Submission

For the Energy Competition Task Force and interested parties on "level playing field" proposal and underlying issues

By an independent expert panel comprising

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9 May 2025

For ease of reading, this submission uses relatively short rather than the more typical long form narrative.

We have chosen not to number headings or paragraphs to reduce clutter.

Guiding insights on electricity policy

Energy is fundamental to economic activity and the conduct of much of our daily lives. New Zealanders and businesses depend on affordable and secure energy and increasingly expect their energy to be renewable.

Briefing to the Incoming Minister of Energy[1]

The essence of a well-functioning wholesale electricity market is many different parties, managing their own risks, responding to competitive pressures and accurate price signals, continually looking for ways to serve their current and potential customers more effectively than their competitors.

Market Development Advisory Group[2]

Electricity markets are designed markets. They did not emerge from an unorganised marketplace.....

Electricity markets are designed to provide reliable electricity at least cost to consumers[3]...

Despite some bumps along the way, the markets have largely succeeded in the goal of providing reliable electricity at least cost to consumers. This is no simple task...

Electricity market design is far from static. New challenges are emerging with the ongoing transformation of the electricity industry.

Electricity markets are necessarily complex.[4] This follows from the complexity of the engineering and economic problems that must be solved.

Still designers should strive to keep the design as simple as possible. Complicating features should only be added if they are necessary and consistent with market principles.

Prof Peter Cramton[5]

...new generation and related services [are expected to run] into many tens of billions of dollars. This investment must be efficient to deliver reliable electricity supply at lowest possible cost to consumers.

Government Policy Statement on Electricity Industry[6]

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[1] MBIE, January 2025
[2] MDAG , Price discovery in a renewables-based electricity system, Final recommendations paper, 11 Dec, 2023 [MDAG Final]l, para 6.3. Further quote: “Wholesale electricity markets do not design themselves”, Prof Paul Joskow, *Designing Wholesale Electricity Markets*, MIT, 20 March 2006:
[3] This can be broken down into two key objectives. The first is short-run efficiency: making the best use of existing resources...The second objective is long-run efficiency: ensuring the market provides the proper incentives for efficient long-run investment
[4] (see Stoft, Power System Economics: Designing Markets for Electricity,(2002) for a good discussion).
[5] Cramton, Electricity market design, Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612
[6] October 2024, at para 5

Executive Summary

Fundamental choice – market vs administered access

At its essence, the Task Force is seeking to address two key concerns:

- The risk of significant market power in the supply of flexible hedge contracts; and
- 'Non-equivalence' of input costs between vertically integrated and non-integrated firms.

As we see it, the first matter is a real competition issue; the second is not.

The Task Force's proposed remedy of these issues would represent a fundamental change in the way risk is managed in the wholesale electricity market.

It would steer the hedge contract toward an administered (regulated) access regime in which the regulator would unavoidably become the decision-maker on whether a contract offering is consistent with a hypothetical benchmark where the seller is assumed to be indifferent to internal versus external supply. The complexity and layers of issues to be addressed in such a process are huge. More importantly, it would fundamentally change expectations in relation to the role of the regulator.

By contrast, we favour strengthening the core pillars of the wholesale market to ensure that it can function well and fully harness the drive to lower costs and find innovative solutions to the underlying supply and demand challenges.

Pressure leading to Task Force's formation

This paper starts with the central concern that gave rise to the Task Force – very high wholesale electricity prices during the peak of winter last year. Ministers called for "immediate steps"[7] and "bold action"[8] making it clear that they "will not accept a repeat of last winter."[9]

The Task Force was formed "to consider the complex factors underlying wholesale prices and put in place a suite of measures to help address the current issues across the energy system."[10]

Task Force's problem-definition: lack of competition due to vertical integration

We are not aware of any analysis published by the Task Force distilling the underlying problems and therefore measures needed to address those problems. On its formation, the Task Force seems to have launched with a view that:

- High spot and contract prices are due to lack of electricity supply.
- The answer (put simply) is to get more generation into the system sooner. (The Task Force also seems to imply that more competition would have delivered more new generation, which would have helped in managing the winter '24 'dry year').

[7] 14 August 2024 - https://www.stuff.co.nz/nz-news/350377189/govt-working-options-control-electricity-prices-willis

[8] 13 February 2025 - https://www.rnz.co.nz/news/political/541739/watch-nicola-willis-talks-supermarket-competition-as-economic-forum-kicks-off

[9] 13 February 2025, Minister of Energy - https://www.rnz.co.nz/news/political/541804/energy-minister-simon-watts-delivers-ultimatum-to-gentailers

[10] https://comcom.govt.nz/news-and-media/media-releases/2024/energy-competition-task-force-set-up-to-improve-electricity-market-performance

- For this to happen, the wholesale market needs stronger competition. The Task Force seems to imply that competition on and among the four main gentailers is relatively weak.

- Stronger competition can (should) come from the independent (non-integrated) players – they have a vital role to play.

- However, independent players' ability to compete effectively is constrained by an 'unfair' advantage that vertical integration gives the four main gentailers. In particular, gentailers can supply electricity to their retail arms on more favourable terms than they offer competing independent parties.

- This 'self preference' advantage for the gentailers is particularly problematic in relation to shaped hedges, which are typically backed by flexible generation.

- To enable more effective competition from independent players, regulatory measures are required to 'level the playing field' between independents and the four main vertically integrated players.

On the one hand, the Task Force says the key competition problem arises with the four main gentailers if their vertical integration is combined with market power over the supply of a key service (like shaped products).

On the other hand, it is clear that the Task Force considers that vertical integration causes a key competition issue even if the gentailer does not have significant market power.[11]

[11] RMR Issues, chapter 7, para 1.5. This is also reflected in the Task Force's stated preference that it proposed non-discrimination principles should apply to all hedge contracts, not just shaped hedges

Burden of proof

It is also clear that from the Task Force's perspective, while "the evidence of gentailers exercising market power is not clear cut," the burden of proof is on the gentailers to proof that they are not.[12]

Our approach to defining the problem

Our approach to defining the problem(s) to be addressed starts by outlining a frame of reference against which we can gauge potential problems. The epicentre of our framework is the core policy goal reliably meeting electricity demand from least cost supply – in other words lowest possible cost to consumers.

We observe that this is best achieved by a market process with a diversity of parties, managing their own risks, responding to competitive pressures and accurate price signals, continually looking for ways to serve their current and potential customers more effectively than their competitors.

We highlight the four essential elements (pillars) of a well-functioning market: accurate prices, tools and incentives to efficiently manage risk, sufficient competition, and public confidence.

Why the high prices?

Applying this framework, we then consider the issues underlying two sets of high prices: first, the high electricity spot prices in winter '24; and then, the high electricity contract prices since 2019, which have been tracking well above the cost of new baseload generation.

[12] TF, LPF, page 3

We outline the key relevant analysis and observe that extremely high spot prices in winter ’24 were not ‘bad’ and do not indicate market failure. Rather, they were properly signalling underlying physical constraints and uncertainties in the expected cost of future electricity supply.

Put another way, the sustained high contract prices have been reflecting the market’s best risk-weighted assessment of future gas supply.

Neither vertical integration (gentailer self-preference) nor lack of competition (misuse of market power) were material causes of the high prices in either case.

Rather, a root issue, common to both sets of high prices (spot and contracts), is constrained and uncertain gas supply at a physical level:

- In the spot market, tight gas supply coincided with extremely low hydro storage last winter.
- In the contracts market, uncertain gas supply has coincided (until 2024) with the risk of Tiwai closing, making the economics of many new generation options too risky.

While wholesale electricity prices can be highly sensitive to changes in expected gas supply, the wholesale electricity market is relatively blind to changes in factors relevant to the gas supply outlook. This is a core problem that needs to be urgently remedied.

The transition to less gas for electricity generation is happening more quickly than expected. Correspondingly, the wholesale electricity market needs to adapt more quickly with least cost solutions for reliably meeting electricity demand with less gas than expected.

This requires accurate pricing, which in turn requires much better information disclosure of underlying gas supply and demand conditions.

Risk of market power in flexible supply

As our electricity system becomes more renewable, flexible supply is likely to become (in MDAG’s words) the ‘secret sauce’ enabling a range of core wholesale market processes to function effectively.

Among other things, flexible supply ‘fills in the gaps’ when intermittent generation is not generating (due to lack of wind, sun or water).

At present, only around 6% of total generation is intermittent. This is expected to increase to around 50% in the coming 25 years due to a likely huge increase in wind and solar generation.

If fossil-fuelled thermal generation reduces significantly and is not replaced by alternative flexible supply, the remaining providers of flexible supply – that is, those who can store ‘fuel’ to support generation for more than a week – may gain significant market power.

MDAG’s analysis found that they would have the means and incentives to change the pattern of electricity spot prices – to make its volatility more or less. This could deter competing new generation.

The Task Force’s interpretation of this market power risk seems to have been a central influence in its ‘level playing field’ work. The Task Force considers that its non-discrimination proposal will address the market power risk identified by MDAG.[13] We disagree.

[13] Task Force Options paper, para 7.8

MDAG's diagnosis of a market power risk in relation to future flexible supply did not depend in any way on vertical integration. The Task Force's 'level playing field' measures would not change the underlying issue identified by MDAG. As MDAG pointed out, the source of the potential market power – namely, concentrated ownership of 'fuel' to support generation for more than a week – would remain even if the owners of the hydro storage had no retail business or were somehow at arms-length from their retail business. Our recommended approach to address market power is noted below.

Economic analysis of 'level playing field' proposal

The Task Force seeks a type of non-discrimination obligation that gives retailers and generators access to risk management products on substantially the same terms as gentailers supply themselves internally.

Houston Kemp has explored the economic rationale for this approach, set out in Appendix A. They consider the Task Force's proposal is better described as 'equal input regulation' than a level playing field.

Equal input regulation may not be consistent with the Authority's statutory objective to promote competition and economic efficiency because:

- effective competition neither requires nor necessarily leads to firms having access to the same inputs at the same prices.
- attempts to give all firms the same access to the same inputs are likely to reduce competition.
- efficiency would be reduced if a vertically integrated firm offered inputs at below the marginal cost of provision to third party firms.

The Task Force's intervention would require the establishment by each gentailer of a portfolio of internal transactions against which to assess offers from other retailers and generators. However, contrary to the Task Force's intention, such a portfolio will not be 'economically meaningful' and will not establish a reliable benchmark for external transaction.

The Task Force suggests that only vertical efficiencies that are 'cost-based' or 'objectively justified' should be taken into account in distinguishing external offers from internal 'pricing.' However, the potential reliance on cost concepts for internal transfer prices has significant difficulties given the difficulties in costing risk management products due to New Zealand's high degree of reliance on hydroelectric power.

The economic circumstances sitting around this task of administratively establishing a portfolio of hypothetical internal contracts mean that it is very far removed from those applying in other sectors, such as telecommunications, where the use of cost-based principles applied to estimate access prices is routine.

There are further important differences in the economic justification for intervention applying in the telecommunications industry, because:

- the obligation to provide access on a regulated basis arises because of monopoly control over a service[14] so that there is no competition to discipline the terms of access; whereas
- in the situation involved with the provision of wholesale electricity risk management services, there is competition involving four providers for services, such that the setting of regulated access prices may substitute for and likely displace competitive rivalry that could otherwise occur.

[14] Including in the case of mobile termination services, in which competing firms may exert monopoly control over terminating access to subscribers on their network

Further, the economic analysis supporting the Task Force's proposal is insufficient to support its conclusions. The Task Force appears to have given little consideration to weighing the benefits and costs of its proposed intervention, and particularly its potential efficiency consequences.

'Strategic reserve' to manage thermal (gas) risk – Not a good idea

Given the challenges in relation to future gas supply, some governments look at putting in place some sort of capacity mechanism.[15] These are intended to provide assurance that sufficient capacity will be put in place to serve demand.

A 'strategic reserve' mechanism can seem appealing. We strongly recommend against it. Among other things:

- The boundaries of its risk management coverage would likely become elastic over time, particularly under inevitable political pressure, which would seriously weaken incentives on market participants to cover their risks properly, which in turn would decrease security of supply as a whole.
- It would strongly suppress incentives on market participants to innovate and seek lower cost options to cover their high price risks, fundamentally undercutting the core dynamic of a well-functioning market.
- It would also likely increase 'insurance' costs for market participants relative to the counterfactual of encouraging parties to find their least cost 'insurance' options, and
- It would also likely defer investment in some alternative non-thermal resources, with the effect of prolonging reliance on gas and therefore keeping thermal generation in the system for longer and at a higher level than would otherwise have been the case, which is obviously at odds with the goal of making the transition as efficient as possible.

The best solution is to strengthen the wholesale electricity market with the package of measures recommended in this report – in particular, much better disclosure of information impacting on expected gas supply and gas contract prices.

Parallels with 2003 'dry year' – don't repeat mistakes

Winter last year bears strong parallels to winter 2003 which had:

- very low hydro inflows and low lake levels;
- a sudden very substantial write-down of gas reserves in known fields; and
- high prices for gas (high prices for methanol).

The political reaction was also similar with high alarm and calls for a return to centralised management of new generation investment and security of supply. Seeking to lower price volatility and improve security of supply, the government in 2003/04:

- Set up a 'strategic reserve' (Whirinaki), and
- Changed regulatory governance. The Electricity Commission was formed with a new Government Policy Statement (GPS).

[15] The following description of capacity mechanisms is taken from MDAG Options, Library of Options, discussion of recommendations B9 and B10

Following another Ministerial Review in 2009, the 'strategic reserve' scheme was unwound and regulatory governance arrangements were changed again with a new GPS.

It is important not to recycle the policy mistakes from 2003.

Findings on competition in retail and new generation markets

- The Task Force alludes to the possibility of a 'margin squeeze' in the electricity retail market. It also suggests that innovation has stalled in the retail market. It also seems to imply that competition in new generation may be crowded out by the four large gentailers.

- Sapere has analysed the relevant public data to see what light it may shine on these concerns. This analysis is set out in Appendix C below. In summary, the public information does not indicate problems of the kind referred to or implied by the Task Force.

Deindustrialisation?

- Concept Consulting probed the data to get a better picture on trends in electricity use and price trends in commercial and industrial sectors of the economy. This analysis is set out in Appendix B below.

- Of the three sectors in New Zealand that are both large and electricity intensive – namely, aluminum, steel and wood processing – only wood looks to be at risk of further demand reduction. Even then, the scale of the reduction is likely to be limited given remaining production is relatively small after a decade or more of decline.

Our recommendations

A summary of the key issues to address and the actions required are set out in the figure below.

Figure 1: Distillation of issues to be addressed

Pillars of well-functioning market	High winter spot prices	Contract prices above LRMC	Combined issues to address
Accurate (efficient) price signals			(1) Opacity in gas market; (2) 'Political' backing for efficient high prices in scarcity
Tools and incentives to manage spot risk			(1)Strengthen contracts market, including more traded shaped hedges + mandatory market-making. (2) More demand-side flex. (3) Accountability for adequate insurance. (4) Security of supply information. (5) Guidance for system operator in 'crisis' situations
Sufficient competition (or pricing as if no significant market power)			Link to item (1) in "Tools" above. Looking forward, address significant competition risk in flexible supply
Public and political confidence (particularly in pricing)			(1) Enable government to accept and back efficient high spot prices in scarcity. (2) Rebuild confidence in contracts market among various buyer segments

Our summary of our recommendations are set out Table 1 below. These recommendations are more fully explained in section 8.

Table 1: Recommended remedial measures

Name of measure	Key action
Improve accuracy of wholesale prices	
Action 1: Major upgrade of gas market disclosure	Government to require (and enable) major upgrade in disclosure - e.g. 1P and 3P; improve timing; gas contract prices
Action 2: Further improve hedge market transparency	Disclose non-base load offers and bids
Action 3: Government backing of efficient high prices in scarcity	(see **Actions 11** and **12** below)
Strengthen contracts market (tools and incentives for efficient risk management)	
Action 4: Improve range of traded (ASX) products	Add a monthly ASX 'peaky' product to existing quarterly
Action 5: Market-making for "peaky" products	Extend market-making to both the (new) monthly and (existing) quarterly 'peaky' contracts.
Action 6: Stress testing regime	Implement missing MDAG elements. Further action required -- to strengthen backing for high prices signalling real scarcity.
Action 7: Demand-side flexibility (DSF)	DSF market needs to be activated. Critical to competition in flexible supply and reliability at least cost
Action 8: Contract process disclosure	Make rules to require disclosure of process steps by parties negotiating OTC contracts -- essential to enable more effective monitoring and compliance (to better guard against any anti-competitive behaviour)
Action 9: Adjust voluntary OTC code	Enhance disclosure requirements. Clarify if and when non-offering is ok (e.g. no physical backing)

Name of measure	Key action
Action 10: 'Standing' technical industry group	Neutral group of technical experts tasked with continuously looking at products and related ideas with potential common good benefits for contracts market as a whole
Public and political confidence	
Action 11: Seasonal outlook report	Calibrate public expectations with quarterly briefings on current and expected market conditions. [Links to **Action 6** above - stress test regime]
Action 12: Information programme for opinion-makers	Strengthen structured information programme for wider stakeholders on how the market works

Contents

1. About this submission

Panel's brief

- Evaluate the Task Force's problem-definition, options, analysis and proposals;
- Confer (as appropriate) with interested parties to ensure that the various views and interests are properly understood;
- Consider possible improvements to the Task Force's proposals (if necessary) or any options that may better achieve the policy objectives;
- From all options considered, recommend those measures that, as a package, are most likely to best achieve the statutory objective of promoting "competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers;"[16] and
- Submit a report to the Task Force in the name of the panel. For the avoidance of doubt, the panel's report will not be to or for Mercury, or any submission Mercury may make to the Task Force.

Independent Expert Panel
(in no particular order)

Tony Baldwin (convenor) – Independent consultant

Dave Carlson – Director, Carlson Consulting

Dave Smith – Director, Creative Energy Consulting

Dr Stephen Batstone – Director, Sapere Research Group

David Reeve – Director, Sapere Research Group

Greg Houston – Partner, Houston Kemp

Daniel Young – Partner, Houston Kemp

The group also received discrete, objective analysis from **Simon Coates** – Director, Concept Consulting.

[16] Section 15, Electricity Industry Act 2010

Policy framework

We applied the Statement of Government Policy of October 2024,[1] noting in particular that:

> "New Zealand should have abundant and affordable energy at internationally competitive prices."
>
> "The Government therefore expects the electricity system to deliver reliable electricity at lowest possible cost to consumers. This includes sufficient electricity infrastructure to ensure security of supply and avoid excessive prices."
>
> "This is best achieved by…an efficient wholesale electricity market with many different wholesale buyers and sellers of electricity, managing their own risks, responding to competitive pressures and accurate price signals, continually looking for ways to serve their current and potential customers more effectively than their competitors."

Group's analytical approach

- Approach the issues with an open mind, being aware of one's own preconceptions and biases;
- Apply rigorous critical thinking, formulating views and building understanding on the basis of analytically robust evidence;
- Carefully and in good faith consider the views of all key stakeholders, including other panel members;
- Have no regard to Mercury's regulatory preferences; and
- Develop proposals and recommendations as a group that seek to best advance the statutory objective and Government policy objectives.

Mercury's role and view

- Mercury's role in this submission is limited to funding the expert group and providing basic logistical and organisational support.
- Mercury has not exercised any control or material influence, nor implied any policy or commercial expectations, in relation to the group's work. The work has been undertaken at arms-length from Mercury.
- Mercury has made it clear that it has no interest in participating in a market in which some parties can "screw the scrum." Effective competition is fundamental, together with public confidence that the market is delivering reliable electricity at lowest possible cost to consumers. Mercury supports improvements to the wholesale market that are most likely to best achieve those goals.

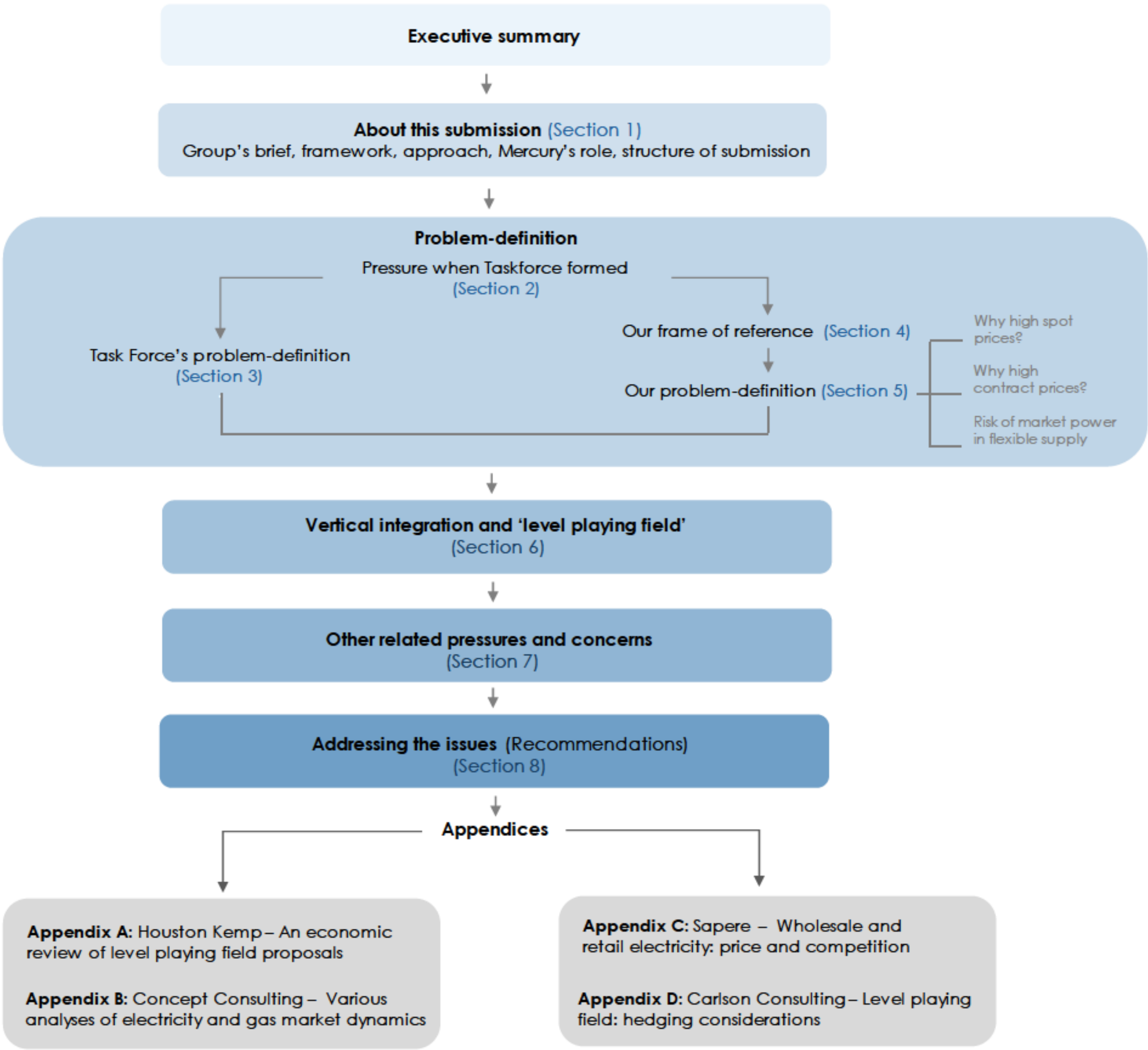
Need to tie together processes in progress

Three overlapping workstreams are in progress:

- **Implementation of MDAG recommendations**, as directed by the Government in the GPS. These recommendations include measures to address the core problem identified in the Task Force's [LPF] consultation paper.
- **Energy Competition Task Force**, which was established in response to the fuel shortage and period of sustained high wholesale prices in August 2024. It is focused on two overarching outcomes: (a) enabling new generators and independent retailers to enter, and better compete in the market and (b) providing more options for consumers.
- **Government's market performance review** the scope of which includes review of the issues and proposals put forward by the Task Force.

Diversity of thought is always helpful, but clearly it will be important to reconcile differences and distil the preferred solution to avoid a muddle of overlapping actions.

Structure of this submission



2. Pressures when Task Force formed

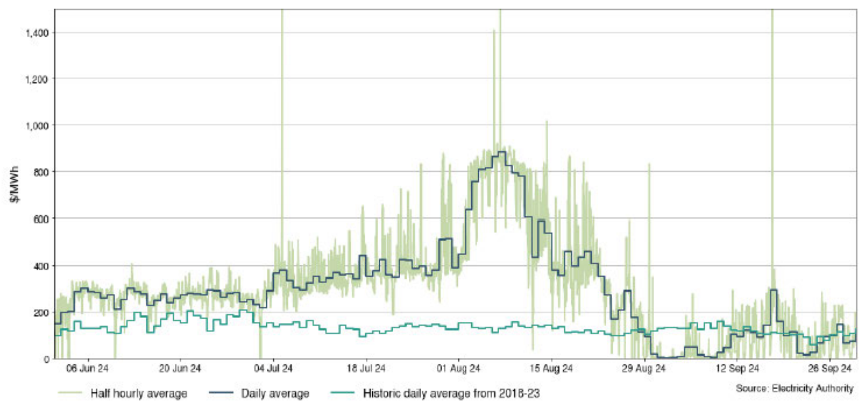
Relevance of context

The Task Force formed in response to very high electricity spot wholesale prices in the middle of winter last year. Those high prices crystalised a range of pressures and concerns about the electricity system, which inform the Task Force's approach.

Figure 2: Mix of electricity pressures and concerns crystalised in winter '24

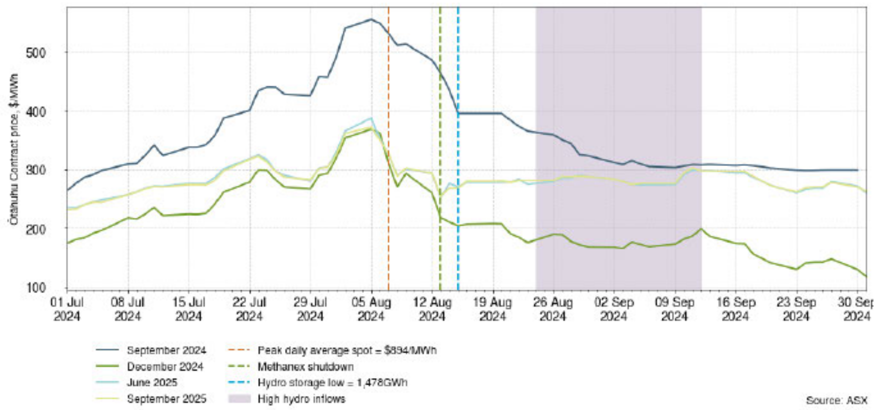
High price event – winter '24

Figure 3: Electricity spot prices, July-mid August 2024



Spot prices increased from roughly $300/MWh in early July to up to $820/MWh in early August, then eased in late August and September to below $200/MWh.

Figure 4: Electricity contract price, July- mid August 2024



2024 contract prices increased as risk of fuel shortage increased, then decreased sharply on 13 August 2024 when Methanex shut down (releasing gas for electricity generation).

Emergency measures activated

- Tiwai reduced demand (in two steps) freeing up 185MW, which saved about 330GWh or 7% of New Zealand's total hydro storage.[17]
- In response to conditions on the ASX, in early August the Authority urgently enabled a relaxation of market making measures (widening of spreads and reduced lot sizes) to improve liquidity.[18]
- Not long after, Methanex halted production and sold its gas to Genesis and Contact, which dropped the spot price to around $400/MWh.[19] This led to the market making requirements reverting to original settings and was followed by an urgent code change to give more certainty around how settings may be adjusted during times of stress.
- Non-urgent outages were moved to September.[20]
- The Authority also established weekly energy margin reporting in response to concerns that gentailers may be financially benefiting from the tight supply situation.[21]

Pulp and paper cut load and shut-down

- Winstone Pulp International (WPI) and Pan Pac turned down production.[22]
- WPI then announced closure of its Tangiwai sawmill and Karioi pulp mill, with 230 jobs lost.[23]
- Oji Fibre Solution (OFS) announced the closure of Penrose mill with 72 jobs lost.[24]
- And earlier this year, OFS announced the closure of its paper division at Tokoroa's Kinleith mill from end of June 2025 with 230 jobs lost.[25]
- Neither WPI nor OFS were hedged against high spot prices.

But some firms did well

- On 9 October 2024, Sequal Lumber announced that it was ramping up to double production at its Kawerau sawmill.
- Sequal hedges its electricity costs and uses less energy than pulp and paper mills.[26]

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[17] Electricity Authority, Review of winter 2024, 8 April 2025 at para 1.7
18 Guidance for market-making requirements revised | Electricity Authority, 20 August 2024. https://www.ea.govt.nz/news/press-release/guidance-for-market-making-requirements-revised/
19 Electricity Authority, Review of winter 2024, 8 April 2025 at para 1.8
20 Electricity Authority, Review of winter 2024, 8 April 2025 at para 2.12
21 Electricity Authority releases first Energy Margin Dashboard | Electricity Authority,19 Aug, 2024. https://www.ea.govt.nz/news/press-release/electricity-authority-releases-first-energy-margin-dashboard/
22 On 6 August 2024 (as wholesale spot prices hit [$800/MWh]), WPI paused work for 14 days

[23] On 20 August 2024 - https://www.rnz.co.nz/news/business/525702/forest-product-company-to-shut-entire-operation-as-result-of-energy-prices
[24] On 18 September 2024 - https://www.rnz.co.nz/national/programmes/checkpoint/audio/2018956103/oji-fibre-solutions-paper-mill-closes-72-jobs-lost
[25]On 14 February 2025 – https://www.rnz.co.nz/news/national/541815/more-than-200-jobs-to-be-axed-as-kinleith-mill-closes-paper-division
[26] https://www.rnz.co.nz/news/thedetail/530199/boom-or-bust-in-the-sawmill-industry

Mix of claims and concerns

Forward prices above cost of new generation

- Since 2018/19, electricity contract prices have been significantly above the estimated cost of baseload new generation.
- It is argued that the cost of hedge contracts to cover shortage risks were elevated (even if purchased before the shortage risk increased).
- Understandably, market power concerns have been raised.

Claims of anti-competitive behaviour

- Independent retailers have made various claims, including:
  - "Margin squeeze" – where the gentailers price below costs to squeeze competitors out of the market.
  - "Cannibalisation concerns" – where the gentailers delay building generation to keep the prices up.

Vertical integration seen as the problem

- Claims by independent retailers – in peak of winter '24, independent retailers asked the Electricity Authority (the Authority) to –

> "take urgent action to address the underlying issues of vertical integration...[r]equiring corporate separation (where the gentailers must operate their generation and retail businesses as separate companies), together with arms-length and non-discrimination rules."[27]

- In its May 2024 report on New Zealand, the OECD suggested:
  - Competition is too weak in electricity retailing (among other industry sectors).[28]
  - Large gentailers had been exercising unilateral market power (on the basis of "high electricity prices in New Zealand over the past two decades").[29]
  - Looking at separating retail from generation if competition "remains insufficient."[30]
- Calls for vertical separation are not new – this intervention has been considered and not adopted many times over the last 25 years.

[27] By letter on 7 August 2025 at paras 10 and 14 - https://comcom.govt.nz/__data/assets/pdf_file/0020/363008/Attachment-to-Electric-Kiwi-submission-Letter-from-Matthews-Law-to-Electricity-Authority-7-August-2024.pdf
[28] OCED, Economic Survey: New Zealand, May 2024 at page 56
[29] OCED, Economic Survey: New Zealand, May 2024 at page 64 - this view is known to reflect the views of parts of the government bureaucracy. However it is at odds with the evidence, certainly up until 2018/19 – https://www.oecd.org/en/publications/oecd-economic-surveys-new-zealand-2024_603809f2-en.html
[30] OCED, Economic Survey: New Zealand, May 2024 at page 65 – this view is known to reflect the views of parts of the government bureaucracy

Ministers' reactions – expect bold action

- Called for "immediate steps"[31] and "bold action" – Minister of Economic Growth.[32]
- Status quo is not meeting the Government's 'abundant and affordable' objective – Minister of Energy.[33]
- "Everything is on the table" to get power prices to internationally competitive' levels – Minister of Energy.[34]
- Spiking prices and uncertain supply "are also a major barrier to industry and the jobs it supports" – Minister of Economic Growth.[35]
- Power-price volatility is costing the country international investment – Minister of Energy.[36]
- Four main gentailers are "profiteering" – Associate Minister of Energy.[37]
- The OECD suggested that high electricity prices will exacerbate productivity problems.[38]
- The Government says it is looking to increase competition in the banking, grocery, and electricity sectors as part of Government's goal of increasing productivity – Minister of Economic Growth.[39]

> In this vein, the Task Force has presented its 'level playing field" proposal as –
>
> "...representing the biggest change in the market in several decades. It essentially requires fair treatment for everyone to help boost competition and security of supply" –
>
> Anna Kominik to Katherine Ryan on 'Nine to Noon,' RNZ, 27 February 2025

[31] 14 August 2024 - https://www.stuff.co.nz/nz-news/350377189/govt-working-options-control-electricity-prices-willis
[32] 13 February 2025 - https://www.rnz.co.nz/news/political/541739/watch-nicola-willis-talks-supermarket-competition-as-economic-forum-kicks-off
[33] Energy News – 20 Mar 25 - https://www.energynews.co.nz/news/resource-consents/815253/costs-must-come-down-minister-leaders-say
[34] https://www.energynews.co.nz/news/electricity-prices/813418/future-gentailers-table-watts
[35] 13 February 2025 - https://www.rnz.co.nz/news/political/541739/watch-nicola-willis-talks-supermarket-competition-as-economic-forum-kicks-off
[36] https://www.energynews.co.nz/news/electricity-prices/813418/future-gentailers-table-watts
37 8 August 2024: Shane Jones accuses big power companies of profiteering - https://www.rnz.co.nz/news/political/524482/shane-jones-accuses-big-power-companies-of-profiteering. In the same media report, Geoff Bertram of Victoria University also argued that "this is a market where scarcity goes straight through to profiteering"
38 OECD, December 2024 - https://www.oecd.org/en/publications/2024/12/oecd-economic-outlook-volume-2024-issue-2_67bb8fac/full-report/new-zealand_94257160.html
39 Nicola Willis, Economic Growth Minister, 13 February 2025 - https://www.rnz.co.nz/news/political/541739/watch-nicola-willis-talks-supermarket-competition-as-economic-forum-kicks-off

3. Task Force's problem-definition

Cure only works if it fits the ailment

It is easy to conflate the pressures and concerns and follow an intuitive sense of what the problems seem to be.

The electricity system and market are complex.[40] This is unavoidable – it follows from the complexity of the engineering and economic problems that must be solved.[41]

Diagnosing the real underlying problem is key. A remedy only works if it fits the true ailment.

The trick is to act decisively and without delay, but to make sure you've gotten to the analytical nub of things.

Task Force's role

The Task Force was formed –

> "to consider the complex factors underlying wholesale prices and put in place a suite of measures to help address the current issues across the energy system."[42]

We are not aware of any analysis published by the Task Force distilling the underlying problems and therefore measures needed to address those problems.

Problem-definition on formation

On its formation, the Task Force seems to have launched with a view that a root problem is lack of competitive pressure on (and among) the four main gentailers, and the remedy is to enable non-integrated firms to deliver stronger competitive pressure.

The Task Force's logic seems to be as follows:

- We need more generation in the system sooner –

> "Bringing more generation online sooner puts more electricity into the system, which is the best way to protect New Zealanders from fuel shortages in the future."[43]

- To achieve this, we need more competitive pressure on the four main gentailers. The core problem is that competition on or among the four main gentailers is weak (not strong enough).
- Non-integrated (independent) generators and retailers have a critical role to play in providing this stronger competition."

In the Task Force's view:

> "Enabling a wider range of market participants should promote investment and competition, which should lead to lower average prices for consumers and greater energy security."[44]

40 (see Stoft Power Systems Economics: Designing Markets for Electricity, (2002) for a good discussion).
41 Cramton, Electricity market design, Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612
42 https://comcom.govt.nz/news-and-media/media-releases/2024/energy-competition-task-force-set-up-to-improve-electricity-market-performance
43 https://comcom.govt.nz/news-and-media/media-releases/2024/energy-competition-task-force-set-up-to-improve-electricity-market-performance
44https://comcom.govt.nz/news-and-media/media-releases/2024/energy-competition-task-force-considers-eight-actions-to-strengthen-electricity-market. The Task Force also states: "...new generation and retail competition will play a key role providing more options to

- To this end, the Task Force on its formation set out two key outcomes it is seeking to achieve:[45]
  - "Enabling new generators and independent retailers to enter, and better compete in the market;" and
  - "Providing more options for end-users of electricity."
- To enable stronger competition from non-integrated (independent) generators and retailers, the Task Force (also on its formation) set out a package of four actions:
  - Gentailers offer firming for Power Purchase Agreements (PPAs).
  - Standardised flexibility products (as recommended by the Market Development Advisory Group (MDAG).
  - Virtual disaggregation of the flexible generation base as a backstop measure (as recommended by MDAG).
  - Level playing field measures ('non-discrimination rules'), as a backstop, to be promptly deployed if other interventions are not effective.

Task Force's problem-definition

What is needed: "Bringing more generation online sooner...is the best way to protect New Zealanders from fuel shortages in the future".

↕

Core problem: Lack of competition on or among the four main gentailers

↕

Role of independents:
Critical to providing effective competition

↕

Barriers to competition from independents:
- Access to hedge products backed by flexible generation (large hydro storage)
- Vertical integration (integrated retailers get preferred hedges compared to independent retailers)

↕

Package of measures:
- Gentailers to offer PPAs
- Standardised flexibility products
- Virtual disaggregaton (as a backstop)
- Level playing field measures

consumers to manage their electricity use and cost, enhancing security of supply and applying downwards pressure on prices, including through substantial increases in generation investment. Consumer outcomes will be poorer without this competitive pressure" - TF, LPF, para 3.51(d)

[45] See above. The Task Force confirmed this approach on 9 September 2024 - https://comcom.govt.nz/news-and-media/media-releases/2024/energy-competition-task-force-considers-eight-actions-to-strengthen-electricity-market

Grounds for weak competition conclusion?

Insufficient competition on or among the four main gentailers seems to be at the core of the Task Force's problem-definition.

What are the Task Force's grounds for this view? The 'Level Playing Field' options paper points to:

- Generation market shares – the share of the four gentailers, taken as a block, has stayed at around 85% since 2010.[46]
- Retail market shares – independent retailers' share in total increased to around 16% in the 12-year period from 2008 to 2020, but has not changed significantly since then.
- Retail innovation – the Task Force argues that innovation in the New Zealand retail market is less developed than other markets,[47] and that the competitive impact expected from independent retailers' "appears to have stalled," which "highlights a competition risk."
- The prolonged gap between long run marginal cost (LRMC) and forward electricity prices – the Task Force simply notes the competing explanations as to why it has happened – due to barriers to new entry or expansion in generation, or it may be due to material market uncertainties[48] – the Task Force does not express a view.

The Task Force also seems to be saying: whether (or not) the evidence points to weak competition on or among the four main gentailers, vertical integration and market power in flexible generation give those gentailers an unfair advantage over independent parties, which impairs the independents' ability to compete, and therefore those advantages need to be 'levelised' to strengthen competition.

Market power analysis and burden of proof

The Authority points out (in a related paper) that it is –

> "not seeking to make a definitive finding on whether a gentailer has or is exercising substantial market power. Instead, we draw insights from our own market power analysis as to whether there are any problems that may exist, and which might require policy intervention."[49]

On the question of burden of proof, the Task Force says:

> "While evidence of gentailers exercising market power is not clear-cut, the liquidity and pricing risks are clear", the parties disagreeing have not presented any evidence to show that the concerns are not valid."[50]

This is akin to the independent retailers' argument – in short, proving misuse of market power is hard, but it can be presumed as it is built into the structure of vertical integration.[51]

[46] TaskForce Level Playing Field measures Options paper, , para 3.14 [Task Force Options paper]
[47] Ibid., para 3.15. See also RMR Issues, Chapter 2, paras 4.12 and 4.14
[48] for example, gas supply uncertainty, whether the Tiwai Pt aluminium smelter would continue to operate, the previous Government's proposed Lake Onslow pumped hydro scheme, and investment lag – Task Force Options paper, para 3.42. Scarcity was other reason.

[49] Electricity Authority, Risk Management Review, 27 February 2025, [RMR Issues], chapter 7, paras 1.4. The Authority adds: "Our focus in this review is different to – and broader than – the misuse of market power test under the Commerce Act" - RMR Issues, chapter 7, para 1.30
[50] Task Force Options paper, page 3
[51] RMR Issues, Update, para 6.21: "Independent retailers argue that the inability or difficulty in finding conclusive evidence of the exercise of market power is a common issue with vertical

Interestingly, the Authority also asserts that the case for intervention does not depend on market power:

> "...even if no gentailer has substantial market power in any relevant risk management market and there is no evidence of coordination, there may still be good reasons for a policy intervention in relation to risk management to promote competition in the retail electricity (or indeed wholesale) market."[52]

integration and why it is considered regulatory best practice to separate vertically integrated parties to address the real risk of such exercise of market power. The Independent Electricity Retailers' position is that gentailers do not have incentives to expand generation to keep pace with demand, and there is insufficient liquidity in hedge"

[52] RMR Issues, chapter 7, para 1.5

4. Our frame of reference

Our analysis of the underlying problem is different from the Task Force's. We explain how and why below.

First, we set out the key elements of a well-functioning wholesale market, against which possible issues of concern can be evaluated.

Core policy goal – reliable least cost supply

> We want the system to reliably meet electricity demand at least cost to consumers, over the short, medium and longer terms.[53]

Put another way –

> In any timeframe, we want the next increment of demand for electricity to be met from the lowest cost source.

Wholesale prices should reflect supply and demand conditions

Intuitively, very high prices in times of scarcity can feel like 'profiteering' or market power or the like, especially if some consumers can't cover the higher costs.

While it can be difficult to distinguish good high prices from bad high prices,[54] it does not follow that high prices are necessarily a 'bad,' or that a system producing very high prices is not working properly.

Spot prices are not capped in New Zealand. They change every half hour to reflect physical conditions.

We want wholesale prices to reflect the balance of electricity supply relative to demand. High prices are essential to signal when supply could be short.

Put simply, wholesale price should signal the lowest cost option available to meet the next increment of demand at the relevant time and location.[55]

These price signals inform buyers and sellers of wholesale electricity on how to use their resources, whether to increase or decrease their risk cover, and whether to look for other ways of meeting their needs.

Volatile spot prices are not a 'bad'

To say that volatile spot prices is a good thing will seem like an oxymoron to many stakeholders and politicians. Intuitively, volatile spot prices can feel like a 'bad,' as reflected in recent comments by the Minister of Energy that "power-price volatility is costing the country international investment."[56]

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[53] "Electricity markets are designed to provide reliable electricity at least cost to consumers" – Peter Cramton, Electricity market design, Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612. This is the essence of the Electricity Authority's statutory objective. If the objective of meeting society's environmental objectives, we get the 'energy trilemma' – reliability, lowest cost and sustainability. The environmental objectives are set outside the electricity sector in laws such as those covering consenting arrangements and the Emissions Trading Scheme.
[54] "Market power and Electricity Competition", William W Hogan, 25 April 2002 at slides 9 and 10
[55] The price discovery process is explained in paragraphs 237-240 of Annex 3 of MDAG's High Standard of Trading Conduct Discussion Paper (originally published in February 2020, and republished alongside our Issues Paper in February 2022). We further note the view of Reeve, Stevenson and Murray (at Sapere) (July 2021) that "efficient pricing delinks from observable cost because observable costs contain insufficient information for efficient pricing over time".
56 https://www.energynews.co.nz/news/electricity-prices/813418/future-gentailers-table-watts. Note also comments attributed to the Minister of Economic Growth: Spiking prices and uncertain supply "are also a major barrier to industry and the jobs it supports" - 13 February 2025 - https://www.rnz.co.nz/news/political/541739/watch-nicola-willis-talks-supermarket-competition-as-economic-forum-kicks-off

On the contrary, volatility is an inherent feature of a highly renewable electricity system where spot prices properly signal real changes in the cost (value) of producing (or storing) another unit of electricity as physical conditions change.[57]

In any half hour, we want electricity demand to be met from lowest cost sources. But what is lowest cost varies with the weather – how much sun (for solar power), wind (for wind power), or water (for hydro generation) – and also the relative value of coal, gas or diesel.

In other words, the cost of supply varies at an underlying physical level. We want the spot price to signal these actual changes in costs (or values).[58]

Artificially suppressing or smoothing those spot price signals could cause serious problems in how participants manage their risks and, in turn, whether we get enough investment coming online at the right time.[59]

Given the importance of governments not intervening to suppress efficient spot prices, it is very important to strengthen public and political understanding of how pricing works and what to expect as we transition to more renewables.

As explained by MDAG, volatility is likely to increase in the future as electricity supply becomes more and more renewable.

This highlights the importance of ensuring the availability of hedge contracts and other tools for market participants to efficiently manage their spot price risk.

Buyer and sellers need tools and incentives to manage their spot price risks

Our market design recognises that:[60]

- risks, and optimal options for managing them vary among market participants; and
- each market participant is best placed to understand the risks they face, and the mix of tools and cover to best manage those risks.

Keeping the responsibility for risk management on each participant rewards those who seek out the lowest cost options, including for investment in new supply. And investment efficiency represents the largest single impact the electricity industry has on the New Zealand economy.

Neither the Government nor the Authority nor the System Operator is supposed to step in to insulate wholesale market participants from risk or to protect them from their failure to manage their own energy supply risks. To do so would only increase the risk of shortage. Such interventions can cause a vicious circle because they can undermine incentives on market participants to manage their own risks properly, chilling hedging and new investment leading to increased scarcity, more periods of high prices and reduced security.[61]

Risk management tools can be:

[57] MDAG Final Recommendations
[58] Volatility is caused by several factors – relatively inelastic demand; our long, stringy transmission network; highly changeable weather; large variations in hydro inflows; step-changes in the cost of supply (across hydro, wind, geothermal, gas, coal and diesel); and (hopefully seldomly) by the exercise of market power.
[59] MDAG Final Recommendations
[60] MDAG Final at C.3 and C.4
[61] GPS, para 21

- physical options (e.g. an ability to increase supply or reduce or shift demand, or store energy); or
- financial arrangements where parties contract with others who can manage the underlying risk at a lower cost.

As MDAG highlights, the contract market plays two vital roles. First, it provides products that wholesale buyers and suppliers can use to manage their exposure to spot price risks. The contract market's second critical function is to provide signals to guide longer term decisions – especially investment in generation, storage and demand-side capability.[62]

Sufficient competition is crucial

As the Commerce Commission explained: "Competitive behaviour is a dynamic process – one that emerges from the rivalry of market participants." It is a process that puts downward pressure on costs and prices, particularly by promoting continuous improvement and innovation.

