guarantee Scheme will see the Crown cover up to 80 per cent of each supported loan to firms using at least 0.1PJ of gas each year, in return for banks passing on lower interest rates (at an unknown level).

- In this context, and the lack of a plan for process heat gas demand (55PJ pa in 2025) suggests the government is relying on:
  - the market driving a sufficient level of fuel switching, which, as we will show, will **be tepid without significant ETS reform**; and/or
  - new significant gas discoveries occurring and being brought to market at an affordable price, **in time to arrest the decline in domestic gas supply for remaining users**, and/or
  - LNG being a long-term affordable fuel source for New Zealand, which - given the price is entirely determined by factors outside New Zealand's control - may **require future governments to subsidise an unknown LNG price for an unknown number of businesses for an unknown time** - an uncapped liability.

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2.2 Imminent renewable investment can displace a significant amount of gas generation

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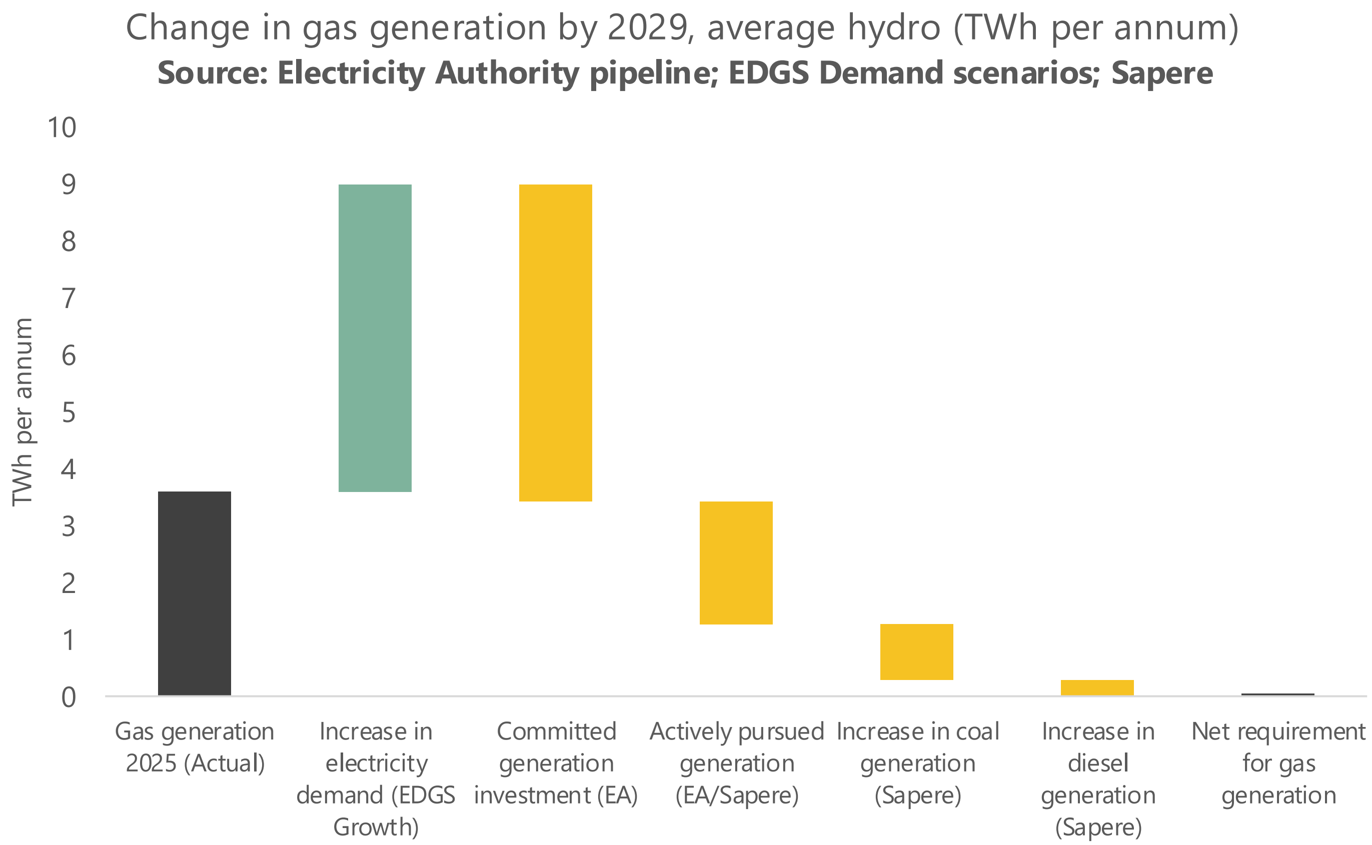
Imminent renewable investment and modest increase in coal generation will eliminate 25PJ per annum of gas consumption



Gas generation in 2025 (3.6TWh) consumed **25 PJ of gas**. On the assumption that a diesel solution to dry-year and peaking requirements is in place by winter 2028, gas can be eliminated from electricity supply in 2029 if we assume:

- new diesel generation providing peaking support of 260GWh in an average hydro year (and 2,400TWh of generation in a dry hydro year, not shown);
- the most aggressive demand growth scenario in MBIE's EDGS ('Growth')
- all committed* generation projects in the EA's generation pipeline are built
- Some of the actively pursued* generation projects in the EA's pipeline are built.

* See slide 21 for definitions. While we take the investment timings for committed projects as given in the EA's pipelines, we have conservatively delayed the actively pursued projects by 2 years later than shown in the EA's pipeline. Combined with the aggressive demand scenario, our modelled need for additional coal generation is a very conservative analysis.

2.3 Accelerated fuel switch of industrial process heat is feasible, and is a significant tool for managing declining gas reserves

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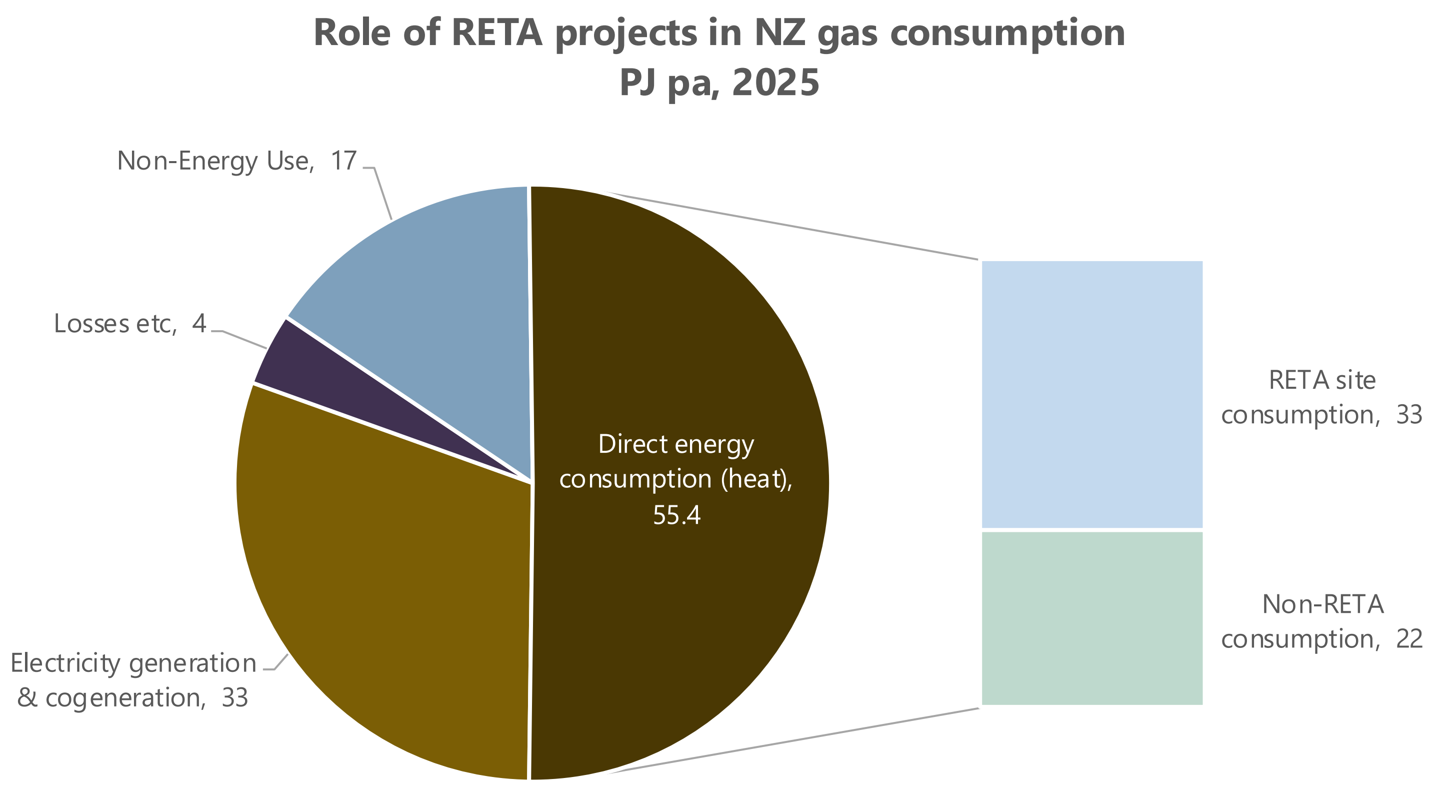
Process heat fuel switching is the most significant tool to manage gas decline



Consumption of natural gas by businesses and households for energy (heat) makes up around 50% of total natural gas consumption.

EECA's 3-year "Regional Energy Transition Accelerator" (RETA) programme has assessed the commercial attractiveness of fuel demand reduction and fuel switching options for around 800 sites around the country, of which nearly 500 sites consumed natural gas in 2022.

The RETA programme mainly focused on sites which had existing boilers greater than 500kW in size – it did not include residential and SME use of gas.

Notwithstanding, consumption of natural gas by RETA sites accounts for around two thirds of direct natural gas consumption in 2025, and is a similar quantity to that consumption by the electricity sector.

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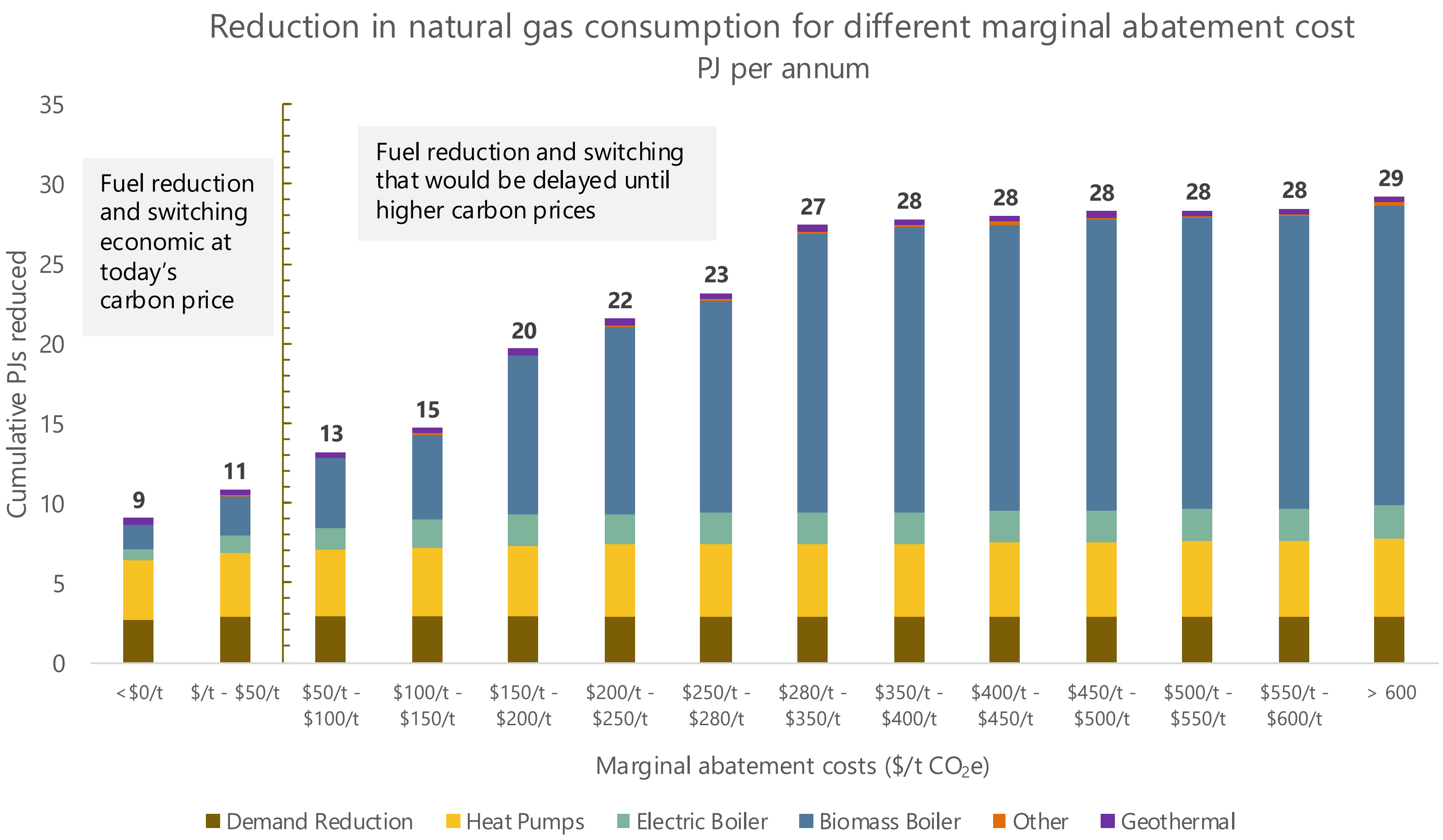
However, the majority of fuel switching projects will be delayed until carbon prices rise