The ideal in our wholesale electricity market is a level of competition such that no party has the means and incentive to exercise significant market power.[63]

However, there are some situations where it is extremely difficult (or not economically efficient) to achieve effective competition. Where this occurs in the spot market, a seller's offer price must be consistent with the offer it would have made if no seller could exercise significant market power.[64]

Best to have many parties competing to find least cost options

The range of potential 'supply' options is changing rapidly. New technologies continue to emerge as the world embarks on a quest to electrify much of its energy demand. This will drive costs and technology in ways we can't predict.

History clearly shows that no single person or small group of decision-makers has the field of vision, know-how or bandwidth to see or deploy the full range of potential 'supply' solutions.

Further, each risk situation or opportunity has its own parameters, often seen only by parties with a particular focus on the relevant conditions and technology.

Put simply, it is much better to have a diversity of parties competing to find the best solution to a particular situation – and a filtering mechanism that rewards the best solutions.

This is the essence of a market.[65]

Why not a more centralised approach?

For many people, the idea of central organisation coordinating things feels a lot better.

[62] MDAG Final, para 7.13

[63] Market power becomes significant when its exercise would have a net adverse impact on economic efficiency, which includes productive, allocative and dynamic efficiency. This concept is reflected in Electricity Industry Participation Code 2010 at cl 13.5A.

[64] 'Trading conduct rule' Clause 13.5A of the Code.

[65] As John Culy observed in the prelude to the formation of the wholesale market in 1999: "Decentralised investment decision-making, involving a wider range of investment options, which, to satisfy funding organisations, requires rigorous project appraisal, risk analysis, risk management and cost control. This is likely to lead to a preference for more flexible, smaller scale, less capital intensive and shorter lead time projects" – Culy (1992) at 5.1 (p.22).

Centralised approaches come in various forms (including capacity mechanism or ‘strategic reserves’).

Advocates assumed that a centralised approach would achieve streamlining efficiencies, better investment coordination, and better ensure security of supply with some form of capacity mechanism or ‘strategic reserve.’

For other proponents: “…the mischief lies in the idea that electricity can be marketised…a benevolent, efficient state monopoly would be preferable.”[66]

The evidence of history, and the dynamic nature of the future, strongly suggest otherwise. A centralised approach is likely to increase costs for consumers and lower security of supply.

Public and political confidence

Governments need to reinforce (and not unintentionally undermine) incentives on market participants to manage risk properly. This means (among other things):

- accepting high prices in times of scarcity;
- not ‘softening the landing’ for unhedged participants (this would only increase the risk of shortage and raise costs for consumers); and
- recognising that government intervention can cause a vicious circle where measures can chill investment leading to increased scarcity, more high prices and greater insecurity.

[66] Jane Clifton, The New Zealand Listener, 2003

Figure 5: Four 'pillars' of a well-functioning wholesale electricity market

Source: MDAG

Major strengthening required

As explained by MDAG, significant upgrades are required to the wholesale electricity market to enable it to function effectively in a highly renewable system. This is reflected fully in the Government Policy Statement on the Electricity Industry of October 2024. In particular, the contracts market needs to do some 'heavy lifting' to meet likely greater demands for more risk management services.

100% reliability is too expensive[67]

Electricity outages can be very unpalatable from a political viewpoint, but the cost of delivering those last tiny fractions of percentages of absolute security are *very* expensive.

Most consumers prefer to tolerate some very low risk of outage rather than pay much higher power bills.[68]

The ideal outcome is that consumers receive the level of reliability that reflects their willingness to pay.

Importance of demand-side response

New Zealand's hydro system is expected to be a vital source of flexibility as the system shifts towards renewable supply. However, we will also need other flexibility sources to help balance the system.

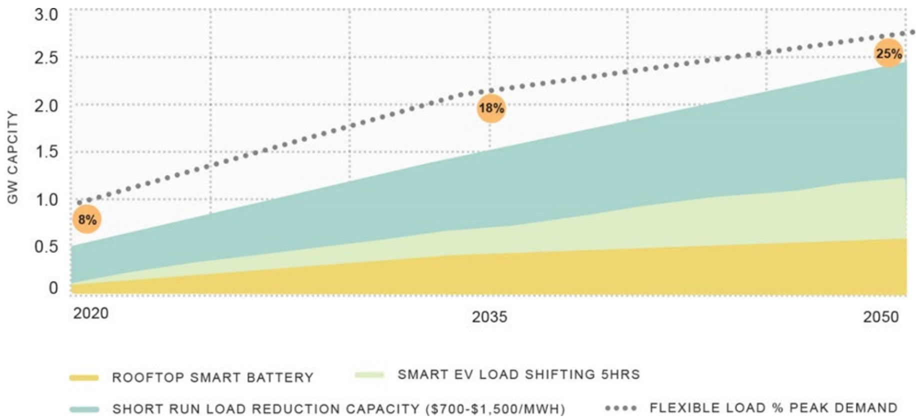
Demand-side flexibility (DSF) has the potential to become a very significant source of flexibility. This flexibility may be in the form of time-shifting of

[67] MDAG Final, section 3
[68] In some cases, consumers with very low risk tolerances are installing solar/batteries on their properties to provide security. This will become an increasingly feasible option for consumers as cost curves for these technologies come down. However, this option will not be available to all consumers due to cost implications, thus creating the potential for further inequities.

demand (with no change in aggregate usage) or altering the aggregate usage dependent upon system conditions. Electricity consumers who can alter their demand are likely to see much greater benefits from providing this flexibility to the system.

As shown in Figure 6, MDAG projected that flexible demand (as a percentage of total demand) would increase from 8% to 18% by 2035 and reach around 25% of total demand by 2050.

Figure 6: Demand-side flexibility (by Concept Consulting for MDAG, 2023)



Demand-response is not at odds with economic growth

There is a view that it makes no sense (or sends the wrong signal) to have electricity users reducing demand to 'get through' a period of fuel scarcity. The power system is there to support industry to grow – industry is not there to support the power system.

Contrary to this view, it makes very good economic sense for consumers to reduce demand if:

- the firm shifting or reducing electricity demand makes more money selling the electricity back into the system than to making the thing they produce at their plant; and
- the cost of buying back their electricity is cheaper than the alternative power back up. It makes no sense to build more expensive rarely used electricity generation.

5. Our problem-definition

Making sense of high wholesale prices

This is the animating public and political concern

Core stakeholder concern centres on high prices. Extreme spot prices in winter ’24 set off serious political alarm bells. Sustained high contract prices are (understandably) viewed by many with deep scepticism.

Many commentators and stakeholders have drawn the conclusion that these high prices must be due to the big players flexing market power. Either:

- they have been ‘jacking up’ prices; or
- if prices are high due to a shortage of electricity supply, the big players created the shortage by holding back new supply to keep prices up; or
- if it is not about holding prices up, then lack of new electricity supply is due to (or made significantly worse by) lack of competitive pressure.

Whatever the case, market power (or lack of competition) is widely viewed a root cause (or material contributor) to high wholesale prices.

This therefore is the focus of our problem-definition.

We look at two high profile examples of high wholesale prices

Two examples seem to encapsulate the full range of concerns and potential issues:

- The extremely high spot prices in winter ’24.
- The sustained high prices in the electricity contracts market, which have been tracking well above the cost of new (baseload) generation since 2018/19.

We examine these two cases below, looking to distil key problems that need to be addressed.

High spot prices in winter ‘24

What happened, briefly?[69]

Water storage was low going into winter ’24. Hydro generation in the third quarter of 2024 was the second lowest over the past thirty-two years.

This required large amounts of thermal generation, but the gas sector was unable to provide such volumes and meet all the demands from all the other gas consumers.

As a result:

- Gas and electricity prices increased to very high levels – the electricity spot price reflected the expected cost of thermal generation using expensive gas or (sometimes) diesel.[70]
- Very large amounts of coal were burned at the Huntly power station.

[69] Source – Concept Consulting report in Appendix B
[70] While hydro generation may set the clearing price (see Figure 34 of the Authority’s review of winter 2024), hydro offers were properly reflecting the expected cost of additional gas (from sources like Methanex). For more on opportunity cost and scarcity rent, see Annex 3 of MDAG’s High Standard of Trading Conduct Discussion Paper, February 2020 at [paras 223-227

- Some demand for electricity and gas was curtailed, particularly from industrial consumers.[71]

Methanex eventually agreed to on-sell to Genesis and Contact its remaining gas-entitlements, and Methanex idled its remaining train for the period from mid-August to the end of October.

Soon after, the electricity supply and demand balance lurched from significant scarcity to significant surplus, with gas and electricity prices collapsing to close to zero.

This was due to a combination of the following:

- Methanex's gas becoming available to Contact and Genesis.
- Rain in the hydro catchments, materially reducing the need for thermal generation.
- Meridian exercising its option to require the Tiwai smelter to reduce demand.

Let's briefly assessed what happened in terms of the four essential pillars of a well-functioning wholesale electricity market (as outlined in section 4 above).

Were spot prices accurate? *Yes, but could be improved*

Contrary to wide-spread claims of misusing market power or 'profiteering,' spot prices in winter '24 reflected underlying costs and supply, not the exercise of significant market power.[72]

The Authority's review found that that the high spot prices properly reflected scarcity of fuel:

> "In the short term, these high wholesale prices reflected the risk of running out of stored water. As storage declined, many hydro operators raised offer prices to discourage hydro-dispatch, to ensure future hydro storage would not run out. However, thermal generators did not have gas available to run at full capacity, and increased offer prices to prevent running out of thermal fuels. This fuel shortage resulted in a dramatic price increase."[73]

The key issue of concern in relation the accuracy (efficiency) of wholesale electricity price signals is:

- **Gas market disclosure** – By comparison with the wholesale electricity market, the gas market is extremely opaque. Though changes in gas supply strongly influence wholesale electricity prices (as shown in Figure 7), the wholesale electricity market is relatively blind to vital indicators of possible change in expected gas supply. (This is discussed further below).

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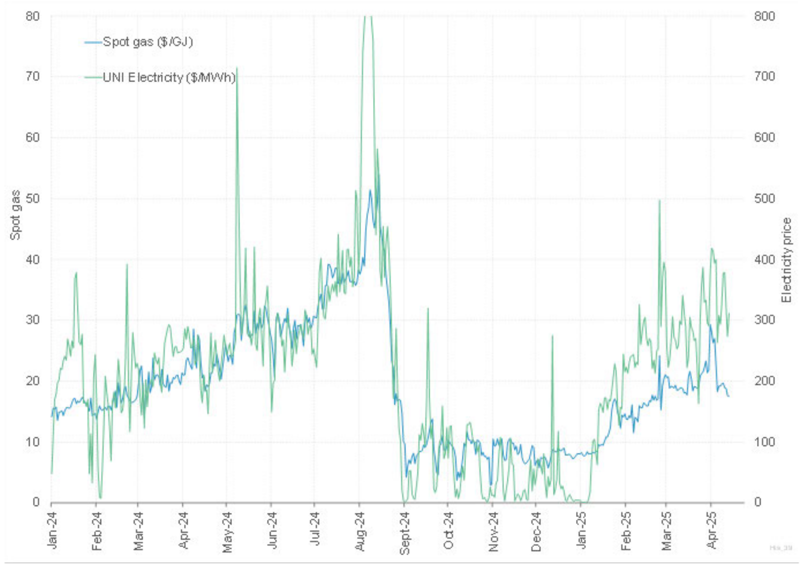
[71] In some cases this has been permanent in terms of the industrial site closing. In particular, (a) closures of some wood processing sites, due to a mixture of electricity and gas price and (b) the permanent idling of two of Methanex's three methanol production trains. The Waitara Valley train had already been idled in 2021, and one of its Motunui trains was idled in March 2024. Methanex subsequently indicated that these are likely to be permanently retired.

[72] Electricity Authority, Review of winter 2024", *8* April 2025 at para 5.3

[73] Electricity Authority, Review of winter 2024", *8* April 2025 at para 1.5. On 18 September 2024, WPI then announced on [20 August] that it was planning to close the sawmill and pulp mills near Ruapehu permanently at the cost of 230 jobs. Oji Fibre Solution (OFS) announced that it was permanently closing its Penrose mill, at the cost of 72 jobs

Figure 7: Daily average gas and electricity prices (real $2024)

[showing a very close correlation between gas and electricity prices]



Source: Concept analysis of Authority and EMS data

Did the risk management market work efficiently? *Could be improved*

Most wholesale electricity buyers were hedged going into winter ’24 and therefore their electricity purchase costs did not change (at least in the short term).

However, unhedged buyers in the wholesale market faced a serious increase in electricity costs buying on spot.

Winstone Pulp International (WPI), Pan Pac and Oji were unhedged and reduced demand during the high price period. WPI and Oji Fibre Solutions subsequently decided to permanently shut down various operations.

However, the Authority found in its recent review of winter ’24 that all three parties “had access to enough hedges ahead of time to be fully hedged for July-September 2024.”[74]

We see six issues in the electricity risk management market requiring action:

- **‘Beef up’ contracts market**: A range of measures to strengthen the contracts market are essential, including more standardised ‘shaped’ hedge contracts[75] with liquidity (and therefore mandatory market making). Our recommended package is explained in more detail in section 6 below.

- **Strengthen accountability risk management:** This is part of ‘beefing up’ the contracts market but, in the context of spot market risk, it needs to be reinforced. The Authority has recently proposed changes to the ‘stress testing’ regime, but more needs to be done. This is explained further in section 6 below.

[74] Electricity Authority, Review of winter 2024, April 2025 at para 1.11

[75] ‘Shaped’ hedges give the buyer protection against high spot prices at specific times – such as when intermittent supply is low and/or demand is especially high

- **Demand-side flexibility (DSF):** As noted above, the market for DSF is significantly under-developed, particularly for a more intermittent system.

- **Security of supply information:** As called for in the GPS,[76] ensure that all information relevant to the supply and demand outlook (including risks)[77] is up to date, comprehensive, collated and presented in an integrated manner readily accessible to all stakeholders.[78]

- **Guidance for System Operator:** As called for in the GPS,[79] ensure that clear and comprehensive guiding principles and impartial procedures are in place for the System Operator to follow in power system emergencies, including any public calls for electricity conservation or reduced consumption.

- **Elevated contract prices:** While it is obviously not sensible to expect a 'good' price for fire insurance when the house is already on fire, hedge buyers fairly question why contracts prices in general have been tracking well above the cost of new baseload generation for so long. We examine this issue more closely below.

Was lack of competition a material factor in the high winter prices? *No*

The Authority found that overall "generation offers were consistent with the trading conduct rule and reflected underlying costs and supply."[80]

The trading conduct rules requires that, situations where one or more seller has significant market power, the seller's offer price must be consistent with the offer it would have made if no seller could exercise significant market power.[81]

Level of political and public confidence in winter '24 spot prices? *Very low*

This fourth pillar of a well-functioning wholesale electricity market performed poorly. Government and regulators were highly sceptical about the high winter spot prices. It was widely assumed to reflect the exercise of market power or 'profiteering' by the gentailers. Indeed, the Authority started to investigate whether the gentailers were making excessive profits.[82]

While it can be difficult to distinguish good high prices from bad high prices,[83] it does not follow that high prices are necessarily a 'bad', or that a system producing very high prices is not working properly.

As noted above, the Authority's review (published in early April 2025) found that winter '24 spot prices were properly signalling the marginal cost (and risks) relating gas supply for thermal generation.

So the key concern in relation to public confidence is 'political' acceptance of very high prices in periods of scarcity –

- As explained above, if supply is tight, we want spot prices to reflect the scarcity – which can mean very high prices - and we want market

76 GPS, para 22(a)
77 Covering short to medium to longer term horizons.
78 Noting that the integration of this information in a readily accessible form needs to be improved. This information underpins an efficient wholesale market, including how the market responds to high price risks and new investment opportunities
79 GPS, para 22(d)

80 Electricity Authority, Review of winter 2024, 7 April 2025 at para 5.1
81 'Trading conduct rule', clause 13.5A
82 Electricity Authority Internal Transfer Price and Retail Gross Margin post implementation review, 7 November, 2024, https://www.ea.govt.nz/documents/5981/RGM_and_ITP_post_implementation_review.pdf
83 "Market power and Electricity Competition", William W Hogan, 25 April 2002 at slides 9 and 10

participants to believe that those prices will 'stick' and so they need to cover their exposure to the risk of very high spot prices.

- Without this political and regulatory 'buy in', the market will perceive that it faces less risk of high prices and so wholesale buyers will take out less 'insurance', which in turn signals to generators that they don't need to so much fuel; back-up generation for scarcity situations is not built; lower cost demand-side response is not arranged; and with lower average spot prices (due to political intolerance of high prices) electricity consumption is marginally higher than otherwise -- all of which leads to higher costs and less security of supply for consumers.

- Which is to say, political' backing for efficient high prices is critical.

Vertical integration impacts on winter '24?

The Task Force alludes to evidence (from the Authority's recent 'Risk Management Review') of competition risks arising from vertical integration, which "gained more prominence recently, particularly following the fuel shortage issues of August 2024."[84]

It is not at all clear how vertical integration was a material adverse factor in the performance of the wholesale electricity market in the context of winter '24.

[84] Task Force Options paper, paras 3.37-3.38

Summary of issues from winter '24

Applying our frame of reference, a summary of the issues to be addressed is set out in the table below.

Figure 8: Issues to address for a well-functioning market

Pillars of well-functioning market		Issues to address
Accurate (efficient) price signals		(1) Opacity in gas market; (2) 'Political' backing for efficient high prices in scarcity
Tools and incentives to manage spot risk		(1) 'Beef up' contracts market, including traded shaped hedges + mandatory market-making. (2) More demand-side flexibility. (3) Accountability for adequate insurance. (4) Security of supply information. (5) Guidance for system operator in 'crisis' situations
Sufficient competition (or pricing as if no significant market power)		Link to "Tools" above -- (2) More traded shaped hedges. Looking forward, address significant competition risk in flexible supply
Public and political confidence (particularly in pricing)		Enable government to accept and back efficient high spot prices in scarcity

High wholesale contract prices

As noted earlier, the sustained 'gap' between wholesale electricity prices and the estimated cost of new baseload generation has been a festering sore in the industry.

We briefly recap what happened and why, and the compare key elements against our frame of reference outlined above.

Yardstick for whether there is a problem

In a well-functioning market, contract prices should track the cost of new baseload generation.[85] This is a normal competition law yardstick.[86]

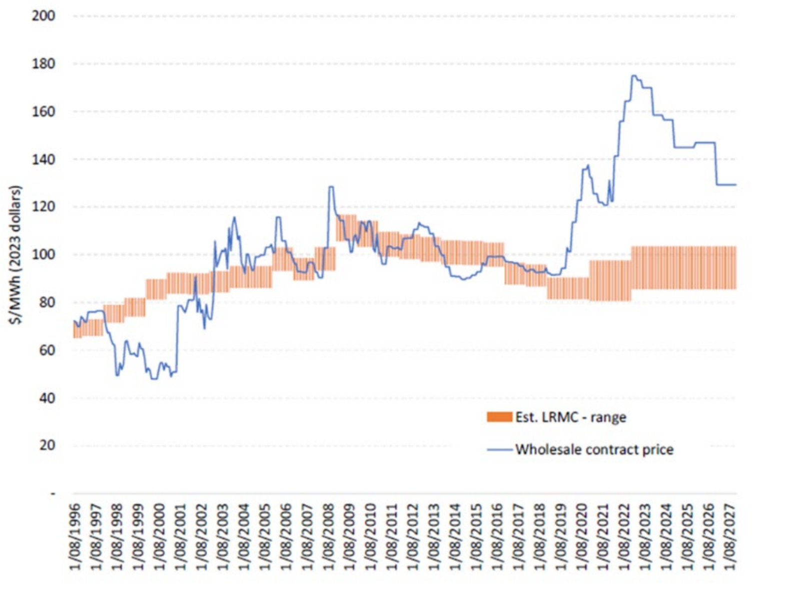
The New Zealand wholesale electricity market performed well on this measure until 2018/19.

As shown in Figure 9, the 'gap' between the cost of new generation and contract prices since 2018/19 has been significant and sustained.

Easy to assume market power

"The key test of market power is whether contract prices have exceeded the cost of new supply. If that were occurring on a sustained basis, there would be substantial concerns about the potential for economic efficiency losses and the transfer of wealth from consumers to suppliers through over-charging".[87] So it is understandable that many stakeholders would assume at face value that this price-cost 'gap' is due to the exercise of significant market power.

Figure 9: Contract prices and estimated costs for new baseload supply (2023)



Source: Concept Consulting (2023)

85 The Authority in New Zealand and the AEMC in Australia consider that the correct measure of whether prices are efficient in the electricity spot market is whether average spot prices over time reflect long run marginal cost (LRMC). For a description of the Authority's view, see EA, Dec 2017 at 9.4. For a description of the AEMC's view, see Yarrow, Decker, Nov 2014 at top of p.22 and "Market behaviour rules in New Zealand and internationally", Sapere (Kieran Murray, Toby Stevenson, Sally Wyatt & Eva Hendriks), 29 November 2012 at p.6. This LRMC approach was used by the 2018/19 Electricity Price Review (see "First Report for Discussion", New Zealand Government, 30 August 2018 at p.32) and the 2009 Ministerial Review of Electricity Market Performance (see Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009, Volume 2, at 239 – cited with approval by "The Economics of Electricity", Dr Brent Layton, 4 June 2013 at para 17). See also "Cost Shifting: the single buyer model with price discrimination", Lewis Evans, New Zealand Institute for the Study of Competition and Regulation No. 3: 18 April 2013 at p.4

86 Yarrow, Decker, Nov 2014 at top of p.22

87 Electricity Technical Advisory Group, "Preliminary Report", August 2009 (to the Minister of Energy), para 244

The 'gap' between the cost of new generation and contract prices since 2018/19 may well have been a consideration behind the Task Force's view that greater competitive pressure is required on the four main gentailers to bring forward new generation more quickly, with independent (non-integrated) parties to fulfil that role.

The Task Force cites the price-cost 'gap' within its list of evidence and concerns showing "there are good reasons" for the 'level playing field' measures.[88]

Some stakeholders go further and argue that the price-cost gap is caused by incumbents with significant market power delaying the delivery of new generation with a view to holding up prices. This claim seems to have gained some currency in official and political circles.

> However, keep in mind that this is a risky strategy that requires cooperation among other suppliers to succeed. In a competitive market for new generation (with a many parties running hard to get their projects up), any incumbent generator that delays its own investment risks ceding the opportunity to a competitor (another incumbent or a new entrant). There is no clear evidence of the incumbent suppliers holding back their projects to keep prices up.

Crux question

The crux questions is, why has it happened?

- What caused the market to move into a disequilibrium state during the latter half of 2018, and why has it persisted?
- Why has new generation not come on-stream when the forward prices seem to signal that it is economic to do so?

> At face value, it looks like an investor in new generation would get the lion's share of the margin between LRMC and the contracts market price. But not so – keep in mind that the contract prices are for a 0.1MW quarterly ASX contracts for difference, which is obviously quite different from long term (7+ year) contract for supply from a new generation project

Why the 'gap'? What the analysis shows in summary

Contract prices jumped in 2018/19 in response to the sudden reduction in gas supply from the Pohokura field.

New generation was not built to bring electricity supply and demand back into equilibrium for a combination of two key reasons:

- The gas industry continued to signal their expectation that further drilling and other reserve management initiatives should retore gas supply, which, if successful, would have lowered wholesale electricity prices and undermined the economics of new generation investment.
- The risk of the Tiwai smelter exiting[89], which would have collapsed the wholesale price of electricity, suddenly making most new generation projects uneconomic. (This risk ran particularly from NZAS's announcement of a strategic review in October 2019 through until May 2024 with the announcement of new contracts for the next 20 years).

[88] Task Force Options paper, para 3.51, which refers to the concerns in paras 3.37 to 3.47, which includes the price-cost 'gap' chart (which is at 3.41 and 3.42). However, the Task Force seems to 'sit on the fence' as to whether the price-cost 'gap' shows barriers impacting on competitors entering or expanding, or whether it is explained by a range of other factors such as gas supply uncertainty, whether the Tiwai Pt aluminium smelter would continue to operate, the previous Government's proposed Lake Onslow pumped hydro scheme, and investment lag – TF, LPF, para 3.42

[89] This risk resolved with the announcement in May 2024 of new contracts for the smelter

Even if the market had believed that gas supply would remain constrained and Tiwai would not exit (and therefore the higher prices would continue), it would still have taken some years for significant new generation projects to come online given the unavoidable lead times involved.

The evidence indicates a massive amount of new generation is now in the pipeline, a significant proportion of which is from independent parties.

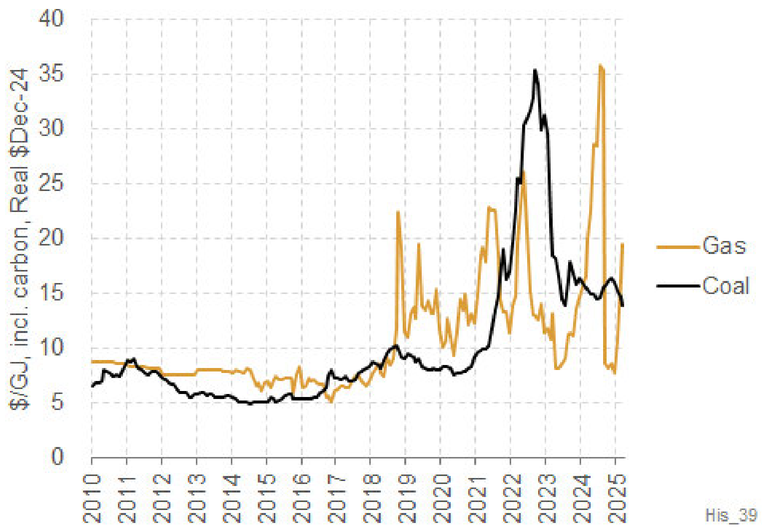
The critical problem to fix in relation to high electricity contract prices is the opacity of the gas market. The key action required is to substantially improve disclosure of information on factors relevant to expected supply and demand of gas.

We elaborate briefly on each of these summary points as follows, drawing directly on the analysis of Concept Consulting presented in Appendix B.

Impact of gas prices and supply uncertainty

The principal reason for the disequilibrium situation is the price of fuel for New Zealand's thermal power stations suddenly jumping up in the latter half of 2018 and staying at elevated levels ever since.

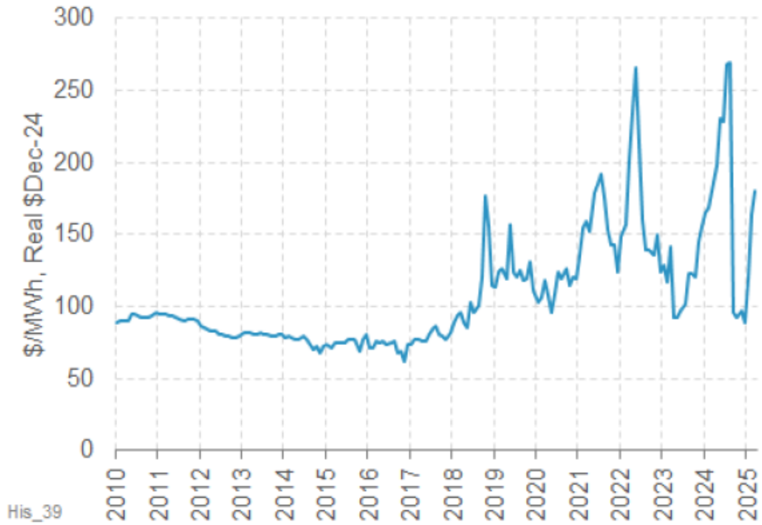
Figure 10: Monthly average gas and coal prices including carbon, Real $2024



Source: Concept analysis of EMS and IEA data

These costs for coal and gas translate directly into higher prices for thermal generation (as illustrated in Figure 11).

Figure 11: Thermal 'SRMC index', Real $2024 [90]

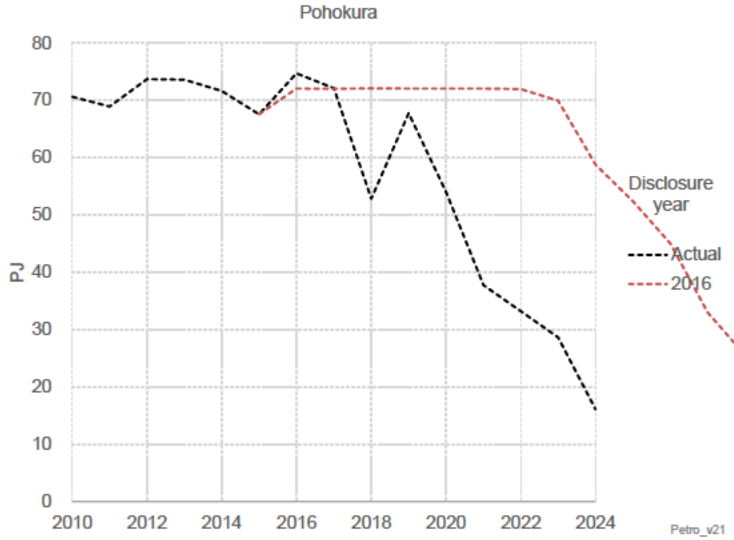


Source: Concept analysis of EMS and IEA data

As is now well known, the spike in gas prices in 2018 was due to the sudden failure in March 2018 of the offshore wells for the Pohokura gas field – at the time, New Zealand's largest gas field, supplying approximately 38% of New Zealand's gas needs.[91]

The scale to which this reduction in gas production was not anticipated is illustrated in Figure 12, which compares the projection of annual production disclosed by the field's operator, OMV, at the beginning of 2016, compared with actual production.

Figure 12: 2016 projection of expected Pohokura output versus actual



Source: Concept analysis of MBIE data

Given the out-of-the-blue nature of the 2018/19 gas price spike, and the long lead time for developing new generation projects, it is not surprising that new generation did not come on-stream in the years immediately following.

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[90] Being a simple weighted-average of the variable operating costs of thermal power stations Constant weightings have been applied, which are intended to be rough reflections of the amount of time the different types of thermal stations are the marginal price-setters on the system: CCGT = 10%, Rankine = 40%, OCGT = 50%. Clearly, the actual relative weightings vary over time, but the intention of this simple 'index' is to illustrate the general nature and scale of thermal cost increases.

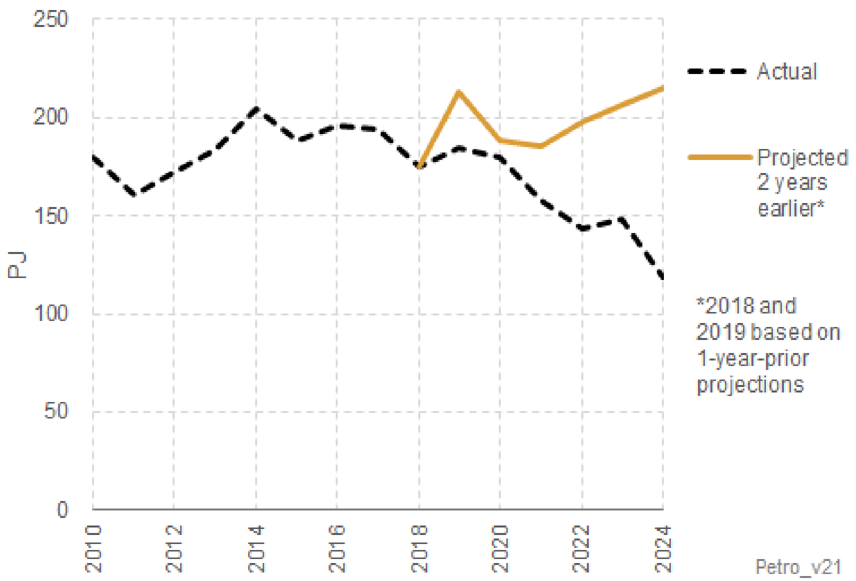
[91] Note also that In February 2018 there was a temporary shutdown of all Maui production, reducing gas supply by about 100 TJ/day (sufficient to run a large thermal unit). Before Maui returned to operation, bubbles were discovered near an offshore pipeline used to bring Pohokura gas to shore. This was followed shortly after by the shutdown of all offshore Pohokura production until August 2018, reducing gas supply by about 100 TJ/day. Pohokura offshore production again ceased from October to December 2018 due to a different technical problem. – Concept Consulting (2019) for MDAG in the context of developing a new 'trading conduct rule'

But why has more significant new generation not been built since then in response to the sustained high contract prices for electricity? In short, because the market expected prices to drop back to equilibrium levels, based on upstream gas producers' continued projections that gas production would return to, and even exceed, the previous high levels of production.

To this end, in the years following Pohokura's sudden drop, its field operator undertook a range of interventions. In addition, development wells were drilled at several other fields (to the cost of $1.5 billion from 2019 to 2023) (not including other wells for exploring or appraising potential new fields).

Despite this activity, actual outcomes were far less than projected, as shown in Figure 13. Production in 2024 was 45% less than was projected at the start of 2022.

Figure 13: Projected versus actual gas production



Source: Concept analysis of MBIE data

Key problem – poor information disclosure in gas market

Projecting reserves and production from a gas field is, by its nature, inherently uncertain – that is a given. It follows that forward electricity price curves reflecting expected gas supply will also be necessarily uncertain.

However, the uncertainty is not amorphous. Considerable information is generated within the gas industry to better define probabilities of future gas supply. However, only limited strands of this information are disclosed.

The non-disclosure seriously constrains the ability of buyers and sellers in the wholesale electricity to form a more informed view on probability-weighted forward gas prices and associated electricity price signals relevant to new generation investment and other risk management options.

Urgent action is required to upgrade the gas market disclosure requirements to bring them into line with the approach to disclosure in the wholesale electricity market.[92]

This action is currently beyond the scope of the Authority's jurisdiction, so it may require a change in legislation (depending on which regulatory process is used to put it in place).

This is discussed further below.

The Authority's recent initiative to get better information on volumes of thermal fuel available to electricity generators may be helpful[93], but still constrained. It does not open information driving supply and demand expectations in the gas market itself. This reflects the limits of both the Authority's jurisdiction and the gas industry' self-governing model.

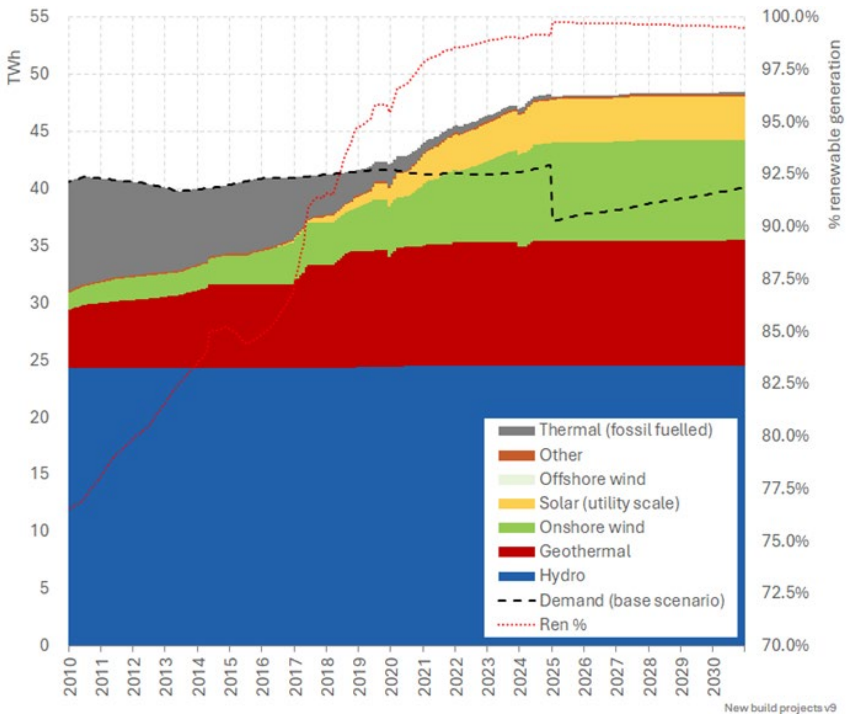
Impact of Tiwai uncertainty on contract prices

A few months after the sudden reduction in gas supply in 2018, the owner of the Tiwai aluminium smelter announced a strategic review of its future, consistently indicating that closure was a very real possibility.

Clearly, the impact of almost 13% of New Zealand's demand suddenly exiting at the end of 2024 would have been dramatic.

For illustrative purposes, Concept Consulting modelled a scenario where new generation came online on-time to maintain supply-demand equilibrium expecting Tiwai to stay, but Tiwai exits at the end of 2024 (refer to Appendix B).

Figure 14: Supply / demand outcomes from build schedule given perfect gas foresight and expecting Tiwai to stay, but Tiwai exits at end of 2024



This illustrates how the market would lurch into a situation of over-supply from 2025 onwards. The associated low prices would materially harm the profitability of projects built in the preceding years in response to the high prices caused by expected reductions in gas supply.

92 As noted by Saperein mid-2018, the Minister Energy raised the issue of information disclosure requirements for market participants where information could have an impact on the downstream gas market. The resulting changes by the Gas Industry Company to information disclosure focused on unplanned outage or planned outage at a gas production facility or a gas storage facility for all gas and related market participants but not on the prospects for future production

93 Electricity Authority, Improving Access to thermal fuel, consultation paper, January 2025

So, it is not at all surprising that new generation investment was deferred pending decisions on Tiwai's future, which did not happen until May 2024 when Tiwai's owner announced an extension of 20 years (with no ability to exit within the first 10 years).

Impact of NZ Battery Project

To briefly recap, this Government project ran from 2020 to 2023. It was set up to "explore renewable energy storage solutions for when our hydro lakes run low for long periods."[94] The Lake Onslow pump-storage scheme was the project's primary option, but in case it turned out to be not viable, the Government was also looking for a portfolio of 'dry year' 'battery' alternatives.

Whatever the real prospects of the Lake Onslow project, the critical adverse impact of this initiative was the signal the Government was sending to the electricity market. In short, they were saying: "we (the Government) will take care of 'dry year' risk".[95] Understandably, any private sector plans for new plant or other options to cover high prices in shortage periods would have been put on hold.

Why accurate prices are so important

To recap, contract prices in the electricity market should signal the expected cost of meeting electricity demand over the medium and longer terms, which in turn signals:

- Whether to use or conserve discretionary resources (like hydro storage or potentially curtailable demand); and
- When to invest in new generation, storage or demand response capability.

But prices are probability-weighted views on expected supply and demand conditions, which depend fundamentally on the quality, timeliness and fullness of the information provided to the market about factors influencing supply and demand.

Based on information provided by gas producers, the wholesale electricity market seems to have given significant weight to the risk of gas supply returning to 'normal,' which would have made new generation uneconomic on a risk-adjusted basis (particularly with the Tiwai exit risk added in).

As it turned out, the gas supply situation got worse, not better, and Tiwai did not exit. Of course, neither hindsight nor perfect insight (in real time) are realistic.

It does not follow that the wholesale electricity market got it wrong – on the contrary, buyers and sellers made rational decisions based on the risk information available (which, in passing, had nothing to do with market power).

The crux issues are, how to improve the accuracy of the electricity contracts market, and why it matters?

On the 'why' – this is particularly pronounced when supply and demand are extremely tight, when the supply cost curve rises very steeply (up through scarce gas and coal generation) until it reaches the scarcity rent[96] required to induce consumers to reduce demand.

[94] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery

95 With Lake Onslow, this would have extended to cover 'firming' intermittent renewables supply

96 MDAG, "Efficient price benchmark", February 2020 at paras 233-235 https://www.ea.govt.nz/documents/1099/09-Fundamentals-of-Efficiency-in-Electricity-Prices-Annex.pdf

In this upper end of the supply cost curve, relatively small but material increments of lower cost generation (or demand-side flexibility) can have a non-linear effect in lowering spot prices, which in turn can cause a cascading flow of potential benefits in the direction of lower costs and better security of supply.

This links back to the quality of price signals in the electricity contracts market to signal the value of building new generation – and, as outlined above, forward electricity prices can be quite sensitive to probability-weighted expectations of future gas supply, which in turn links back to the importance of more accurate information on risks relating to gas supply.

The crux issue is then, can we improve the accuracy of the electricity contracts market in relation to future gas supply? The answer is, most certainly yes.

Compared to the wholesale electricity market, information disclosure in the gas market is constrained and coarse. (More below in section 0 on improvements that could be made).

Lack of competition not a material cause of high contract prices

As noted above, it is understandable that many stakeholders would assume at face value that the 'gap' between electricity contract prices and the cost of new (baseload) generation has been due to the exercise of significant market power by gentailers (acting together or alone).

However, as outlined above, the reason for the 'gap' has been more prosaic, rooted as it is in critical physical supply uncertainties (namely, expected gas production and whether Tiwai would stay or go).

Potential market power in flexible supply

As identified by MDAG, there is a potential market power issue in relation to the provision of longer duration flexible supply.

While this is has not been a material factor to date in the electricity contract prices tracking above the cost of new generation, it has the potential to become a material factor in the foreseeable future.

This is discussed further in the following section.

Summary of issues from 'gap' between contract prices and cost of new generation

Applying our frame of reference (as set out in section 4), a summary of the issues to address is set out in the table below.

Figure 15: Summary of issues to address

Pillars of well-functioning market		Issues to address
Accurate (efficient) contracts price signals		Prices accuracy constrained by opaque gas market
Tools and incentives to manage risk (including new generation)		(1) Opaque gas market. (2) 'Beef up' contracts market, including traded shaped hedges + mandatory market-making. (3) Accountability for adequate 'insurance'
Sufficient competition (or pricing as if no significant market power)		Link to item (2) in "Tools" above. Looking forward, address significant competition risk in flexible supply
Public and political confidence (particularly in pricing)		Rebuild confidence in contracts market among various buyer segments

Risk of market power in flexible supply

Framing the issue

MDAG identified the potential for a thinning of competition in the provision of flexibility contracts covering periods of a week or longer.

The Task Force's interpretation of this issue seems to be a central influence on its thinking behind its 'level playing field' proposal.

Given the importance of this issue, it is therefore helpful to first frame it and recap what MDAG concluded and why.

What is flexible supply?

Four characteristics stand out:

- It needs both stored fuel and the ability to start and ramp up and down relatively quickly.
- The amount of available 'flex' cover also depends on the duration or volume of the storage – the greater the storage, the greater the 'flex' capacity.
- 'Flexible supply' includes demand-side flexibility, where consumers shift their demand in time or alter their total demand.
- Flexibility 'cover' is also achieved by combining different types of generation – for example, baseload with peaking plant.

Sources of flexible supply include:

- For the short term (up to a few days) – batteries (lithium ion and potentially other types), demand-side flexibility, hydro generation (with storage for hours to a few days), and thermal generation.
- For the medium to longer term (a few days to several weeks) – hydro generation (with sufficient storage), thermal generation (with sufficient gas, coal and/or diesel), and some forms of demand-flexibility.

This is a focus of innovation around the world. New sources of flexibility are likely to emerge over time – technologies are developing in flexible demand, pumped hydro storage, gravitational storage devices, and compressed air systems. Biofueled thermal generation is also in the mix.

Why flexible supply is important

Among other things, it 'fills in the gaps' when intermittent generation is not generating. 'Intermittent' generation is where output changes quickly with the weather (sun, wind and water inflows).

At present, only around 6% of total generation is intermittent. This is expected to increase to around 50% in the coming 25 years due to a likely huge increase in wind and solar generation.

As MDAG observed,[97] flexible hedges (backed by flexible generation) are important:

- For investment in new generation – by helping developers to create products that are useful to end-use consumers, and that in turn provides revenue to underpin ongoing investment.

[97] The content below draws directly from MDAG's Recommendations paper, B.4

- For intermittent generators – by enabling them to sell more of their output using standard baseload products without incurring undue spot price risk, which increases the overall hedge capacity of the country's intermittent generation base.

- For investors in new physical sources of flexibility[98] – by creating more stable revenue streams and price signals that can assist them with investment decisions.

- For demand side flexibility (DSF) – by improving price discovery for the value of flexibility (from the market trading standardised flexibility contracts).

- For electricity retailers – by providing additional tools (flexible hedges) to manage spot risk, which in turn improves competition in the electricity retail market.

Competition may thin

MDAG identified:[99]

- A risk of competition thinning in the provision of flexible supply for periods of a week or longer. As fossil-fueled generation reduces (with lower cost renewable generation coming online), control of medium and longer-duration flexible supply may become more concentrated among parties with the flexible hydro generation capacity and the remaining thermal capacity (all other things being equal).

> **Recap – what is a flexibility contract?**
> A flexibility contract describes a hedge contract that provides the buyer with protection against high spot prices at specific times – such as when wind generation is low and/or demand is especially high.

- New physical sources of longer-duration flexibility are likely to emerge over time and would increase competition in the spot market.

- However, the size and timing of deployment for these resources is uncertain, creating the potential for thinning of competition in the meantime.

- If access to flexible resources in the spot market were to become a bottleneck in competition terms, that could have very significant implications for functioning of the wider electricity market.

MDAG's focus on the structure of spot prices

In summary, MDAG observed:[100]

- There is no universal approach to apply when analysing competition in the future.

- However, it is important to consider the structure of spot prices. If some parties have sufficient market power to sustainably alter the structure of spot prices, those parties would likely have scope to influence competitive dynamics in other parts of the wholesale market.

- A particular concern would arise if parties could increase the 'volatility of volatility' – that is, appreciably increase uncertainty about the future

[98] For example, batteries, demand-side response, green thermal or pumped hydro
[99] MDAG Recommendations at D.5
[100] MDAG Recommendations at D.8

structure of spot prices as that might deter some types of new entry and therefore increase *average* prices.

- Market power can be regarded as significant if the economic cost of the harm exceeds economic cost of the remedy.[101]

MDAG's findings

MDAG's analysis found that:[102]

- Larger generators with substantial flexible hydro bases may well have greater means and incentive to exercise market power in the supply of flexibility products as thermal generation declines.
- Larger generators with significant flexible resources would not appear to face much direct cost or disruption from raising the volatility of volatility in the spot market.
- It seems likely that significant volatility of volatility in the spot market would deter (or raise costs for) potential new entrant intermittent generators.
- If increased volatility of volatility in the spot market did hinder (or raise entry costs for) new intermittent generation, that could lead to higher average prices which could be of significant benefit to incumbent suppliers.
- On the other hand, the simulation analysis also found that the competition concerns in the spot market could be appreciably reduced if wholesale buyers could access flexibility contracts on reasonable terms.
- The availability of such contracts would be expected to support competition in three key ways:
  - Wholesale purchasers would be able to better manage their spot price risk exposures.
  - The greater the degree of forward contracting by parties with significant flexible hydro bases, the smaller the incentive they would have to exercise market power in the spot market. Their offer behavior in the spot market would be likely to align with their (already committed) forward contracting.
  - Sales of flexibility contracts with a visible forward price would provide a benchmark against which other sources of flexibility could compete and make investments.

MDAG's conclusions

MDAG concluded that:

- Although their analysis could not be determinative because of uncertainties about the future, it highlights a risk that they think cannot be ignored.
- Ideally, this thinning of competition will self-correct as new sources of flexibility enter the market.

[101] This is the definition proposed by Professor Yarrow and reflected in trading conduct provisions of the Code. Of course, there may be instances where the economic cost of the harm is very sizeable, but nonetheless smaller than the economic cost of the remedy. Further, the exercise of market power is not made acceptable by high costs to remedy or prevent it.

[102] MDAG Recommendations at D.17 and D.18

- However, the risk of declining competition for longer-duration flexibility contracts must be proactively managed – rather than adopting a 'wait and see' approach.[103]
- The Authority should proactively pursue a graduated set of measures to safeguard competition for flexible supply, which are outlined in section 0 below.

MDAG's market power problem does not depend on vertical integration

MDAG's diagnosis of a material market power risk in relation to future flexible supply did not depend in any way on vertical integration.

As MDAG pointed out, the source of the potential power – namely, concentrated ownership of hydro storage – would remain even if the owners of the hydro storage had no retail business or were somehow at arms-length from their retail business.

Task Force's reasoning on market power

> "The competition risk is clear — Gentailers have the opportunity and incentive to restrict generation and retail competition because of their control of the flexible generation base, and therefore of the firming/hedging input their competitors need (at least in the short to medium term)".[104]

The Task Force has focused on two matters: vertical integration and market power.[105] In a nutshell, the Task Force's reasoning seems to be as follows:[106]

- Shaped hedge contracts are crucial for non-integrated retailers and generators, and commercial-industrial consumers.
- Shaped hedge contacts rely on backing mainly from flexible hydro and thermal generation.
- 90% of all hydro and thermal generation is owned by four gentailers (taken as a block).
- With their vertical integration, gentailers have the means and incentives to use their flexible generation to support their own retail and intermittent generation, and to discriminate against independent retailers and generators.
- This would restrict competition from non-integrated retailers and generators, which would weaken downward pressures on costs and prices overall, to the long term detriment of consumers.
- As evidence of gentailers exercising this market power, the Task Force points to:[107]
  - independent retailers only receiving one offer in response to requests for shaped hedges over a third of the time and it is not clear why gentailers do not respond to requests for proposals;
  - OTC super-peak hedge contract prices trade at substantial premium over ASX baseload prices adjusted for shape and it is not clear whether this is justified; and

[103] MDAG Recommendations at 1.44
[104] Task Force Options paper, para 3.51(a)
[105] Task Force Options paper, 3.22. We discuss vertical integration in more detail in section 6
[106] Task Force Options paper, 3.27-3.33; and page 3
[107] Task Force Options paper, pp 28-30.

- an ongoing gap has developed between the forward curve derived from ASX hedge prices and the cost of new generation build.

Over time, control over flexible generation may become even more concentrated among a few parties.[108]

Drawing the threads together – what are the root problems?

Importance of problem-definition

As emphasised earlier, a remedy only works if fits the ailment. Getting the diagnosis right is key.

As Professor Bill Hogan observed, the most difficult problem [in electricity] is distinguishing 'good' high prices from 'bad' high prices. In the presence of shortages, high prices can be efficient, a symptom of market failure, or the result of bad market design.[109]

In the heat of the moment (and for some time following), it was widely assumed that the extreme lift in spot prices in mid-August last year must have been due to misuse of market power.[110]

Our view of underlying issue – market adapting to reduced gas

However, the extremely high spot prices in winter '24 were not 'bad' and did not indicate market failure. Rather, they were properly signalling underlying physical constraints and uncertainties in electricity supply.

Similarly, sustained high contract prices (since 2018/19 tracking above the cost of new generation) have been reflecting the market's best risk-weighted assessment of future gas supply.

A root issue, common to both sets of high prices (spot and contracts), is constrained and uncertain gas supply (at a physical level).

In the spot market, this coincided with extremely low hydro storage last winter. In the contracts market, it coincided (until 2024) with the risk of Tiwai closing, making the economics of many new generation options highly uncertain.

Yet, while wholesale electricity prices can be highly sensitive to changes in expected gas supply, the wholesale electricity market is relatively blind to changes in factors relevant to the gas supply outlook.

As outlined in section 5, the transition to less gas for electricity generation is happening more quickly than expected. Correspondingly, the wholesale electricity market needs to adapt more quickly with least cost solutions for reliably meeting electricity demand with less gas than expected.

This drives to the fundamentals of a well-functioning wholesale market, as explained in section 4, namely – many different parties, managing their own

[108] Task Force Options paper, page 3. See also: "The ability to expand flexibility resources is constrained, especially resources that can firm longer duration sequences. Other flexibility resources that can address shorter-duration sequences, such as mass-market demand response and vehicle-to-grid, are still developing." Task Force Options paper, paras 3.29, 3.32(b) and (c)

[109] "Market power and Electricity Competition", William W Hogan, 25 April 2002 at slides 9 and 10

[110] Indeed, the Authority quite quickly started to investigate whether the gentailers were making excessive profits

risks, responding to competitive pressures and accurate price signals, continually looking for ways to serve their current and potential customers more effectively than their competitors.

The remedial action required now is harness this dynamic by better enabling the market to better deliver least cost solutions to reliably meet electricity demand as gas use declines and renewable resources increase.

To this end, the focus needs to be on strengthening the pillars of the wholesale electricity market with:

- More accurate price signals;
- Stronger risk management tools and incentives; and
- Restoring public and political confidence (particularly in high prices in periods of scarcity).

We also need to anticipate the competition issue in relation to flexible supply (as outlined above).

Task Force's view of underlying issue – lack of competition due to vertical integration

Recapping on the Task Force's problem-definition – their logic seems to be as follows:

- High spot and contract prices are due to lack of electricity supply.
- The answer (put simply) is to get more generation into the system sooner. (The Task Force also seems to imply that more competition would have delivered more new generation, which would have helped in managing the winter '24 'dry year').
- For this to happen, the wholesale market needs stronger competition. The Task Force seems to imply that competition on and among the four main gentailers is relatively weak.
- Stronger competition can (should) come from the independent (non-integrated) players – they have a vital role to play.
- However, independent players' ability to compete effectively is constrained by an 'unfair' advantage that vertical integration gives the four main gentailers. In particular, gentailers can sell electricity (implied hedges) to their retail arms on more favourable terms than they offer to competing independent parties.
- This 'self preference' advantage for the gentailers is particularly problematic in relation to shaped hedges, which are typically backed by flexible generation.
- To enable more effective competition from independent players, regulatory measures are required to 'level the playing field' between independents and the four main vertically integrated players.

6. Vertical integration and ‘level playing field’

Economic concept of the Task Force's interventions

As outlined earlier, much of the Task Force's concerns hinge off a view that there is a lack of competition due to vertical integration and that levelling of the playing field is required to address this. Houston Kemp explores the economic propositions underpinning these views in Appendix A.

The Task Force seeks a type of non-discrimination obligation that gives retailers and generators access to risk management products on substantially the same terms as gentailers supply themselves internally.

This is better described as "equal input regulation" than a level playing field.

To draw a rugby analogy, the Task Force's proposal goes beyond a level playing field by requiring that each team would be given the same players, strategies, training etc.

Equal input regulation may not be consistent with the Authority's statutory objective to promote competition and economic efficiency because:

- effective competition neither requires nor necessarily leads to firms having access to the same inputs at the same prices;
- attempts to give all firms the same access to the same inputs are likely to reduce competition; and
- efficiency would be reduced if a vertically integrated firm offered inputs at below the marginal cost of provision to third party firms.

Effectiveness and workability of the Task Force' interventions

The Task Force's intervention would require the establishment by each gentailer of a portfolio of internal transactions against which to assess offers from other retailers and generators.

The establishment of such transactions will not be 'economically meaningful' and will not establish a reliable benchmark for external transaction because:

- internal transactions represent transfers of value between different segments of a gentailers and so gentailers are indifferent as to their level; and
- a gentailer would equally be happy to charge itself more than other retailers or generators.

The Task Force's step 1 intervention proposes reliance on observations of market rates to set internal transfer prices (ITPs). This cannot address concerns about market power that affect the pricing of risk management products.

The Task Force's step 3 intervention proposes that all risk management products be transacted through a common platform. This is a very high-cost intervention that may have little effect where a gentailer can identify and make offers on its own risk management products, since it is prepared to pay more for these than other buyers.

The Task Force suggests that only vertical efficiencies that are 'cost-based' or 'objectively justified' should be considered in distinguishing external offers from internal 'pricing'.

The potential reliance on cost concepts for ITPs has significant difficulties given the difficulties in costing risk management products due to New

Zealand’s high degree of reliance on hydroelectric power. If such costs could be estimated then they:

- would be likely to change dynamically in response to market circumstances;
- cannot be expected to reflect any prices that are locked in by reference to a portfolio established at a prior point in time; and
- would likely not discern vertical efficiencies in the way that the Task Force assumes would be feasible.

The economic circumstances sitting around this task mean that it is very far removed from those applying in other sectors, such as telecommunications, where the use of cost-based principles applied to estimate access prices is routine.

- In these cases, the Commerce Commission has applied cost-based methodologies to estimate access prices that are firmly grounded in the relatively stable and readily identifiable costs of building and operating physical assets.

There are also further important differences in the economic justification for intervention applying in the telecommunications industry, because in those cases where cost-based principles are used, (explored further in Houston Kemp’s work presented in Appendix A), the obligation to provide access on a regulated basis arises because of monopoly control over a service, (so that there is no competition to discipline the terms of access).

However, in this circumstance (i.e. the provision of risk management services) there is competition involving four providers for services, such that the setting of regulated access prices may substitute for and likely displace competitive rivalry that could otherwise occur.

Economic analysis and alternative options

Economic analysis demonstrating that a preferred option would give rise to net benefits that are positive and exceed those of other options is expected to underpin regulatory or policy interventions.

The Task Force states its belief that the benefits of its proposal would exceed the costs, yet the principal basis for this finding appears to originate in an implicit assessment that the harms arising from lost vertical efficiencies for the large gentailers would be more than offset by greater competition for the retail supply in electricity.

The economic analysis supporting the Task Force’s proposal is insufficient to support its conclusions. The Task Force appears to have given little consideration to weighing the benefits and costs of its proposed intervention, and particularly its potential efficiency consequences.

An economic analysis of the Task Force’s proposal is further complicated by the fact that it comprises three distinct interventions, yet the likelihood and timing of the application of each intervention is uncertain. This highlights the importance of clearly defined triggers in forming an assessment of the costs and benefits of the proposal in the round.

The introduction of an alternative and preferable option for addressing the Task Force’s concerns, involving the expansion of market-making obligations, which relative to the proposed non-discrimination obligations, would be both:

- better targeted, in the sense that it addresses the source of concern, being the availability of risk management products to non-integrated retailers; and
- more ‘scalable’, in the sense that it can be adjusted in its degree of intrusion so as to be proportionate to the degree of concern.

Regular reviews could be used to assess the success of these obligations in achieving desirable market outcomes, with the option available to further deepen these obligations, either by making a greater proportion of flexible generation subject to these requirements, or to broaden the scope of the obligations.

An expansion of market-making obligations is a reflected in our recommendations in section 8.

7. Other related pressures and concerns

Gas transition – special arrangements required?

Our future electricity system relies much less on gas

In our existing electricity system, thermal generation (fuelled by gas, coal and diesel) plays a pivotal role in providing power for:

- Base-load – generation is running all the time with a constant flow of fuel;
- 'Firming' – generation is filling in the 'gaps' when wind, solar and hydro are low; and running to enable hydro storage to be lifted; and
- 'Peaking' – generation kicks-in quickly for relatively short periods when prices are very high.

In projections looking at the electricity system in 2035 and 2050:[111]

- Dependence on thermal generation is significantly reduced by the addition of a large amount of new renewable generation. This change is driven by economics: lower cost renewables – wind and solar in particular – displace a significant amount of more expensive thermal generation (coal, gas and diesel).
- Hydro storage is used differently. It acts as the system's main provider of medium term 'firming'. Hydro storage levels are recharged by renewables (not so much by thermals). Both hydro and renewables run with a higher level of 'spill' (up from 2% to 8-10% of total generation). While it may seem counter-intuitive, this is not a 'bad' – rather, it is lower cost overall than building new generation that avoids this spill.
- The future system has quick start peaking capacity to cover very tight (high price) situations. Economic demand-side flexibility also plays an important role (up from around 8% to 25% of peak demand). Batteries also play a significant role for short duration firming and peaking.

Read here for more detail on this low cost future system scenario.

Transition to reduce reliance on gas has been delayed

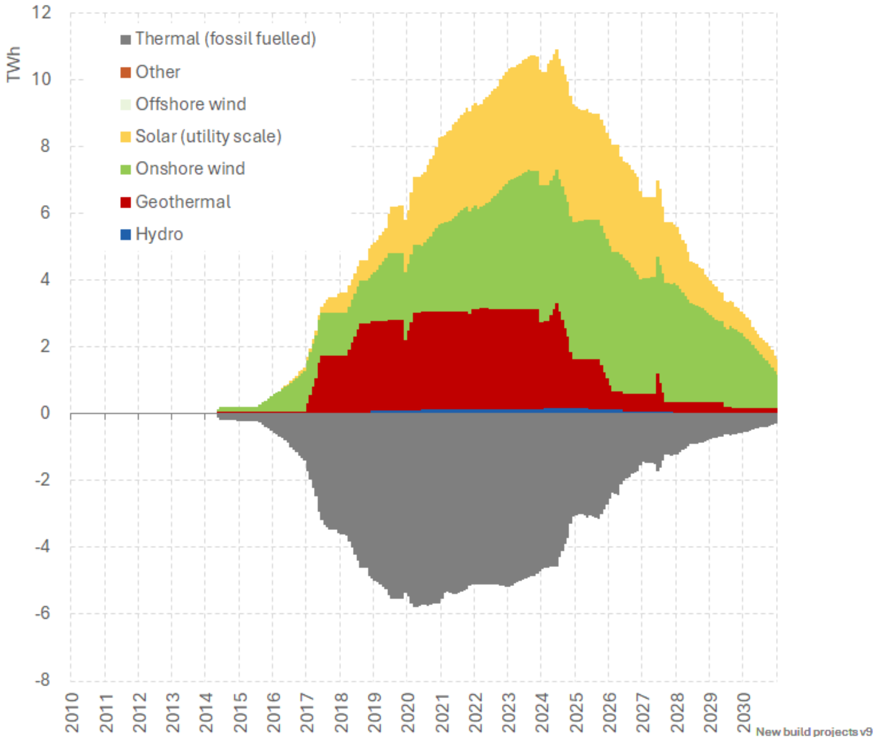
As explained earlier, investment in new generation has been suppressed since 2019 by:

- the Tiwai risk (until 2024); and
- market expectations that gas supply would return to 'normal' (or better).

To illustrate the relative impact of this suppression, Concept Consulting (Appendix B) has estimated the profile of new renewables required to keep the system in equilibrium.

[111] **Important caveat:** This forward view reflects the results of simulation modelling undertaken by John Culy for MDAG. Keep in mind that simulations are not forecasts

Figure 16: Difference in generation outcomes between perfect foresight and base scenarios[112]



Source: Concept Consulting

While this is a hypothetical that assumes perfect market foresight, it conveys the reality we are "starting behind the eight ball" (or "we're in catch up mode") in the transition in reducing reliance on gas and coal generation.

But the investment pipeline is now bulging

Helpfully, the pipeline of new investment is now bulging. As of 1 Jan 2025:

- 2,900 GWh is committed.
- A further 8,000 GWh has received consents, 4,650 GWh of which is classed as being 'actively pursued' (with the status of the other 3,350 GWh being 'unclear').
- 11,700 GWh is in the process of applying for consents.
- A further 49,300 GWh worth of projects have been announced but have yet to reach the stage of applying for consents.

Figure 17 and Figure 18 below show the 'pipeline' of projects in this database, differentiating by project development status and technology or developer.

[112] In case you are wondering, the reason that the total increased renewable generation isn't an exact mirror of the offset thermal generation, is because some amount of the increased renewable generation would be spilled.

Figure 17: Project pipeline by development status and technology

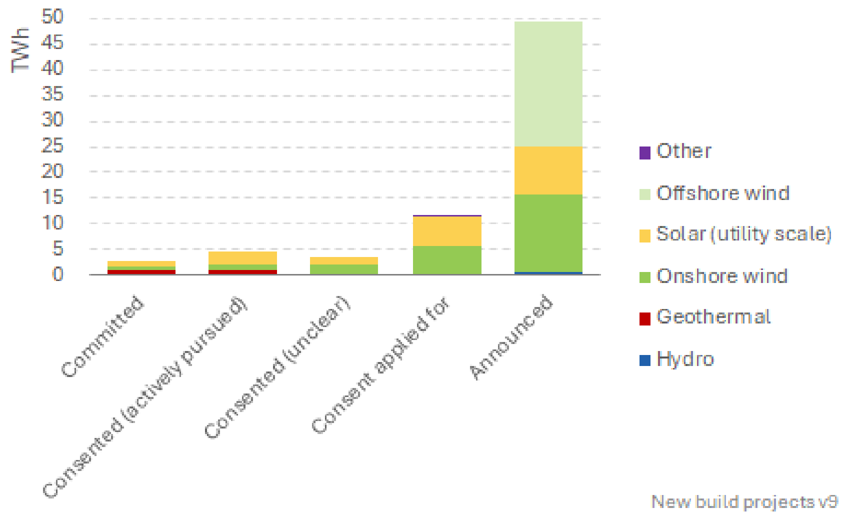
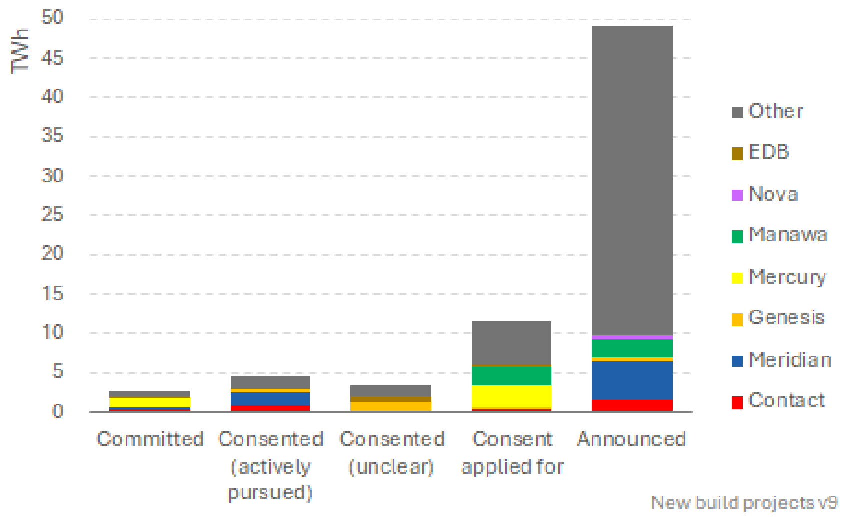


Figure 18: Project pipeline by development status and developer

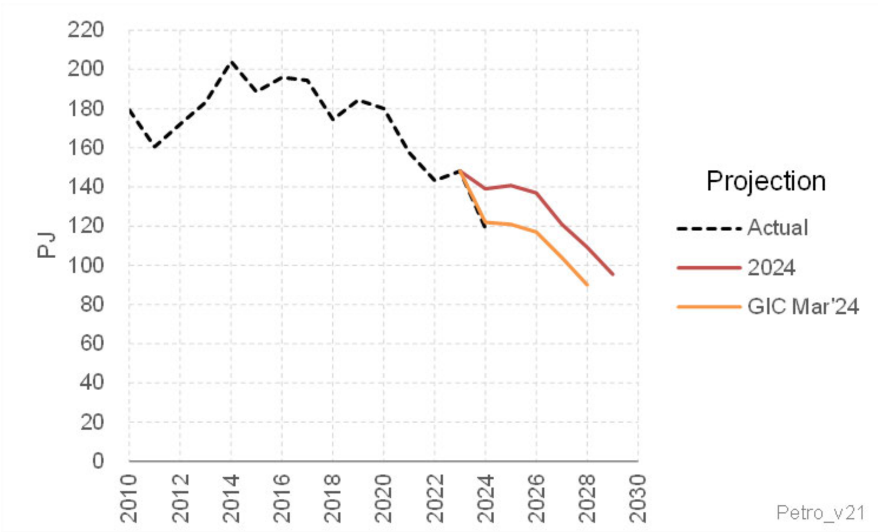


Is there enough gas to cover the transition?

Put broadly, there is concern about whether enough new renewables will come online to substitute for thermals before gas supply available to electricity generation runs out or becomes too expensive.

Coal alone is not sufficient to cover the transition. Gas is key, but its supply is in decline.

Figure 19: Projected 2P gas production compared with actual



Source: Concept analysis of MBIE and GIC data

Note that total gas production for the first quarter of this year appears to have stabilised at around 300 TJ/day,[113] but this is less than half the output from the gas sector that was being achieved in 2017.

Increasing scarcity of gas supply means on-going high spot and contract prices for electricity when gas is needed for generation, but supply is short.

Further, as gas supply declines, questions may also be raised about how the gas system's infrastructure costs (pipelines and the like) are covered on lower revenue, and how thermal generators' share of those costs (and its own plant maintenance costs) should be recovered among electricity market participants.

Reflex assumption – too hard for the market to solve

A common political and policy reflex to this sort of situation is for government to step-in on the assumption that "it's all too hard and too important for the market to deal with on an apparently *ad hoc* basis. It needs coordination – a plan that cuts through the uncertainty and ensures security of supply".

Governments typically look to some sort of capacity mechanism.[114] These are intended to provide assurance that sufficient capacity will be put in place to serve demand.

The 'family' of capacity mechanisms includes many variations: a capacity market for firm capacity (or firm energy), strategic reserves, targeted capacity payments and market-wide capacity payments, call option, and reliability certificate (retail reliability obligation).

Among this menu, the 'strategic reserve' mechanism can seem appealing.

'Strategic reserve' sounds good

Strategic reserve ('SR') schemes are a targeted capacity mechanism. They apply to a subset of resources on the system, rather than all resource providers.

SRs are typically used to address low probability high impact events.

A SR is viewed as the 'spare wheel' to cover very rarely occurring events that participants would not otherwise insure against:

- In essence, SR schemes make capacity payments to underpin retention or construction of *specific* resources; and
- Seek to preserve 'normal' incentives for all other resources as far as possible. To this end, resources in an SR scheme are supposed to be tightly quarantined from the rest of the system – otherwise their presence simply defers investment in another resource and overall reliability is unchanged.[115]

[113] This is largely due to recent drilling at the Turangi and Pohokura fields bringing on new gas

[114] The following description of capacity mechanisms is taken from MDAG Options, Library of Options, discussion of recommendations B9 and B10

[115] Quarantine arrangements typically include: (a) rules that require very high minimum offer prices for strategic reserve resources, or for clearing prices to be set to shortage values (VoLL) when resources are used; (b) rules that provide for strategic reserve resources to be used only as last resort to keep lights on, and once all 'market' resources have been exhausted; and (c) a levy mechanism to recover costs not recouped via spot revenues. If used, wholesale spot prices are set at very high level to ensure investment incentives are not undermined. For example, in Germany if strategic reserve is used will see price of 20,000 Euros/MWh [around 32,000 NZ$/MWh] -as advised in July 2022 by officials at the European Union Agency for the Cooperation of Energy Regulators in discussions with MDAG. This reflects that strategic reserves are designed to address events with very high impact and low probability.

New Zealand tried a 'strategic reserve' in 2003 – it failed

This was the case with New Zealand's strategic reserve scheme introduced in 2003 -- the Whirinaki diesel fired station.

Despite a strong intent at the outset, it proved impossible to maintain a proper quarantine for the scheme during an extended drought in 2008.[116] Subsequent to that event the scheme was reviewed and terminated.[117]

Parallels with 2003 'dry year' – don't repeat mistakes

Winter last year bears strong parallels to winter 2003 which had:

- very low hydro inflows and low lake levels;
- a sudden very substantial write-down of gas reserves in known fields; and
- high prices for gas (high prices for methanol).

The political reaction was also similar with high alarm and calls for a return to centralised management of new generation investment and security of supply. Seeking to lower price volatility and improve security of supply, the government in 2003/04:

- Set up a 'strategic reserve' (Whirinaki), and
- Change regulatory governance. The Electricity Commission was formed with a new Government Policy Statement (GPS).

Following another Ministerial Review in 2009, the 'strategic reserve' scheme was unwound, and regulatory governance arrangements were changed again with a new GPS.

It is important not to recycle the policy mistakes from 2003.

Different with 'Thermal Co'?

Variations on the idea of a 'Thermal Co' – floated a few years ago by Contact Energy – are akin to a 'strategic reserve'. All thermal generation and related assets might be pooled into a single entity to act as a centralised provider of thermal electricity supply and related hedges.

No doubt, Commerce Act clearance or enabling legislation would be required. And no doubt, some may view it as sufficiently different to be not comparable to the Whirinaki scheme.

However, whether fully Crown-owned, privately owned or a mix of both, the similar economic efficiency risks and costs would likely arise. These tend to be inherent in centralising a significant part of the market's risk management services.

Over time, it would likely increase costs overall and potentially not improve reliability. Among other things:

- The boundaries of its risk management coverage would likely become elastic over time, particularly under inevitable political pressure, which would seriously weaken incentives on market participants to cover their

116 See www.ea.govt.nz/assets/dms-assets/409Winter-Review-Report.pdf.

117 In 2009 the government accepted a recommendation from the Ministerial Review of the Electricity Market that the reserve energy scheme be abolished and the Whirinaki plant sold. See Whirinaki plant to be sold | Beehive.govt.nz.

risks properly, which in turn would decrease security of supply as a whole;

- Overtime, some sort of targeted capacity payment for its services would likely be introduced, which (given the incentive problem) would likely lead to higher costs over time.

- It would strongly suppress incentives on market participants to innovate and seek lower cost options to cover their high price risks, fundamentally undercutting the core dynamic of a well-functioning market.

- It would also likely:

  - increase 'insurance' costs for market participants relative to the counterfactual of encouraging parties to find their least cost 'insurance' options and

  - defer investment in some alternative non-thermal resources,

  - with the effect of prolonging reliance on gas and therefore keeping thermal generation in the system for longer and at a higher level than would otherwise have been the case,

  - which is obviously at odds with the goal of making the transition as efficient as possible.

- Its institutional design and function would also likely –

  - become political over time;

  - have poor incentives and accountability on decision-makers to deliver efficient outcomes;[118] and –

  - put the focus of risk management on the 'strategic reserve' scheme's role and rules, leading to a competition of who can best 'game' the decision-makers.

A 'strategic reserve' scheme can have some political appeal in that it reduces headline spot price that would otherwise appear.

- This is because part of the value that would otherwise be in the spot price is paid separately as a fixed amount, like an insurance premium, which is much less visible from a public point of view.

- However, the overall cost is no less – on the contrary, for the reasons noted above, the overall cost is likely to be higher.

Decentralised approach a lot better

As outlined in section 4, history clearly shows that no single entity or small group of decision-makers has the field of vision or know-how or bandwidth to see or deploy the full range of potential 'supply' solutions. It is much better to have a diversity of parties, responding to accurate price signals, competing to find the best solution to a particular situation.

The gas supply outlook poses a challenge for the gas and electricity markets. However, it does not follow that centralising fossil-fuelled generation into a single entity would deliver more efficient (least cost) solutions than a diversity of parties responding to accurate price signals.

118 A recent example of problems with a centralised approach to buying gas is the Government Procurement Agency's recent failure to renegotiate its 'all of government gas supply contract.

A 'Thermal Co' type entity would likely distort and undermine the dynamics of a well-functioning market.[119]

As the European Commission noted in November 2016, parties should first seek to "address their resource adequacy concerns through market reforms…no capacity mechanism should be a substitute for market reforms."

The best solution is to strengthen the wholesale electricity market with the package of measures recommended in this report – in particular, much better disclosure of information impacting on expected gas supply and gas contract prices.

Lack of competition in retail market?

The Task Force alludes to the possibility of a 'margin squeeze' in the electricity retail market. It also suggests that innovation has stalled in the retail market. It also seems to imply that competition in new generation may be crowded out by the four large gentailers.

Sapere has analysed the relevant public data to see what light it may shine on these concerns. This analysis is set out in Appendix D below. In summary, the public information does not indicate problems of the kind referred to or implied by the Task Force.

Retail market share

As evidence of a competition problem, the Task Force points to retail market shares – independent retailers' share in total increased to around 16% (by ICP share) from around 2% in the 12-year period from 2008 to 2020 but has not changed significantly since then (reducing slightly to 15%).

They suggest that competitive impact of new entry in the retail market appears to have stalled, highlighting a competition risk "particularly given that a group of small to medium retailers are pointing to a specific issue (as they see it) as a barrier to expansion."[120]

Vibrant competition in the retail market ensures choice for consumers and puts pressure on retailers to minimise costs and share these savings with consumers.

To explore the concerns around retail competition further, Sapere in Appendix C has reviewed publicly available information to determine whether retail prices and margins reflect underlying cost structures. A competition issue would arise if the gentailers were pricing below cost.

Sapere's analysis identifies that the retail market is functioning as expected given the broader issues currently impacting on the wholesale and contracts markets (explored elsewhere).

Contract market challenges[121] flow through to gentailers and independents differently as they have different cost structures, i.e. gentailers generally enter into longer term supply arrangements and have long-term cover through the nature of vertical integration (fixed costs), whereas independents are generally more exposed to short-medium term contractual cover (more variable costs) and medium sized retailers would generally fall somewhere in between. Its notable that, if there were insignificant distortions between wholesale and contract prices, participants would be indifferent between the

[119] Similarly, 'warming contracts' are also not recommended – See MDAG Final at 8.13-8.14, and MDAG Options, A10, page 14

[120] Task Force Options paper, para 3.15

[121] Such as a distortion between wholesale and contract market prices and/or preferences not to contract.

wholesale and contract markets and costs for each retailer would be equivalent.

Market shares are driven by underlying cost functions and reflect the competitive equilibrium. Current wholesale and contract market challenges are resulting in relatively higher variable costs for independents which flows through to impact their retail market share.

Finally, we note that the measures applied in Figure 3 of the Options Paper are not useful for assessing competition. Over the period measured demand did not grow and yet generation shares between the gentailers and others varied by 1.2TWh, or 130MW baseload equivalent (around $600m using geothermal as the baseline). The conclusion in the Options Paper seems to assume that there is no competition between the big four gentailers, which is not true.

'Retail squeeze' claim

The Risk Management Review did not specifically focus on retail pricing and did not investigate if a margin squeeze is occurring.

The Task Force however recognises that these concerns have been raised and appears to consider this in determining the existing approach to ITPs is not fit for purpose.[122] The ability to identify conduct issues such as a margin squeeze is also considered in exploring the options (such as accounting separation).[123]

A retail margin squeeze can arise under two scenarios:

- increasing competition; and
- due to a predatory pricing strategy.
- The first is desirable as the search for a competitive equilibrium should discover minimum long run costs (*ceteris paribus*). The latter is a competition concern, though we note for predatory pricing to be valuable it would have to sustainably reduce competition so that prices could rise in the long-term.

Given the significance of claims a retail squeeze is occurring, Sapere has reviewed retail offers from independents and gentailers within five network areas using publicly available information. They identify no evidence of gentailers pricing below cost.

The allegations of a non-competitive retail squeeze (i.e. predatory pricing) do not fit the facts (i.e. the total market share of small to medium retailers remains significant) and predatory pricing behaviour wouldn't be rational (i.e. there are low barriers to entry which would make this strategy unlikely to be profitable as competition will always come back). The differences in margins are largely explainable by wholesale and contract market issues causing differences in relative cost structures (outlined above).

Retail innovation claim

As another piece of evidence of a competition problem, the Task Force points to limited retail innovation, arguing that innovation in the New Zealand retail market is less developed than other markets[124], and that the competitive impact expected from independent retailers' "appears to have stalled", which "highlights a competition risk."[125]

[122] Task Force Options paper, para 3.46
[123] Task Force Options paper, para 4.8
[124] Task Force Options paper, para 3.15. See also RMR Issues, Chapter 2, paras 4.12 and 4.14
[125] Task Force Options paper, para 3.15.

Sapere's work identifies that the Task Force's narrow interpretation of innovation potentially ignores much less obvious innovation that is occurring such as retail price efficiencies.

Most innovation is not a "big bang" in nature. For example, the recent announcement by Lodestone that it intends to enter the retail market as a gentailer with a highly innovative integrated approach to sales.

Sapere also identifies that most innovation often occurs when there are periods of greater market stress. Higher prices are a strong driver of innovation, and it is expected that there will be considerable innovation off the back of the current wholesale/contracts market scenario. For example, innovative tariff offers to seek to achieve different household usage outcomes and targeted acquisition strategies.

The Task Forces level playing field proposal risks reducing incentives for innovation, noting that innovation shouldn't be a goal in its own right but the outcome of dynamic efficiency.

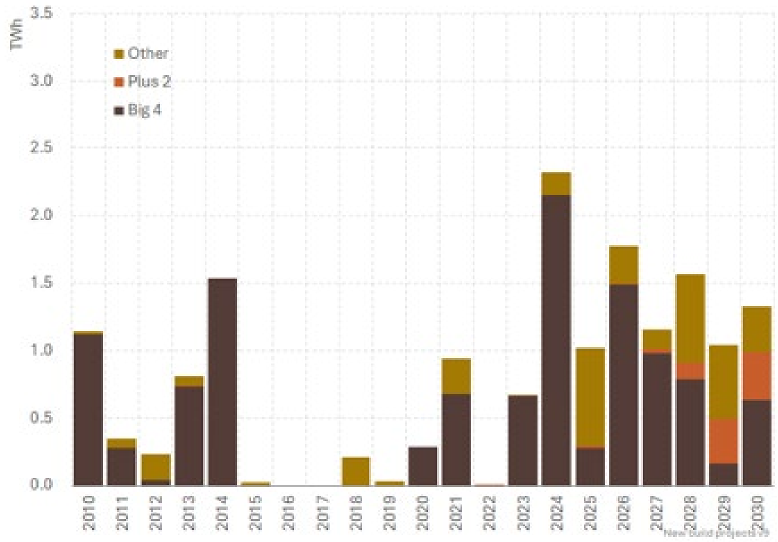
Lack of competition in new generation market?

The continuation of high generation market shares (~85% gentailer share since 2010) and recent attempts at consolidation are pointed to as evidence of a competition problem in the Task Force's work.

Sapere and Concept Consulting work looks at investment in generation and unpick those external factors that have impacted on build decisions, including Tiwai exit, gas market issues, energy policy uncertainty etc. This is explored in further detail elsewhere in this paper.

Concept Consulting identifies a currently bulging pipeline of new generation that is being built by a variety of developers – including many new entrants.

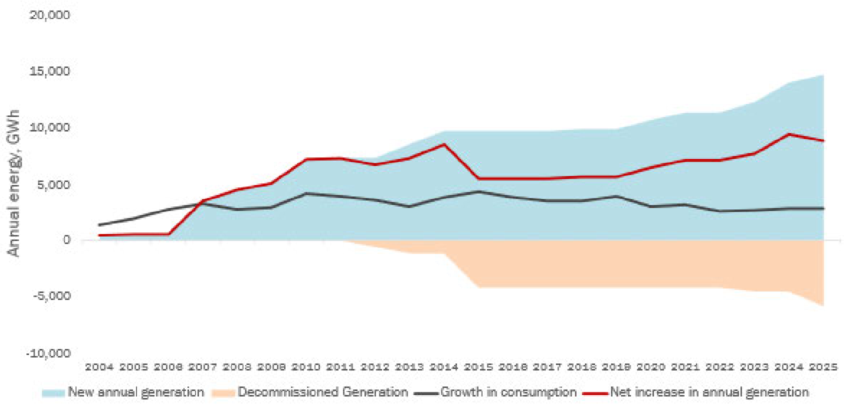
Figure 20: Base scenario of new renewable generation developments by developer type (up to 2024 +actual)



Source: Concept Consulting

Work by Sapere also identifies that since 2003, NZ has seen a net increase in annual expected generation of about 8.8TWh, compared to a cumulative demand growth of about 2.8 TWh (refer to Figure 21).

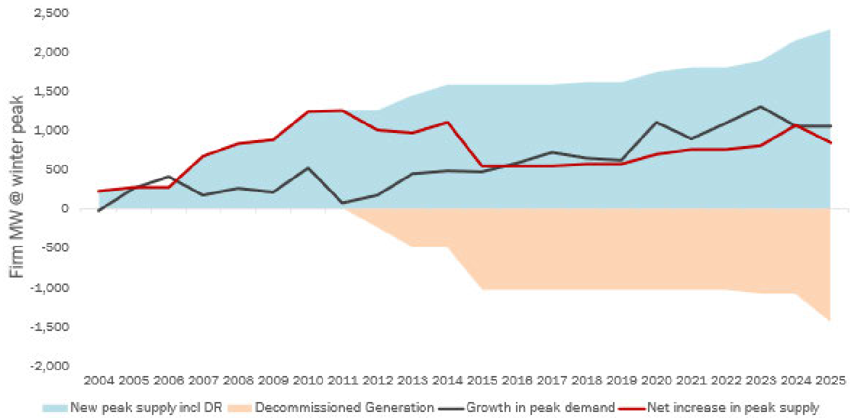
Figure 21: Supply- demand balance – annual consumption (2003 – 2024)



SOURCE: Whiteboard Energy

However, Sapere identify that the rate of build isn't necessarily the issue, it's the mix of generation being built that is the challenge. This is evidenced by increases in peak demand outstripping the generation fleet's ability to respond as thermal has been displaced.

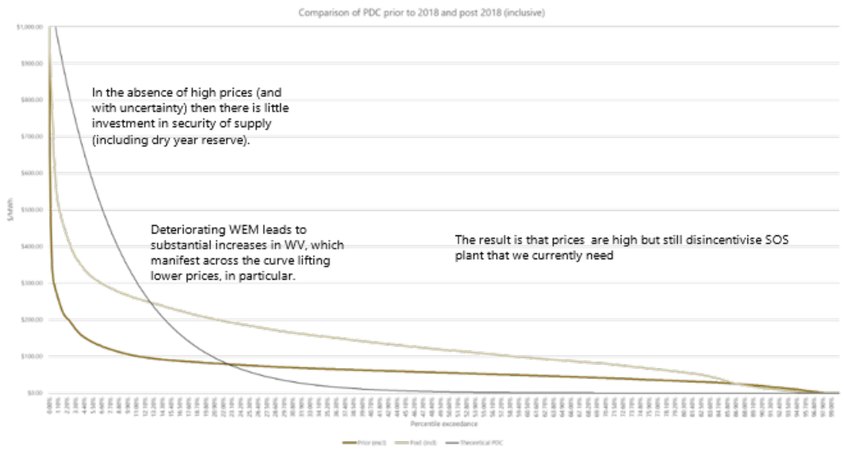
Figure 22: Supply- demand balance – firm winter capacity (2003 – 2024)



SOURCE: Whiteboard Energy

Sapere further explores the challenges with ensuring security of supply using price duration curves. They identify that issues have arisen due to challenges with the structure of wholesale and contracts markets prices not rewarding investment in low utilisation assets that would support security of supply, and that the flow on impacts of eroded security of supply has resulted in hydro water values lifting more generally.

Figure 23: Long run Price Duration Curve (since gas market problems)



Source: Sapere Research Group

Sapere conclude that addressing barriers to entry in low utilisation plant should be a priority, along with addressing contract markets concerns. They note that barriers to entry to low utilisation plant external to the electricity market are at least as significant as electricity market prices, e.g. gas market concerns and a fear of investing in fossil fuel thermal even for low utilisation peaking.

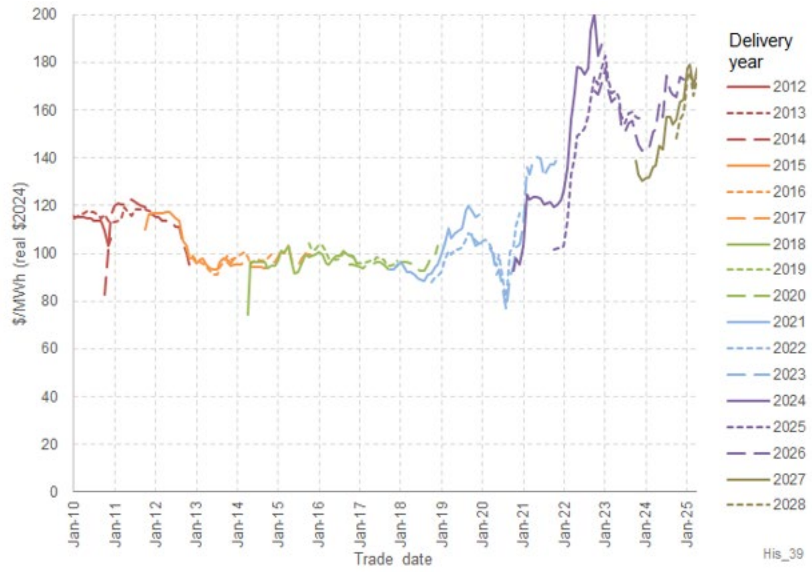
Update on electricity price components

In addition to broader concerns around the affordability of electricity given the “cost of living crisis”, recent high wholesale prices and increases in the allowable revenue for network companies are anticipated to impact on consumers.

Concept Consulting’s work explores recent trends in wholesale/contract pricing, along with how end user pricing for different consumer segments has evolved.

Analysis of forward contracts traded a year ahead of settlement identifies the current system imbalance which has emerged since the latter half of 2018.

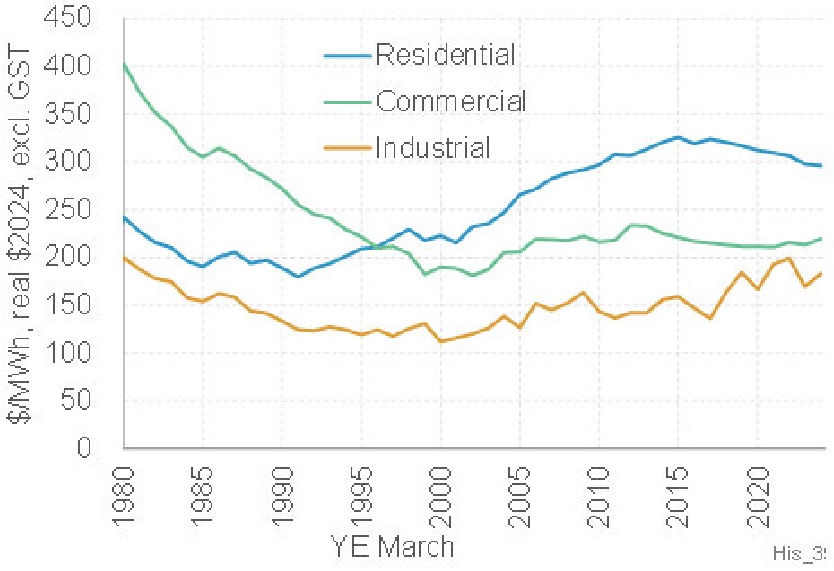
Figure 24: ASX Otahuhu forward contracts for calendar year strips (real $2024)



Source: Concept analysis of Electricity Authority data

Concept also plots average electricity prices paid by three different consumer segments since 1980. Of note is that since 2015, residential consumers have enjoyed real price decreases.

Figure 25: Average electricity prices (real $2024)



Source: Concept analysis of MBIE data

Concept's work further unpicks this to identify that the energy component of residential electricity prices has fallen in real terms since 2020, but that the lines component has started to tick up again in line with the recent regulatory reset as of 1 April 2025.

Concept further explores the various components of the annual average price metrics to allow a comparison of the extent to which the increase in wholesale prices has flowed through to different classes of electricity consumers.

They identify that the slight fall in the energy component of residential electricity prices between 2021-2024 suggests some combination of:

- retailers hedging wholesale prices across multiple years;
- reductions in the metering and retail cost-to-serve components of retail pricing; and/or
- reductions in the net margins earned on retail sales.

While unable to be definitive, Concept notes that "... the scale of compression between year-ahead contract prices and retail prices suggests that multi-year hedging must have played a material role."[126]

Is deindustrialisation a problem? Update on industry trends

With the recently announced closures of a sawmill and pulp and paper operations, concerns have been raised as to whether high wholesale electricity prices may be leading to a general 'deindustrialisation' in New Zealand.

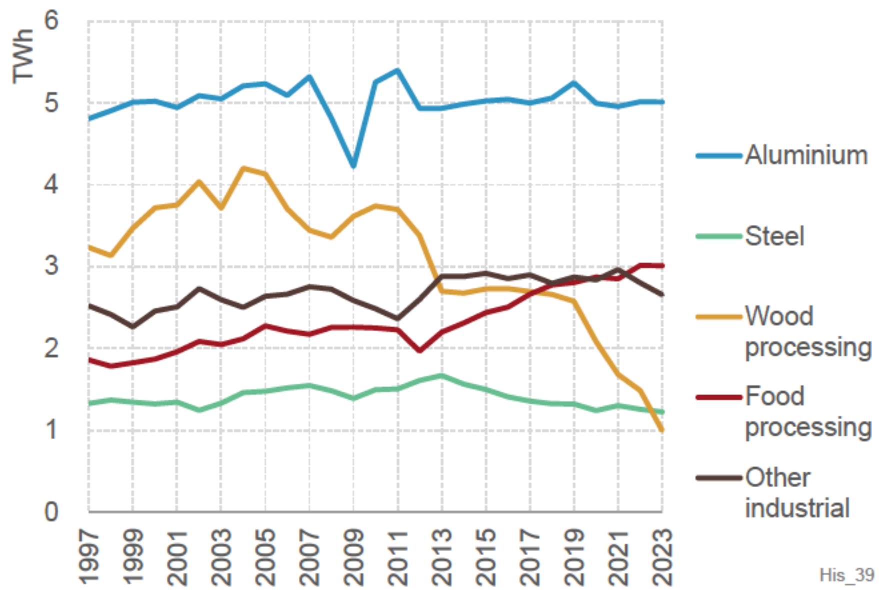
Analysis by Concept Consulting (Appendix D) considers the extent to which energy prices have driven de-industrialisation in New Zealand, and whether any such energy-price-driven de-industrialisation is likely to continue. Concept's analysis is set out in brief below.

- Only one sector – wood processing – shows a steep decline since 2005, having been behind much of the growth in the seven years prior.

[126] Various analyses of current electricity and gas market dynamics, Concept Consulting, 4 May 2025, page 29 see Appendix B of this report.

- Three sectors – aluminum, steel, and 'other' – have had broadly flat demand.
- One sector – food processing – has shown strong demand growth, particularly over the past decade.

Figure 26: Industrial sector annual electricity demand



Source: Concept using MBIE data

The key take-away from Concept Consulting work is that there are only three industrial sectors that are both significant consumers of electricity <u>and</u> electricity intensive <u>and</u> trade exposed:

- Aluminium production
- Steel production
- Wood processing, split between:
  - Market pulp
  - Packaging and industrial paper
  - Carton-board
  - Reconstituted wood panels
  - Tissue paper.

Turning to the three sectors that are both large and electricity-intensive, only wood processing looks to be at risk of further demand reduction. Even then, the scale is likely to be limited as, sadly, there is not much electricity-intensive production left to exit. It is also reasonable to assume the most vulnerable, the remaining wood processing facilities operations will have exited first – i.e., with the worst combination of electricity intensity and commodity prices.