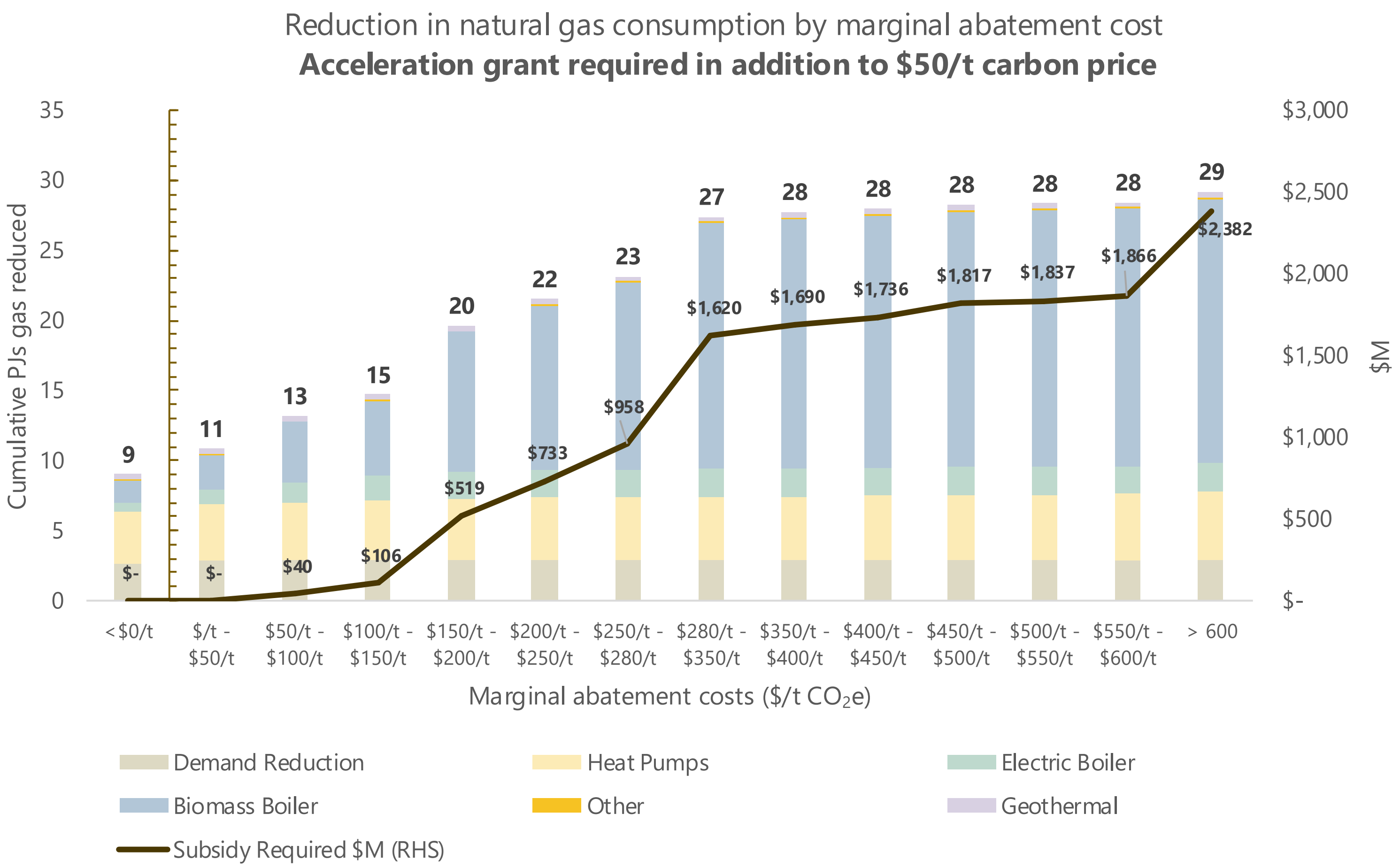
The economics of gas demand reduction and fuel switching projects depend on expectations of gas, electricity and biomass prices, as well as the carbon price.

RETA analysis suggests that if process heat users believe the carbon price will remain around its current level, around 11PJ of projects would provide a positive rate of return if implemented today, because their marginal abatement costs are less than $50/t.

Another 18PJ of demand reduction and fuel switching projects are possible, but would have to wait for require higher carbon prices to be economic.

1. Note that we amended RETA's assumed gas price path for large industrials. This price applied only to three very large process heat users. Our price path assumed the industrial gas price reached $25/GJ (carbon exclusive) by 2035 and remained at that level. All other gas prices were left at EECA's base case assumptions.

In the absence of a strong carbon price signal, a grant is necessary to accelerate fuel switching



In the absence of a strong forward signal of the carbon price, we have calculated the financial shortfall that all firms would face if they switched away from natural gas in the next few years, assuming the carbon price remained at $50/t.

No contribution would be required to the 11PJ of projects with marginal abatement costs less than the current ETS price (~$50/t).

To accelerate the 4PJ of fuel switching projects that have marginal abatement costs between $50/t and $150/t, grants totalling $106M would be required.

Grants totally $958M – less than the capital cost of the LNG terminal – would accelerate 12PJ of gas demand reductions through fuel switching projects (in addition to the 11PJ of economic projects).

Higher levels of fuel switching could be achieved with more significant grants. However, the next slide shows that accelerating the 12PJ of fuel switching is sufficient to significantly extend the life of the gas reserves.

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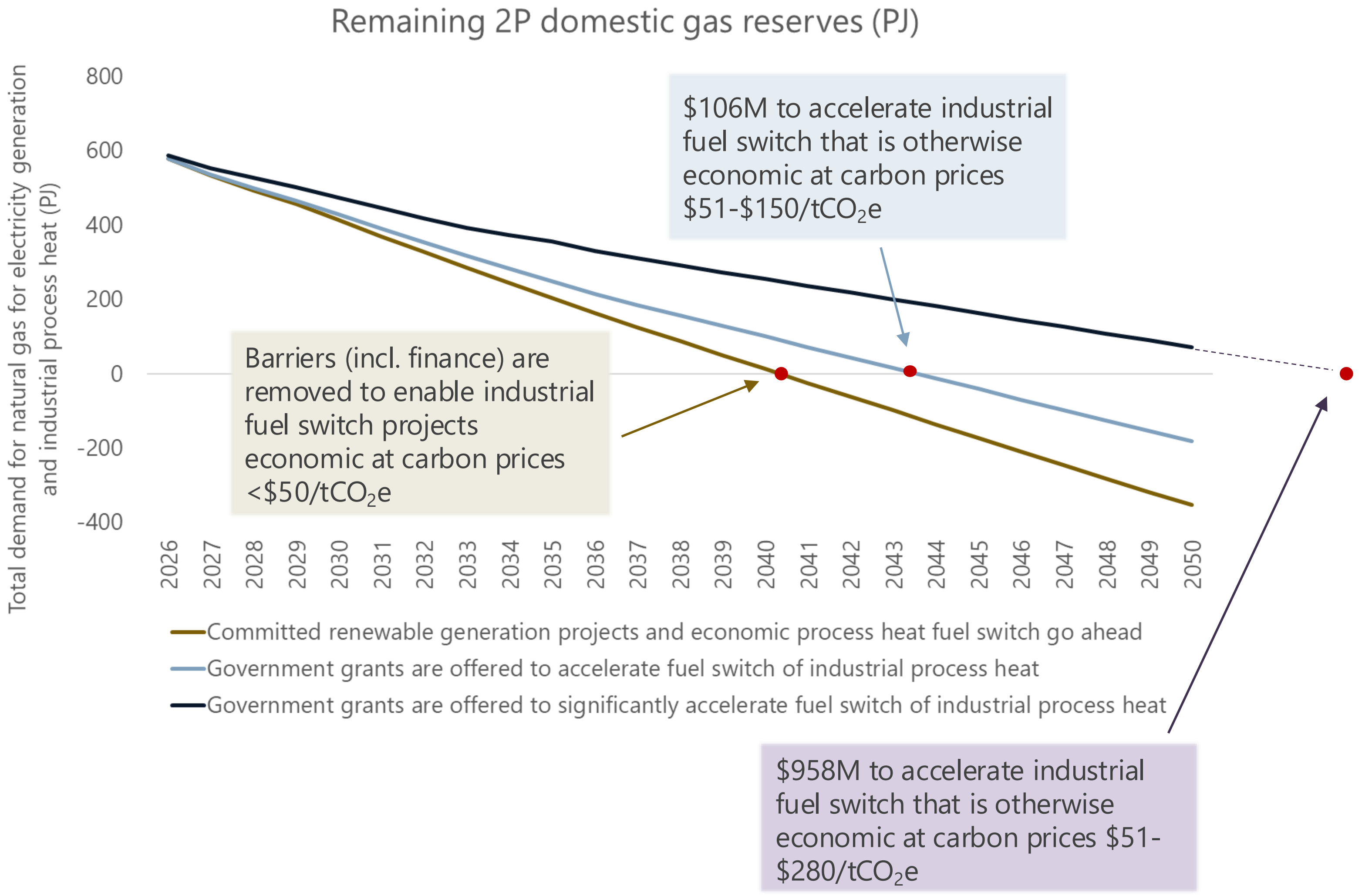
Grants can significantly accelerate fuel switching to match the decline in gas reserves