Turning back to electricity, of the other two large electricity-intensive sectors the outlook looks strong:

- the Tiwai aluminiumsmelter has started a tender process for long-term electricity supply to *increase* production, and
- the Glenbrook steel mill has signed a long-term electricity supply contract with Contact Energy and is making a significant investment in an electric arc furnace.

Other industrial sectors are also investing in electrification projects that should increase electricity demand

8. Addressing the issues (Recommendations)

Integrated summary of issues to address

The table below shows the key issues identified in relation to both 'problem' market situations (high winter spot prices; and contract prices above cost of new build).

Figure 27: Key issues identified

Pillars of well-functioning market	High winter spot prices	Contract prices above LRMC	Combined issues to address
Accurate (efficient) price signals			(1) Opacity in gas market; (2) 'Political' backing for efficient high prices in scarcity
Tools and incentives to manage spot risk			(1)Strengthen contracts market, including more traded shaped hedges + mandatory market-making. (2) More demand-side flex. (3) Accountability for adequate insurance. (4) Security of supply information. (5) Guidance for system operator in 'crisis' situations
Sufficient competition (or pricing as if no significant market power)			Link to item (1) in "Tools" above. Looking forward, address significant competition risk in flexible supply
Public and political confidence (particularly in pricing)			(1) Enable government to accept and back efficient high spot prices in scarcity. (2) Rebuild confidence in contracts market among various buyer segments

Purpose of this section

In this section, we outline the actions that need to be taken to address the key issues identified above.

Given the significance of the declining gas supply, we also briefly discuss whether any special regulatory arrangements are required.

Improve accuracy of wholesale electricity prices

Better disclosure in the gas market

As outlined earlier, expected gas supply can have a highly significant impact on spot and contract electricity prices.

As Concept Consulting explains in Appendix B current rules require gas producers to submit information to MBIE at the beginning of each year detailing:

- Their estimates of the reserves and contingent resources within each of their fields.[127]
- Their estimates of the production profile of the reserves over subsequent years.

Key problems with this disclosure include the following.

It is late

MBIE gets the information from the gas producers early in the year but doesn't release it until the second half of the year. The reason for the delay is not clear, but it makes it harder for gas and electricity participants to make well-informed risk management decisions.

It is too infrequent

Once a year is too infrequent to help energy market participants understand the gas situation – particularly at a time of significant market stress. Quarterly information provision would greatly improve the situation:

- Any increase in administration costs for gas producers is likely to be significantly outweighed by the improvement in decision-making outcomes for the large (and highly capital intensive) electricity and gas sectors.
- In any case, we understand that most gas field operators already update their production projections on a more regular basis for their own internal management processes.

Market needs to see 1P and 3P production profiles

It is standard practice for petroleum producers to undertake projections of expected gas production at different levels of probability – typically P10, P50, and P90 (known as 1P, 2P, and 3P) reflecting projections with a 10%, 50%, and 90% probability that gas production will be less than projected.

[127] Reserves are accumulations of gas where the gas producer has already made, or has committed to make, the investment in development wells to extract the gas. Contingent Resources are gas accumulations where the gas field operator has expectations of the gas being there (to varying degrees of probability) but where it hasn't yet made any commitment to undertake the investment (and may never make such an investment) to develop the gas.

Gas producers are only required to provide 2P projections in their annual disclosures to MBIE. The market doesn't see the downside (1P) or upside (3P) projections.

Factoring the 1P downside is particularly important given its potential asymmetric impact. With less gas, prices can start to rise steeply as the sector moves up the cost-supply curve and, beyond a certain point, move very steeply indeed as prices start to be set by the demand-side's willingness to pay.

By contrast, the price effect of more gas can be relatively minor: Methanex has generally been able to absorb surpluses with little effect on price, plus gas can be held in the ground one year for production the next – postponing the need for additional drilling.

Disclosing 1P and 3P projections would enable energy market participants to develop more accurate probability-weighted gas (and electricity) price expectations, which in turn better inform risks management and new investment decisions.

Production profile is only annual

Given the current significant gas supply scarcity, a monthly profile (if only for the first three to four years of the projection) would materially improve the ability of energy market participants to understand the extent to which gas supply is likely to be insufficient to meet demand on a within-year basis – particularly over the crucial winter months.

- Again, we understand that gas field operators already produce such profiles on a monthly basis for their own purposes.

Lack of gas contract price disclosure.

The gas contracts market is opaque. There is a serious lack of good information on gas contract prices. This severely hampers a good price discovery process.

Coupled with a relatively concentrated gas market, the risk of inefficient outcomes is high.

By contrast, disclosure in the electricity contracts market is now light years ahead, with further improvement still expected.

Urgent action required

The gas industry has been slow to respond to previous requests for improved disclosure.

A circuit-breaker is required to urgently upgrade gas market disclosure to deliver more accurate prices enabling more efficient risk management and new investment decisions by energy market participants.

As with the electricity market in earlier years, the incumbents' assertions of confidentiality tend not to stand up to rigorous scrutiny, with the efficiency benefits of better disclosure considerably outweighing claimed costs and risks.

Authority's recent initiative helpful but still constrained

The Authority's recent initiative to get better information on volumes of thermal fuel available to electricity generators may be helpful,[128] but still constrained. It does not open information driving supply and demand expectations in the gas market itself.

[128] Electricity Authority, Improving Access to thermal fuel consultation paper, January 2025

This reflects the limits of both the Authority's jurisdiction and the gas industry' self-governing model.

In passing, we note that the Authority says current arrangements do provide sufficient information "for the Authority to effectively monitor security of supply risk".[129] In this case, it makes sense for the Authority to act as an intermediary to collect and publish information for the market; however, it is important for the Authority to guard against 'creep' where this monitoring function is seen as implying some responsibility for ensuring security of supply.[130]

Better disclosure in the electricity contracts market

The Authority has made significant progress in implementing MDAG's recommendation for improved transparency in the contracts market. Its recent proposal to deliver anonymised disclosure of 'OTC' contracts is welcome.

We were about to recommend that the Authority should give effect to MDAG's recommendation on disclosing contract bids and offers – happily, it seems that the Authority is now moving to do so with its just released consultation paper.[131] Note - We have not yet had a chance to fully digest the proposal.

[129] Ibid. at 4.33.

[130] As the GPS states at par 21: "Neither the Government nor the Electricity Authority nor the System Operator will step in to insulate wholesale market participants from risk or to protect them from their failure to manage their own energy supply risks."

Better tools and incentive for risk management

Improve product range and liquidity

From the accompanying report by Carlson Consulting in Appendix D below, we recommend:

- Relooking at the spot trading intervals that define the peak product to see that they provide the most useful risk coverage, i.e. to create a hybrid between peak and super peak or a "peaky product"; (taking into account that we do not suggest both a peak and super peak product is required).

- Adding a monthly peaky product to the exchange (in order to provide both a monthly and quarterly contract).

- Extending market-making to both the (new) monthly and (existing) quarterly peaky contracts and sharing the same platform to allow for netting of positions to reduce margin calls– this could be achieved by shifting a proportion of existing market maker baseload volumes to be split over baseload and peak market making (such that overall market making volumes on the ASX remain the same).

- Before adding any additional products to the exchange (in addition to the recommended monthly peak contract) the Authority would need to carefully consider the likelihood of diluting overall liquidity and the cost of further market making.

[131] Electricity Authority, Improving visibility of competition in the over-the counter contract market, 6 May 2025

Adjust the OTC voluntary code

Further based on Carlson Consulting's advice, we recommend adjustments to the OTC code to:

- Provide greater clarity of the circumstances where it would not be expected that a party would quote or enter into a trade.
- Add greater disclosure requirements into the OTC Code as the first regulatory option to improve confidence in the OTC market.

With a more complete set of exchange traded products (as recommended above), the OTC market as a whole should require less regulatory scrutiny over time (as volumes and open interest build across the exchange product set).

By using the exchange platform as the basis for providing a more complete set of hedging products supported by market-making (as recommended above), the role of OTC should shift to providing additional and more customised options to exchange based trading where parties are free to contract (or not) on a willing buyer willing seller basis.

Given the small size of the New Zealand market, new products without market-making support have a much-reduced chance to build liquidity. Exchange-traded products with market making support is the preferrable option to establish a core set of products that can be used to provide a sufficient building block approach to meet hedging requirements

Stress test – further upgrade

The stress test is a key mechanism in reinforcing the responsibility of each market participant to adequately cover their exposure to spot price risk.

MDAG recommended a set of upgrades to the stress test rules. Some of these have been implemented by the Authority, but it is not clear from the Authority's relevant decision paper if all the important changes have been put in place. Some of MDAG's proposed upgrades may have seemed minor, but they were not.

More needs to be done, well in advance of possible shortage periods, to reinforce awareness – not only among wholesale buyers and sellers, but also among government representatives – that responsibility for covering the risk of high spot prices rests with each market participant.

Among other things, we also recommend extending the stress test rules to cover disclosure to all end customers and to form part of the market joining (registration) requirements.

Contracting process disclosure

Another key action to strengthen the contracts market is for the Authority to put in place disclosure rules for OTC contracting. As recommended by MDAG,[132] these rules should provide for disclosure of processes leading to the formation of OTC contracts.

The rules should apply to all OTC trading, noting that the competition concerns are more acute for flexibility contracts but apply across the contract market.

[132] MDAG Final Report, Recommendation 8

The primary purpose of this recommendation is to strengthen the basis for regulatory scrutiny of non-price terms and behaviour by parties seeking to agree OTC contracts.

Unlock demand-side flexibility

As note earlier, DSF has the potential to play a much more significant role as a lower cost alternative to flexible generation.

MDAG set out an extensive analysis of the reasons it has been slow to get traction. MDAG observed how, for the last 100 years, the overwhelming share of resources in the industry has been put into systems for the supply-side. So, it is not surprising that the systems in place to enable demand-side participation are embryonic at best.[133]

However, MDAG also observed that, given the changes in technology and wholesale market signals now in progress, the essential elements for an efficient market in DSF can now be put in place.

To this end, MDAG set out a package of recommendations to unlock economically efficient DSF.

With the pressure rising on flexible supply, putting those recommendations in place is now more urgent and will form a critical part of promoting effective competition in the wholesale market.

As outlined earlier we think it makes good economic sense for electricity users to reduce demand where:

- the firm shifting or reducing electricity demand makes more money selling the electricity back into the system than from making the thing they produce at their plant; and
- The cost of buying back their electricity is cheaper than the alternative power back up.

What counts is reliably meeting demand from the lowest cost sources. Economic demand-side response is one of those sources.

Technical industry group to keep upgrading the contracts market

As noted earlier, the future electricity system is likely to characterised by innovation and unexpected change. Options for risk management are likely to keep changing as well.

Given the importance of a well-functioning contracts market, we recommend the industry establishing an expert technical group, to meet regularly and to remain in place for the foreseeable future.

Ideas are constantly surfacing within the industry – like the recent concept put forward from Jarden & Co on a possible alternative firming instrument. Other ideas percolate within participant organisations but don't see the light of day.

The working group we have in mind would act as an neutral 'apolitical' group of technical experts tasked with continuously looking for product and related ideas that might have common good benefits for the hedge market as a whole – a place to take germs of ideas floating around the industry and see if they would add significant value to the risk management across the wholesale market.

[133] MDAG Final Report Recommendations, A.5

This could include consideration of possible new standardised hedge products.

There needs to be careful choice and design of such products. If intermittent renewable generation is to make a contribution to security of supply then standard PPAs are not ideal. Standard PPAs do not incentivise plant availability and firming innovation during scarcity. They also create an incentive to run in periods of relative surplus regardless of underlying short-run costs and location in the grid. When there is risk of spill (hydro, wind, or solar) the market needs to clear on SRMC to ensure allocative efficiency and incentives for productive efficiency.

It would not be a 'representative body', but rather a small pool of 'bright minds.' If a product or related idea looked promising, then it would go a wider group for consideration – the Authority and wider advisory group would come in at that point.

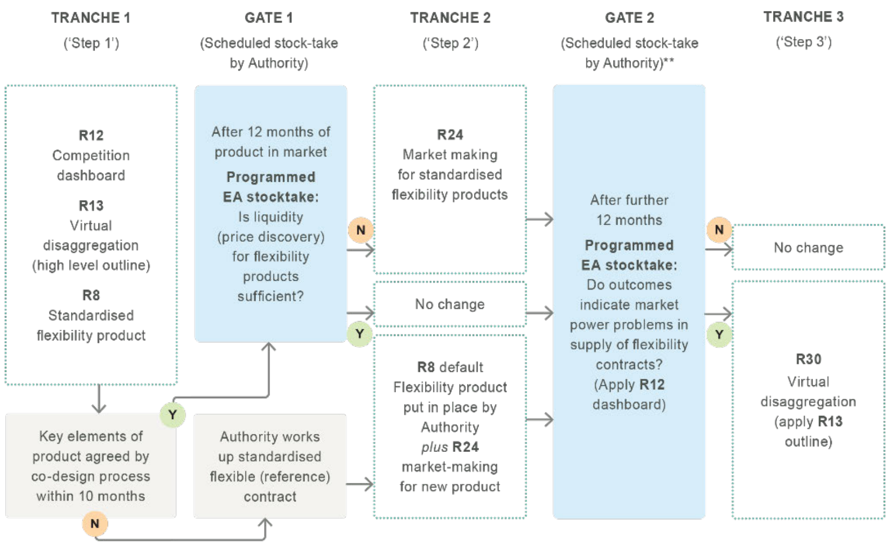
Without such a group, continuous improvement is *ad hoc* and too many good ideas that would benefit the common good go missing.

Anticipate competition risk in flexible supply

We recommend market-making now

- We agree with MDAG's recommended package of measures to address the potential risk of significant market power in the supply of flexible generation, as outlined in section 5 above.
- This builds on the other measures recommended by MDAG to improve the accuracy of prices and strengthen the contracts market.
- We agree in principle with MDAG's progressive approach of first pursuing measures that have lower risks of unexpected adverse consequences.
- However, as noted above, we recommend market-making at the outset, rather than waiting another 12 months on MDAG's 'rachet' plan, as this will proactively addressing the concerns about access to shaped products at competitive prices.
- Market-making should apply to both a baseload and "peaky" product.
- This is a change from MDAG's 'rachet' plan set out in Figure 28.

Figure 28: Progressive 'ratchet' steps for competition in supply of flexibility contracts



* **Other pro-competitive measures** (not shown) include improved information (Recommendations 1, 2, 3, 17), contract process disclosure (Recommendation 9), DSF (Recommendations 3, 4, 5, 8, 10, 11, 18, 19, 20) and stronger monitoring and enforcement (Recommendation 21).

** Competition stock-takes by Authority continue every 12 months.

As MDAG pointed out, these risk management tools can be adjusted along the way – for example, by modifying the form of the standardised flexibility contract, or modifying the trading platform, could broaden the number of trading participants and improve forward price discovery and liquidity.

Other measures

As MDAG observed, government and public confidence in the wholesale market is foundational. It feeds into the role government's play in reinforcing participants' incentives to manage risk properly in response to efficient spot price signals (including when those prices are high and/or volatile). Policy-makers and people who shape public opinion therefore have a reasonable understanding electricity system's current situation and outlook. In short, there is a strong need to regularly calibrate expectations, to avoid surprises and explain the weather linkages in more concrete terms.

The Authority should strengthen its information programme about the electricity system and market to key stakeholders, explaining core dynamics (for example) how security of supply is managed, both physically and via contracting and the nuanced role that the government plays.

The Authority needs to ensure that clear and comprehensive guiding principles and impartial procedures are in place for the System Operator to follow in power system emergencies, including any public calls for electricity conservation or reduced consumption.

Potential concentration risk not addressed by Task Force approach

The Task Force considers that its proposed approach to implementing non-discrimination will address the underlying issue that originally led to MDAG recommending virtual disaggregation.[134]

We disagree. MDAG's diagnosis of a material market power risk in relation to future flexible supply did not depend in any way on vertical integration.

As MDAG pointed out, the source of the potential power – namely, concentrated ownership of hydro storage – would remain even if the owners of the hydro storage had no retail business or were somehow at arms-length from their retail business.

No aspect of the Task Force's proposal would address this.

Choice of market vs administered regulatory approach

Our approach is looking to use market solutions to address the risk of significant market power in the supply of flexible generation and related hedge products; in particular, more efficient discovery of market price for those services.

By contrast, the Task Forces preferred approach adopts a process in which the regulator will unavoidably become the decision-maker on whether a contract offering is consistent with a hypothetical benchmark where the seller is assumed to be indifferent to internal versus external supply.

For the reasons outlined in section 4, a market approach is unquestionably better at reliably meeting consumer demand at least cost.

[134] Task Force Options paper, , para 7.8

Summary of recommendations

Table 2: Recommended remedial measures

Name of measure	Key action	Comment
Improve accuracy of wholesale prices		
Key problem: Gas market is opaque. Wholesale electricity prices are strongly influenced by expected gas supply, but market information on factors impacting on gas supply outlook and gas prices is limited. Wholesale electricity market is light years ahead.		
Action 1: Major upgrade of gas market disclosure	Government to require (and enable) major upgrade in disclosure - e.g. 1P and 3P; improve timing; gas contract prices	EA initiative to get thermal fuel info from electricity market participants is good but still limited
Action 2: Further improve hedge market transparency	Disclose non-base load offers and bids	Welcome recent EA proposal for greater OTC visibility
Action 3: Government backing of efficient high prices in scarcity	(see **Actions 11** and **12** below)	
Strengthen contracts market (tools and incentives for efficient risk management)		
Key problems: (i) lack of market reference prices for the value of flexibility; (ii) offering (availability) of efficiently priced flexible hedges; (iii) information to enable more effective monitoring		
Action 4: Improve range of traded (ASX) products	Add a monthly ASX 'peaky' product to existing quarterly	Expected to improve price discovery
Action 5: Market-making for "peaky" products	Extend market-making to both the (new) monthly and (existing) quarterly 'peaky' contracts.	On MDAG list for new shaped product but bring forward and apply to ASX products.

Name of measure	Key action	Comment
Action 6: Stress testing regime	Implement missing MDAG elements. Further action required - - to strengthen backing for high prices signalling real scarcity.	Some progress. Further action required. Vital to a well-functioning energy-only market
Action 7: Demand-side flexibility (DSF)	DSF market needs to be activated. Critical to competition in flexible supply and reliability at least cost	On MDAG programme but risk of 'poor cousin' ranking. Urgency required
Action 8: Contract process disclosure	Make rules to require disclosure of process steps by parties negotiating OTC contracts -- essential to enable more effective monitoring and compliance (to better guard against any anti-competitive behaviour)	On MDAG list but more urgent action required
Action 9: Adjust voluntary OTC code	Enhance disclosure requirements. Clarify if and when non-offering is ok (e.g. no physical backing)	
Action 10: 'Standing' technical industry group	Neutral group of technical experts tasked with continuously looking at products and related ideas with potential common good benefits for contracts market as a whole	Without such a group, continuous improvement is ad hoc and too many good ideas with common good ideas go missing.
Public and political confidence		
Key problems: Political and public backing for high prices efficiently signalling scarcity is fundamental. Government plays a crucial role in reinforcing the need for market participants to properly cover their exposure to high prices. This underpins suppliers acting to ensure adequate fuel and capacity, which in turn delivers security of supply. Need to better support public and political backing for accurate wholesale prices (including high prices in scarcity)		
Action 11: Seasonal outlook report	Calibrate public expectations with quarterly briefings on current and expected market conditions. [Links to **Action 6** above - stress test regime]	On MDAG list and EA says 'complete'. But seem to have misunderstood action required
Action 12: Information programme for opinion-makers	Strengthen structured information programme for wider stakeholders on how the market works	Needs to be upgraded

HOUSTONKEMP Economists

An economic review of the Energy Task Force's level playing field proposals

A report prepared for independent expert submission

7 April 2025

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Disclaimer

Contents

Executive summary

This report addresses the Energy Competition Task Force's (the Task Force's) proposal for level playing field measures in the electricity sector. The focus of this report is the essential economic propositions underpinning the Task Force's proposals.

Economic principles underpinning the proposal

Distilling the Task Force's concerns to their economic fundamentals, we observe that there appear to be three, ie:

- market power wielded now or in prospect by the large gentailers in the supply of flexible generation;
- leverage of that market power through the foreclosure of non-integrated retailers; and
- insufficient liquidity and transparency in markets for risk management products due to vertical integration in and of itself.

The intervention proposed by the level playing field options paper is the imposition of a regulatory requirement expressed as non-discrimination (or 'equivalence', or 'even-handedness') on large gentailers requiring them to give other retailers and generators access to risk management products on substantially the same terms as the large gentailers supply themselves internally.

The Task Force proposes that these non-discrimination obligations be structured as three steps, via which escalating interventions may be imposed if initial elements are deemed unsuccessful.

The Task Force contends that its 'level playing field' proposals, ie, giving all retailers access to the same inputs at the same costs are consistent with the Authority's statutory objective that involves the promotion of competition and economic efficiency. In our opinion, this is better described as an 'equal input regulation' than a level playing field. A level playing field would give everyone the same ability to acquire inputs, but it would not give everyone exactly the same inputs.

However, there is a clear distinction between providing all firms with the same inputs, and the economic elements of the Authority's statutory objective. This is because:

- effective competition neither requires nor necessarily leads to firms having access to the same inputs at the same prices;
- attempts to give all firms the same access to the same inputs are likely to reduce competition; and
- efficiency would be reduced if a vertically integrated firm was required to offer inputs at below the marginal cost of provision to third party firms.

Effectiveness and workability of ITPs

The effectiveness and practicability of the Task Force's proposed non-discrimination obligations is open to substantial doubt. In forming these proposals, the Task Force effectively assumes the existence of internal risk management transactions within the large gentailers or otherwise requires the establishment of a portfolio of such transactions as a benchmark against which to assess offers to other retailers and generators.

However, notwithstanding the Task Force's intentions, the establishment of such transactions will not be 'economically meaningful' and will not establish a reliable benchmark for external transaction.

Internal transactions represent transfers of value between different segments of a gentailers and so gentailers are indifferent as to their level. This highlights there is no firm economic basis upon which to raise concerns about the prospect of a large gentailer setting *lower* prices for its internal risk management transactions as compared to those that its charges other retailers or generators. A gentailer is indifferent about the terms on which it transacts with itself and would equally be happy to charge itself *more* than other retailers or generators.

Further, there are significant effectiveness concerns for the Task Force's proposed approaches to its intervention, including:

- for step 1, in which reliance on observations of market rates would be used to set ITPs, would simply result in external pricing for risk management products being benchmarked to the same level as current market outcomes and therefore resulting in no change to pricing outcomes; and
- for step 3, in which all risk management products must be transacted through a market platform, will be similarly ineffective where a gentailer can identify its own risk management products and make offers on these products.

Further, there is no well-understood cost-based method by which to assess internal transfer prices for risk management products due to New Zealand's high degree of reliance on hydroelectric power and further, even if such costs could be estimated:

- they would be likely to change dynamically in response to market circumstances;
- they cannot be expected to reflect any prices that are locked in by reference to a portfolio established at a prior point in time; and
- they would likely not discern vertical efficiencies in the way that the Task Force assumes would be feasible.

Economic analysis and alternative options

Typically, economic analysis demonstrating that a preferred option would give rise to net benefits that are positive and exceed those of other options is expected to underpin regulatory or policy interventions. This is all the more relevant given the significance of the intervention proposed by the Task Force and the importance of the electricity sector to the New Zealand economy.

In our opinion, the economic analysis supporting the Task Force's proposal is insufficient to support its conclusions. The Task Force appears to have given little consideration to weighing the benefits and costs of its proposed intervention, and particularly its potential efficiency consequences.

The Task Force states its belief that the benefits of its proposal would exceed the costs. However, the principal basis for this finding appears to be an implicit assessment that the harms arising from lost vertical efficiencies for the large gentailers would be more than offset by greater competition for the retail supply in electricity.

The intrinsic challenges associated with assessing the benefits of intervention in the electricity market lend support to a more flexible form of intervention that is more easily scalable to the degree of concern and evidence, as this evolves. Although the Task Force's proposal is framed as three steps of increasing intervention, it does not represent a gradual process of adjustment.

An economic analysis of the Task Force's proposal is further complicated by the fact that it comprises three distinct interventions, yet the likelihood and timing of the application of each intervention is uncertain. This highlights the importance of clearly-defined triggers in forming an assessment of the costs and benefits of the proposal in the round.

In light of these assessments, we propose the introduction of an alternative and preferable option for addressing the Task Force's concerns, involving the expansion of existing market-making obligations. Relative to the proposed non-discrimination obligations, this option would be both:

- better targeted, in the sense that it addresses the source of concern, being the availability of risk management products to non-integrated retailers; and
- more 'scalable', in the sense that it can be readily adjusted in its degree of intrusion so as to be proportionate to the degree of concern.

Regular reviews could be used to assess the success of these obligations in achieving desirable market outcomes, with the option available to further deepen these obligations, either by making a greater proportion of flexible generation subject to these requirements, or to broaden the scope of the obligations.

1. Context for this report

We have prepared this report to inform an independent expert panel's submission[1] in response to the options paper prepared by the Electricity Authority (the Authority) in relation to the Energy Competition Task Force's (the Task Force's) proposal for level playing field measures in the electricity sector.[2]

The focus of this report is the essential economic propositions underpinning both the Task Force's proposals and the options proposed by the Authority for their implementation. Throughout this report, we refer to these collectively as the Task Force's proposals – both because it is convenient to do so and because it is unclear where the boundary lies between elements of the options paper for which either the Task Force and/or the Authority are responsible.

1.1 Concerns raised by the Task Force

The level playing field measures options paper ('options paper') arises out of concerns held by the Task Force around:

- the high degree of wholesale market volatility that has persisted in New Zealand's electricity market since 2018 and which is expected to continue, driving increased demand for risk management products;[3]
- the control exerted by four large businesses that are vertically integrated between electricity generation and electricity retail (or 'the large gentailers') on New Zealand's flexible generation base, which underpins the ability to supply risk management products;[4] and
- the complaints raised by independent retailers about a refusal by the gentailers to supply risk management products and/or pricing these at a level that is too high to support competition in electricity retail markets.[5]

The Task Force characterises these concerns broadly as being:[6]

> …risks to competition arising from Gentailer vertical integration.

The Task Force explains that these risks arise where a vertically integrated firm, with at least some degree of power in one of the markets in which it operates, can exercise this market power to advantage its affiliated operations in another market.[7] This is known in economics as foreclosure, and is one of the risks to competition raised by the Task Force.[8] Other risks identified by the Task Force, being those related to liquidity and transparency,[9] may arise regardless of market power and do not turn on its existence.

The Task Force explains that, in principle, these risks could manifest in relevant markets for electricity risk management products in New Zealand because the risk management products that non-integrated retailers and generators need may not be supplied, or they may not be supplied on a competitive basis or otherwise

[1] Baldwin T, Carlson D, Smith D, Batstone S, Reeve, D, Houston G and Young D, *Submission for the Energy Competition Task Force and interested parties on "level playing field" proposal and underlying issues*, 7 May 2025.

[2] Electricity Authority, *Level playing field measures*, Options paper, 27 February 2025 (hereafter 'options paper').

[3] Options paper, paras 2.10-2.13.

[4] Options paper, paras 2.16-2.17 and 3.28-3.30.

[5] Options paper, para 2.18.

[6] Options paper, para 3.1.

[7] Options paper, para 3.22.

[8] Options paper, para 3.23(b).

[9] Options paper, para 3.23(a) and (c).

'even-handedly'. The manifestation of such risks would result in higher input prices and higher electricity prices for New Zealand consumers in the long run.[10]

The Task Force highlights evidence that it considers demonstrate a risk of competition issues for risk management products, comprising:

- the Authority's risk management review issues paper, which found that:[11]
  - over a third of the time, retailers receive only one offer in response to requests for shaped hedges; and
  - although over the counter (OTC) baseload and peak risk management contracts are likely to be competitive, super peak risk management contracts trade at an unexplained premium over baseload prices when adjusted for shape;
- an ongoing and unexplained gap between the forward curve derived from ASX risk management contracts and the cost of new generation build;[12] and
- the existence of a disconnect between the internal transfer price (ITP) reported by the large gentailers and their retail prices, indicating that these businesses 'may not be exposed to the same choices, risks and costs faced by non-integrated retailers'.[13]

The Task Force notes that it is engaging in other efforts to support the development of a market for power purchase agreements (PPAs) in New Zealand and to facilitate the development of standardised flexibility products to improve access to risk management products. However, the Task Force considers that these workstreams are not likely to:[14]

> …fully address the broader risk of Gentailers discriminating in favour of their own internal business units over non-integrated competitors in relation to firming or hedging

On this assessment, the Task Force proposes the introduction of non-discrimination measures to overcome:[15]

- competition risk due to the ability and incentive of large gentailers to limit competition because of their control of the flexible generation base; and
- the informational advantage enjoyed by the large gentailers due to the limited transparency of their internal risk management transactions.

1.2 Distillation of the Task Force's concerns

Distilling the Task Force's concerns to their economic fundamentals, we observe that there appear to be three, ie:

- market power wielded now or in prospect by the large gentailers in the supply of flexible generation;
- leverage of that market power through the foreclosure of non-integrated retailers; and
- insufficient liquidity and transparency in markets for risk management products due to vertical integration in and of itself.

[10] Options paper, para 3.24.

[11] Options paper, para 3.39.

[12] Options paper, paras 3.41-3.42.

[13] Options paper, paras 3.43-3.45.

[14] Options paper, para 3.49.

[15] Options paper, para 3.51.

The existence of policy concern as to the arrangements for access to flexible electricity supply is understandable.[16] Access to risk management underpinned by flexible supply is likely to be an important input to both:

- the entry of new retail participants, who need to manage the risks arising from purchasing electricity from the spot market; and
- the development of new intermittent renewable electricity projects, such as solar and wind, which may seek financial firming that extends beyond the capabilities of batteries.

As a matter of principle, if there is insufficient competition in the provision of flexible supply and the associated market for risk management products, this can be expected to have long term consequences for competition in generation and retail markets.

However, the existence of periodic market power held by parties that control flexible forms of generation is not, by itself, sufficient reason for intervention. The periodic, transitory possession of market power is an intrinsic feature of New Zealand's energy-only market. All generators require prices periodically to exceed their marginal costs of supply in order to recover their fixed costs – the so-called 'missing money'.

Rather, the policy priority should be to address the potential for New Zealand's gentailers to possess enduring or substantial market power in flexible sources of generation and its associated risk of exclusionary conduct by means of restricting access to the risk management products necessary for entry or expansion in flexible generation. This conclusion is consistent with the finding of the Market Development Advisory Group (MDAG) that:[17]

> …competition concerns in the spot market could be appreciably reduced if wholesale buyers could access flexibility contracts on reasonable terms.

1.3 Task Force's proposed non-discrimination intervention

The intervention proposed by the level playing field options paper is the imposition of a regulatory requirement expressed as non-discrimination (or 'equivalence', or 'even-handedness') on large gentailers requiring them to give:[18]

> … retailers and generators access to products (for example, hedge contracts) on substantially the same terms as Gentailers supply themselves internally.

The Task Force proposes that these non-discrimination obligations be structured as three steps, via which escalating interventions may be imposed if initial elements are deemed unsuccessful. These comprise:

- step 1 – the introduction of non-discrimination obligations as a series of principles applying to risk management products, with which each large gentailer would be required to comply and to demonstrate compliance;
- step 2 – the imposition of more detailed and prescriptive rules governing how gentailers would be required to interact with buyers of risk management products; and
- step 3 – the mandatory trading of all risk management products through a market platform.

The draft non-discrimination principles proposed by the Task Force are set out at table 1.1 below.

[16] See for example: Matthews Law letter to the Electricity Authority, *Request for urgent action in wholesale electricity market and corporate separation*, 7 August 2024, appendix 1. This appendix reflects our opinion and economic analysis.

[17] Market Development Advisory Group, *Price discovery in a renewables-based electricity system*, Final recommendations paper, 11 December 2023, para D.18.

[18] Options paper, para 5.5.

Table 1.1: Draft non-discrimination principles

Principle	Description
Principle 1	A gentailer must not discriminate against buyers in favour of its own internal business units, or between buyers, for the supply of (and in relation to the price and non-price terms of) risk management contracts without a cost-based, objectively justifiable reason.
Principle 2	A gentailer must establish an economically meaningful portfolio of internal transfer prices that reflects its internally traded hedges to demonstrate it has met its non-discrimination obligations
Principle 3	Credit terms and collateral arrangements must reflect an objective assessment of the risk of trading with a buyer
Principle 4	A gentailer must ensure that any commercial information relating to risk management contracts made available to its internal business units is also made available to any buyers.
Principle 5	A gentailer must protect buyer confidential information and not disclose this information to any internal business units that compete with the buyer.
Principle 6	A gentailer must establish, maintain, keep and disclose records that demonstrate its compliance with these non-discrimination principles.

Source: Options paper, appendix B, paras 1-6.

Under step 1, large gentailers would have discretion as to how they comply with the principles, as long as they demonstrate this compliance.

Step 2 would eliminate or reduce this discretion by prescribing specific rules for how the large gentailers must interact with risk management customers, for example by reference to their reporting of internal risk management transactions, other access terms and information disclosures.[19]

Step 3 would require all risk management products to be transacted through a market platform. The Task Force discusses options under step 3 to reduce further any advantages that the large gentailers might have, ie:[20]

- the elimination of scale advantages by requiring that all risk management products to be sold in small unit amounts; and
- the elimination of all vertical efficiencies by preventing the large gentailers from trading risk management products with themselves through the platform.

1.4 Structure of this report

The remainder of this report is structured as follows:

- in section 2 we assess the economic principles underpinning the Task Force's proposal and show that the Task Force's conception of a level playing field may not be consistent with the promotion of competition and economic efficiency;
- in section 3 we review the effectiveness and workability of ITPs, which underpin steps 1 and 2 of the Task Force's proposal, and show that ITPs would not be 'economically meaningful' and will not establish a reliable benchmark for external transactions; and
- in section 4 we discuss the economic analysis that would be required to determine whether the Task Force's proposal gives rise to net benefits and propose an alternative option, based on expanded market-making, that we consider would better respond to the Task Force's concerns.

[19] Options paper, para 6.26.

[20] Options paper, para 6.30.

2. Economic principles underpinning the proposal

The statutory objective of the Authority is to promote competition, efficiency and reliable supply in the electricity industry. This statutory objective is an important reference point for the Task Force's proposals because, if they proceed, they will require amendments by the Authority to the Electricity Industry Participation Code (the Code).

The Task Force contends that its 'level playing field' proposals, ie, giving all retailers access to the same inputs at the same costs are consistent with the Authority's statutory objective.[21]

In this section, we explain that there is a clear distinction between providing all firms with the same inputs, and the economic elements of the Authority's statutory objective. This is because:

- effective competition neither requires nor necessarily leads to firms having access to the same inputs at the same prices;
- attempts to give all firms the same access to the same inputs are likely to reduce competition; and
- efficiency would be reduced if a vertically integrated firm offered inputs at below the marginal cost of provision to third party firms.

2.1 Objective of the Authority is to promote competition and efficiency

The Authority's main statutory objective is:[22]

> To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Competition is a dynamic process of rivalry, whereby firms strive to maximise their profits by offering price-product-service packages to consumers that are more attractive than that of their rivals, whilst minimising their costs.[23] A well-known definition of competition is that:[24]

> [Competition is] rivalry between individuals (or groups or nations), and it arises whenever two or more parties strive for something that all cannot obtain.

The fact that 'all cannot obtain' is an important attribute of competition because it reflects that firms (in this case) are competing *against* one another, eg, sales gained by one firm are usually lost by another.

Competition is driven by the profit motive, ie, the desire to maximise profits provides an incentive for firms to improve their products or lower their costs to allow a firm to set prices temporarily above their costs.

The process of rivalry occurs along many dimensions, depending on the product or service in question. Firms can compete, amongst other things:

- to provide better quality products than rivals;
- to provide lower prices than rivals;
- to purchase the best or lowest price inputs; and

[21] Options paper, para 5.6.

[22] *Electricity Industry Act 2010*, s 15(1).

[23] See, for example: Brunt, M, *Market definition issues in Australian and New Zealand trade practices legislation*, Australian Business Law Review, 18, 1990, p 96.

[24] Stigler, G, Competition, in Durlauf, S and Blume, L (eds), The New Palgrave Dictionary of Economics, 2, Palgrave Macmillan, 2008, p 1. This definition is referred to in: Vickers, J, Concepts of Competition, Oxford Economic Papers, 47, 1995, p 3.

- to innovate and offer new products.

Economists recognise three types of economic efficiency that can be enhanced or improved as a result of competitive rivalry between producers, ie:

- productive (or technical) efficiency, which refers to a market outcome whereby products and services are provided at the lowest possible cost, using facilities of optimal scale, over the long run, with existing technology;
- allocative efficiency, which refers to the use of society's resources to produce the mix of goods and services that is most highly valued – this is achieved when prices and profit levels are consistent with the real resource cost of supplying each product, including a normal profit reward to suppliers; and
- dynamic efficiency, which refers to the ability of markets to adapt over time in response to changes in consumer preferences and/or technology through the development of new products and services and/or production processes.

The promotion of competition and economic efficiency are consistent objectives for the Authority. Promoting competition will help to achieve economic efficiency. In particular it will help to achieve:

- productive efficiency, since:
  > firms that face competitive pressure from rivals have an incentive to reduce their costs of production in order to increase their profits; and
  > more productive firms will set lower prices for their products and so expand their output, whilst less productive firms will shrink and possibly exit altogether;
- allocative efficiency, since:
  > firms facing stronger competition will set lower prices, such that more demand is satisfied;
  > firms that are unable to compete effectively will divert their resources to more productive endeavours; and
- dynamic efficiency, by providing suppliers with a strong incentive to develop new and innovative products or more cost-efficient production processes in an effort to increase profit.

2.2 Equal input regulation does not promote competition or efficiency

The Task Force sets out that its 'level playing field' proposals are consistent with the objective set out above because it is expected to promote competition.[25] The options paper considers various 'level playing field measures', which are regulations to 'ensure fair and even-handed access treatment of all participants in a market.'[26]

We understand that, by these statements, the Task Force means that the level playing measures will give all retailers the same access to the same risk management products at the same prices. For example, the Task Force states that:[27]

> Non-discrimination requirements would promote a level playing field by giving retailers and generators access to products (for example, hedge contracts) on substantially the same terms as Gentailers supply themselves internally. This would likely provide a substantial competition benefit…

[25] Options paper, para 5.6.

[26] Options paper, p 8.

[27] Options paper, paras 5.5-5.6.

> Non-discrimination obligations are then targeted at ensuring competing retailers and generators can access these standardised flexibility products on an equal footing. Together they should make a material difference to the promotion of competition.

In our opinion, this is better described as an 'equal input regulation' than a level playing field. A level playing field would give everyone the same ability to acquire inputs, but it would not give everyone exactly the same inputs.

For example, a rugby match is typically played on a level playing field, but rugby teams have different players, training, and support staff. They choose the best players, training strategies and staff to give them the greatest advantage over their rivals as possible. It is therefore possible that on game day, one team has a considerable advantage over another, despite playing on a level playing field.

It would not increase the standard of the competition to require that all rugby teams were given the same players, strategies, training etc. No team would have any incentive to improve their training or acquire the best players if that were the case.

We explain below that an 'equal input' regulation does not promote competition or efficiency because:

- effective competition does neither requires nor necessarily leads to access to the same inputs at the same prices;
- giving all firms access to the same inputs reduces competition; and
- efficiency would be reduced if a vertically integrated firm offered inputs at below the marginal cost of provision to third party firms.

2.2.1 Effective competition neither requires nor leads to access to the same inputs

Effective competition does not require all the competing firms to have access to the same inputs at the same prices. Rather, effective competition involves firms trying to find better and cheaper inputs and reorganising their businesses to make the most effective use of such inputs. An equal input regulation in which all firms could access the same inputs at the same prices would eliminate this form of competition, weakening economic efficiency.

It is not the usual outcome of effective competition to find that all firms use the same inputs at all times. Rather, when competition is effective, firms can be expected to try to find and use better inputs than their rivals, so they are unlikely to be using exactly the same inputs at the same costs. Some firms may experiment with new and cheaper suppliers trying to get an edge over their rivals. Firms that can do this successfully can earn greater profits, at least for a time.

The Task Force contends that offering all firms access to the same inputs provides a benefit to competition by:[28]

- reassuring firms that they are competing on an equal footing; and
- addressing any competitive impacts arising as a result of gentailers and third parties procuring hedging contracts in different ways.

The benefits to competition referred to by the Task Force do not appear significant, given that:

- firms in an effectively competitive market typically do not have assurance that their rivals use the same inputs for the same prices – competing firms live with the uncertainty that their rivals may have access to better and/or lower priced inputs; and
- measures directed at ensuring that the same product can be purchased at the same price by internal business units and external retailers does not solve any competition issue caused by gentailers and third

[28] Options paper, para 5.5.

parties procuring hedging contracts in different ways, because these prices could still be above the competitive level.[29]

Elsewhere the Task Force expresses the concern that it seeks to address by reference to the fact that, through their vertical integration, the large gentailers may not be exposed to the same 'choices, risks and costs' faced by non-integrated retailers.[30] The large gentailers face different choices, risk and costs from their competitors because they have made different choices and incurred different risks and costs in the past. This is normal in a competitive market.

2.2.2 Giving all firms access to the same inputs reduces competition

Imposing obligations that require rival firms to have the same access to the same inputs eliminates competition between the firms in relation to the search for and use of the best inputs. It prevents firms from looking for cheaper inputs, and so reducing their prices, or using different inputs in a better way and so improving their products. By consequence, economic efficiency is reduced.

For example, competition would be reduced if all coffee shops purchased the same coffee cups at the same prices. This would reduce competition between coffee shops because:

- coffee shops would not try to find better quality or lower priced cups because this is either prevented, or any benefit would be immediately passed on to rivals who would have access to the same coffee cups; and
- coffee shops would be prevented from attracting customers by having better quality coffee cups than rivals.

Allowing competition for inputs promotes economic efficiency because the firm that values the input most highly can be expected to acquire the input. For example, allowing firms to integrate vertically in order to acquire inputs can be expected to lead to the most efficient form of supply. On the other hand, giving everyone equal access to all inputs prevents the mechanism by which firms that value an input most highly can acquire that input.

2.2.3 Offering inputs at below marginal cost would reduce efficiency

The marginal cost of self-supply is an economically meaningful and cost-based reference point for an internal trade between the generation and retail units of a gentailer. By 'marginal cost', we include all relevant economic costs (including risks and opportunity costs) associated with the provision of additional risk management services.

For a gentailer with vertical efficiencies, we would expect the marginal cost of self-supply to be lower than the marginal cost of supply to external firms. Obliging a gentailer with vertical efficiencies to offer the same input to external firms at a price consistent with its marginal cost of self-supply would result in those external firms paying a price for that input that was less than the marginal cost of its provision, because when provided to an external party no vertical efficiencies would arise. This outcome would in turn lead to economically inefficient outcome, ie:

- there would be allocative inefficiencies resulting from over-provision of the gentailers' internally-organised risk management services, because they would be priced below their marginal cost; and
- there may be dynamic inefficiencies arising if firms rely on the mispriced risk management products rather than investing in lower cost alternatives.

Further, the vertically integrated firm can be expected to divest to avoid such unprofitable supply, and so some or even all vertical efficiencies would be lost.

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[29] We discuss these issues further at section 3.2 of this report.

[30] Options paper, para 3.45.

Vertical efficiencies are not passed on to rivals when there is effective competition. Where there are vertical efficiencies from self-provision, a vertically integrated business constrained by effective competition would not set its prices so as to allow other businesses access to its vertical efficiencies because, by their nature, those vertical efficiencies are not applicable in relation to transactions that a vertically integrated firm conducts with those external businesses. Indeed, the avoidance of the transactions costs associated with entering into explicit hedging agreements in relation to the substantial proportion of a gentailer's generation output and/or its retail load is likely to be an important component of the efficiencies associated with the vertical integration of electricity generation and retailing functions.

3. Effectiveness and workability of ITPs

The effectiveness and workability of the Task Force's proposed non-discrimination obligations is open to substantial doubt. In forming these proposals, the Task Force effectively assumes the existence of internal risk management transactions within the large gentailers or otherwise requires the establishment of a portfolio of such transactions as a benchmark against which to assess offers to other retailers and generators.

In this section we explain that, notwithstanding the Task Force's intentions, the establishment of such transactions will not be 'economically meaningful' and will not establish a reliable benchmark for external transactions. This is because:

- internal transactions represent transfers of value between different segments of a gentailers and so gentailers are indifferent as to their level; and
- there is no well-understood cost-based method by which to assess internal transfer prices for risk management products due to New Zealand's high degree of reliance on hydroelectric power and further, even if such costs could be estimated:
  - they would be likely to change dynamically in response to market circumstances;
  - they cannot be expected to reflect any prices that are locked in by reference to a portfolio established at a prior point in time; and
  - they would likely not discern vertical efficiencies in the way that the Task Force assumes would be feasible.

In the following section 4.3 we explain an alternative approach by which a benchmark for external risk management transactions could be determined that would not be affected by these concerns.

3.1 Obligations require a portfolio of internal transactions

The Task Force's proposal for non-discrimination obligations operates under an assumption that the large gentailers enter into explicit risk management transactions between their generation and retail functions or that they can be required to establish such arrangements.

The foundation for this assumption arises from the principle adopted by the Task Force that the large gentailers should offer risk management products to other retailers and generators on 'substantially the same' terms as they do to themselves *and* that they should be able to demonstrate this.

This principle is underpinned by the approach taken by the Task Force to non-discrimination obligations, which it describes as:[31]

> …a level playing field measure that, in relation to the supply of hedges, would require Gentailers not to treat themselves substantially differently from their non-integrated competitors, or to treat different competitors substantially differently.

Similar conceptual underpinnings for the Task Force's approach to non-discrimination obligations are described and applied elsewhere in the options paper.[32]

[31] Options paper, p 8.

[32] See for example: Options paper, paras 4.15-4.16, 4.28, 5.5, 6.18 and 6.24.

Notwithstanding any in-principle concerns about this conceptualisation of non-discrimination (which we explain in section 2.2 above), its implementation requires observation of the internal risk management conduct of the large gentailers.

The very nature of vertical integration means that there are no observable internal risk management transactions occurring within the large gentailers. One of the key benefits of vertical integration is the ability of generation to provide a natural risk management function against a retailers' expected load, offsetting the transactions costs of entering into contracts that would achieve a similar effect, as well as the risks associated with the availability, pricing and security of such contracts.[33]

To overcome this lack of observable internal trading and to make non-discrimination obligations workable, the Task Force proposes that the large gentailers would be required to establish prices for internally traded risk management products that would form benchmarks against which to assess its conduct in transactions with retailers and generators. This is reflected in the draft non-discrimination principles, which require that:[34]

> A gentailer must establish an economically meaningful portfolio of internal transfer prices that reflects its internally traded hedges to demonstrate it has met its non-discrimination obligations.

3.2 ITPs are unlikely to be either economically meaningful or effective

There is no economic reason for the reported price of any internal or implied risk management 'transaction' to be 'economically meaningful'.

Within a vertically integrated business such as a gentailer, notional transactions can take place at any price with no effect on the profitability of the overall business, since any price set on such services is both paid and received by itself, with no net effect. Put another way, to the extent that gentailers make internal hedging offers to themselves in order to comply with regulatory requirements, these will only represent transfers of value between different segments of their business and cannot alter the fundamental economics of their hedged position.

Consistent with these observations, the Authority has previously found that the current ITPs:[35]

> … are not a useful measure for any assessment that is seeking to better understand competition in the retail electricity market.

For the same reasons, there is no firm economic basis upon which to raise concerns about the prospect of a large gentailer setting *lower* prices for its internal risk management transactions as compared to those that it charges other retailers or generators. A gentailer can be expected to be indifferent about the terms on which it transacts with itself and would equally be happy to charge itself *more* than other retailers or generators.

It follows that the Task Force's primary focus around the prices of risk management products should be on the *level* of the *market prices* charged to retailers and generators, not their *relativity* as compared to internal prices.

When set alongside the potential economic rationales underpinning the Task Force's intervention, this indicates that the most relevant such rationale relates to market power wielded now or in prospect by the large gentailers in the supply of flexible generation or risk management products backed by flexible generation.

This has important implications for the design of any intervention and raises significant questions over the effectiveness of ITPs and non-discrimination principles in overcoming the Task Force's concerns. In particular, we explain in sections 3.2.1 and 3.2.2 below why step 1 and step 3 of the Task Force's proposed

[33] This benefit is amongst those identified by the Task Force – see: Options paper, para 3.17.

[34] Options paper, appendix B, para 2.

[35] Electricity Authority, *Internal transfer price and retail gross margin post-implementation review*, 7 November 2024, para 5.5.

non-discrimination obligations are unlikely to be effective. We do not review step 2 because, although it promises more specific requirements, these are not set out by the Task Force and so we are unable to evaluate the proposed intervention.

3.2.1 Using market rates to set ITPs is unlikely to be effective

The Task Force proposes as part of its step 1 intervention that non-discrimination obligations would be determined by reference to ITPs that it assumes could be made 'economically meaningful' by means of a requirement that they be based on: [36]

> …observable market rates for comparable risk management contracts, including baseload, peak and super-peak contracts (such as the standardised flexibility product) adjusted for the internal requirements of the gentailer.

In principle, we agree with the Task Force's approach of harnessing market forces to constrain the conduct of the large gentailers. We explain in the following section 4.3 the means by which market forces can be deployed to give rise to transparent, liquid and robust pricing of risk management products.

However, reliance on observations of market rates to set ITPs, which would in turn be used to benchmark prices for other risk management contracts, is unlikely to address the problem that the Task Force states that it is trying to solve.

If the Task Force is concerned about a risk of competition issues affecting the price of risk management products, then using observed market prices as the basis for constraining the conduct of gentailers that it suspects of exercising market power (whether unilaterally or jointly) will be ineffective. Such an approach to setting ITPs would simply result in external pricing for risk management products being benchmarked to the same level as current market outcomes and therefore resulting in no change to pricing outcomes.

It is possible that an ITP based on market prices could change some non-price aspects of market outcomes – for example, by increasing the liquidity of trading at the market price. This may give rise to some near term benefits to buyers of risk management products. However, it may also increase the costs for some sellers of risk management products if the market price – being the observed price at which some transactions occur – represents a price at which those sellers are not willing to exchange risk.

3.2.2 Trading all risk management products may not be effective

The Task Force proposes as part of its step 3 intervention that all risk management products must be transacted through a market platform. The degree of effectiveness of this style of intervention is likely to depend on its design – with some potential implementations being either ineffective or harmful for competition and economic efficiency. In section 4.3 we propose an alternative option for addressing the Task Force's concerns that is conceptually on the same spectrum as step 3 of the Task Force's proposal, albeit reflecting a much more flexible and lower-cost approach to providing access to risk management products.

We explain in section 3.2 above that a gentailer is indifferent as to the terms on which it transacts with itself and would equally be happy to charge itself *more* than other retailers or generators – because the price at which it interacts with itself is economically meaningless.

It follows that any transactions through a market platform in which a gentailer can identify its own risk management products *and* make offers on these products will be ineffective. A gentailer would remain the natural buyer of its own risk management products and would be prepared to pay more for these products than any other retailer or generator, were they to be transacted through a market platform. Accordingly, implementation of the step 3 mechanism with these characteristics would be unlikely to change either:

- the extent to which the large gentailers transact risk management products with themselves; or

[36] Options paper, appendix B, para 15(a).

- the price or the quantity of risk management products sold by the large gentailers.

The Task Force explains that it could configure the step 3 intervention to further reduce any advantages that the large gentailers might have, eg, by preventing the large gentailers from trading risk management products with themselves through the platform.[37] However, this amendment has the potential to give rise to significant harm to competition and economic efficiency.

We would expect an intervention of this type to result in substantial changes to the way in which trading of risk management products would take place. In particular, the large gentailers would be required to acquire risk management products only from other businesses. This intervention would be likely to eliminate completely the principal form of vertical efficiencies that are enjoyed by the large gentailers. Indeed, it would go further by conferring benefits on gentailers that choose to divest their generation and retail arms into separate businesses, since this would provide them more options from which to purchase risk management products.

The long term effects of an intervention of this kind would increase the costs of supplying electricity, and most likely the price that consumers must pay for that electricity. This follows from a straightforward application of the economic principles that we present in section 2.2 above, ie:

- it is likely that the reason that large and vertically integrated businesses dominate the supply of electricity in New Zealand is because this is the lowest cost means of supplying electricity;[38] and
- interventions that prevent businesses being able to compete through pursuing the least cost means of service provision are likely to raise costs, and therefore prices.

3.3 Costs underpinning ITPs are unobservable and difficult to estimate

Although there is no internally traded price (or set of prices), in some circumstances it may be economically meaningful to say that, in principle, the 'marginal cost' applicable to each relevant point in time is the implicit reference point for an internal trade of a particular risk management product. This is because marginal cost reflects the resources that the integrated business must expend by 'purchasing' the input from itself, rather than at arms' length from another business.

However, in the context of New Zealand's energy system, with the high relative importance of hydroelectric power as a flexible resource, the concept of marginal cost is extremely difficult to pin down. Further, it is likely to be difficult to discern the marginal cost associated with self-supply from the marginal cost associated with serving external firms, such that vertical efficiencies may be lost if ITPs are set on this basis.

3.3.1 Marginal costs are unobservable and dynamic

The marginal cost for a hydro generator is derived by reference to its water value, ie, the value ascribed to its stored water at the applicable point in time. This value varies from time to time and, depending on the type of hydro generator, within days and/or across weeks, months and years since, at any point in time, the water value for a given hydro generator will reflect:

- the extent of its storage capacity, which may vary substantially across each of its generation units;[39]
- its near term (ie, seasonally influenced) and long term expected inflows;

[37] Options paper, para 6.30.

[38] An alternative view – that large and vertically integrated businesses dominate the supply of electricity in New Zealand because they leverage market power in the supply of generation into the retail market – has important economic flaws. A monopolist generator would prefer to transact with a competitive and efficient retail business, in preference to its less efficient affiliate, because this will lead to higher firm profits. This follows from the economic proposition that there is only "one monopoly profit".

[39] By way of example, a run-of-the-river or very low storage hydro generator can expect its water value to fluctuate significantly within periods as short as a day or an hour, while a hydro generator with substantial storage capacity can expect its water value to vary by much smaller degree and over much longer time periods.

- its sustainable annual output valued at the annual average market price for that output; and
- the extent to which recent inflows and/or offers of capacity into the market have caused its water level to depart from the level implied by the various considerations described above.

This variability in turn indicates that if a single, economically meaningful ITP could be calculated, it would, at best, be:

- an approximate and highly aggregated price that did not correspond with any identifiable hedging instrument; and
- expected to change frequently as new information about water inflows and market prices comes to light.

Further, since the stock of water and/or characteristics of each hydro generator are different for each gentailer, the ITP that each generator would report would be different and would be expected to change in response to transactions that a gentailer enters.

In contrast, the Task Force appears to assume that a portfolio of hypothetical internal contracts administratively established at a point in time would be relevant for the pricing of all or most subsequent offers of risk management products to buyers.

The economic circumstances sitting around this task mean that it is very far removed from those applying in other sectors, such as telecommunications, where the use of cost-based principles applied to estimate access prices is routine. For example, the Commerce Commission (the Commission) regulates (or has regulated in the past):

- the price of fibre fixed line access services (FFLAS) provided by local fibre companies (LFCs);
- the price of copper fixed line access services such as unbundled copper local loop (UCLL) and universal bitstream access (UBA), provided by Chorus; and
- the price of mobile termination access services (MTAS), provided by mobile network operators (MNOs).

In each of these cases, the Commission has applied cost-based methodologies to estimate access prices. Access prices in these examples are firmly grounded in the relatively stable and readily identifiable costs of building and operating physical assets.

In addition to these fundamental distinctions, there are further important differences in the economic justification for intervention applying in the telecommunications industry, because:

- in each of the examples set out above, the obligation to provide access on a regulated basis arises because of monopoly control over a service (including in the case of MTAS, in which competing firms may exert monopoly control over terminating access to subscribers on their network) so that there is no competition to discipline the terms of access; whereas
- in the situation involved with the provision of risk management services, there is competition involving four providers for services, such that the setting of regulated access prices may substitute for and likely displace competitive rivalry that could otherwise occur.

3.3.2 Cost-based vertical efficiencies are likely to be difficult to estimate

The Task Force recognises that vertical efficiencies between generators and retailers exist, but its assessment does not take account of these efficiencies, and they may be lost if the Task Force's proposals are implemented.

The Task Force sets out a range of vertical efficiencies that can arise from the integration of generation and retail functions, including lowering risk, reducing financial costs, lowering transaction costs and economies of scope.[40] It says these are 'valuable',[41] but makes no attempt to describe or estimate the magnitude of the efficiencies. They could, therefore, be much greater than any of the potential benefits identified by the Task Force.

The Task Force identifies the use of contracting and demand response as a substitute for vertical integration,[42] leaving unclear the extent to which it considers that vertical efficiencies reduce costs for the supply of electricity. We note that the Authority has previously said that contracts are not an effective substitute for vertical integration:[43]

> …while non-integrated retailers do have options for risk management … these options may not provide the same level of risk reduction that vertical integration provides. That is, non-integrated retailers cannot reproduce the risk-reducing benefits of physical hedging by pure contractual portfolios.

The Task Force presents the in-principle contention that competitors of the large gentailers should have access to inputs on substantially the same terms as implied by internal transactions.[44]

On the question of whether the large gentailers should be able to retain their vertical efficiencies by offering different terms to their external customers as compared to themselves, the Task Force presents a variety of positions, that generally reflect a requirement that it be 'cost-based' and 'objectively justifiable'.[45] This framing of the regulatory obligation would allow the large gentailers to retain their vertical efficiencies only where these are:

- 'cost-based' or 'cost efficiencies', the meaning of which is unclear but may imply some distinction between costs and risks that is not economically meaningful; and
- 'objectively justifiable', which appears to place the onus on the large gentailers to quantify vertical efficiencies that they seek to retain.

The Task Force does not engage with the question of whether vertical efficiencies enjoyed by gentailers would be capable of being measured in the 'objectively justifiable' manner that it proposes to require. The most important of the vertical efficiencies most likely reflects the transactions costs savings and risk mitigation derived from being able to better manage risks by means of the internal provision of generation and/or demand side management. These benefits are inherently difficult to quantify with any precision and so it is unclear – and the Task Force does not explain – how gentailers would be able to calculate ITPs that would net off these benefits in a manner that would satisfy subsequent regulatory scrutiny.

The outcome is therefore likely to be ITPs that may incorporate vertical efficiencies that do not apply to the supply of risk management products to external firms. We explain in section 2.2.3 that offering risk management products at prices below marginal costs would give rise to both allocative and dynamic inefficiencies.

[40] Options paper, para 3.17.

[41] Options paper, para 3.20.

[42] Options paper, para 3.20.

[43] Electricity Authority, *Reviewing risk management options for electricity retailers*, Issues paper, 7 November 2024, para 7.5.

[44] Options paper, para 5.5.

[45] Options paper, appendix B, paras 1, 14 and 16.

4. Economic analysis and alternative options

Typically, economic analysis demonstrating that a preferred option would give rise to net benefits that are positive and exceed those of other options is expected to underpin regulatory or policy interventions. This is all the more relevant given the significance of the intervention proposed by the Task Force and the importance of the electricity sector to the New Zealand economy.

In this section, we:

- explain that the Task Force's economic analysis proposal is insufficient, relative to a typical economic or policy analysis that would include an evaluation of the costs and benefits of each option;
- discuss the intrinsic challenges with assessing the benefits of intervention in the electricity market and how this might influence the design of any intervention proposed by the Task Force; and
- introduce an alternative and preferable option for addressing the Task Force's concerns, involving the expansion of market-making obligations.

4.1 Economic analysis of the proposal is insufficient

Typically, economic analysis demonstrating that a preferred option would give rise to net benefits that are positive and exceed those of other options is expected to underpin regulatory or policy interventions. For example:

- the Authority is required to undertake an evaluation of the costs and benefits of any proposed amendment to the Code;[46] and
- in most countries significant government decision-making is expected to be accompanied by some form of economic analysis – in New Zealand this is known as regulatory impact analysis.[47]

In our opinion, the economic analysis supporting the Task Force's proposal is insufficient to support its conclusions. The Task Force appears to have given little consideration to weighing the benefits and costs of its proposed intervention, and particularly its potential efficiency consequences.

The Task Force states its belief that the benefits of its proposal would exceed the costs. For example, it contends that:[48]

> We currently consider that the costs incurred by Gentailers in complying with non-discrimination principles are likely to be outweighed by benefits to consumers arising from greater competition, particularly over the longer-term.

The principal basis for this finding appears to originate in an implicit assessment that the harms arising from lost vertical efficiencies for the large gentailers would be more than offset by greater competition for the retail supply in electricity. The Task Force acknowledges that its proposal would affect vertical efficiencies, ie:[49]

> …this change may have implications for the Gentailer business model, with one of the key benefits of vertical integration being reduced and their retail business consequentially losing some level of certainty about the durability of a key input.

[46] Electricity Industry Act 2010, s 39(2).

[47] Ministry of Regulation website, https://www.regulation.govt.nz/our-work/regulatory-impact-analysis-ria/, accessed 30 April 2025.

[48] Options paper, para 6.51.

[49] Options paper, para 6.50.

Weighing against these costs, the main benefit noted by the Task Force as arising from its proposed non-discrimination obligations is an increase in the externally-offered volumes of risk management products.[50]

We agree with the Task Force that these are important issues. However, missing from the Task Force's options paper is:

- a clear evidence-based assessment supporting its view that the benefits arising from an increase in the externally-offered volumes of risk management products exceed the costs arising from a lessening in the vertical efficiencies of electricity supply; and
- any assessment or finding that its preferred option is the lowest cost means by which these benefits could otherwise be achieved.

4.2 Challenges with assessing benefits of interventions

We explain above that the Task Force's proposed intervention appears to reflect an assumption that the benefits it would achieve in overcoming market power exceed the costs that this would impose through the loss of vertical efficiencies and potential harm to the competitive process. However, the options paper does not set out any analysis that would support this conclusion.

In general the economic analysis of a competition measure in New Zealand's electricity market is difficult. This has important consequences for the style of intervention that the Task Force should consider – being one that is scalable to the size of the problem that it seeks to address.

An economic analysis of the Task Force's proposal is further complicated by the fact that it comprises three distinct interventions, yet the likelihood and timing of the application of each intervention is uncertain. This highlights the importance of clearly-defined triggers in forming an assessment of the costs and benefits of the proposal in the round.

We discuss these observations in more detail below.

4.2.1 Any intervention by the Task Force should be scalable to the size of the problem

We explain in section 1.2 that the periodic, transitory possession of market power is an intrinsic feature of New Zealand's energy-only market. This in turn raises well-understood difficulties with identifying the degree to which the possession of such market power is a competition concern.

Since the question of whether (or not) there is potential for market power in an energy-only market to be enduring and substantial is inherently difficult to resolve by empirical analysis, the Task Force's priority should be to develop measures that are capable of being introduced and enhanced in a gradual process of successive adjustment, in response to strengthened empirical evidence.

Although the Task Force's proposal is framed as three steps of increasing intervention, it does not represent a gradual process of adjustment.

Steps 1 and 2 of the Task Force's proposal, in which ITPs are set through a methodological approach, appear to reflect an attempt to replicate and perhaps to supplant the process of a competitive market through administrative requirements on price-setting by firms that are already in competition with one another. This would not be a gradual adjustment and the Task Force does not describe how the process of moving between steps 1 and 2 would be responsive to the degree of concern and extent of economic evidence. It appears likely that movement to step 2 and more prescriptive intervention would be inevitable if step 1 is ineffective as we suggest in section 3.2.1 above.

However, we have not seen evidence sufficient to conclude that competition is performing so poorly that it would be preferable to rely instead on administrative controls in an industry in which there are four large

[50] Options paper, paras 6.39-6.43.

gentailers. Reliance on administrative controls is unlikely to perform as well as competition because, even if the intervention is successful at requiring gentailers to offer risk management products at marginal cost, it will eliminate incentives that gentailers face to invest or innovate in relation to the flexible sources of electricity supply.

Step 3 of the Task Force's proposal represents a fundamental change to the arrangements for risk management contracting. For the reasons that we explain in section 4.3, step 3 would impose costs that far exceed those required to increase the availability of risk management products to non-integrated retailers.

4.2.2 Well-defined triggers are required to underpin an assessment of the proposal

The Task Force's proposal comprises three distinct interventions – being steps 1, 2 and 3. This complicates any economic assessment of the Task Force's proposal, since:

- each of these interventions will likely have different benefits and different costs; and
- it is unclear when or in what circumstances each of these interventions would apply.

However, there are approaches that are capable of overcoming this complication.

Conceptually, we understand that steps 1, 2 and 3 are ordered in increasing degree of intervention. It appears likely that more significant interventions are associated with both higher direct and indirect costs than less significant interventions. The economic case for more significant interventions therefore turns on the premise that they may be appropriate to address more significant harms.

For the Task Force's proposal to contain three distinct interventions, it must be the case that each of these interventions could be said to give rise to the greatest net benefit for at least some reasonably foreseeable set of economic circumstances.

It follows that the key element to demonstrating that a proposal constructed in this way maximises net benefits is to show the range of circumstances for which each intervention is best suited. The boundaries between these circumstances therefore represent the 'triggers' that identify where one intervention becomes more net beneficial than another.

4.3 Enhanced market-making could address the Task Force's concerns

Our observations earlier in this report highlight that the non-discrimination obligations proposed by the Task Force are not well-suited for the purpose of addressing the competition risks that it identifies. These findings suggest the need for a solution that is both:

- better targeted, in the sense that it addresses the source of concern, being the availability of risk management products to non-integrated retailers; and
- more 'scalable', in the sense that it can be adjusted in its degree of intrusion so as to be proportionate to the degree of concern.

In our opinion, the Task Force's objectives for its intervention would be better promoted by the introduction of enhanced market-making obligations on gentailers.

Market-making obligations are not a new concept in New Zealand and are already imposed on the large gentailers in respect of base load futures. The current arrangements require each large gentailer:[51]

- to provide buy and sell quotes for a minimum of 24 monthly 0.1 MW base load futures at each of the Otahuhu and Benmore reference nodes, for the current month and each of the next five months;

[51] Electricity Industry Participation Code, s 13.236L and definitions of "NZ electricity futures" and "total required volume",

- to provide buy and sell quotes for a minimum of 24 quarterly 0.1 MW base load futures at each of the Otahuhu and Benmore reference nodes, for each calendar quarter that is available for trade on an exchange;
- to provide buy and sell quotes at a bid-ask spread that does not exceed the greater of 3 per cent or NZ$2; and
- to continue to provide buy and sell quotes until it has traded the total required volume of 2.4 MW of base load futures in relation to each base load future product on which it is required to quote.

It follows that the implementation costs of enhanced market-making obligations are likely to be lower than other means by which access to risk management products can be provided. However, the provision of market-making obligations still come at a considerable economic cost, which must be considered by the Task Force in framing its preferred degree of intervention. For example, the costs of implementing and operating the commercial market-making scheme, which comprises 20 per cent of market-making, was $14.4 million in 2021-22,[52] indicating that the overall cost of the scheme is likely to be in the order of $70 million per year.

In our opinion, market-making obligations are a much preferable form of intervention to those based on the use of ITPs, because they are market-based. This intervention places a very strong obligation on gentailers to provide access to risk management products, without the potentially extensive yet presently opaque reporting requirements associated with administrative interventions such as steps 1 and 2 of the Task Force's proposal. Further, to the extent that there are differences between the individual circumstances of gentailers, we would expect this to result in market prices that are aligned across them and are accessible to independent retailers.

Market-making obligations provide a mechanism for exposing the large gentailers to direct and transparent competition with each other in setting the price for risk management products. A gentailer would not have an incentive to set prices for its risk management products above or below its internal cost of supplying those products (excluding its efficiencies in self-supply) because, if it did so, it would expose itself to the prospect that other market participants (including other gentailers) may arbitrage that position, such that it could end up either over-contracted (ie, short on generation) or under-contracted (ie, long on generation), relative to its risk preferences.

Enhanced market-making obligations should extend the scope of existing market-making obligations to include a wider range of risk management products, rather than just base products. This is targeted towards the concerns noted by the Task Force, by allowing retailers to tailor better their use of risk management products to reflect their risks. Enhanced market-making obligations could also increase the scale of market-making obligations, where these are insufficient, to ensure that there is sufficient depth or liquidity across these instruments.

The use of market-making obligations is inherently flexible. Regular reviews could be used to assess the success of these obligations in achieving desirable market outcomes, with the option available to further deepen these obligations, either by making a greater proportion of flexible generation subject to these requirements, or to broaden the scope of the obligations.

In this respect, the use of market-making obligations is conceptually on the same spectrum as step 3 of the Task Force's proposal. However, step 3 exists at one end of a spectrum of market-making obligations, in which *all* risk management products of *all types* must be traded in a market environment. The cost of degree of intervention is likely to be exceedingly high, as compared to more measured implementations of market-making arrangements that meet the need for access to risk management products at reasonable prices.

[52] Ministry of Business, Innovation & Employment cabinet paper, *Electricity Authority levy increase funding the commercial market making scheme*, 9 November 2021, paras 33-34.

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Various analyses of current electricity and gas market dynamics

4 May 2025

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Concept is one of New Zealand's leading applied economics consultancies. We have been providing useful, high-quality advice and analysis for over 25 years. Our roots are in the electricity sector and our practice has grown from there. We have developed deep expertise across the wider energy sector, and in environmental and resource economics. We have also translated our skills to assignments in telecommunications and water infrastructure.

Our directors have held senior executive roles in the energy and telecommunications sectors, and our team has a breadth of policy, regulatory, economic analysis, strategy, modelling, forecasting and reporting expertise. Our clients include large users, suppliers, regulators and governments. Our practical experience and range of skills means we can tackle difficult problems and provide advice you can use.

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Contents

1 Introduction

This note sets out analysis in four areas:

- system balance – examines current structural shortfall in electricity generation capability, its drivers, and outlook for restoring balance
- gas market – recaps recent gas market issues, lessons from recent history, and near-term outlook
- prices – reviews how wholesale and end user pricing for different consumer segments has evolved
- de-industrialisation – reviews scope of past and future electricity price-driven reductions in industrial activity.

2 System balance shortfall

Current and recent high prices have two key drivers:

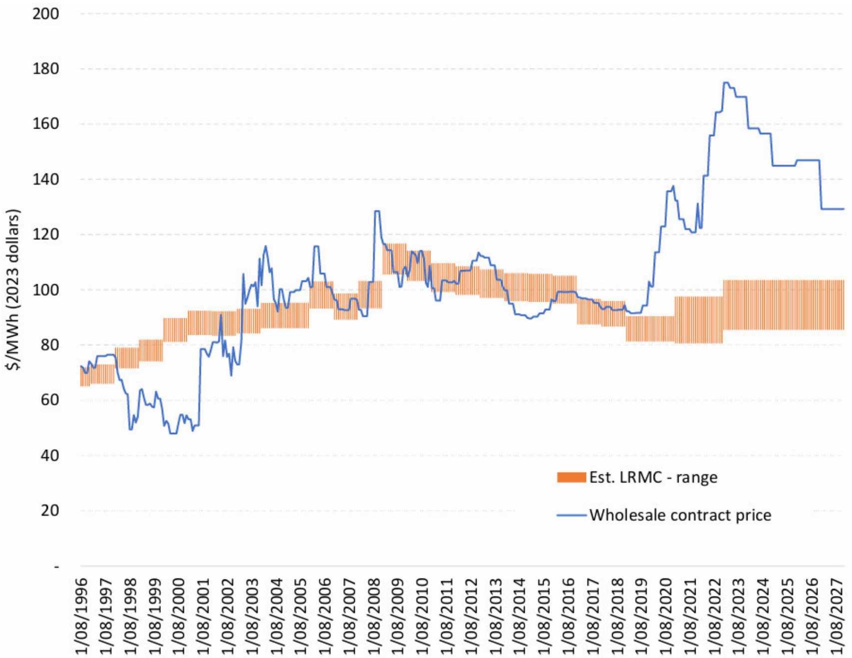
1. weather – low rainfall in hydro catchments means there has been a shortage of New Zealand's key renewable 'fuel'. This is a long-standing recurring feature of our hydro-based electricity system that will inevitably correct (or reverse) itself eventually when it rains
2. system balance – more fundamentally, there is currently a structural shortfall in electricity generation capability relative to demand. In this paper we refer to this as a 'system balance' shortfall.

A key indicator of the shortfall is the extent to which forward contract prices are above levels consistent with the long-run marginal cost (LRMC) of building new generation.[1]

This was illustrated in Figure 4 of the Electricity Authority's Level Playing Field options paper, repeated as Figure 1 below.

1 LRMC is the cost of expanding supply to meet demand. This includes the levelised cost of energy (LCOE) for the lowest cost mix of new generation, plus the cost of 'firming' that new generation to match the within-day and through-year profile of demand.

Figure 1: Contract prices and estimated costs for new baseload supply



Source: Copied from https://www.ea.govt.nz/projects/all/energy-competition-task-force/consultation/level-playing-field-measures/

Forward contract prices for a year in advance are the best indicator of system balance, because their price is not influenced by current weather (or hydro storage) conditions.

These prices should represent likely spot price outcomes given the expected system balance, probability-weighted across the range of possible weather outcomes – eg, the chances of it being 'dry' versus 'wet'.

If the system balance is short, there is greater need to call on higher-priced supply sources – particularly when renewable generation is scarce during lulls in rain, wind or sunshine, or demand is high on cold days. Higher-priced supply sources include thermal generation (whose operating costs are much higher than renewable generation) and, at times of extreme scarcity, demand curtailment.

High contract prices are a signal to generators that it would be profitable to expand generation capability. Then, as new generation is progressively built in response to the price signal, the shortfall should progressively reduce until system balance is restored. At that time, contract prices should return to levels consistent with LRMC.

This dynamic of high contract prices incentivising generation investment is indeed what is starting to happen in New Zealand, with a large number of projects being progressed – albeit at various stages of development.

However, questions have been raised as to whether the pace of development has been fast enough, with prices having been high for around six years and with the ASX forward curve out to 2028 remaining stubbornly high. In this respect, it should be noted that the analysis in Figure 1 was undertaken in 2023. Since that time, if anything the separation between contract prices and LRMC has gotten worse, with forward contract prices being even higher relative to LRMC than was the case in 2023.

Against this background, this section of this paper presents analysis of:

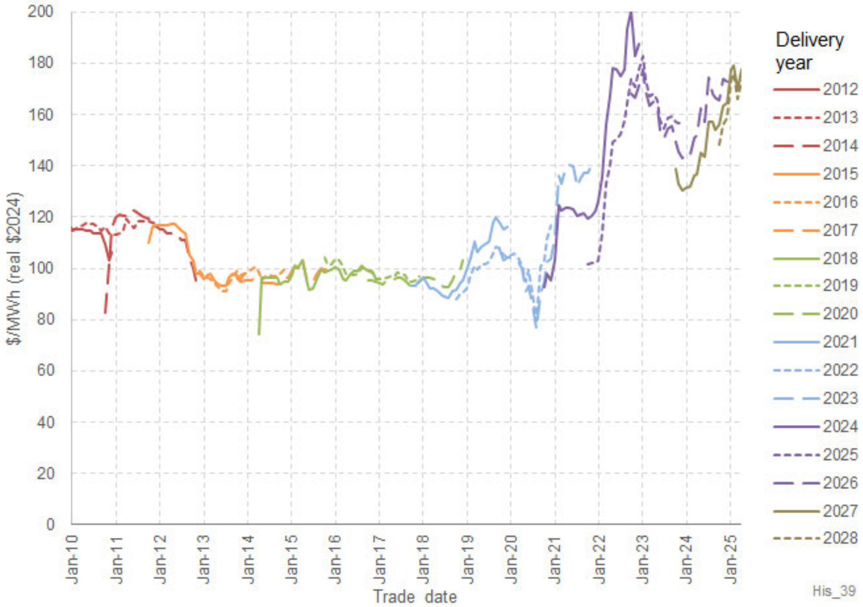
- potential causal factors for the current shortfall
- when the system is likely to return to a balanced position
- the level of investment that could (with perfect foresight) have prevented the shortfall and elevated prices experienced since late 2018
- the impact of uncertainty regarding the post-2024 future of the Tiwai aluminium smelter.

2.1 What caused the current shortfall?

Figure 2 indicates that New Zealand enjoyed a period of relatively stable contract prices, consistent with a balanced system, from the latter half of

2012 through to the first half of 2018.[2] At these prices, it would not have been profitable to build significant new renewable generation – ie, there was no need for new supply.

Figure 2: ASX Otahuhu forward contracts for calendar year strips (real $2024)

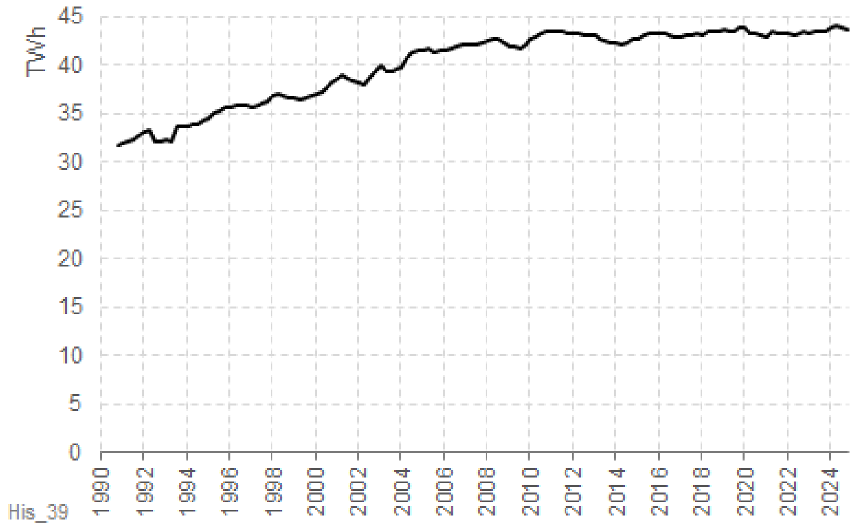


Source: Concept analysis of Electricity Authority data

What then caused the market to move into a disequilibrium state during the latter half of 2018, and why has it persisted?

Figure 3 indicates that it was <u>not</u> due to a rapid increase in demand, as there has been minimal demand growth since 2010.

Figure 3: Rolling four-quarters demand for generation (to Dec '24)

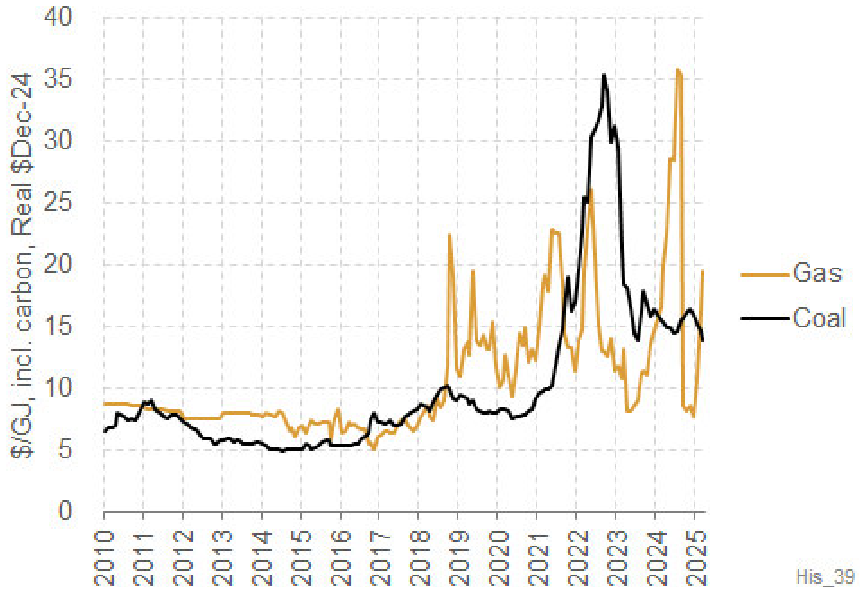


Source: MBIE data

Figure 4 indicates the principal driver of shortall was a sharp and sustained increase in fuel costs for New Zealand's thermal power stations from the latter half of 2018.

2 All prices in this paper are in real $2024 terms, with historical and forecast consumer price index (CPI) movements used to convert from nominal to real.

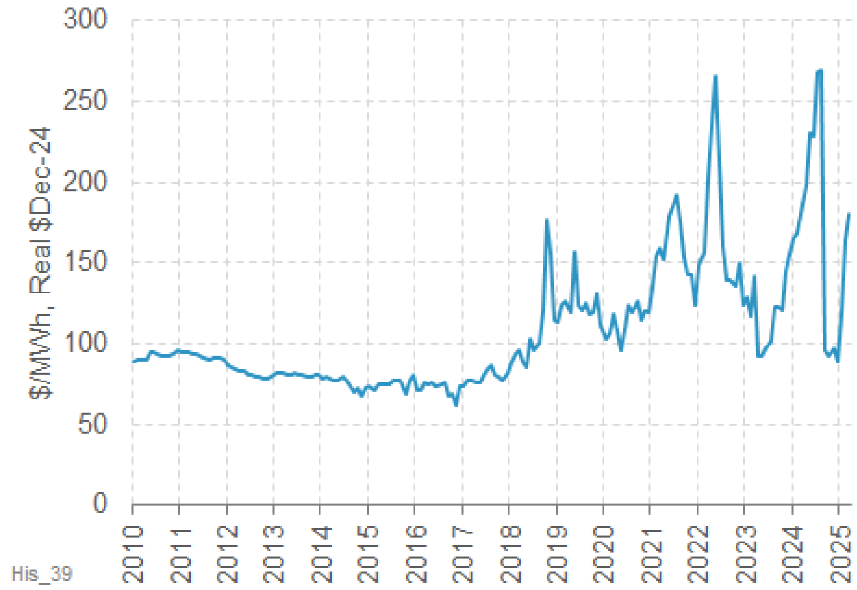
Figure 4: Monthly average gas and coal prices including carbon, Real $2024



Source: Concept analysis of EMS and IEA data

The broad effect on the cost of thermal power stations is illustrated in Figure 5, which shows a 'thermal SRMC index', being a simple weighted-average of the variable operating costs of thermal power stations.[3]

Figure 5: Thermal 'SRMC index', Real $2024



Source: Concept analysis of EMS and IEA data

The impact of this change in fuel cost is that:

1. prior to mid-2018 it was generally not profitable to build new renewable stations to displace thermal power stations

3 We have applied constant weightings that broadly reflect how often each type of thermal stations is the marginal price-setter: CCGT = 10%, Rankine = 40%, OCGT = 50%. Clearly, the actual relative weightings vary over time, but the intention of this simple 'index' is to illustrate the general nature and scale of thermal cost increases.

2. since mid-2018 it has become profitable to build new renewable stations to displace most thermal (reducing system cost, and hence lowering electricity prices)[4]

This thermal displacement has started to happen – as detailed further in the next sub-section – but it is reasonable to ask why it didn't happen sooner.

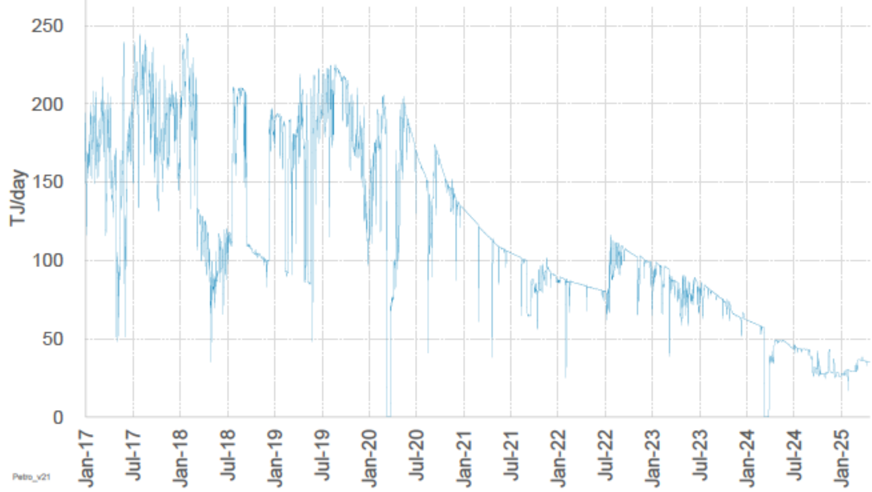
2.1.1 Gas supply has been persistently far less than projected

The initial explanation is that the rapid and sustained increase in gas prices from mid-2018 was unexpected.

The immediate cause of high gas prices in 2018 was the sudden failure in March 2018 of offshore wells for the Pohokura gas field – at the time, New Zealand's largest gas field, supplying approximately 38% of demand.

Figure 6, highlights the severity of the loss. For comparison, the loss was approximately equivalent (slightly larger) to a CCGT operating at full capacity.

Figure 6: Daily production from the Pohokura gas field

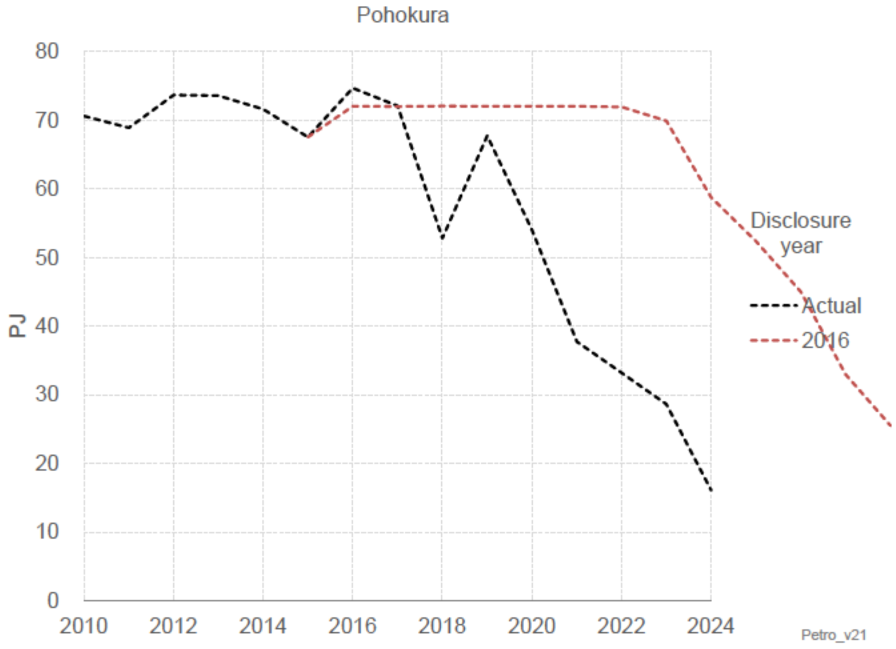


Source: GIC data

Figure 7 highlights that this loss was unexpected. It compares a publicly disclosed 2016 projection of annual production by OMV (the field operator) with actual annual production.

4 The reasons it would not be cost-effective to displace all thermal power stations are explained in some detail in our October 2022 '*Which way is forward?*' report (specifically see pages 13 to 15) – available for download here: https://www.concept.co.nz/updates. In short, while it is cost effective to build renewables to displace thermals from high-capacity-factor flexibility duty (ie, plant that is on most of the time and turns down at times of surplus), it is progressively less cost-effective to displace thermals from low-capacity-factor flexibility duty (ie, plant that is off most of the time and only operates during acute scarcity). This is due to differences in relative cost-structures (renewables are high-capex-low-opex, while thermal is the reverse) plus renewables variability becomes increasingly difficult to manage if relied on for low-capacity-factor flexibility.

Figure 7: 2016 projection of expected Pohokura output versus actual



Source: Concept analysis of MBIE data

The out-of-the-blue nature of the production loss and resulting gas price spike in mid-2018 meant it was not possible to respond with new generation, noting it typically takes many years to develop and commission a power station. Engineering studies, planning, negotiating with landowners, consenting, building a grid connection, sourcing equipment and completing construction all take time – particularly for geothermal and wind projects which, at the time, were the only technologies that were cost-effective (because utility solar was still relatively expensive).

For wind, an additional challenge was that some of the sites that had consents from several years earlier were for turbine technologies that were no longer cost competitive. In simple terms, for a given potential wind farm site the consents acquired several years ago were for a larger number of smaller, less efficient turbines. In contrast, using the latest technology would result in a smaller number of larger but more efficient turbines. This change in technology meant that sites had to be re-consented.

This long lead time for developing new renewable projects goes some way to explain why, for the years immediately following mid-2018, the market was short of renewables.

However, another (arguably more significant) factor for the delay is persistent over-signalling (and under-delivery) of gas production.

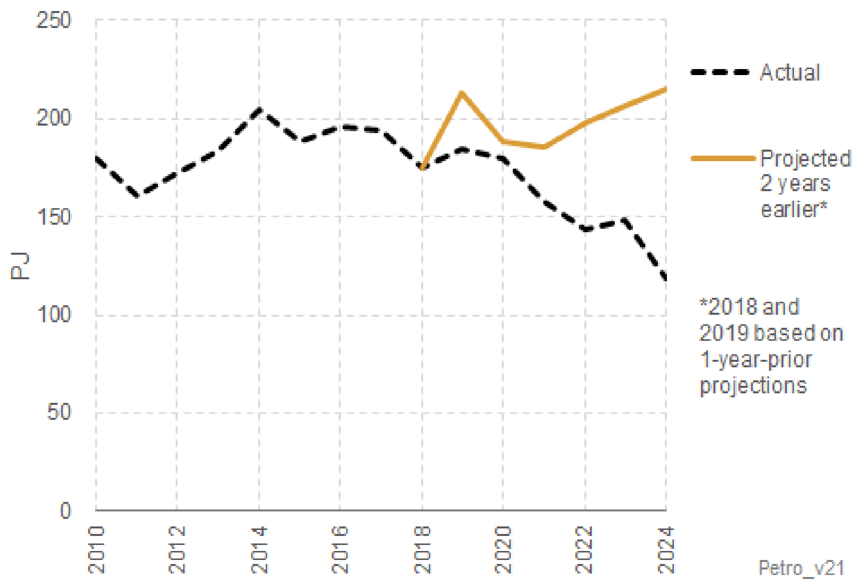
Following the failure at Pohokura, OMV indicated it was going to make a number of interventions to restore the field back to full production. Other operators signalled commitments to drill development wells at all of New Zealand's other main gas fields. In aggregate, upstream gas producers projected that gas production would return to, and even exceed, the previous high levels of production.

Over subsequent years, significant drilling activity did indeed take place – over $1.5 billion was invested from 2019 through to 2023 on development wells alone (ie, not including wells for exploring or appraising potential new fields).

Despite all this activity, Figure 8 shows that actual production was far less than projected. This was due to a combination of:

- drilling results being generally significantly worse than expected; and
- existing wells for many fields (particularly the offshore fields) declining – and in some cases failing – at a faster rate than expected

Figure 8: Projected versus actual whole-of-NZ gas production



Source: Concept analysis of MBIE data

The scale of shortfall was such that production in 2024 was 45% lower than projected at the start of 2022.

This situation, of persistently over-signalling and under-delivering gas production, will have materially dampened incentives to build new generation. Although short-term gas prices were high enough to justify new renewables, investors would have expected prices to ease back as gas production recovered to historical levels.

Importantly projections of gas supply provided by field operators were only on a P50 basis – ie, an equal probability that production would turn out higher or lower.

No projections were provided of the potential downsides to gas production – noting there is inherent uncertainty as to how much gas will be produced from a well once it is drilled, or how quickly its output will decline and eventually fail.

Because of these inherent uncertainties, it is standard practice for petroleum producers to prepare projections at different levels of probability – typically P10, P50, and P90 (known as 1P, 2P, and 3P) reflecting projections with a 10%, 50%, and 90% probability that gas production will be less than projected. However, gas producers are only required to provide 2P projections to the market at large through their annual disclosures to MBIE.

The lack of 1P projections in particular, meant energy market participants had no information regarding the downside risk for gas production.

Understanding downside (1P) projections is much more important than upside (3P). This is because there is a significant asymmetry:

- if there is a gas shortfall, prices rise steeply as supply moves up the cost curve, then steeper again if gas shortfall is particularly acute as demand rationing become necessary.
- in contrast, over-supply has relatively muted impacts. Methanex can generally absorb surpluses with little effect on price, and gas can be held in the ground one year for production the next – postponing the need for additional drilling.

If energy market participants had access to 1P and 3P projections, they would have had a better opportunity to develop a risk-weighted view of future gas prices, which would have provided a stronger signal to expand renewable generation.

Had new renewables been built just a couple of years earlier, it would have materially eased (although probably not completely eliminated) the extreme fuel scarcity experienced in Winter 2024 and is being experienced again this year – noting that pricing was driven in Winter 2024 (and again in 2025) at the extremely steep part of the cost-supply curve associated with demand rationing.

Section 3.2.1 sets out additional recommendations for improvements to gas disclosure requirements to improve this situation.

2.1.2 Uncertainty over the Tiwai aluminium smelter posed a significant risk for new renewable investments

Compounding the issue of gas production being materially lower than projected, there was also significant uncertainty regarding the future of the Tiwai aluminium smelter beyond its 2024 contract expiry. Had the smelter closed down, which its owners were indicating was a very real possibility, there would have been a 13% reduction in electricity demand – immediately pushing system balance into over-supply, with low prices and no need to build new generation. This risk would have significantly suppressed the incentive to build new generation.

This risk was removed in mid-2024 when the smelter signed a 20-year extension contract with no ability to exit within the first 10 years.

2.2 When will system rebalance?

After years of successive gas supply disappointments, the electricity sector now appears to accept that high gas prices are the new normal. Coupled with improved certainty regarding the Tiwai aluminium smelter, a wave of new generation developments are being actively progressed.