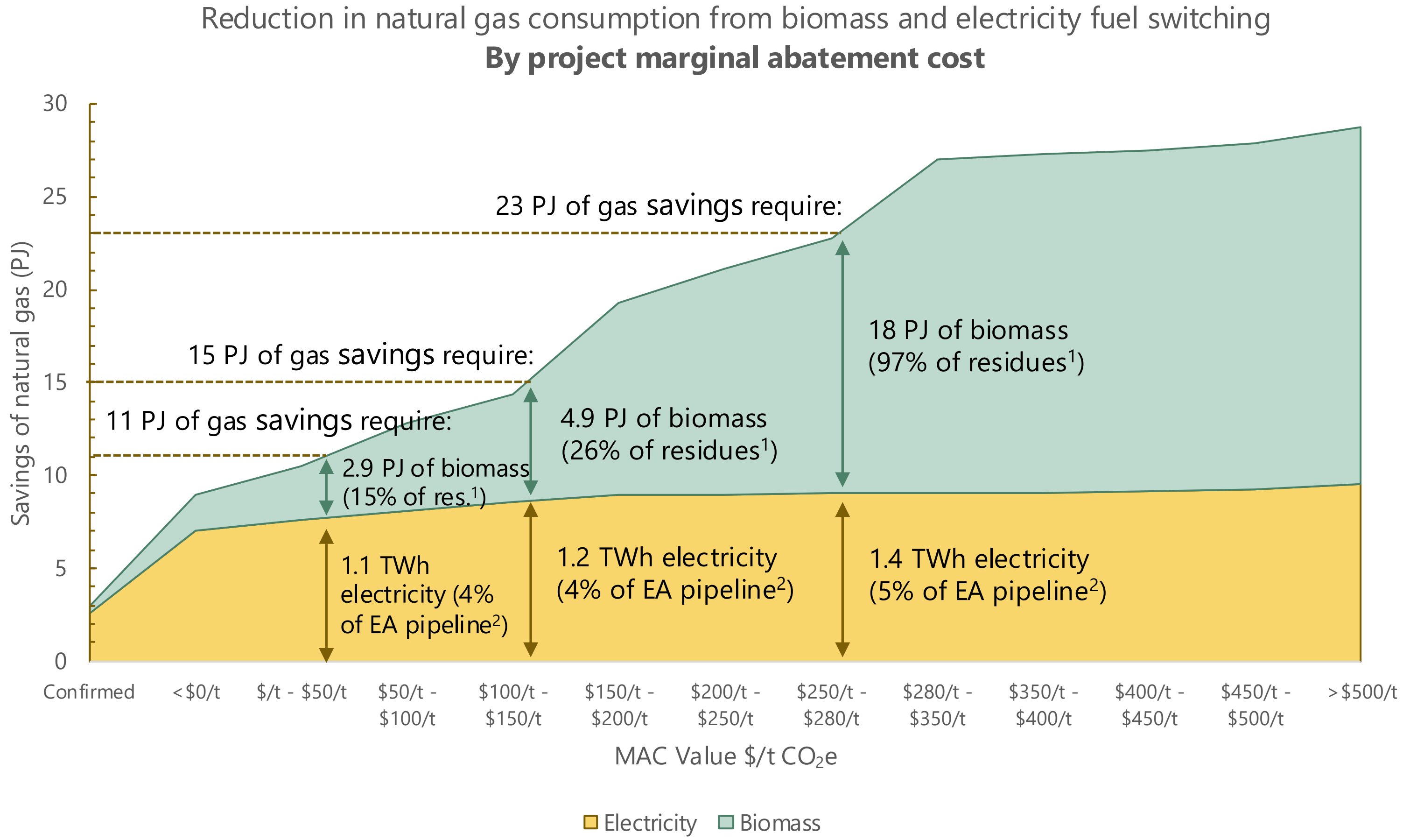


This chart shows the rate of depletion in existing natural gas reserves, assuming different rates of industrial process heat fuel switch. In electricity generation, gas from current reserves is only used for peaking after 2034 (for a diesel & RES solution) or 2038 (for LNG & RES solution), noting that the start year has minor effect on the chart. When existing gas reserves are depleted, BESS and demand response would be used for peaking.

This chart assumes a 6% WACC for fuel-switching, already 2 percentage points below TSY's commercial discount rate. **The Gas Transition Guarantee Scheme will lower debt costs, but on its own will not accelerate fuel switching fast enough* to track declining gas reserves, so grants to the scale shown here would still be needed.**

* We have no information on how much this scheme is expected to lower the cost of finance for fuel switching businesses. However, across the $1.2B of debt being underwritten, a 1% reduction in the finance rate is equivalent to an $80M contribution to fuel switching. This is less than our low level of acceleration grants above (blue line)

Which alternative fuel is doing the heavy lifting of gas switching?



1. Available harvesting and processing residues, not currently used by existing demand. These are 'economically available' residues calculated using a methodology as described in EECA's regional RETA reports.
2. Electricity Authority Generation Pipeline – committed and actively pursued projects.

RETA's "MAC Optimal" fuel switching choice

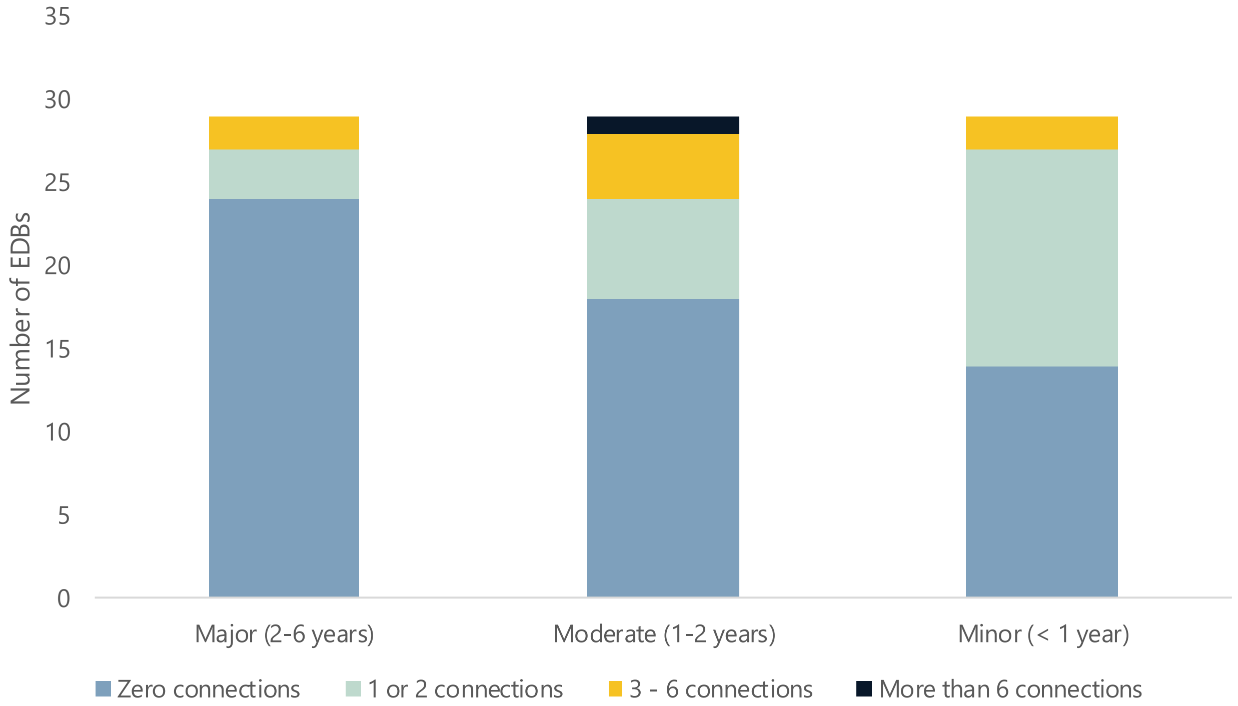
EECA's RETA analysis determined which alternative fuel (electricity, biomass, geothermal or renewable gas) provided the lowest cost fuel switching option for each business.