This sub-section considers how long it is likely to take to restore the electricity system to a balanced state, which should in turn see an end to elevated forward contract prices.

For this analysis, Concept has drawn on its database of potential new generation projects. This continuously-updated database records information about each generation project gleaned from developer announcements and other reports and studies.

Figure 9 and Figure 10 below show the 'pipeline' of projects in this database, differentiating by project development status and technology or developer.

Figure 9: Project pipeline by development status and technology

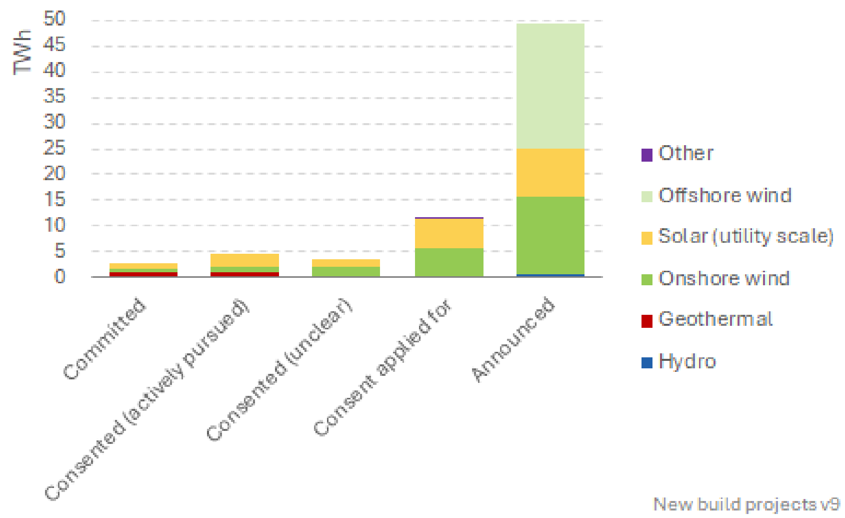
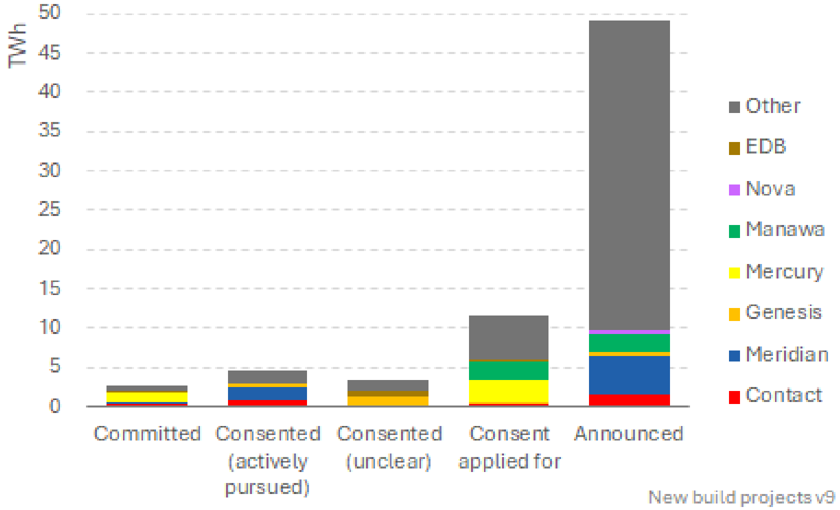


Figure 10: Project pipeline by development status and developer



2.2.1 Indicated commissioning dates

Figure 11 shows how much generation (expressed as GWh of energy per year) would be added to New Zealand's system if every project in our database were to proceed as per each developer's indicated commissioning date.

Figure 11: Projected GWh added if every generation project was built according to developer indications (up to 2024 = actual)

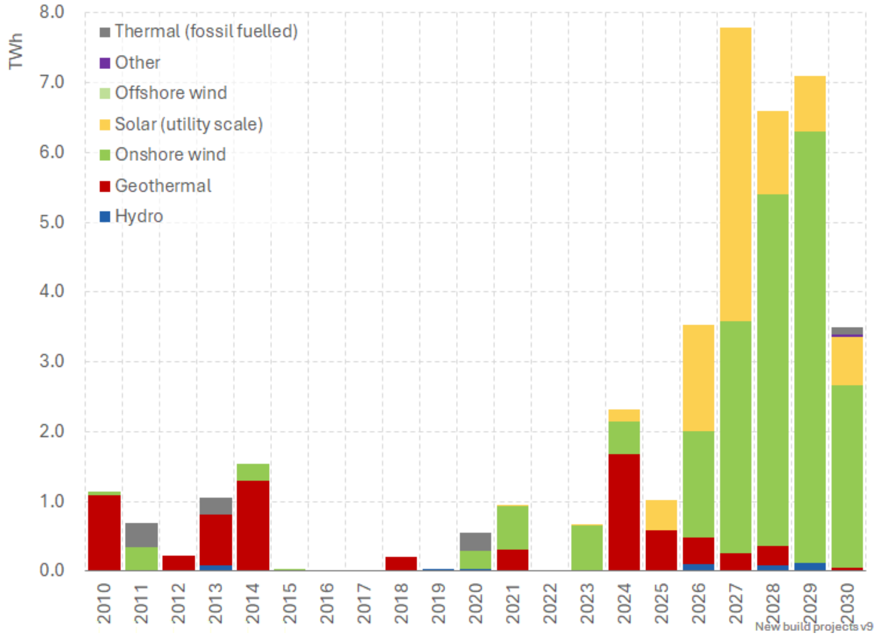
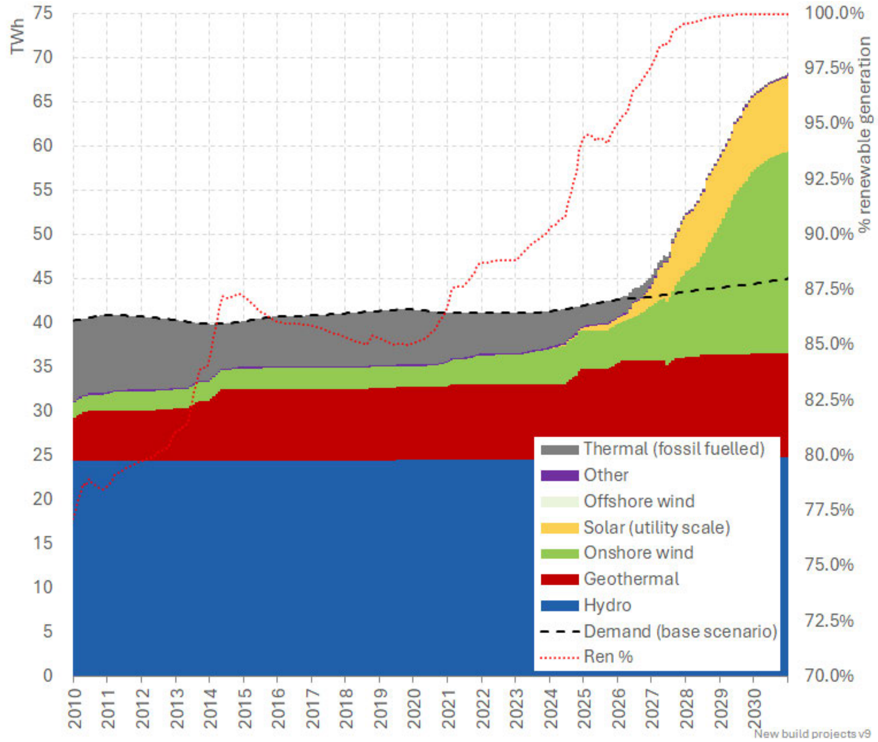


Figure 12 shows the resulting system balance outcome, assuming Concept's central demand growth projection of 0.75% per year from 2024 through to 2030, inclusive, based on our assessment of transport and process heat electrification over this period.

Additionally, the 'Ren %' line shows the percentage of generation that comes from renewable sources. This is the mean % generation, across all 'weather years'. (Ie, across the range of potential hydro, wind, and solar outcomes).

Note that the chart adjusts historical hydro and thermal generation to reflect mean hydrology, ensuring consistency between historical and projected system balance. The chart also excludes industrial cogeneration.

Figure 12: Projected system balance if every generation project was built according to developer indications (up to 2024 = actual)



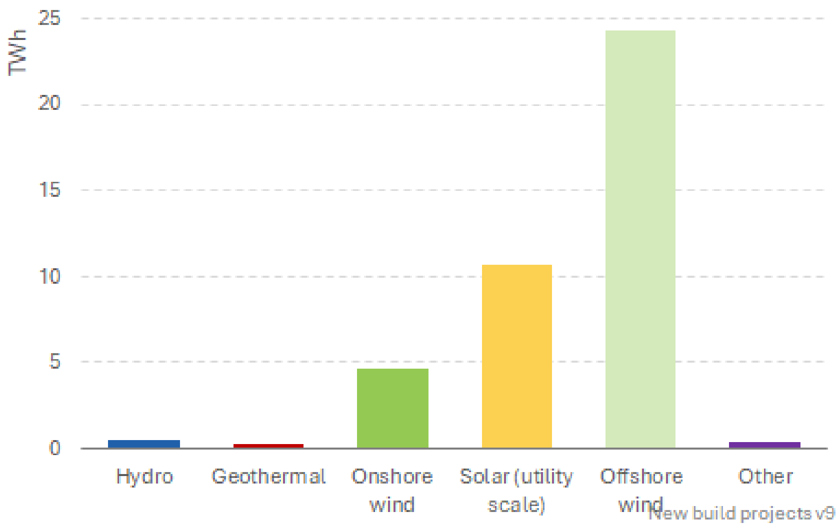
This projection indicates that, if all renewable projects were to be developed and commissioned at the dates indicated by the projects' developers:

- by 2028, thermal would be substantially displaced in a mean hydrology year (but would retain a significant role if 2028 were drier than average)
- beyond 2028, the system would move progressively toward a position of significant over-supply (unless demand growth picks up to an extreme extent, or developers significantly push back their plans).

The over-supply projected towards the end of this decade is clearly unrealistic. In this respect it is worth noting there are also *additional* projects for which developers have not indicated commissioning dates. These amount to a further 40.7 TWh per annum – ie, more than today's total demand and more than twice the amount of development shown in the earlier projection.

Figure 13 provides a breakdown of this additional potential supply by technology.

Figure 13: Additional announced projects for which no commissioning date has been announced



2.2.2 Realistic projection

To provide a more realistic projection, we have applied weightings to developments depending on their status, which we categorise as:

- commissioned – ie, already built

- committed – ie, under construction or passed FID[5]
- consented (actively pursued)[6]
- consent applied for
- announced – ie, a prospective project has been announced by the developer, but it hasn't reached the stage of applying for consents.

In our base scenario, projects that are committed are assumed to be 100% likely to go ahead, with no delay relative to the developer's announced timing.

For other project statuses, we apply the, by assumption, uncertainty de-rating factors shown in Table 1.

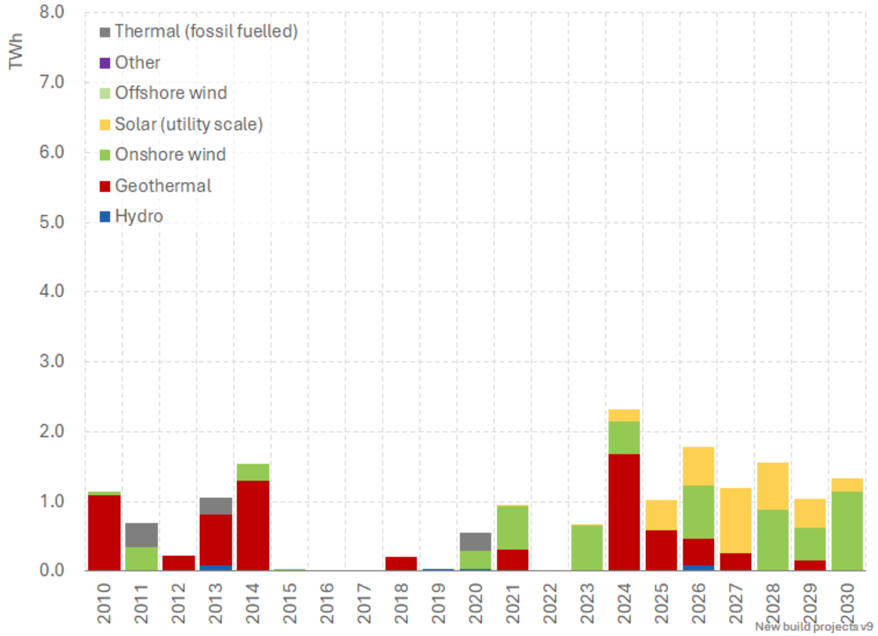
Table 1: Factors applied to projected projects in Base scenario

	Committed	Consented (actively pursued)	Consented (unclear)	Consent applied for	Announced
Prop'n proceeding	100%	64%	40%	22%	12%
Avg delay (mths)	0.0	7.9	11.9	20.0	21.3

New build projects v9

The resulting build schedule is shown in Figure 14 on the same scale as Figure 11, then in Figure 15 with a smaller vertical axis (which we then use for all subsequent graphs).

Figure 14: Base scenario of new generation developments (up to 2024 = actual)



5 FID = Final Investment Decision, after which the project will move to the construction phase.

6 This excludes consented projects where the developer has not indicated a likely completion date, as these projects are likely to be treated as future options, rather than actively pursued projects.

Figure 15: Base scenario of new renewable generation developments – smaller vertical axis scale (up to 2024 = actual)

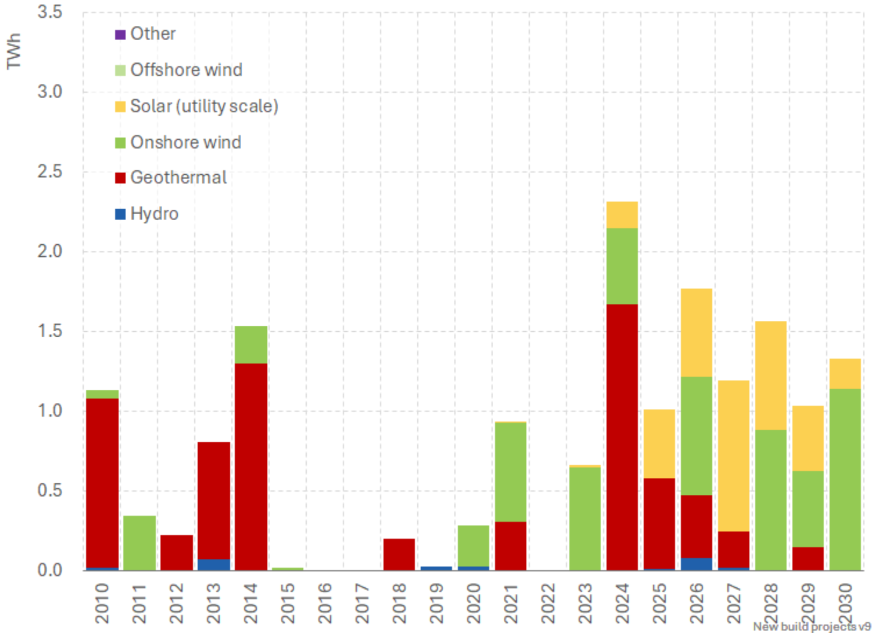
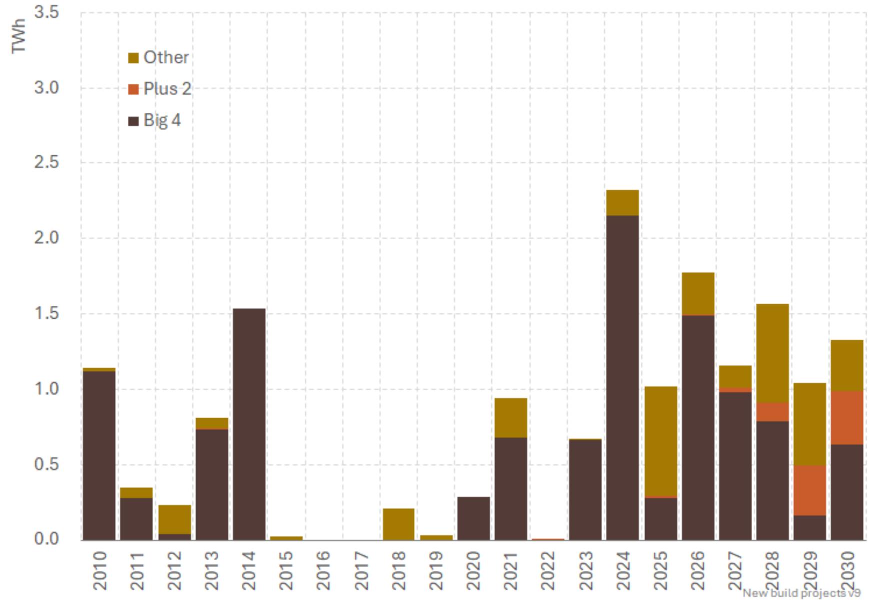


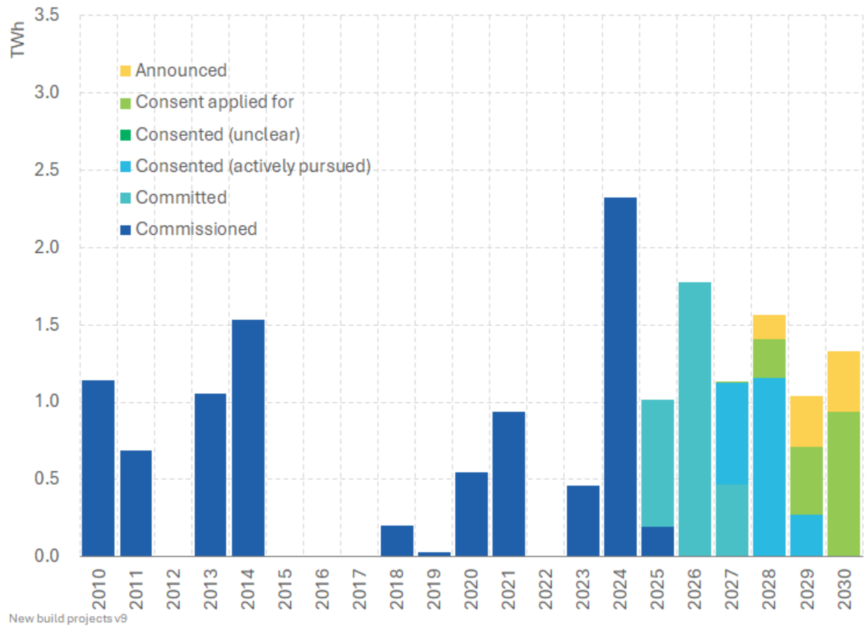
Figure 16 shows breaks down this historical and projected build by develop type – separating out the 'Big 4' gentailers (Contact, Meridian, Mercury, and Genesis), the 'Plus 2' gentailers (Manawa and Nova), and all 'Other' developers.

Figure 16: Base scenario of new renewable generation developments by developer type (up to 2024 = actual)



To provide further insight as to the likelihood of the projects being developed, Figure 17 breaks projects down by development status.

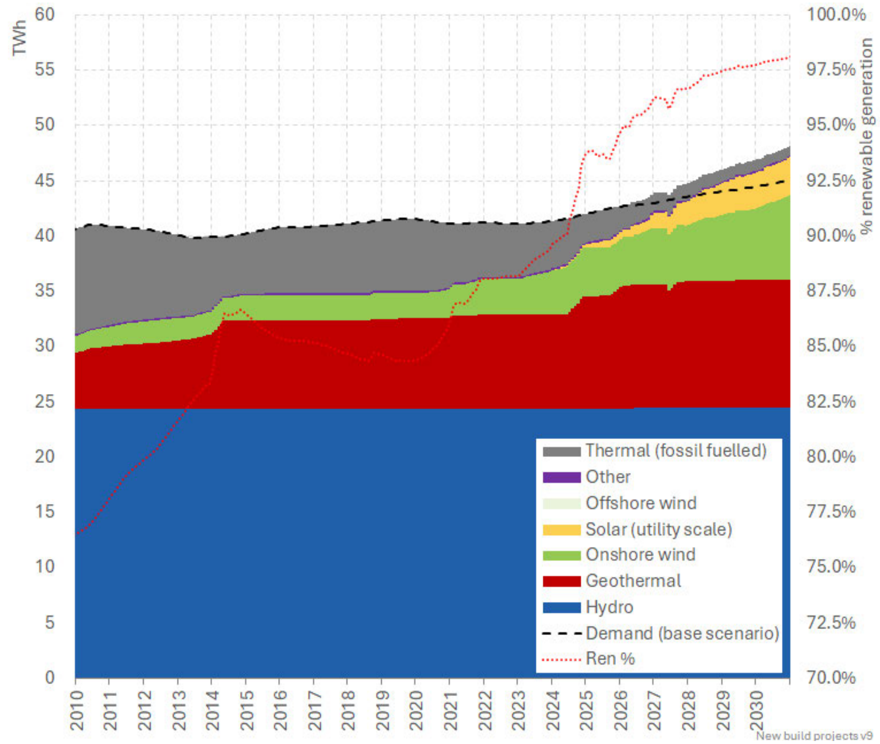
Figure 17: Base scenario of new generation developments by development status (up to 2024 = actual)



A significant proportion of the projected projects out to 2028 have a high-confidence development status – ie, 'committed' or 'consented (actively pursued)'. We have applied relatively conservative assumptions regarding the proportion of projects developed and their timing.

Figure 18 shows the projected system balance adopting the more realistic weighted developments from our base scenario.

Figure 18: Base projected system balance (up to 2024 = actual)



For latter years, the projected balance shows a cumulative total of renewable generation above the demand line, plus retention of some thermal generation. This reflects that:

- projections are on the basis of a mean 'weather year' – with mean rainfall, wind, sunshine and temperature
- at times (even within a mean year) there will be renewable 'spill' – eg, when it is warm and sunny, lakes are high, and the wind is blowing
- at other times, thermal will be required to firm supply – eg, when lulls in wind and sunshine coincide with low lakes and low temperatures.

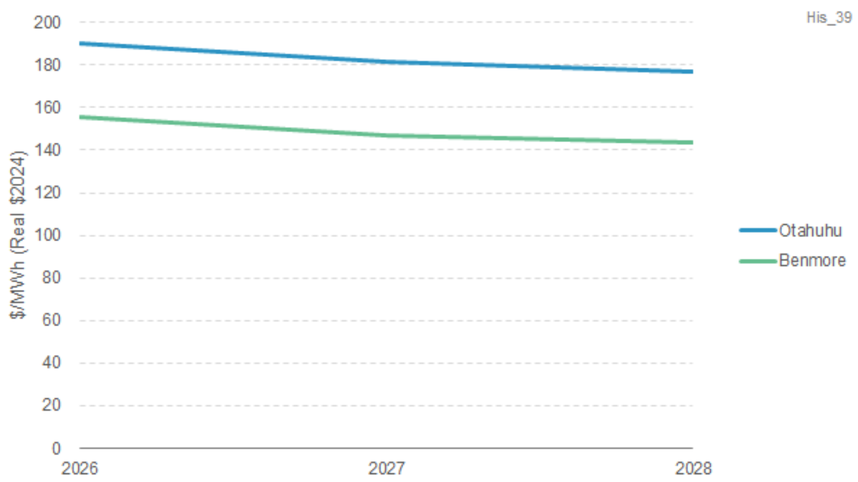
We combined the projections from Figure 18 with modelling from our most recent quarterly price forecasting to assess how quickly the system moves back into balance.[7]

This indicates that:

1. the system will be in balance by mid-2030, with contract prices returning to LRMC-driven levels
2. by mid-2028, the market will be close to balanced, with prices no longer significantly elevated above LRMC values.

This differs from the current ASX forward curve (shown in Figure 19),which indicates an expectation of shortfall persisting into 2028 – albeit with some relaxation compared to 2025.[8]

Figure 19: ASX hedge prices for calendar years 2026 to 2028, traded on 25 April 2025



This divergence between modelled and traded prices in 2028 could reflect a range of factors. Beyond caution and pessimism provoked by recent history, this could include market expectations of:

- greater delays to new generation
- more rapid demand growth
- higher thermal fuel prices.

In our price forecasting, we have assessed the sensitivity of outcomes to these factors and, while they could explain some of the difference, we still come to the conclusion that ASX prices for the outer years appear elevated beyond our assessment of market fundamentals. It is beyond the scope of this study to examine this issue in more detail.

2.3 What could have been built to prevent shortfall?

As set out in 2.1, two significant reasons for the current system balance shortfall are:

1. gas supply expectations – the mid-2018 supply shock was unanticipated, and producers subsequently over-signalled how quickly gas supply would be restored. The expectation of a return to lower gas prices dampened the signal to build renewables to displace thermal
2. Tiwai exit – until a new long-term contract was announced in mid-2024, there was a risk the aluminium smelter at Tiwai would cease production from the end of 2024. This material downside risk (amounting to 13% of electricity demand) further dampened the signal to build new supply.

We have assessed what would “should” have been built if developers had perfect foresight that gas prices step up and stay high from mid-2018 and that the smelter would commit to operating beyond 2024.

7 We updated our price forecasts quarterly and they are available for one-off purchase or on a subscription basis.
8 Our modelling projects 2025 prices that are only slightly lower than ASX prices.

To do this, we brought forward by 'x' years all projects developed after month 'y', and varied x and y until a balanced solution was found. This is a relatively simple approach that provides a reasonable first-order approximation up until the mid-2020s.[9]

The resulting parameters were to bring forward by seven-and-a-half years any projects commissioned from November 21 in our base scenario.

Figure 20 shows this "perfect foresight" build schedule, and Figure 21 shows the resulting system balance.

Figure 20: Renewable build schedule required to deliver a balanced market given perfect foresight of gas prices and Tiwai's decisions

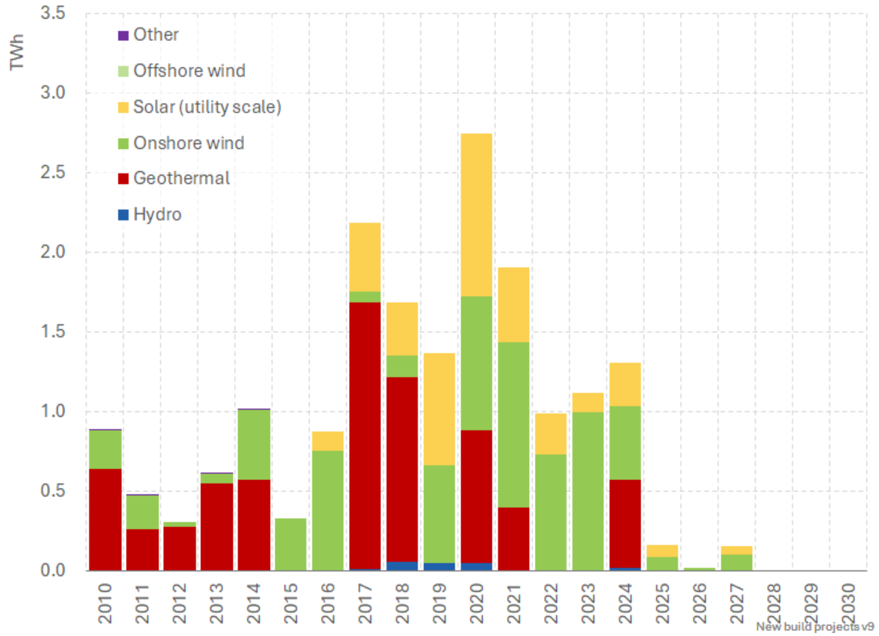


Figure 21: System balance with perfect foresight regarding gas supply and Tiwai production

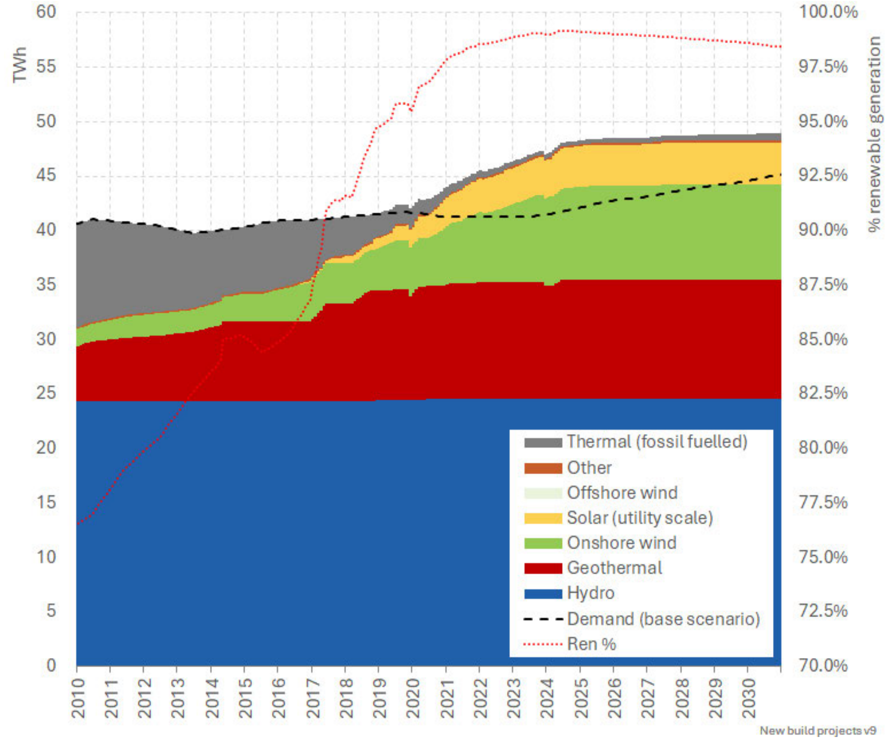
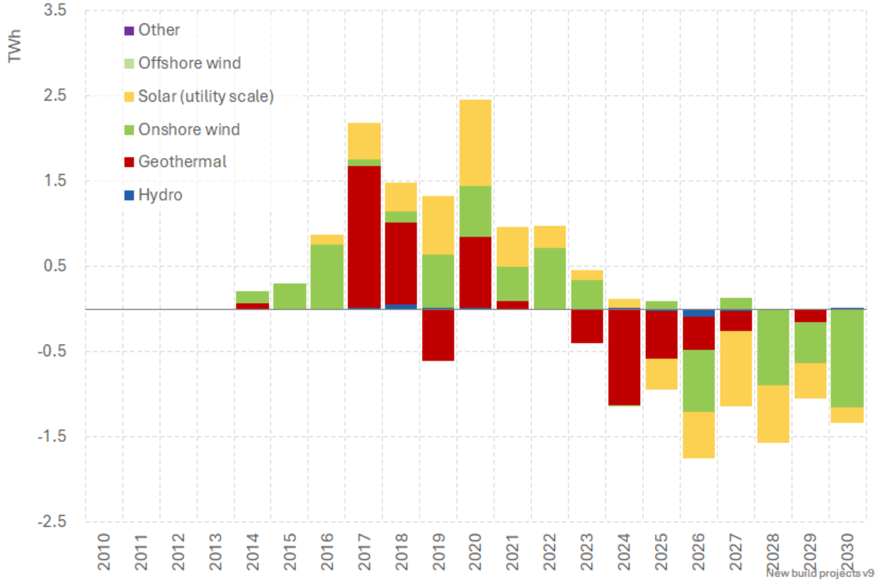


Figure 22 below shows the difference in build schedules between the two scenarios – ie, the difference between Figure 20 and Figure 15.

[9] A more sophisticated optimisation, which would alter outcomes in later years, is beyond the scope of this paper.

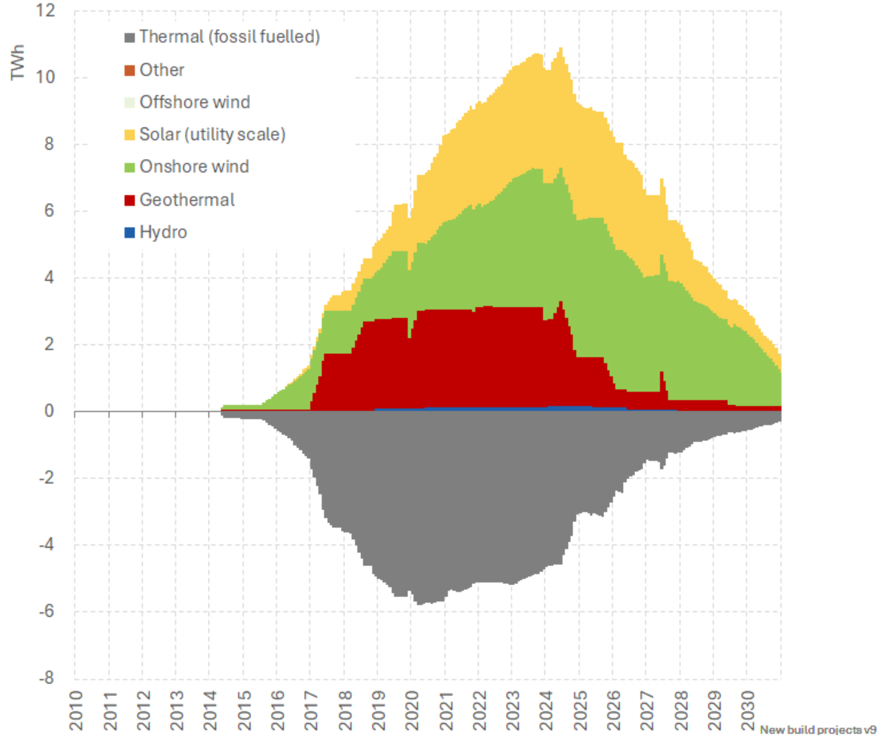
Figure 22: Difference in build schedules between perfect foresight and base scenarios



This shows the significant increase in build that would have been required throughout the middle of the last decade. Given the lead times for development, including engineering studies, consenting applications, and the like, this would have required efforts gearing up from 2012 or earlier.

Figure 23 shows the difference in generation outcomes between the perfect foresight and the base scenarios. Unsurprisingly, the perfect foresight world would have required far less thermal generation.

Figure 23: Difference in generation outcomes between perfect foresight and base scenarios[10]



10 Note that increased renewable isn't an exact mirror of reduced thermal because a portion of the renewable production would be spilled.

2.4 How significant was Tiwai uncertainty?

To illustrate the destabilising effect of uncertainty around Tiwai's prospects, the following two charts show the system balance outcomes for both the base and perfect-foresight scenarios, but with Tiwai exiting at the end of 2024.

Figure 24: System balance outcomes for base scenario if Tiwai exited at end of 2024

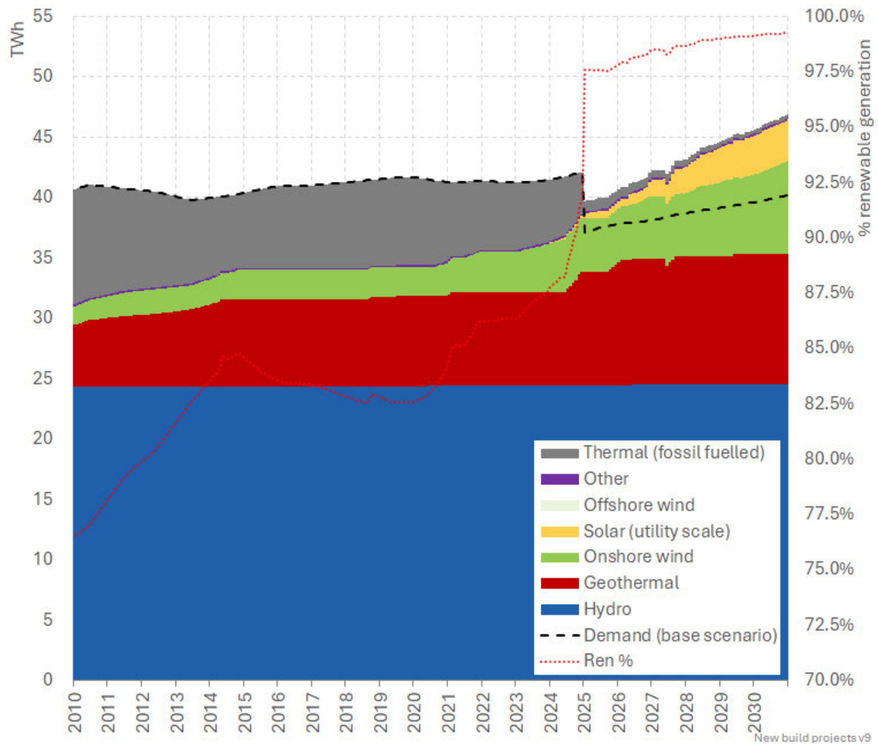
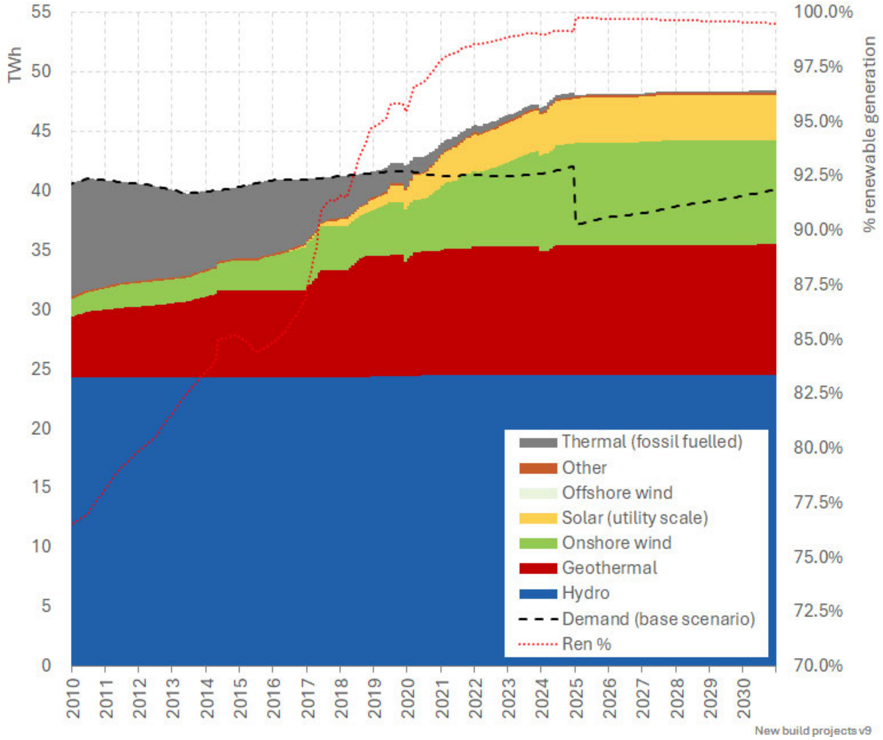


Figure 25: System balance outcomes for perfect foresight scenario Tiwai exited at end of 2024



The two figures illustrate how the system would have lurched into over-supply from 2025 onwards. The associated low prices would materially harm the profitability of projects built in preceding years – especially in the perfect foresight scenario.

With respect to the Base scenario, had Tiwai exited at the end of 2024, almost none of the projects projected to be built from 2025 through to mid-2029 would be required to bring the system into balance. Were they to still to proceed after a Tiwai exit, they would push the system into a surplus situation, with the resulting low prices making the investments unprofitable.

3 Update on gas market issues

As set out in section 2.1, the current tightness in the electricity system is in large part due to problems in the gas sector. This section of the report:

- recaps gas market issues experienced over the past decade, with a focus on the most recent years
- draws out some lessons from this experience
- provides a high-level evaluation of the future outlook for the gas sector.

3.1 Recap on past decade

After almost a decade of relatively balanced gas supply, in March 2018 an unexpected large-scale loss of supply from the Pohokura gas field (then New Zealand's largest field) caused the price of gas to rise significantly. In turn, this caused the cost of thermal generation to almost double.

For the following five years, the gas sector consistently indicated that planned drilling campaigns would restore gas production to past levels. This in turn would be expected to return gas prices to levels consistent with a balanced gas market. This expectation significantly suppressed the price signal to build renewables to displace thermal generation.

However, despite investing $1.5 bn drilling development wells, results were significantly below expectations across all six of New Zealand's main fields. In addition, several fields experienced rates of decline and well-failure that were faster than expected. Accordingly, rather than returning to balance, gas scarcity progressively worsened.

Declining gas deliverability was significantly masked in 2022 and 2023 because they were relatively wet years[11], reducing the need for gas-fired thermal generation and resulting in relatively subdued electricity spot prices. While this may have provided some short-term relief from the gas scarcity situation, it may also have weakened the impetus for larger electricity and gas consumers (and some retailers) to hedge forward. It may also have further suppressed the price signal to develop additional renewable generation.

However, 2024 turned out to be very dry – particularly in the critical winter quarters when electricity demand is highest. The third quarter was extremely dry, with hydro generation being the second lowest over the past thirty-two years. The resulting demand for thermal generation then brought gas market scarcity to light with:

- gas and electricity prices rising to extreme levels (as illustrated Figure 27 on page 24 later)
- very large volumes of coal burned at the Huntly power station
- some curtailment of electricity and gas demand, particularly from industrial consumers
- potentially, some permanent demand reductions. In particular, Methanex permanently idled two of its three methanol production trains[12] and some wood processing sites closed citing energy prices as a contributing factor.

Although Methanex idled one of its Motunui trains in March 2024, it kept the other train operating for most of the winter, even though the price of gas was substantially above the likely net-back it could receive from using the gas to produce methanol. At the same time, as illustrated in Figure 26, New Zealand was consuming large amounts of coal to power the Huntly thermal generator (effectively, New Zealand was making methanol out of coal).

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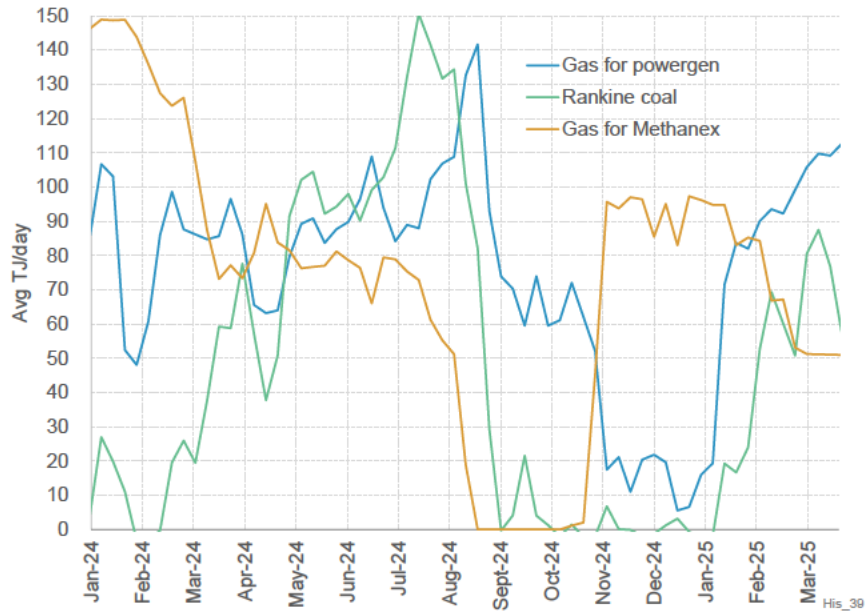
11 2023 and 2022 were the second and third highest years, respectively, in terms of hydro generation over the past twenty-five years.

12 The Waitara Valley train had already been idled in 2021, and one of its Motunui trains was idled in March 2024. Methanex subsequently indicated that these are likely to be permanently retired.

Figure 26: Weekly fuel consumption



Source: Concept analysis of GIC and Electricity Authority data

Eventually, however, Methanex did agree to on-sell its remaining gas entitlements to the two main gas-fired generators, Genesis and Contact, and idled its remaining train for the period from mid-August to the end of October.

This gas reallocation significantly alleviated electricity market scarcity. Soon after, the market lurched into significant surplus, with gas and electricity prices collapsing to close to zero, because:

- toward the end of July, Meridian exercised its contractual option to call on demand response from the Tiwai aluminium smelter, and subsequently
- heavy rainfall started refilling hydro reservoirs, displacing the need for thermal generation.

It appears that history has been repeating itself in 2025 with another extremely dry inflow situation, high coal use for electricity generation, high gas and electricity prices and, despite this, Methanex only reducing consumption to approximately 51 TJ/day.

It is not clear why, since economic fundamentals would strongly support reallocation of gas from methanol to electricity, Methanex has not struck a deal to on-sell its gas to electricity generators.

3.2 Lessons from recent history

3.2.1 There is an information problem

Greater transparency of gas production and contract pricing information would enable energy users, including the electricity generators and users, to improve their decision-making.

Gas producers are required to submit information to MBIE at the beginning of each year detailing their estimates of:

- reserves and contingent resources within each of their fields[13]
- projected production profiles for the reserves.

13 Reserves are accumulations of gas where the gas producer has already made, or has committed to make, the investment in development wells to extract the gas. Contingent Resources are gas accumulations where the gas field operator has expectations of the gas being there (to varying degrees of probability) but where it hasn't yet made any commitment to undertake the investment (and may never make such an investment) to develop the gas.

While the information that MBIE subsequently publishes is useful, it is arguably inadequate to support efficient decision making by parties impacted by gas supplies. Key issues are:

- delay – the information, which MBIE receives early in the year, is not published until the second half of the year
- frequency – annual updates are too infrequent at times of market stress. A quarterly cycle would significantly enhance information value. We understand at least some operators produce updated projections more frequently for their own purposes, so the incremental cost of disclosing quarterly should be significantly outweighed by improvements in downstream decision making
- risk profile – disclosures only cover expected (2P) production. As set out in section 2.1, information on downside risk (1P production) would provide energy market participants with richer understanding of production risk. We understand operators already produce such profiles for internal use and, in some cases, share this information with their largest customers under the terms of their sales agreements
- within-year profile – disclosed profiles only cover annual production amounts. At times of market stress, it would be helpful for energy users to see monthly profiles, which would help assess crucial winter risk. Again, we understand operators produce monthly profiles (at least for the first few years) for internal purposes.

Information on gas contract prices is even less transparent. Coupled with a relatively concentrated gas market, the lack of transparency can lead to outcomes that excessively favour suppliers over consumers.

In contrast, the electricity sector regulator (the Electricity Authority now and the Electricity Commission previously) has introduced, refined and extended contract price disclosure requirements over time to ensure much superior price transparency for electricity contracts.

It is not clear there is a compelling reason that gas contract pricing should be so much more opaque than electricity.

3.2.2 Methanex now presents an ‘integer’ problem

Historically, Methanex has provided an enormously valuable source of flexibility to the gas and electricity markets, with significant ability to increase or decrease its Methanol production to help balance the system. At times of relative scarcity, Methanex has traditionally on-sold some of its gas entitlement to other consumers such as gas-fired generators (whose usage is more valuable but less steady).

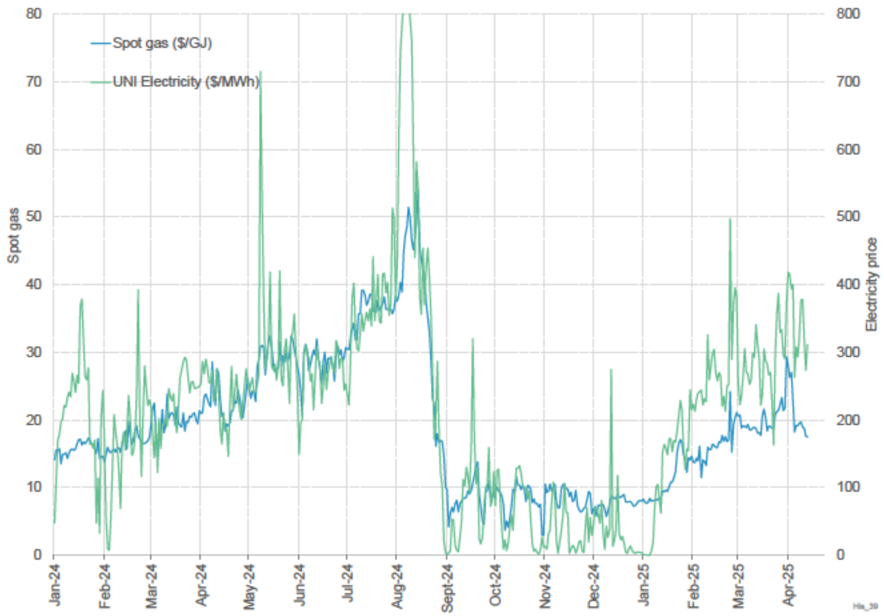
However, methanol production is not infinitely flexible, and each train has technical constraints on its minimum operating levels. Until recently, the per-train limit has not been an issue, as Methanex has been able to balance production across multiple trains.

However, for the last two winters, Methanex has been down to a single train and its minimum operating level presents a ‘block’ on its ability to ramp down production and on-sell gas. To do so, Methanex needs to cease production and on-sell its full volume. This is worthwhile when there is extreme scarcity, but not for less acute situations.

This effect is apparent in Figure 27, where in the early part of 2025:

- electricity supply was stressed, as indicated by coal and gas usage for power generation
- Methanex curtailed its consumption through the early part of this year, freeing up gas for generation, but reached a floor of around 51 TJ/day
- methanol usage then stays at the floor, despite gas and electricity prices remaining at significantly elevated levels (and coal consumption remaining high).

Figure 27: Daily average gas and electricity prices (Real $2024)



Source: Concept analysis of Electricity Authority and EMS data

Were Methanex to on-sell more gas to the generation market, it would likely:

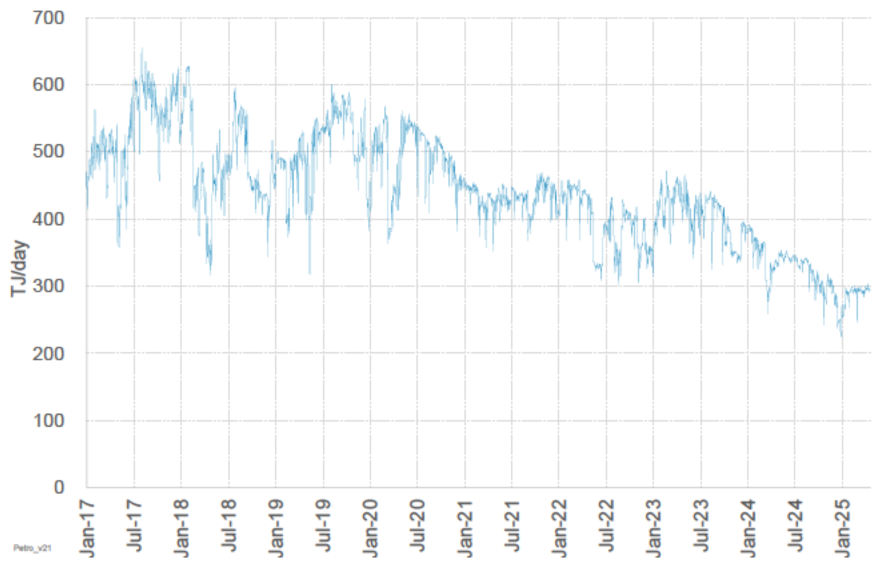
- materially reduce spot gas and electricity prices, and
- significantly reduce the amount of coal burned in the Huntly power station.

The challenges around methanol minimum volumes have parallels with the issues discussed earlier regarding Tiwai uncertainty. In both cases, markets find it difficult to deal with large step-changes in supply and demand – that is, with 'integer' problems. These are an inherent challenge for our relatively small and unconnected energy system. Transparent information is particularly valuable for planning around step-change uncertainties.

3.3 Future outlook

Figure 28 shows that, after two years of steady decline, total gas production appears to have stabilised at around 300 TJ/day from the first quarter of this year. This is largely due to recent drilling at the Turangi and Pohokura fields bringing on new gas.

Figure 28: Total NZ daily gas production



Source: Concept analysis of GIC, MBIE, and Electricity Authority data

While stability is welcome, overall gas supply in New Zealand less than half its 2017 level.

Also, we understand production from the Pohokura 5 well that came online last month is well below expectations, and production from all three of New Zealand's offshore fields (Maui, Pohokura, and Kupe) is declining more rapidly their operators projected at the start of last year.

Currently no more drilling is committed for these offshore fields – almost certainly permanently so in Kupe's case. Whether further drilling happens for Pohokura and Maui will likely be tied to Methanex's future – in particular, because Methanex is the only party able to take the high-CO_2 gas that comprises the majority of the additional resources that could be developed at the Maui field.

The poor recent drilling results at these fields and accelerated declines will tend to act against OMV (the field's operator and majority owner) committing significant new capital in expensive offshore drilling campaigns. Additionally, uncertainty over the future of Methanex (as detailed further below) and regulatory uncertainty will also weigh against significant future capital investments in these offshore fields.[14]

Offsetting these negatives, elevated gas prices would improve expected returns were future drilling to be successful.

From a gas supply perspective, there are two relatively bright spots in an otherwise gloomy situation:

- Greymouth Petroleum appears to be having success in its drilling campaigns at its onshore fields, with deliverability picking up from the start of this year. We do not know whether the improvement from these wells is better than Greymouth had expected
- NZEC has had success drilling the onshore Tariki field. Although the increase in production is modest compared to the overall gas market, the field has potential to be developed into a gas storage facility larger than the current (and only) facility at Ahuroa. If this were developed, it could prove enormously valuable in providing the fuel flexibility needed to balance increased renewable generation – particularly if (or when) the remaining Methanex train finally exits.

Additional drilling is underway at Mangahewa, with four wells scheduled to come on stream progressively through the year. Depending on the success of these wells, it is likely further drilling will happen progressively over subsequent years.

No drilling is currently committed for Kapuni. Its high CO_2 content and poor results from the most recent drilling campaign make for a challenging investment decision by Todd, the field's owner-operator.

For Methanex, its long-term future in New Zealand looks uncertain. It has contracted forward for significant quantities of gas out to 2029. However, unless there is a significant new gas field discovered and developed within that time (which seems unlikely), it seems unlikely it would be able to re-contract for 2030 and beyond at prices that would be low enough to support profitable methanol production.

If gas deliverability continues to decline, it may even be economic to idle its remaining train earlier than 2029 – on the basis that other users with higher-value uses could consume all of New Zealand's production. This would create a challenging market dynamic as pressure builds to permanently reallocate gas to its highest value uses.

[14] Regulatory uncertainty relates to possible future governments making policy changes to issues such as field decommissioning liabilities, free NZU allocation to Methanex, and restoring the recently-repealed ban on offshore exploration.

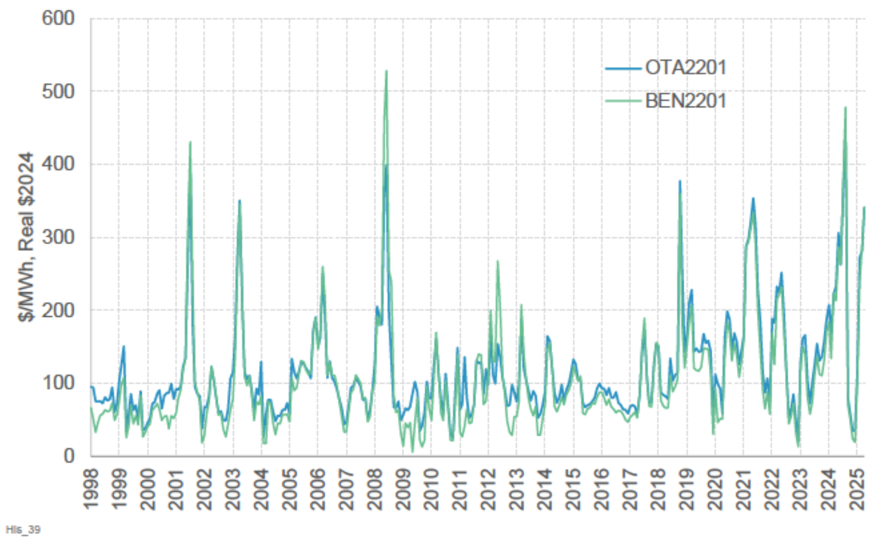
4 Breakdown of prices

This section provides information on the flow-through of high wholesale prices to electricity consumers.

4.1 Wholesale market prices – past and present

Spot prices are currently very high, as indicated in Figure 29. While prices have spiked as high (or even higher) at times in the twenty-seven year history of the market, there has been a clear step up in both average price and volatility since 2018.

Figure 29: Monthly average spot prices at the main ASX nodes (real $2024)



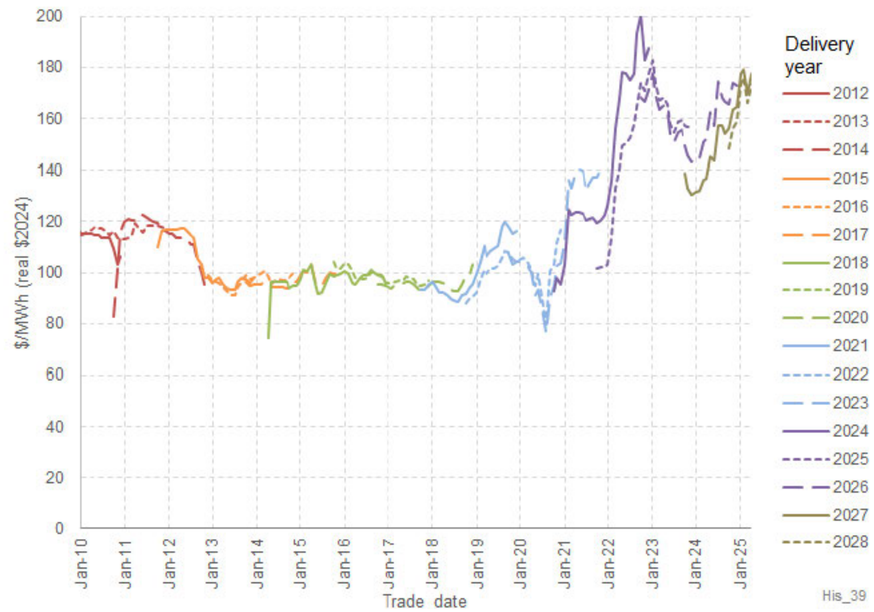
Source: Concept analysis of Electricity Authority data

Although spot prices provide some measure of the state of the market, it is hard to distinguish the impact of weather (eg, dry versus wet hydro conditions) from the impact of overall system balance.

Prices for forward contracts traded a year ahead of settlement provide a better indication of system balance. The price for such contracts is based on a probability-weighted view of future prices, without influence from current storage levels or weather patterns.

Figure 30 shows that year-ahead (and longer-dated) contract prices were relatively stable until the latter half of 2018, and have since risen materially.

Figure 30: ASX Otahuhu forward contracts for calendar year strips (real $2024)



Source: Concept analysis of Electricity Authority data

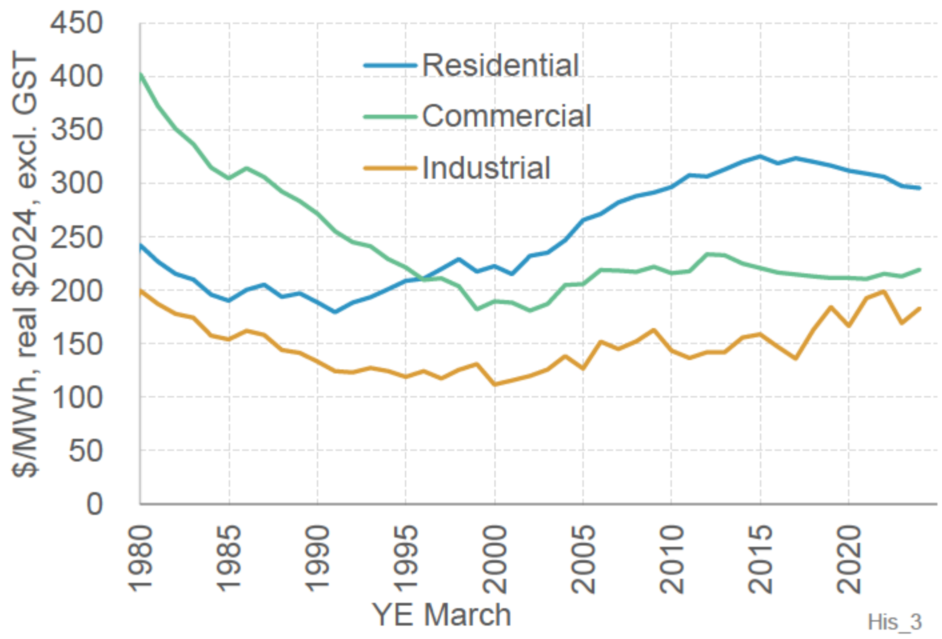
As set out in section 2.1, the rise in contract prices in the latter half of 2018 was principally due to gas supply scarcity, which translated into high gas prices and high thermal generation costs.

As further set out section 3.1, gas producers then consistently projected that gas supply would be restored, which would return gas prices back to more balanced levels – thereby suppressing the signal to build new renewable generation to displace high-cost thermal stations. However, the gas scarcity situation actually got steadily worse. As such, contract prices remained at the elevated levels we are currently experiencing.

4.2 Consumer prices

Figure 31 shows the average electricity prices paid by three different consumer segments since 1980. The prices are presented on an average price basis – that is, they are calculated by dividing the total paid by all consumers in a group (ie, the sum of all variable charges and fixed charges) by the total energy (GWh) consumed by that group. We refer to this as the "fully variabilised" price.

Figure 31: Average electricity prices (real $2024)



Source: Concept analysis of MBIE data

Figure 31 paints a very different picture for each of the consumer groups – particularly between residential and business consumers.

From 1990 to 2015, residential consumers experienced significant price increases. It was therefore no surprise that a Ministerial review into electricity prices was announced shortly after that peak. A key finding from that review was that a significant factor driving this increase in electricity prices was a change in the allocation of shared electricity networks costs – away from business consumers and towards residential consumers. This change in network cost allocation was a key reason why commercial consumers enjoyed a reduction in electricity prices from 1980 through to 2000.

Since 2015, however, the relative fortunes of consumer groups appears to have reversed. In particular, residential consumers have enjoyed real price decreases, whereas industrial consumers have faced material price increases.

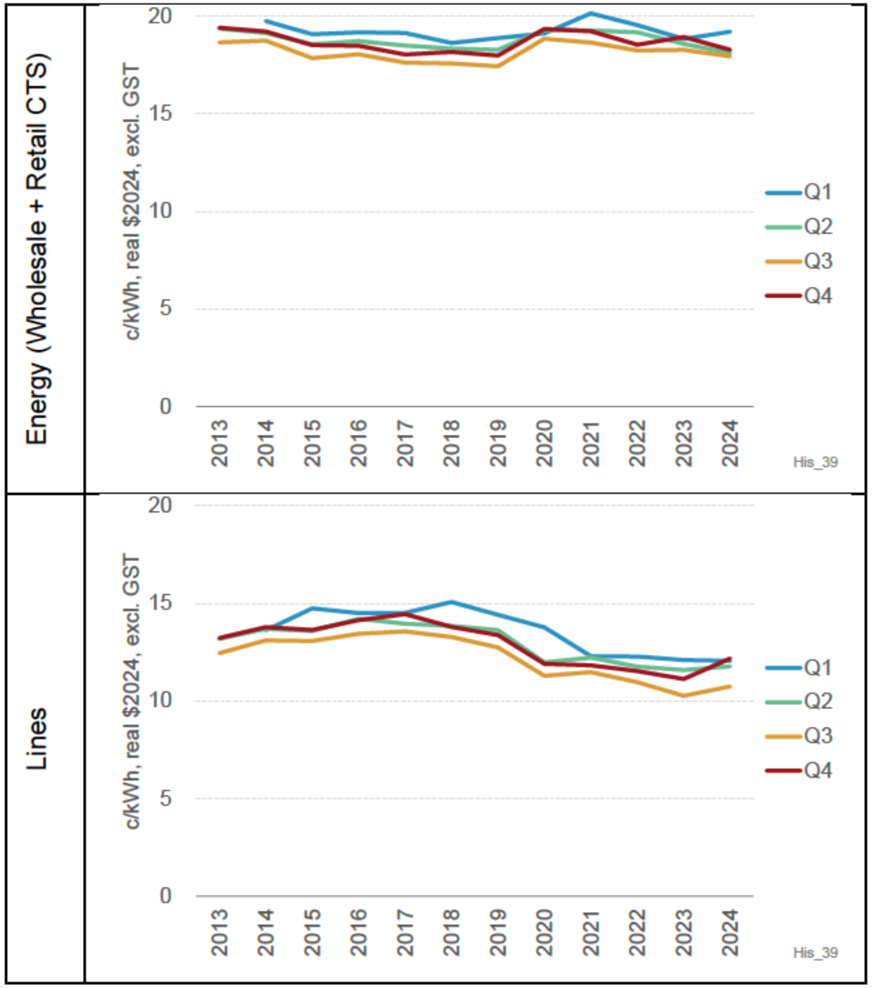
Figure 31 presents data on a year-end March basis, so data for the most recent year-ending March 2025 has not been released.

However, MBIE produces another data set that provides quarterly updates on prices paid by residential consumers – again on a fully variablised basis. This dataset also breaks electricity prices down between:

- energy charges (covering wholesale electricity, plus metering and other retail cost-to-serve costs), and
- lines charges (covering Transpower and electricity distribution costs).

Figure 32 presents this data for the period from June 2013 to December 2024. The data is presented on a quarterly basis to better allow comparison between years. This is because the variablisation process causes quarters with low demand (ie, Q1) to apparently have higher prices than quarters with high demand (ie, Q3). This is because fixed charges are spread over a greater number of kWh in Q3 than in Q1.

Figure 32: Change in components of residential electricity prices



Source: Concept analysis of MBIE data

Figure 32 shows that the energy component of residential electricity prices has fallen in real terms since 2020, including for the most recent year (2024).

However, after a period of steady decline, the lines component of residential prices has started to tick up again, with the latter two quarters of 2024 being higher than the same quarters for 2023. For most of the lines sector, this reflects outcome of five-yearly regulatory revenue "resets". The most recent reset took effect from 1 April 2025 and increased revenue allowance by around 8% on average to reflect higher financing costs, input costs and investment levels.[15]

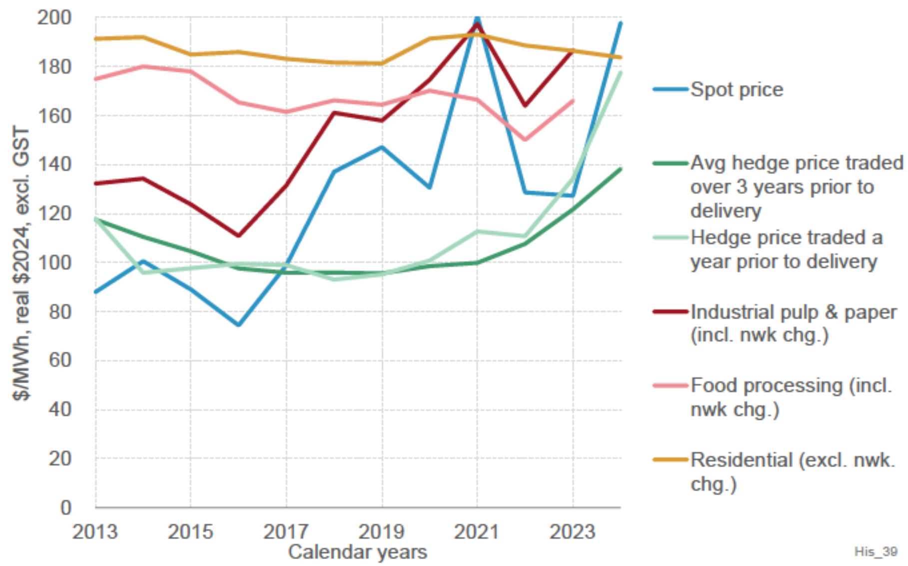
Figure 33 presents a composite of various different annual average price metrics, to enable comparison of the extent to which the increase in wholesale prices has flowed through to different classes of electricity consumer. The data shows:

- three different wholesale price metrics:[16]
  - spot prices
  - hedge prices traded one year prior to delivery
  - the average of hedge prices traded from one to three years prior to delivery
- three different consumer price metrics:
  - the energy component of residential prices
  - industrial pulp and paper prices (including the lines component)
  - food processing prices (including the lines component).

15 The Commerce Commission provides more information on its website. https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-and-transmission-charges-what-are-they,-why-are-they-changing-and-what-does-this-mean-for-your-electricity-bill

16 All three price metrics are load-weighted average of Otahuhu, Haywards, and Benmore nodes, using the following simple load weightings: Otahuhu (55%), Haywards (15%), and Benmore (30%).

Figure 33: Various annual average price metrics (Real, $2024)



Source: Concept analysis of MBIE and Electricity Authority data

The slight fall in the energy component of residential electricity prices (in real terms) from 2021 to 2024 suggests some combination of:

- retailers hedging wholesale prices across multiple years – for example, adopting rolling three-to-four-year ‘book’ of hedge contracts (with their retail commitment hedged using a blend of year ahead, two-year ahead, etc hedges).
- reductions in the metering and retail cost-to-serve components of retail pricing
- reductions in the net margins earned on retail sales.

We do not have data to determine how much each of these factors may have contributed to this fall in the energy component.

That said, the scale of compression between year-ahead contract prices and retail prices suggests that multi-year hedging must have played a material role. This implies that the energy component of residential prices will increase as higher contract prices roll into retailer hedge books.

Despite the food processing and pulp & paper sectors having broadly similar total electricity demands (as shown in Figure 35 in section 5 later), their price outcomes have been very different.

The higher starting price for food processing is likely because a greater proportion of this demand is connected at the distribution network level, rather than as ‘direct connects’ to the transmission network. This may also explain some of the reductions in prices for this sector from 2015 through to 2022, noting that, as illustrated in Figure 32, the lines component of residential electricity charges also reduced during this period.

However, the relative changes in price outcomes between food processing and pulp & paper is most likely explained by differences in contracting approach for the wholesale energy component of electricity purchases. It appears that the pulp & paper sector has adopted a strategy which, relative to the Food Processing sector, is consistent with:

- a higher proportion of electricity purchased on a spot basis
- shorter-term contracting (eg, one to two years ahead rather than a rolling book over a longer period of time)

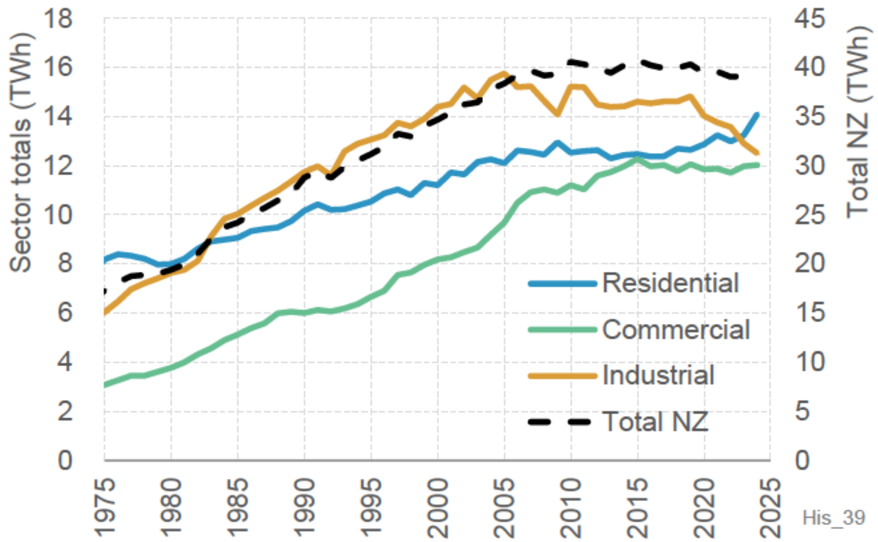
This would explain both the relatively low prices enjoyed by pulp & paper before 2018, and the comparatively steep rise since – ie, closely tracking spot prices.

5 Energy-price-driven de-industrialisation

This last section addresses the extent to which energy prices have driven de-industrialisation in New Zealand, and whether any such energy-price-driven de-industrialisation is likely to continue.

Figure 34 shows that, after at least three decades of almost uninterrupted steady growth, industrial electricity demand abruptly stopped growing in 2005. For the next fifteen years it declined slightly, before starting a more rapid decline from 2020 onwards.

Figure 34: New Zealand sectoral electricity demand



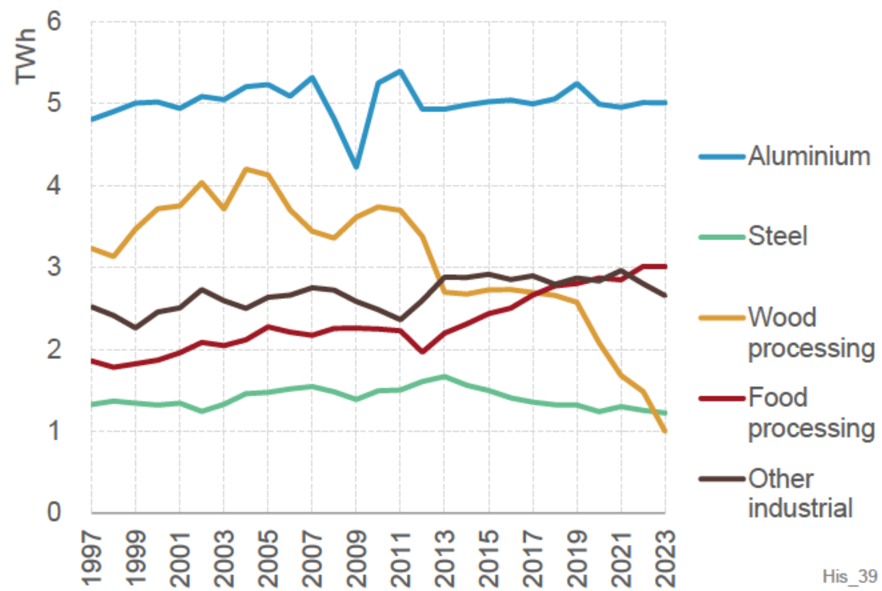
Source: MBIE data

This pattern has raised concerns that the current situation of very high electricity prices are a significant causal factor behind this apparent 'de-industrialisation' of New Zealand, and that high electricity prices are likely to result in a continuation of this downward trend.

Figure 35 provides a more detailed breakdown of the demand across different industrial sectors from 1997 (the earliest that this information is available). It reveals significant variations between industrial sectors:

- only one sector – wood processing – shows a steep decline since 2005, having been behind much of the growth in the seven years prior
- three sectors – aluminium, steel, and 'other' – have had broadly flat demand
- one sector – food processing – has shown strong demand growth, particularly over the past decade

Figure 35: Industrial sector annual electricity demand



Source: MBIE data

While Figure 35 helps understand what has happened to date, it provides little information as to whether other sectors may start to reduce demand in response to sustained high electricity prices.

Sectors at risk of electricity-price-driven de-industrialisation have two characteristics. They must be:

1. electricity intensive – ie, electricity is a big enough portion of their input costs to matter
2. unable to pass increased electricity prices through into higher prices for their products. This mainly applies to firms facing international competition.

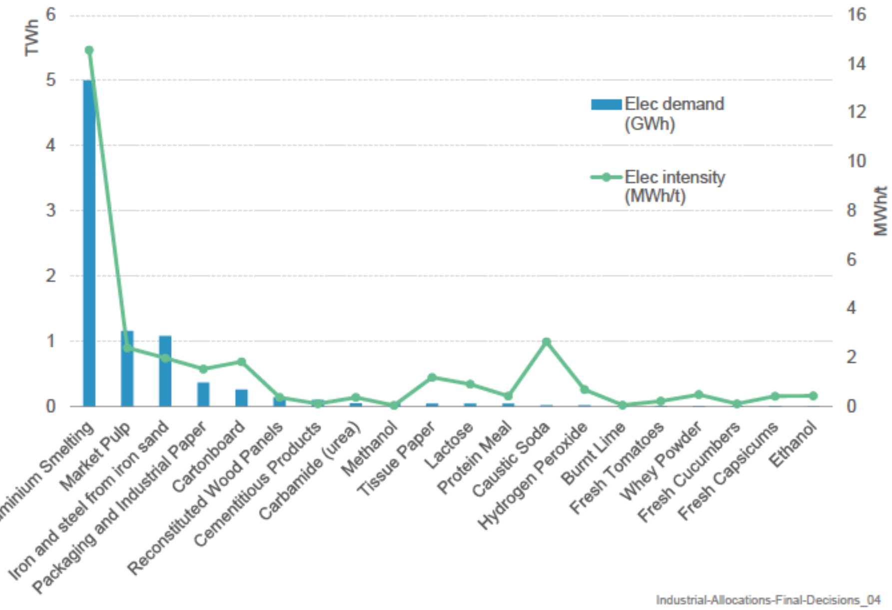
The industrial allocation mechanism in the Emissions Trading Scheme (ETS) provides good information on sectors that have these characteristics. This mechanism was set up to protect Emissions-Intensive Trade-Exposed (EITE) firms who faced higher costs due to a New Zealand carbon price.

Importantly, this mechanism recognised that higher costs could be due to direct emissions of greenhouse gases or due to carbon prices increasing the price of electricity. Information collected and published as part of the industrial allocation process enables identification of which sectors are electricity-intensive and exposed to international competition.

Figure 36 sets out Concept analysis of data published by the Ministry for the Environment as part of the industrial allocation process. It covers all the sectors covered by industrial allocation (ie, all sectors who face international competition and whose direct emissions or electricity consumption is high-enough to warrant material concern regarding price-driven exit). It shows:

- the electricity intensity of the product (expressed in MWh per tonne of the product), and
- the sector's total electricity consumption for 2022.

Figure 36: Electricity intensity and 2022 electricity demand of EITE industrial sectors



Source: Concept analysis of MfE data

The key take-away from Figure 36 is that there are only three industrial sectors that are both significant consumers of electricity <u>and</u> electricity intensive <u>and</u> trade exposed:

- aluminium production
- steel production
- Wood processing, split between:
  - market pulp
  - packaging and industrial paper
  - cartonboard

– reconstituted wood panels

– tissue paper.

These should be the principal sectors where high electricity prices could result in large-scale de-industrialisation. Other sectors are either:

- not electricity-intensive (and so not too exposed to electricity prices)
- too small to materially impact overall New Zealand electricity demand, or
- able to pass-through higher electricity costs to a reasonable extent.

Turning to the three sectors that are both large and electricity-intensive, only wood processing looks to be at risk of further demand reduction. Even then, the scale is likely to be limited as, sadly, there is not much electricity-intensive production left to exit.

With reference to Figure 35, 2023 wood processing electricity demand fell by approximately one-third compared to 2022 demand. The closures announced in 2024 will have resulted in additional falls, partially offset by the Whirinaki mill re-opening in 2024 following repairs from cyclone Gabrielle.[17] We estimate that 2025 wood processing demand will be approximately 0.9 TWh, which is 21% of the level in 2005.

It is hard to estimate the extent to which the remaining wood processing facilities are likely to exit due to electricity prices. This is because there is considerable variation in the:

- electricity-intensity of the different types of wood processing facilities (eg, as between pulp – noting there is also significant variation between kraft and mechanical pulp processes – paper, cartonboard, etc,)
- international commodity prices for each product, and the extent to which New Zealand production is for domestic consumption (and so protected by shipping costs, facing import parity pricing) or export overseas (facing export parity pricing).

Nonetheless, it is reasonable to assume the most vulnerable operations will have exited first – ie, with the worst combination of electricity intensity and commodity prices.

Remaining firms have demonstrated a greater ability to weather current pricing levels but could be exposed if prices were to rise further. In that respect, forward contract prices, while remaining high, are showing some decline. As set out in section 2.2, our modelling of the system balance indicates there is a reasonable hope of contract prices falling faster than the forward curve currently indicates.

However, while significant additional electricity-price-driven exit in the wood processing sector seems unlikely, it is potentially the case that additional exits could occur for other reasons. In particular, as set out in section 3.3, the current situation of extreme scarcity in the gas sector risks further industrial wood processing closures due to the inability to source gas. In this respect, it is notable that at least one of the recent wood processing closures was principally due to gas scarcity, not electricity pricing.

This risk of gas scarcity driving further de-industrialisation, doesn't just apply to wood processing, but to other gas-intensive industrial sectors. In particular, the petrochemical sectors producing methanol and urea:

- Methanex have already shut two of their three methanol production trains, and there is a realistic possibility of remaining train shutting down within the next two to three years unless significant new gas resources are brought to market
- the prospects for the Ballance urea production facility look stronger in the short term as it has contracted forward for a number of years.

[17] Estimated losses of 140 GWh from the Oji-owned Kinleith & Penrose mills, and 230 GWh from the Winstone-owned Tangiwai & Karioi mills. Estimated increase of 295 GWh from the re-opening of the Whirinaki mill.

However, this is likely the next major gas-consuming facility to exit if the decline in gas production continues.

Turning back to electricity, of the other two large electricity-intensive sectors the outlook looks strong:

- the Tiwai aluminium smelter has started a tender process for long-term electricity supply to *increase* production, and
- the Glenbrook steel mill has signed a long-term electricity supply contract with Contact Energy, and is making a significant investment in an electric arc furnace.

Other industrial sectors are also investing in electrification projects that should increase electricity demand. Most notably:

- Fonterra has announced major investments to electrify three of its North Island factories over the next 18 months, moving away from gas and coal-fired boilers at these sites, and
- multiple parties are investing in large, energy-intensive data centres.

In summary:

- only the wood processing sector appears to have materially reduced electricity demand through exiting New Zealand production as a result of high electricity prices – accelerating a process that had started prior to electricity prices increasing from 2018
- the worst of these electricity-price-driven closures for the wood processing sector appear to be over
- other industrial sectors appear unlikely to exit due to electricity prices, and
- some parts of the industrial sector are investing to increase electricity demand, including to reduce their direct exposure to gas scarcity, but
- that is not to say there won't be other reasons why some industrial electricity consumers exit New Zealand. In particular, continued gas scarcity could cause further industrial closures (which would also result in a fall in electricity demand).

Wholesale and retail electricity – prices and competition

Contribution to independent expert panel report for level playing field consultation

David Reeve
6 May 2025

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Glossary

Abbreviation	Stands for
BESS	Battery electric storage system
DR	Demand response
EA	Electricity authority
EDB	Electricity distribution businesses
FPVV	Fixed price variable volume
GM	Gross margin
GWAP	Generation weighted average price
ICP	Installation control point
IR	Instantaneous reserve
LCOE	Levelised cost of energy
LNG	Liquefied natural gas
LPF	Level playing field
LRMC	Long-run marginal cost
MDAG	Market Development Advisory Group
MW	MegaWatt
MWh	MegaWatt hour
NZX	New Zealand Exchange
OCGT	Open Cycle Gas Turbine
OTC	Over-the-counter
PDC	Price duration curve
PPA	Power Purchase Agreement
PV	Present value
RTD	Real-time dispatch
SRMC	Short run marginal cost
SROC	Short run opportunity cost
TKA	Tekapo A
TKB	Tekapo B
TOU	Time of use
VoLL	Value of lost load
WCM	Winter capacity margin
WEM	Winter energy margin
WV	Water value

Acknowledgements

The author acknowledges contributions and reviews from Stephen Batstone, Director, Sapere, and from the wider independent expert panel:

- Tony Baldwin (convenor) – Independent consultant
- Dave Carlson – Director, Carlson Consulting
- Dave Smith – Director, Creative Energy Consulting
- Greg Houston – Partner, Houston Kemp
- Daniel Young- Partner, Houston Kemp.

Executive summary

As part of the contribution to an independent panel report, we have been asked to assess wholesale and retail prices and competition. We have not explicitly looked at contract prices, but issues with contracts markets necessarily had to be identified.

Wholesale market

Our analysis finds problems with recent wholesale market prices:

1. The structure of wholesale prices doesn't reward investment in security of supply, and neither do contract markets.
2. Eroded security of supply has lifted hydro water values resulting in a significant uplift in prices generally.

However, the problems with security of supply are not purely due to price. External factors are at least as significant.

Historically, these factors have included:

- gas market supply issues
- energy policy uncertainty
- the New Zealand Battery project
- demand growth uncertainty
- Tiwai exit
- the future of Huntly.

These issues had deferred investment generally, but, mostly due to the removal of Tiwai uncertainty, the pipeline for new renewable generation has become highly competitive with new investment and new entrants emerging over recent years.

When the projects currently under construction are delivered, we expect that there will be some improvement in energy security and some easing of wholesale prices.

However, there is no investment planned in plant that would be economic at utilisations from 2 per cent to 20 per cent, or even up to 40 per cent if the current structure of prices continues. Battery Electric Storage System (BESS) investment will improve security in the highest demand peak periods, but security for periods of extended still wind conditions and/or cloudy days (in the future), and the worst hydro droughts, will continue to erode.

Again, we think external factors continue to play a role. Our best estimate is that gas market uncertainty and concerns that other currently viable fossil fuels (e.g. diesel) will be orphaned in future political cycles are the key barriers to investment. There is a real fear of investing in thermal generation.

In light of the above, we consider that a strategy of anti-competitive withholding of generation investment is at best extremely hard to prove, and at worst, not credible. The general lift in prices has encouraged competition and new entrants to renewable energy investment. A strategy of withholding security of supply investment would make most sense if a party had a credible peak investment that deterred competing projects, and then deferred their project as long as they could. Otherwise, with peak price adequacy and no barriers to entry, the strategy would attract competition. Instead, we posit that it is revenue inadequacy and barriers to entry that are stifling such investment.

Retail market

Our assessment of the retail market is that it is functioning as expected. The large generator retailers are pricing in such a way that would be reflective of long-run wholesale costs if the wholesale and contracts markets were working as expected. If the differences between wholesale and contract prices were less acute for certain contracts, and 100 per cent of both physical sales and purchase volumes were accessible through a workably liquid contracts market, then the retail market would trend to a sustainable, competitive equilibrium.

With divergence of wholesale and contract market prices, the effective variable costs for vertically integrated generators are less than for smaller retailers that are well hedged. This by itself wouldn't lead vertically integrated generators to accept lower retail margins—they should seek the highest value channel available. However, as the stress testing regime shows, a significant section of wholesale purchases is uncontracted, and then the alternative channel isn't available, which is the problem with limited contract volumes.

The allegation of a deliberate strategy to squeeze retail margins isn't credible. Firstly, because such a strategy isn't working, while there have been retailer exits the total small/medium retailer market share has not been significantly eroded.

Secondly, because such a strategy is unlikely to pay off, as:

- the net increase in new retailers shows that barriers to entry are low
- low barriers to entry mean that, even if there was significant exit which allowed retail prices to lift, retail competition would eventually increase again
- there may be a delay in the return of competition, but the delay would have to be very long for the margin squeeze strategy to pay back in present value terms.

It isn't credible that four large generator retailers would pursue a strategy that isn't working and is unlikely to pay off.

Concerns about innovation seem overstated. Very little innovation occurs quickly and the incentives to innovate are stronger when market prices are high. Most innovation takes time to move from proof of concept to early adoption, to early followers to critical mass. Given that the retail market environment was benign up until 2018, and uncertainty has plagued the market since then (including early commentary that the gas market problems were temporary), then the path of innovation in New Zealand is not obviously impeded. The Taskforce itself identified a lot of innovation in the retail market.

Contracts markets

While we haven't analysed contract markets prices, we have considered the role of contracts on the impact on the other markets (wholesale and retail). We conclude that contracts markets are not working as expected. There are three dimensions that are affecting contracts markets.

First, the standard problems with electricity contracts market remain acute, i.e.:

- inconsistent market understanding
- imperfect information
- acute information asymmetry.

We also note that the stress testing regime hasn't worked as anticipated as the average prices observed in the quarter up to August 2024 were at the level of the E1 stress test, yet market conditions caused public concern with prices and allegedly the exit of industrial customers. The objectives of the stress testing regime were to identify credible upper limit risk levels and ensure market participants understood the risks.

Second, wholesale market problems undoubtedly affect the contracts market. A barrier to entry in generation investment removes the only way to physically manage the risk. This must have an adverse impact on contracts. One of the manifestations of this is the large super peak premium identified by the Taskforce. Prices that need to be covered by low utilisation plant, where investment in that plant is not going ahead, would approach the cost of scarcity. At the same time our analysis shows that prices in the wholesale market are not reflecting that level of scarcity. This leads to large, implied risk premia, i.e. the difference between super peak contract price offers (and likely other periods as well) and observed wholesale prices over the same period.

When contract and wholesale prices diverge significantly, some parties will consider self-cover. This is a valid approach if those parties can anticipate their worst cashflow exposure and ensure that sufficient current assets are available and liquid. If they don't anticipate the worst cashflows they will be made illiquid.

Third, a significant portion of the market seems to be choosing to be uncontracted. This is partially explained under the second problem as some purchasers are choosing to be uncontracted. However, three large generator retailers also often choose not to offer all contracts.

The generator retailer withholding can be partly explained by the first problem. The generator retailers are also physically exposed to pricing that would be physically underpinned by low utilisation plant. Nevertheless, they could still make prices. There is a broader problem with contracting that we don't have an explanation for beyond risk aversion.

We have considered an anti-competitive explanation for the withholding of contract prices. The only way such a strategy could be valuable, where revenue is foregone in one market, is if larger returns could be made in other markets that offset the foregone revenue. We don't consider this is the case in the retail market, where no rational competitor should expect a long-term payoff for the loss of retail margin.

This is also inconsistent with a wholesale strategy where writing contracts would still be more valuable even if they were deferring generation, i.e. the strategies would not be mutually exclusive.

Priorities

The highest priority should be to address the barriers to entry in low utilisation plant. This would have a significant impact on wholesale prices and help correct contracts markets.

The second priority would be to address contract markets concerns. This would underpin investment in all plant required to meet security of supply and encourage full participation in pricing and contracting.

It is also important to address the investment incentives in the structure of wholesale prices. This would involve changing the focus of market monitoring away from short periods of high prices to the long-term price duration curve. There should also be more focus on low price periods, as there are times when prices are lower than they should be to encourage investment. Additionally, the level of low prices is a significant contributor to average prices.

1. Introduction

We have been asked to look at wholesale and retail market prices and competition. We haven't looked explicitly at contract market prices, but we have necessarily had to consider the interaction between all markets.

This report is an input to an independent expert panel report (Baldwin et al., 2025) and should be read in that context.

2. Wholesale

In assessing wholesale prices, we go back to first principles. In a one-part (energy only) market in particular, the structure of prices is critically important. In the following assessment we focus principally on the price duration curve (PDC) and refer to contracts markets where appropriate. Between the two markets, generation investment should be incentivised when required—generation economic at high utilisation for baseload supply, and generation economic at low utilisation for peaking and firming intermittent renewables.

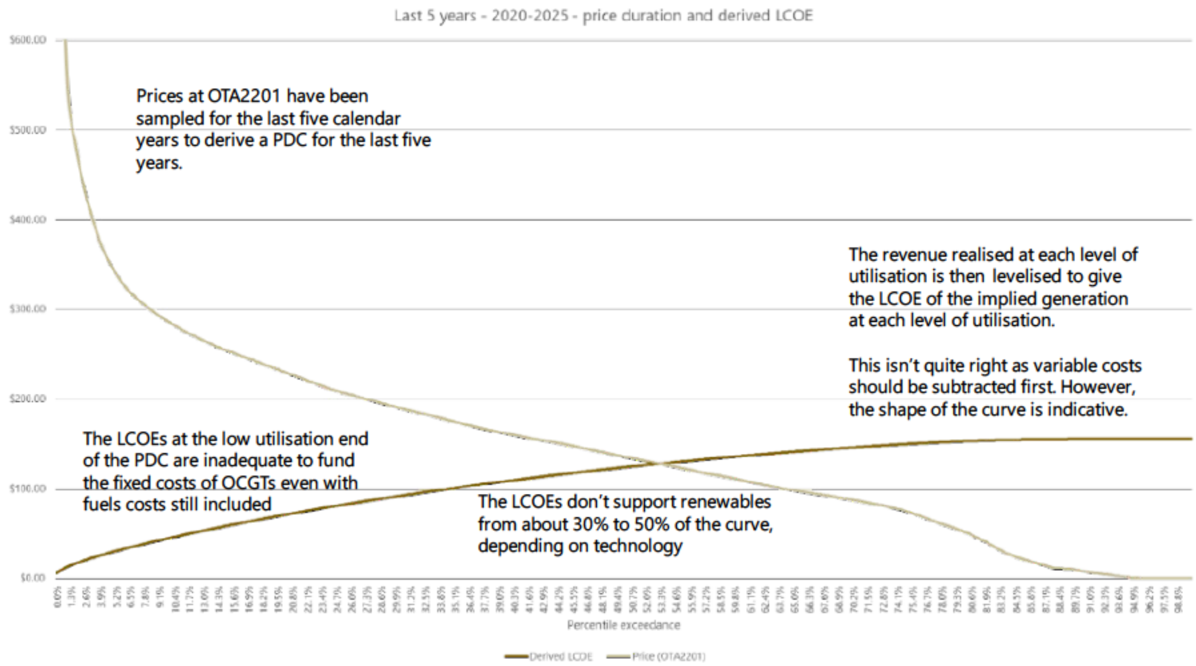
2.1 Prices

The market currently has a problem with reduced security of supply—the winter capacity margin, in particular, but also the winter energy margin (System Operator, 2024).

However, the narrative has been that baseload generation has been withheld and that is holding up prices, which seems like a reasonable conclusion based on the prices observed over the last few years. But what does a deeper analysis suggest about wholesale prices?

2.1.1 Price duration curve and implied Levelised Cost Of Energy

Figure 1: 2020-2025 PDC and implied LCOE



The PDC samples prices over the last five years and orders them from highest to lowest. This shows the prices that apply for utilisations by the percentile exceedance axis. The implied LCOEs are derived by taking the revenue that would be achieved by 1MW of generation at that utilisation, but then levelling across the whole year.

2.1.2 What, theoretically, should the PDC look like?

Answering this question helps highlight the problem with uncertainty. The optimal mix of generation, which implies an optimal PDC, is derived from the available mix of generation and the relative total cost of plant with different fixed and variable cost over different utilisations.