Although the confirmed and economic projects today favour electricity, the higher-cost fuel switching projects favour biomass. Even though electrification – particularly heat pumps – is much more efficient than biomass, high electricity network and upgrade costs still make biomass the lower-cost choice for many businesses.

Meeting the 18PJ biomass demand for the higher-cost fuel switching projects would require a significant acceleration of the biomass market (which is already developing). We note that there are sufficient economically available biomass residues to cater for this, with the potential to divert lower grade logs from export markets.

Transmission and distribution upgrades for electrifying process heat are achievable

Number of connection or network upgrades required for optimal electrification projects by upgrade complexity
Source: EECA



Some businesses who are electrifying may require a network upgrade by Transpower and/or their EDB.

We are aware that some concern has been expressed about the lead time required to upgrade connections and the network to accommodate these electrification projects.

Detailed analysis done for EECA as part of the RETA programme has shown that network upgrades – for the most part – are achievable:

- out of the 615 'optimal' electrification projects, **only 12% (72) require a connection/network upgrade.**
- of these 72, **only 10 upgrades are considered "major" by EECA, and occur in only 5 EDBs**. These could take somewhere between 2 and 6 years to complete.
- The vast majority of EDBs have **2 or fewer upgrades to make, almost all of which are minor (>12 months to complete), with many having no upgrades needed at all.**

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However, network upgrades need a strategic policy focus if we are to succeed at acceleration

- Although there may be a small number of significant upgrades, these upgrades are almost exclusively for large process heat users, and will therefore enable significant gas demand reductions. In our proposed acceleration grant approach, 2.6PJ of annual gas savings correspond to projects needing “major” upgrades.

- Similarly, the timeline assessments conducted by Ergo in the RETA project were on an individual project basis. Ergo’s analysis did not consider the possibility of a simultaneous upgrade for multiple projects, which can create economies of scale though put increased pressure on the local workforce. While our analysis shows that only 3 EDBs would have more than 6 upgrades to undertake, two of these EDBs would be required to make 13 upgrades (across major, moderate and minor complexities).

- The network challenges facing electrification of process heat are similar to those faced by investors in renewable electricity generation plant that, amongst other things, is needed to deliver the electricity required to meet demand for process heat. For process heat electrification to be accelerated, transmission connections for generation plant needs to be accelerated.

- **Acceleration of process heat fuel switching and renewable generation must be combined with a strategic policy approach to network connections**. This may require a combination of regulatory and funding changes to enable a higher pace of network delivery, and allowing EDBs and Transpower to recover revenue in a way that reflects prudent investment risk when multiple parties would collectively benefit from a network upgrade, but are at different stages in the business case process.

The risk of long-term LNG dependency and subsidisation is significant

- If LNG is introduced:
  - If existing reserves continue to decline (especially through redetermination), and the pace of fuel switching is slow, there is a **very high risk that LNG will start being used to meet process heat gas demand**.
  - Assuming that the gas price rises to LNG levels ($27/GJ, including carbon) by 2035, and that the gas users' willingness to pay around the prices they face at the end of 2025 (with a wholesale price of $17/GJ). The government would need to subsidise industrial gas demand over the 2035-2039 approximating $259M (in present value terms). This was calculated assuming 12PJ of annual consumption for industrial process heat users within the $50-$280 t/CO2e in slide 42.
  - After 2039, the fuel switching of these users would need to be accelerated in order to manage remaining gas reserves. The required acceleration grant would be $704M (this is the present value equivalent of the $958M grant delayed from 2035 to 2039).
  - We estimate the **LNG path for dry year and industrial process heat fuel switch is $365M more expensive** than that following the diesel + renewables for dry year and accelerated industrial fuel switch.

	Diesel + renewables for dry-year and accelerated industrial fuel switch	**LNG for dry-year and industrial process heat, then industrial fuel switch**
Cost of the dry-year solution	$2,600M	$3,000M
LNG subsidy for industries	--	$259M
Grant for industrial fuel switch	$958M	$704M
Total	**$3,598B**	**$3,963B**

Shift #3 towards building energy resilience:

Develop firm-energy contracts to accelerate investment in renewables for dry years, and mitigate the business exposure to wholesale prices

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Summary of key points

- The investment case for a firm-energy plant can be underpinned in two ways: relying on efficient and unfettered scarcity pricing in the wholesale market when the plant is needed; or long-term contracting.

- The electricity market has not enabled scarcity pricing to occur as a mechanism for signaling the need for new firm-energy investment [section 3.1].

- A contract market is therefore needed to underpin new firm-energy investment [section 3.2]:
  - The original NZ electricity market design expected investment to be underpinned by contracts.
  - However, these contracts have not eventuated. A mix of poor information on gas reserves, policy uncertainty on the dry-year solution, weak appetite for long-term contracting and high hedge premia prevented effective dry-year contracting, pushing scarcity costs into baseload prices and leaving unhedged users exposed to the 2024 energy shock.
  - This has made the electricity system exposed to gaps in firm-energy investment.

- A policy direction for a long-term firm-energy contract market is urgently needed to set the electricity market up to deliver security of supply in the long term – in the post-Huntly world, and enabling renewables to provide firming [section 3.3]
  - Two responses are required:
    - Procurement of diesel storage and dual-fuel equipment
    - Product and market design for long-term contracts for dry-year firming-energy

- We outline the principles on which a contract market solution can be based, and examples of the types of arrangements that can deliver these principles.

3.1 The wholesale market has not enabled the discovery of a scarcity price to signal the need for new firm-energy investment

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The wholesale market has not enabled the discovery of a scarcity price

- In the absence of contracts, scarcity pricing is important to be able to recover the fixed costs on firm energy investments. Reeve and Murray (2024)* concluded that wholesale prices do not signal scarcity.

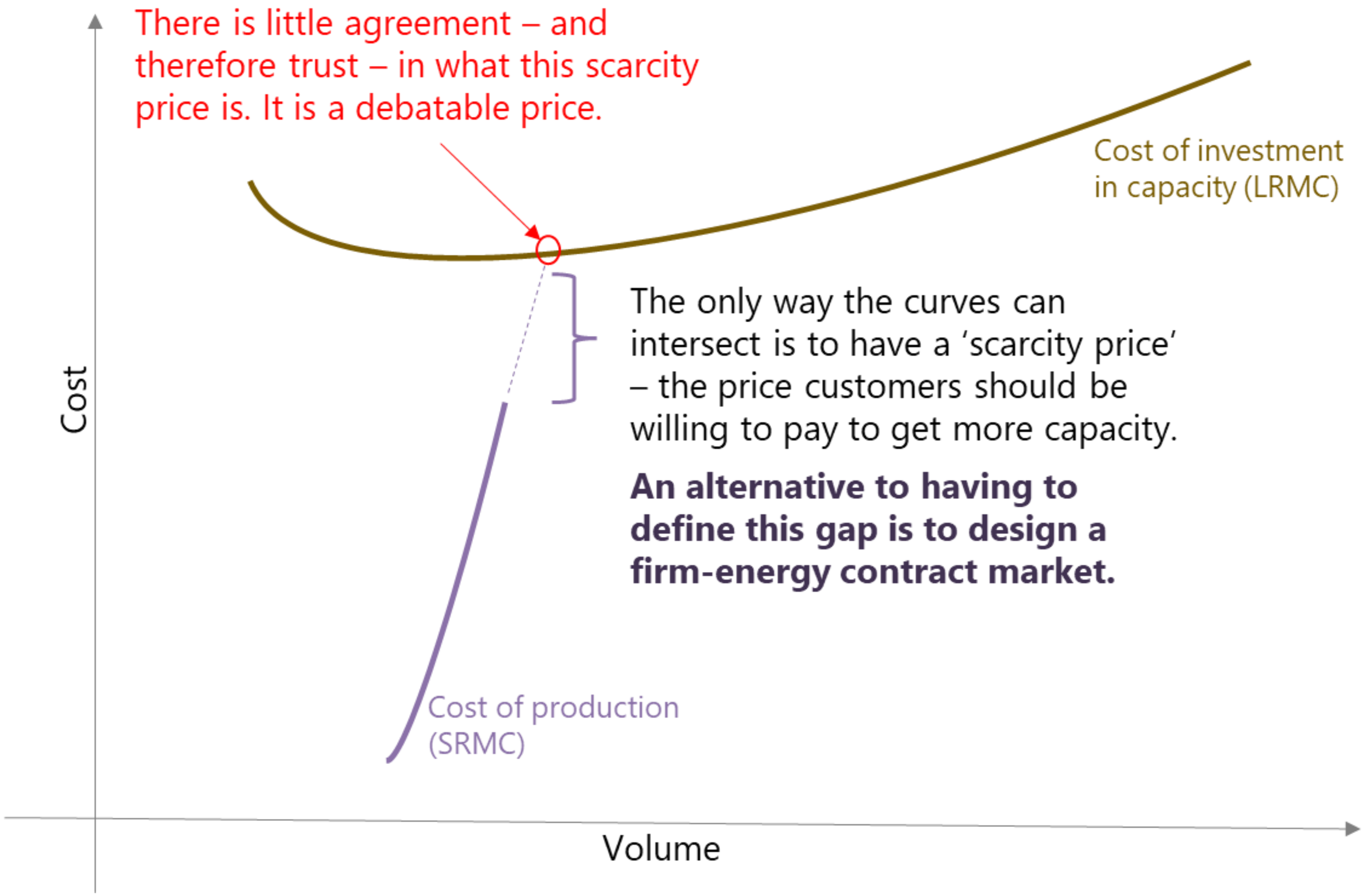
- The market has not enabled the discovery of a scarcity price to underpin investment in dry-year firming generation, due to policy interventions to control high price levels at times of scarcity rather than focus on drivers of higher prices on average.

- This has dampened electricity buyers' expectations of future spot prices and volatility, and thus led them to under-estimate the risks of not contracting.

- The stylised diagram on the next slide illustrates the problem of situation of a missing scarcity price, whereby the SRMC curve (wholesale price does not intersect the LRMC of a firming plant. To address this gap, contracts for dry-year firm energy are needed.

(*) Reeve and Murray (2024). Confluence of factors threatening electricity reliability.

An illustration of the “scarcity pricing” problem



Generation investments are made in blocks, thereby creating the LRMC curve.

The intersection of SRMC and LRMC is the scarcity price needed to underpin investments in firm energy.

Although market participants, have good information about the SRMC up to but not including scarcity pricing, electricity buyers do not necessarily have good information about the LRMC for firm energy.

Therefore, a firm-energy contract market needs to be designed.

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3.2 Firm-energy contract markets are the only alternative to relying on scarcity pricing to underpin investment in firm energy

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Contracts are the best way to underpin firm-energy investment, but they haven’t happened

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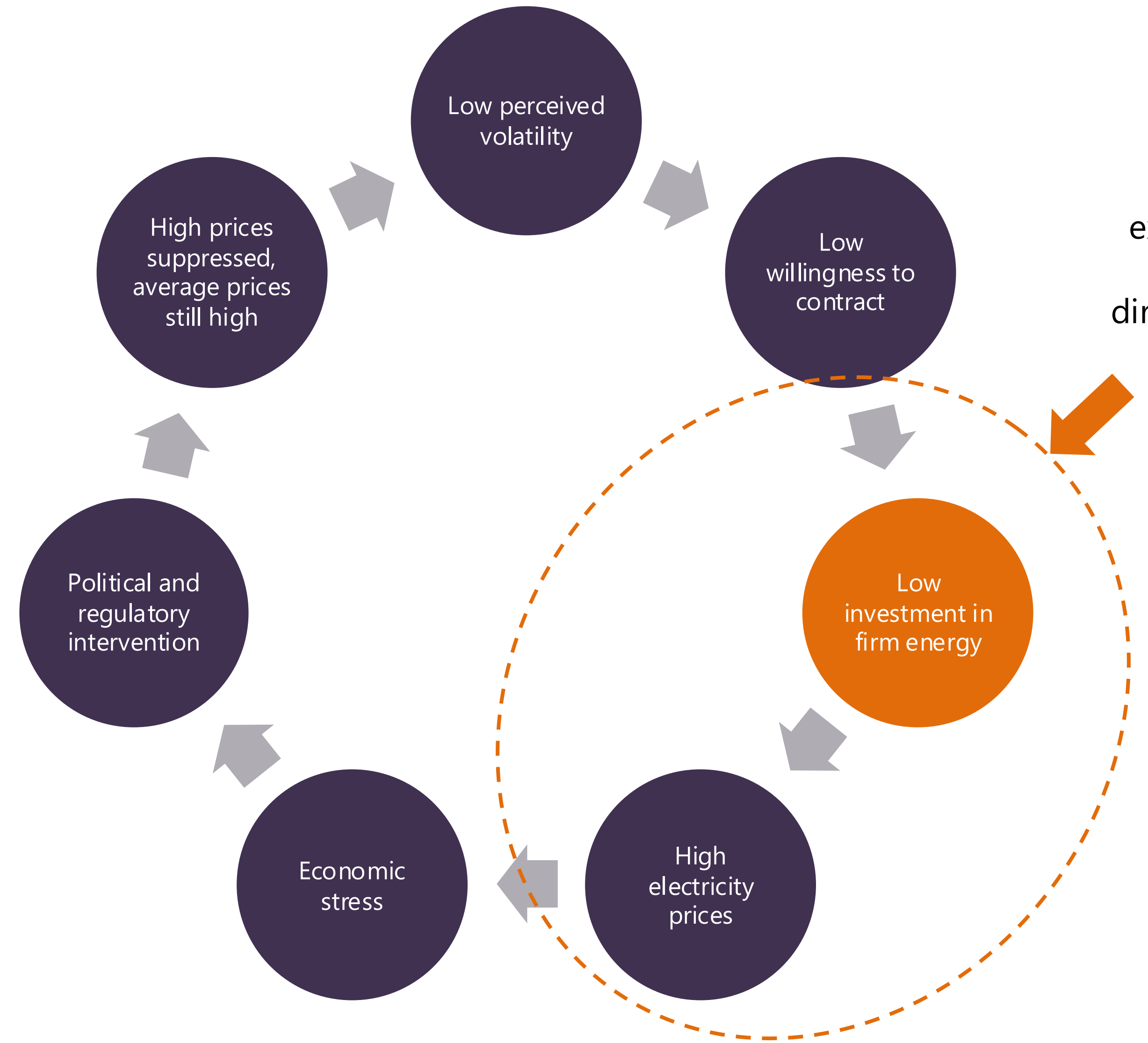
- Because firm generation is only needed in dry years, its revenues are volatile and weather-dependent, dry-year investments are best facilitated by long-term contracts.
- The original NZ electricity market design expected investment to be underpinned by contracts. However:
  - It was assumed that contracting would flourish by simply publishing a wholesale price, and that the counterparties would have sufficiently high creditworthiness to sign long-term contracts.
  - It was assumed that generators and customers would agree on scarcity, volatility and credit and would, therefore, contract.
- However, liquid firm-energy contracts have not eventuated, due to a multitude of factors :
  - Government intervention have made the economics of private investment in firm energy uncertain by signaling a preferred dry-year solution, suppressing the willingness of firm-energy sellers to invest, and thus their willingness to offer firm energy contracts
  - Many potential electricity buyers resist the long-term contracts necessary to underpin firm energy investments or are too risky to contract with on a long-term basis (counterparty risk).
  - Unclear, unreliable gas reserve forecasts have masked the risk of depletion and higher power prices, weakening users’ incentives to lock in electricity contracts.
  - High baseload contract premia can encourage users to self-insure rather than hedge: it is theoretically cheaper to self-cover for wholesale electricity market risk when contract risk premia are higher than the cost of keeping liquid current assets to cover payments (suitably adjusted for risk). This tactic only works if an end-user is able to predict the worst outcome and have sufficient current assets to cover the cash flow in that outcome.
  - Smaller electricity buyers may have an incentive to forgo contracting, on the assumption that larger market participants would undertake inter-generator contracting and investment (the free-rider problem).
- The next slide illustrates the feedback loop of these factors.

There is a reinforcing loop that has prevented firm energy contracting

This reinforcing loop has been a characteristic of the NZ electricity system since its introduction



The 2018-2024 gas crisis exposed the dry-year faultline, and amplified this loop by directly impacting the availability and cost of firm energy

The lack of dry-year firming contracting meant that little new firm capacity was built, and, as a consequence,

- wholesale prices to unprecedented levels;
- general fear of scarcity has been imputed into wholesale prices and contract prices; and
- this severely exposed unhedged users.

3.3 A policy direction for a long-term firm-energy contract market is urgently needed

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A policy direction is urgently needed for designing a long-term contract market for dry-year firming

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- Historically, policy or regulatory intervention has been required to address contract liquidity, for instance:
  - ASX market introduced via GPS 2009
  - Market making obligations introduced and amended by Electricity Authority over 2020-2025
  - Super-peak product exchange introduced in 2026 by the Electricity Authority).
- However, few firm-energy contracts for dry-years have been traded; of those that have, most have been a result of political pressure.
- Therefore, a policy direction is urgently needed for designing long-term contracts market for dry-year firming.

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A contract market can break the loop of low investment in firm energy

This reinforcing loop has been a characteristic of the NZ electricity system since its introduction

A contracts market for firm-energy will break this loop

The 2018-2024 gas crisis exposed the dry-year faultline, and amplified this loop by directly impacting the availability and cost of firm energy

Market design arrangements must be underpinned by core principles

- The principles governing the market design would be:
  - The contract design needs to reflect the risk characteristics of firm energy
  - Sufficiently long duration contracts (e.g. 7-10 years) to manage the risk associated with infrequently required firm energy
  - A high degree of assurance of liquidity sufficient to meet security of supply standards in New Zealand.
- There is a spectrum of potential contract market design arrangements which could deliver these needs:
  - Exchange-listed firm-energy contracts with market-making obligations on large generators
  - Triggers for mandatory firm-energy contracting linked to forecasts of firm-energy gaps
  - Establish a neutral entity sufficiently capitalised (e.g. via a Fund) to contract directly on behalf of consumers to underwrite firm energy investments.
- Whatever set of arrangements are chosen, the design exercise needs to commence immediately. And needs to be done well.
- We note that the above is broadly consistent with the recommendation from MDAG (2023)*, which proposed that this be remedied through the introduction of "flexibility" contracts that would better represent the economics of firm-energy investments.

(*) MDAG (2023). Summary of final recommendations sapere

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