Different assumptions of generation availability (e.g. is gas available or not, and at what price) will mean different 'optimal' outcomes and different PDCs. Uncertainty about what is available creates uncertainty about the efficient PDC. This causes significant problems in robustly assessing the efficiency of prices.

As the most valuable function of electricity markets (in terms of total long run cost) is dynamic efficiency, we focus on a dynamically efficient PDC.

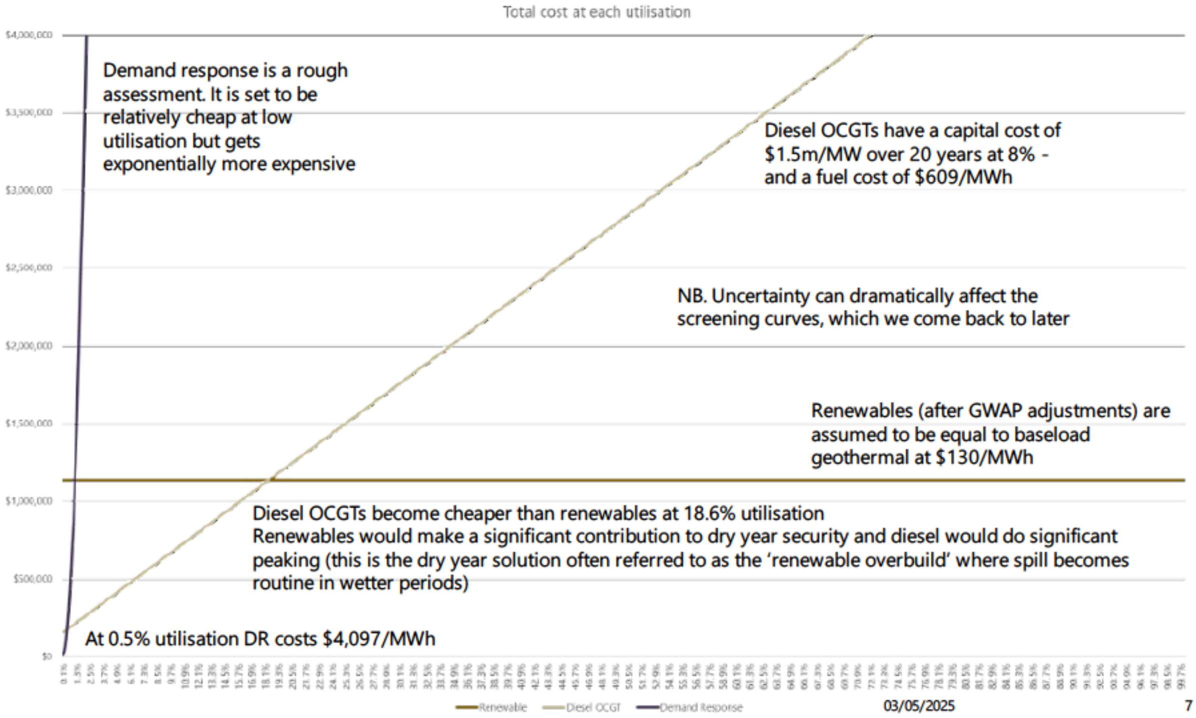
To establish a theoretical PDC, for the purpose of this paper, only technologies that are currently investable are used. To be investable a technology needs to be mainstream today and have fuel availability. To keep things simple, only a sample of each technology type is used:

- For baseload, renewables are used. The assumption for renewables is that, after adjusting for Generation Weighted Average Price (GWAP) effects, the baseload price equals the approximate cost of geothermal.
- For peaking, diesel Open Cycle Gas Turbines(OCGT) are used.
- For the highest peaks, demand response is used (batteries also play a role here but batteries are complicated because we need to assume the charging cost—the assumption is that batteries must equal demand response to be a part of the curve).

2.1.3 Our theoretical screening curves

To demonstrate the theoretically optimal PDC we use a screening curves approach. This approach creates an envelope that describes the boundary for the cheapest generation for levels of utilisation. It is formed by showing the cost function for each technology over different utilisations.

Figure 2: Theoretical screening curves for investment across the whole PDC



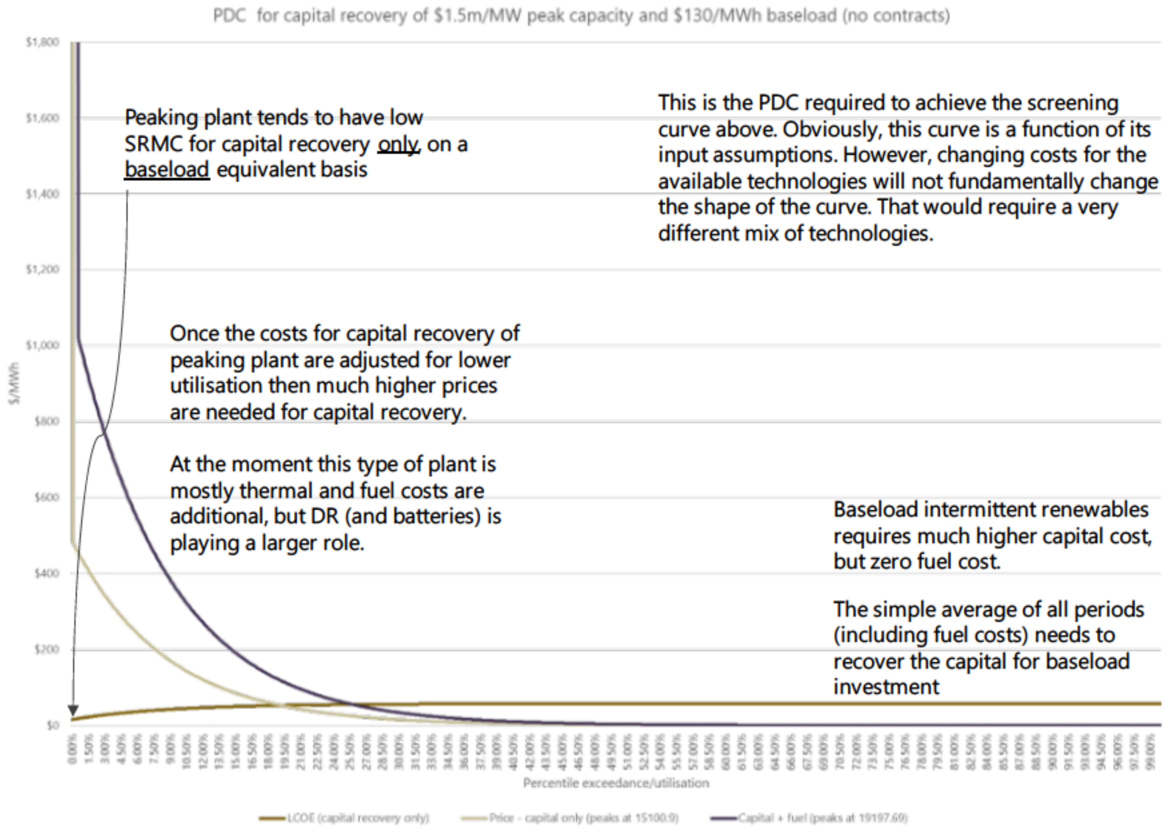
2.1.4 Our theoretical PDC

To convert the screening curves into the theoretical PDC, we assess a curve of implied LCOE for the capital recovery of the plant if it was baseload. Variable costs are treated differently as they are additive to the PDC that would recover annualised capital costs at each point the variable cost is incurred.

We fit this to a smoothed curve that achieves the utilisations above and recognises the smoothing effect of hydro water values to prices. Water values are based on known costs of alternative (generator costs, demand response, and shortage), and rise and fall based on the probability of each technology being required.

The PDC for capital recovery is then derived from spreading the annual costs for the LCOE across the number of hours of running for each point of utilisation. Variable costs (the cost of demand response at the top of the curve, and the cost of diesel below that) are prorated as the curve transitions from maximum demand response and OCGT usage to the use of only renewables.

Figure 3: Theoretical PDC for capital recovery of screening curve



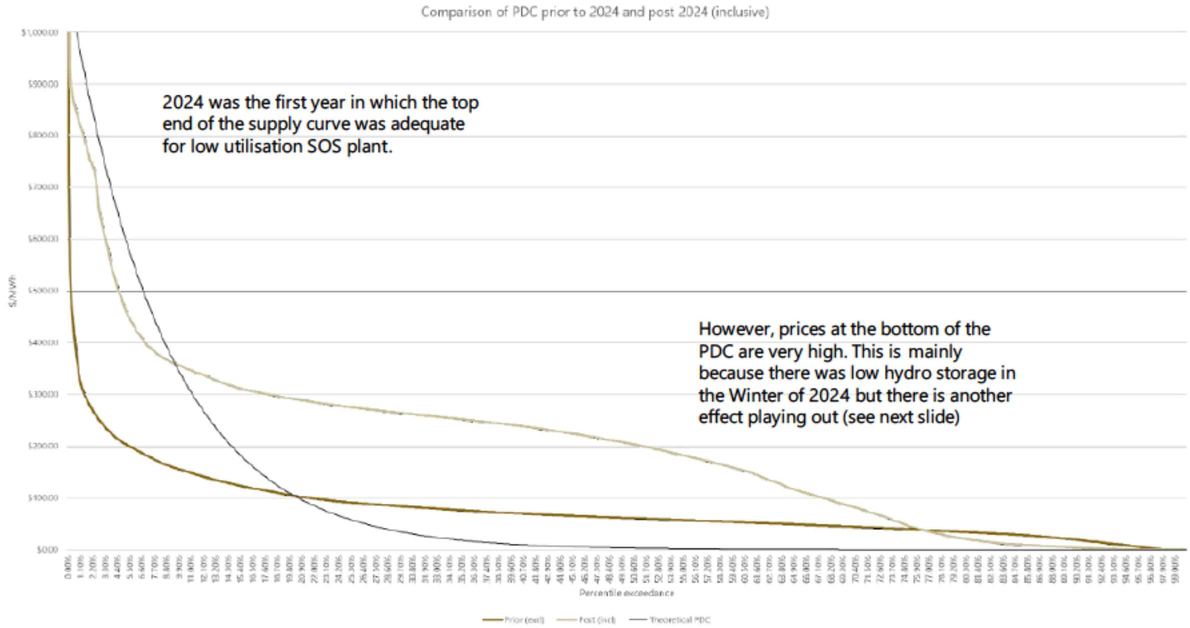
The PDC looks extreme with high prices concentrated at the top end of the curve, but with significant periods where prices are high and even more when they are low.

The high and extended peak prices are necessary for security of supply plant to have revenue adequacy. Commensurately, prices are very low (less than $5/MWh) for 50 per cent of the time. This seems extreme but also makes sense. If renewables are to provide dry year reserve, they need to be ambivalent to spill most of the time. This reinforces the need for significant periods of high prices when they occur. Intermittent renewables need the chance to be generating when prices are high enough to ensure revenue adequacy (and notwithstanding GWAP effects).

It should be noted that this is representing a long-term PDC. Some of the high prices may occur years apart. Some years could be mostly low prices for the duration of the year. This makes cashflow effects extreme and highlights the need for complimentary contract markets. If the market is functioning as it should then both the generators and wholesale purchasers need contract markets for the market to work in practice. Contract markets are at least as critical to investment in security of supply as the wholesale market.

2.1.5 What the PDC actually shows

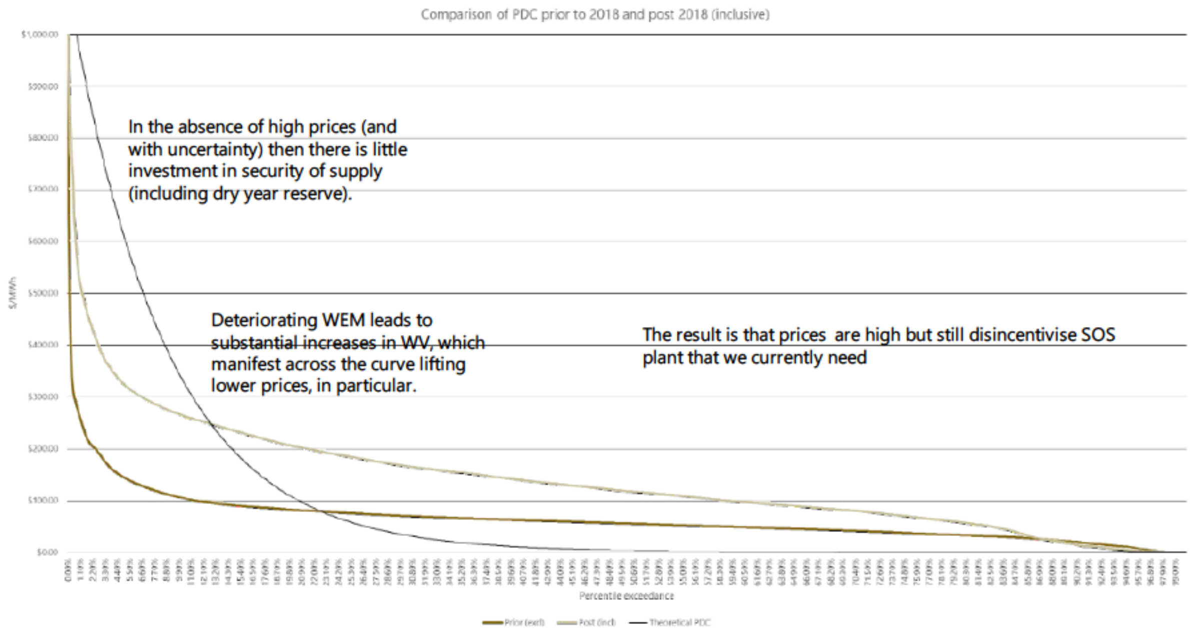
Figure 4: Comparison of 2024 PDC and theoretical



NOTE: PDCs should be assessed over many years to cater for plant utilisation over a variety of inflow years

2.1.6 Long-run PDC (since gas market problems)

Figure 5: Comparison of 2018-2024 PDC and theoretical



2.1.7 What is shaping the PDC?

Figure 5 shows that a longer run PDC does not line up with our theoretical PDC. This indicates that capital recovery is inadequate for low utilisation plant and that prices rise higher than looks intuitively correct for a market with high proportions of renewable generation, i.e. variable costs appear to be setting prices even at high utilisation factors. This raises the question of what is affecting the shape of the curve.

Scarcity pricing

Scarcity prices refer broadly to prices that lift to signal a reducing ability of the energy system to meet demand. During peak periods, scarcity prices should rise as capacity runs out (signalled by the use of very low utilisation generation or peaking assets and, ultimately, by the cost of demand response or shortages). During dry periods, and increasingly dunkelflaute as wind and solar generation grows, scarcity prices should rise as firm energy reserves run out.

As these periods are signalling the prices required for fixed capital cost recovery and/or the scarcity of cash costless fuels, concerns arise as to whether prices rise higher than they need to encourage investment, which would therefore discourage investment in demand. We expand on this issue in section 3.2.2.

Concerns and actions, both within the electricity industry and external to it, have put strong downward pressure on electricity prices. Reeve and Murray (Reeve & Murray, 2024) outline these concerns. We are also of the view that the market monitoring focus on short periods of high prices makes market participants curtail their pricing. We don't have concerns with the quality of market monitoring—our concern is the undue focus.

We suggest less focus on short periods of high prices and far more focus on the long-term PDC. We also suggest some focus on periods of low prices. Inappropriately low prices at times can reduce the incentives for investment, while elevated low prices for long periods lift average prices.

Water values

In New Zealand's wholesale market, variable costs during high proportions of renewable generation are water values (WVs). WVs are variable costs because the decision to generate now from a hydroelectric reservoir uses water that has a future value. This is an opportunity cost, but it is still a variable cost.

In the New Zealand wholesale market WVs are the key indicator of scarcity in firm energy and the level of pricing at these times.

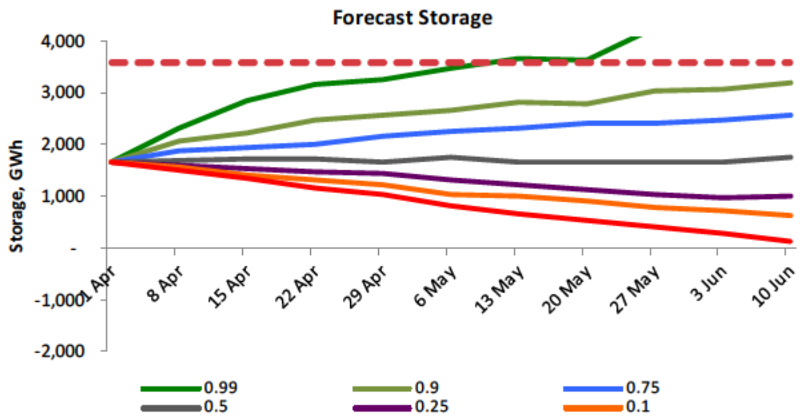
WV is the expected value of carrying water given:

- current storage
- the range of expected inflows
- the prices at which dry year firming generation can be brought to market (shadow prices)
- ultimately, the penalty cost of running out of water for generation.

Figure 6 illustrates this by showing the case for WV when there is plenty of alternative generation, i.e. production expectations are low. The probability of inflow sequences that lead to full storage (with the risk of spill) are higher than sequences that run out. In this scenario the opportunity cost of carrying water is low, i.e. WV is low. However, if a low inflow sequence does occur then WV will lift to the levels needed to encourage other generation to run and reduce the risk of running out.

Figure 6: WV example with low production expectation

WV with high security of supply



SOURCE: Whiteboard Energy's Hydro Simulator

If there is plenty of dry year reserve then there is little chance of running out of water.

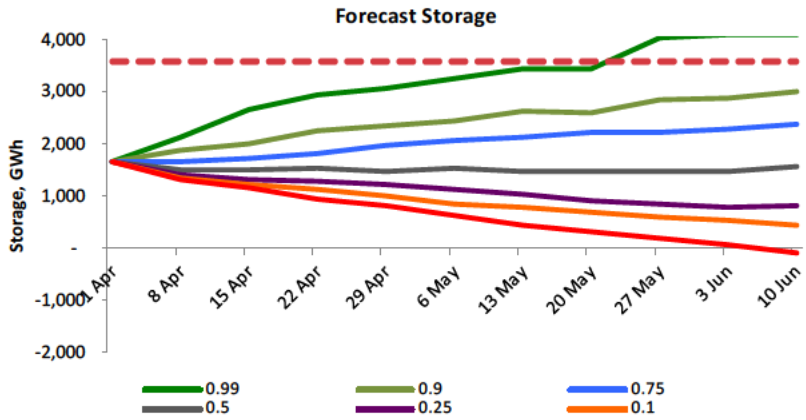
WV can still get quite high as storage drops depending on the costs of the dry year reserve and the likelihood it gets used. For example, if the most expensive dry year reserve is $5,000/MWh then WV will tend to $5,000/MWh as storage declines and the use of dry year firming gets more likely.

WV has to reach $5,000/MWh in the worst case to bring the last resort generation on.

Figure 7 shows the case where there is less generation available to run when storage levels reduce. In this case there is less chance of filling the storage and an increased chance of running out even at the same starting storage. As the cost of alternatives to hydro generation when things get more desperate are very high (i.e. very low plant utilisation, demand response, and ultimately shortage), then this change in expectations can significantly lift WV.

Figure 7: WV example with medium production expectation

WV with lower security of supply



SOURCE: Whiteboard Energy's Hydro Simulator

If there is insufficient dry year reserve then there is a chance of running out of water.

Now, as well as shadow pricing to dry year reserves the case for running out needs to be considered. This requires a price to be set for the cost of energy shortage.

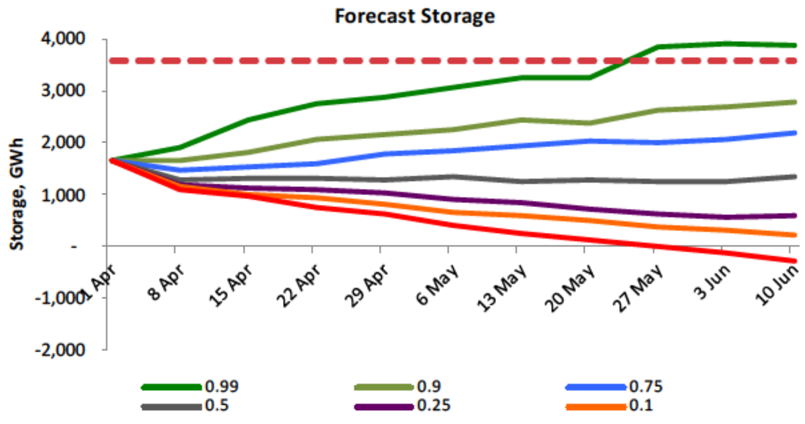
If we use VoLL, for which $20,000/MWh has been used mostly in recent years, then a 1% chance of shortfall gives an expected value of shortfall (i.e. WV) of $200/MWh

If SOS investment has fallen so that there is always some chance of shortfall, even at average storage, then there will be a permanent uplift of WV of hundreds of dollars per MWh

Figure 8 shows the case if even less generation is available to offset hydro generation. Again, the risk of running out increases significantly, again for the same level of storage. While the risk of filling the lake also remains high, the opportunity cost of spill is zero. The cost of alternative plant is very high and so small increases in risk lead to dramatic increases in WV.

Figure 8: WV example with high production expectation

WV with even lower security of supply



SOURCE: Whiteboard Energy's Hydro Simulator

Now if anything affects the SOS outlook, e.g. low storage, large thermal unit outage, low inflow forecast, low snowpack, then any increase in risk can dramatically increase WV, e.g. a 10% chance of Whirinaki running lifts WV by $500/MWh and a 1% increase in the chance of shortfall lifts WV by $200/MWh.

Once there is elevated risk of expensive thermal running and/or shortfall, WV can lift quickly.

WV of many hundreds of dollars are credible.

This effect we are seeing in the PDC is the result of reduced Winter Energy Margin (WEM) leading to higher WV. This in turn generally lifts prices by a significant amount.

Figure 5 also shows that prices are elevated at high utilisations over the PDC prior to 2018, but not by so much. The 2000s were beset by a number of dry periods where security of supply was a concern. This is the same issue we are seeing in the more recent PDC but to a lesser extent. It is the case that with a system relatively well balanced between hydro and thermal contributions, there will likely be an elevated WV at most times. However, in the scenario where we are going to use renewables to contribute to security of supply, then lake levels will be higher generally and WVs low more of the time.

2.2 Wholesale competition

The Taskforce has expressed concern with competition for generation investment. It should be noted that there are natural barriers to entry for generation investment. Startup costs are high, significant expertise is required and economies of scale large, generally. Historically, these barriers were even more significant. Geothermal, for example, requires hundreds of millions of dollars in sunk cost drilling to prove up fields and then hundreds of millions of dollars more to invest in the power plant. Significant geothermal field expertise is needed even before a financial investment decision is made.

The capital cost for newer generation technologies, e.g. wind, have dropped significantly and the expertise can be more variable. While investors with significant capital were still required more parties were able to compete.

Now solar costs have reduced with capital costs that are still quite high (relative to yield), but with much reduced expertise required (and which can be variabilised), and low economies of scale.

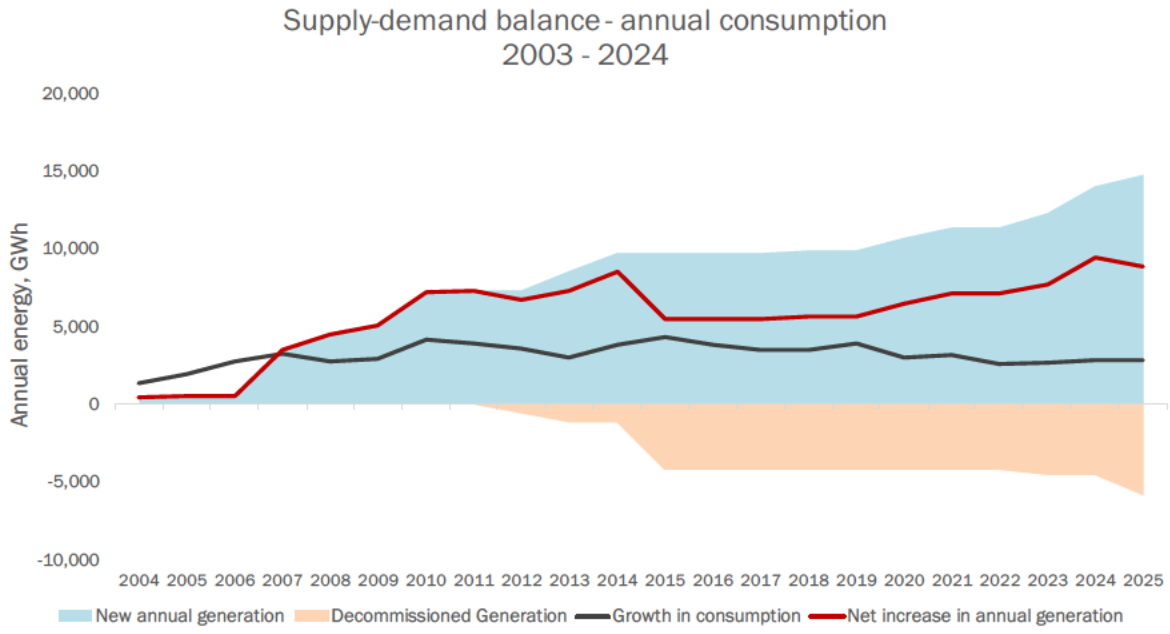
Traditionally you would not expect a large number of competitors in a market the size of New Zealand, but the competitive landscape is changing dramatically.

2.2.1 Is there evidence of restricted generation investment?

The Taskforce is concerned that there is withholding of generation investment to hold up wholesale prices. In terms of evidence of withholding there is a 'game of two halves.'

Baseload supply investment

Figure 9: Investment in baseload supply



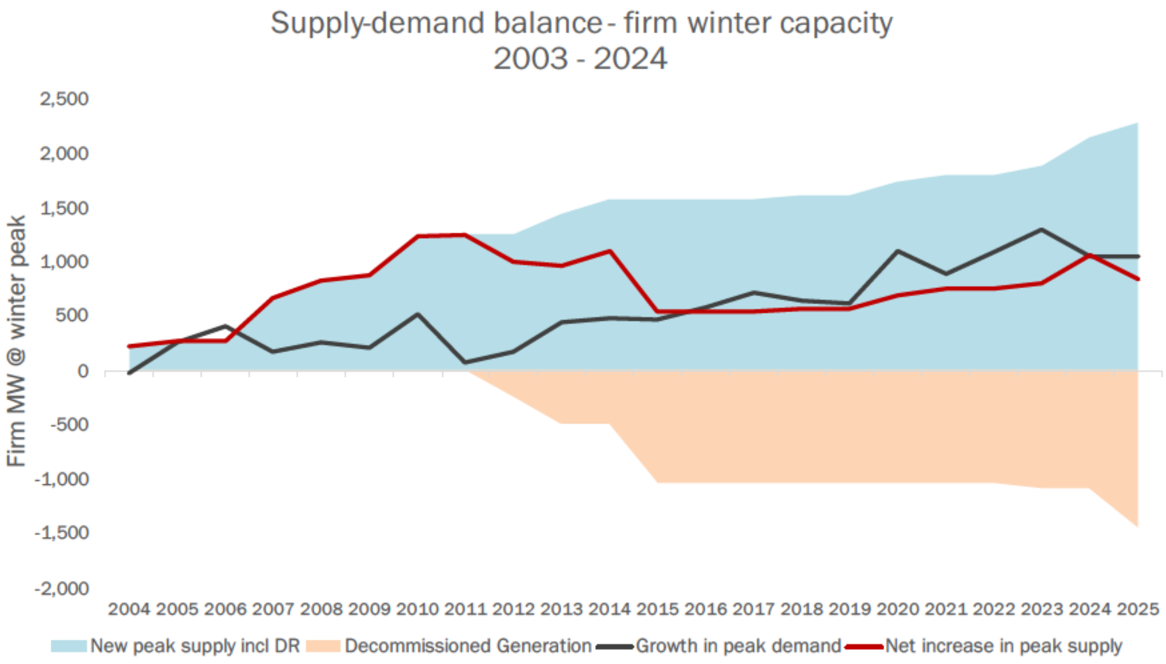
SOURCE: Whiteboard Energy

Figure 9 shows that there has been plenty of investment in baseload supply, over a period of no demand growth. As Figure 9 shows there has also been exit of baseload supply as new renewables have offset thermal generation. Relevant to the WV argument in 2.1.7 the plant investment and divestment is not equivalent. Plant that can flex in response to hydrological conditions has been replaced by plan that doesn't. Also relevant in Figure 9, is that generation potential isn't adjusted for fuel availability but only shows what potential has been invested in the electricity market. The restricted availability of gas has reduced what looks like a healthy supply-demand balance in Figure 9.

The evidence shows no withholding of generation investment in baseload supply of electricity. Supply problems are substantially due to gas supply.

Peak supply investment

Figure 10: Investment in supply capacity



SOURCE: Whiteboard Energy

Figure 10 shows a different story for peak capacity. Where thermal generation displaced has discretion to generate at peak times, subject to fuel and unit availability, wind generation isn't always available at peak times and solar never is, i.e. winter evenings.

The evidence shows an exit in peak capacity without replacement investment.

2.2.2 Competition at the margin

Here we consider whether there could be significant market power in the setting of WVs. This might be the case if the hydro operators dominate the margins (the price setting tranches) and may be able to lift prices without constraint.

Figure 11: Company's share of Real-Time Dispatch (RTD) marginal clearing by unit

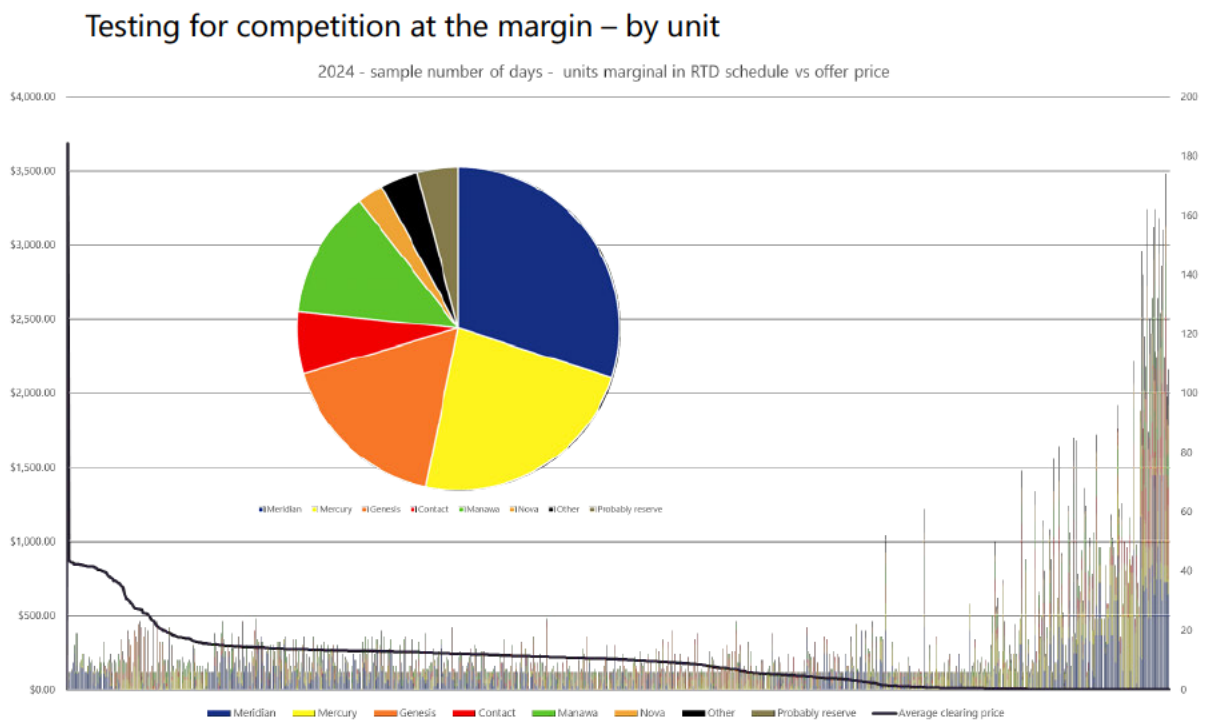
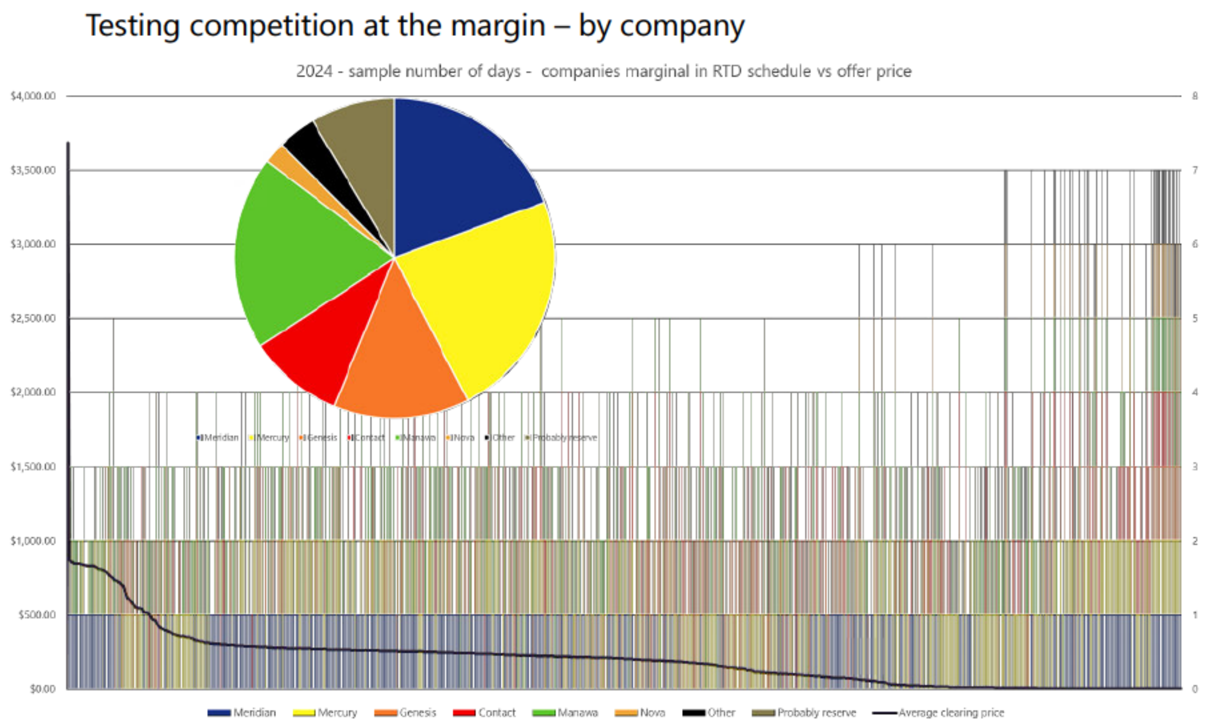


Figure 12: Company's share of RTD marginal clearing by company



The charts above show when units/stations (by owner) or companies were marginal in the RTD schedule. Periods are still 30 minutes and so you would expect to normally have six entities RTD marginal in a period. Where fewer than six RTD marginal entities are discovered in a period, the assumption is that Instantaneous Reserve (IR) was a marginal contributor to the cost of energy and so no price will equal an offer.

At very low prices locational differences are only fractions of a cent and so the marginal generator is difficult to pick. At other times locational differences are small across short links, e.g. from Tekapo A to Tekapo B.

Nevertheless, there is significant price separation across the year. This seems to be due to regional transmission constraints, which is why Manawa is so often marginal but always with another plant.

While Meridian, Mercury, and Genesis are most often marginal, many periods across the whole curve swap marginal generator between RTD dispatches. This suggests that there is competition at the margin. It also suggests that the hydro operators are foregoing volume (and revenue) to other plant. This indicates that WVs are being set to ration water.

2.2.3 How competitive is the investment outlook?

For the forecast of potential generation and the adequacy of potential new investment to meet baseload supply we rely on the Concept paper (Coates, 2025). This shows plenty of generation to meet the demand for baseload supply, even potentially for significant demand growth scenarios. Previous analysis we have done agrees with this assessment.

Is the investment pipeline dominated by the four large generator retailers?

The new investment pipeline is not dominated by the four large generator retailers. In fact, there looks to be more new entrant generators than we've seen before largely because of the low entry costs for wind and solar.

Taking Transpower's connection pipeline, of the eight projects where a Transpower connection is currently under construction, only one is a large generator retailer project.

Certain technologies are dominated by large generator retailers. For example, geothermal has large entry costs and requires significant expertise to develop and so has limited competition. Nevertheless, even in geothermal there are significant competitors to the large generator retailers.[1]

Security of supply

Despite the rosy prognosis for baseload generation competition, we remain concerned with security of supply. As far as we are aware there is no investment in plant that would be economic and reliable to participate in the 2 per cent to 20 per cent utilisation range of the PDC. We note, though, Channel Infrastructure has announced that it is investigating diesel OCGTs with two parties. The Winter Capacity Margin (WCM) looks likely to continue to erode, although there some relief for the lowest utilisation periods from BESS.

[1] Technically, the only independent competitor in geothermal is Eastland Generation. However, Tūaropaki Power Company is substantially independent, and the partners in Nga Awa Purua JV act independently.

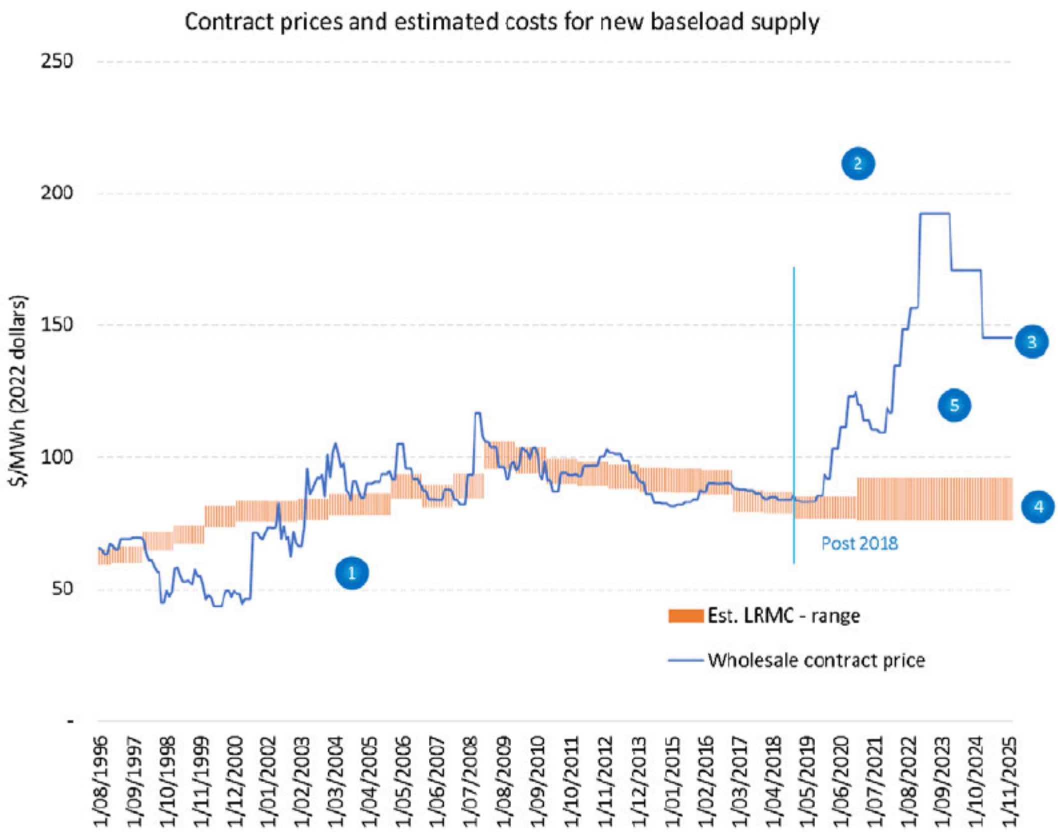
The investment pipeline looks likely to make some improvement to the WEM. However, unless there is a change in the structure of peak prices, we do not think that WEM will fully recover. We demonstrate our concerns in section 2.2.5.

2.2.4 Long-Run Marginal Cost (LRMC) forward price gap

A key question is, if generation is competitive, why has the forward price curve lifted so high above LRMC.[2]

This was assessed by Concept Consulting, originally in their report for the Authority "Generation investment survey—prepared for the Electricity Authority' (2023 update), slide 6" and reproduced in the Level Playing Field paper and below.

Figure 13: Contract prices and estimated costs for baseload supply (Concept Consulting)



Source: Concept Consulting

The chart shows a market anomaly from 2018 to current, where New Zealand Electricity Futures prices substantially exceed the assessed LRMC of new supply for over six years. This is an anomalous outcome as you would expect new investment to have put downward pressure on prices so that they

[2] We don't agree with the definition of LRMC in (Coates, 2025). In our view LRMC has to be assessed across the entire PDC and at different plant utilisation, and also that prices over time aren't level. Nevertheless, we agree that the amount the forward curve has lifted above the investment prices assessed is a concern.

are closer to the LRMC of new supply. One of the tests for market efficiency is that prices don't rise higher than they need to encourage new investment.

The chart above is necessarily simplified, it represents only the case for baseload supply and not supply that needs to operate over lower utilisation, but it indicates a problem nonetheless. It should also be noted that a lot can change in two years. Costs for generation have probably increased a bit since 2023 and the cost of firming (which Concept states are added to the LCOE of generation in the chart) are significantly higher.

To assess the problem fully we need to look at how prices perform for lower utilisation plant, which is the assessment done in section 2.1. This section finds that prices don't have the structure (i.e. the shape of the PDC) to support investment in security of supply. As a result, security of supply has eroded, lifting risk and uncertainty, and lifting hydro WVs. Higher WVs on average lead to elevated prices generally rather than elevating prices that support security of supply.

It is still worth asking the question, if prices are on average high enough, why doesn't investment occur anyway? The first part of that answer is that there has been investment in new generation as shown in Figure 9. The second part of that question is that there was a chilling of private investment due to external uncertainties such as the gas market, Tiwai aluminium smelter, and government interventions such as New Zealand Battery and the 100 per cent renewable target.[3]

There is now evidence that investment is occurring. However, we remain concerned about investment in security of supply, especially peak generation up to up to 40 per cent utilisation factors. These concerns are related to how generation investment occurs and uncertainty about the revenue adequacy that can be supported by peak prices.

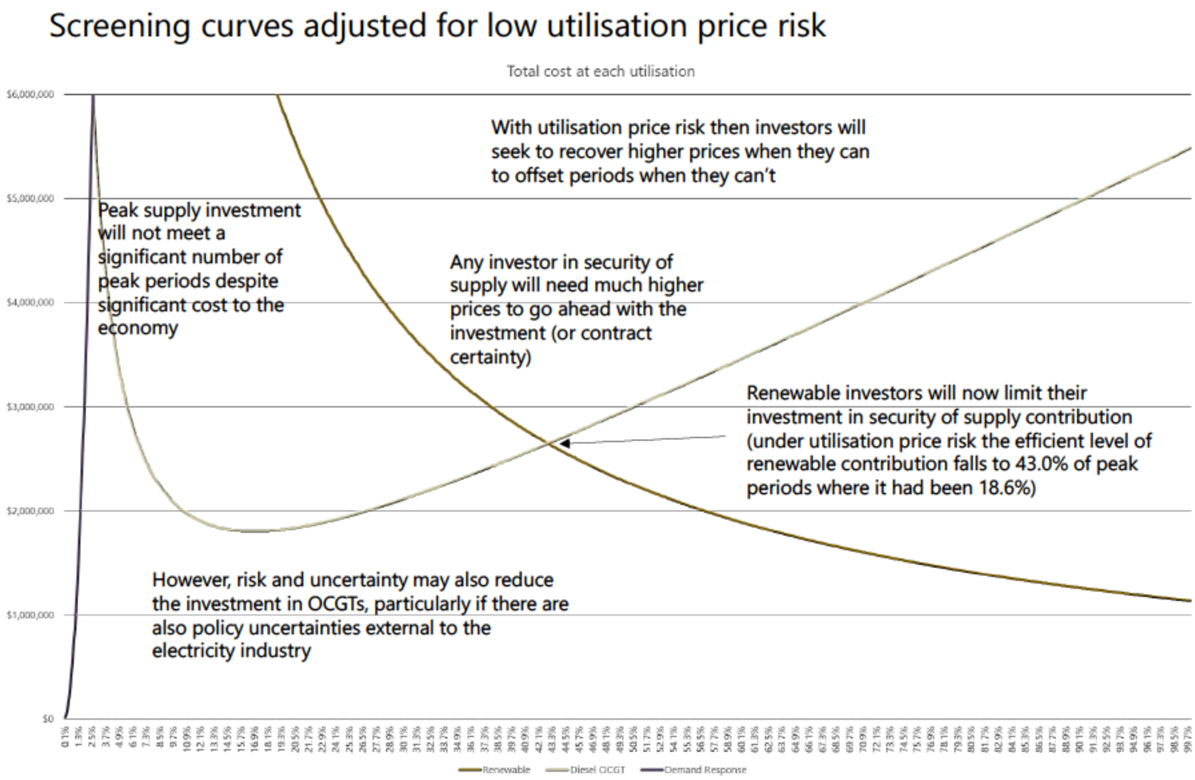
2.2.5 Factors affecting generation investment

Peak price uncertainty

As we discuss in section 2.1, prices don't rise high enough at the right time to support peak investment. However, even just the perception of risk that peak prices won't support investment affects the economics of investment. If investors perceive that peak prices won't support investment, they will seek prices that give revenue certainty over shorter utilisations, i.e. a risk premium on low utilisation plant. In Figure 14 we adjust the screening curves from Figure 2 for this price risk.

[3] The 100 per cent renewable target wasn't officially government policy, but it was perceived as an investment threat.

Figure 14: Screening curves adjusted for low utilisation price risk



As can be seen in Figure 14 this leads the level of investment in renewable generation, and its contribution to dry period risk to fall to 43 per cent utilisation (in our theoretical example) from the 18.6 per cent level expected without price risk. If this was only price risk, then the main outcome would be significant investment in diesel OCGTs (in the absence of available gas contracts). However, there are significant factors preventing investment in fossil fuel thermal generation even for low utilisations for peaking.

Obviously one factor is gas market uncertainty but government policy, or lack of, also plays a significant role. Previous government policy played a significant role in chilling investment in gas and electricity, e.g. through gas exploration ban, uncertainty about 100 per cent renewable energy policy, and New Zealand Battery. However, the current government is also creating uncertainty through the potential to underwrite gas exploration and/or LNG. Investors are also concerned about whether a thermal generation investment could survive political cycles. [4]

Generation investment

Generation investments are based on forecast prices not current prices. The first reason for this is obvious, as generation investments are long-life investments then prices over the long-term may not bear any direct relationship to current prices. The second reason is really a variation of the first. As a

[4] It can be argued that the current government's position on gas is in response to previous policy choices, but this highlights the problem. Rather than refine a consistent and long-term energy strategy, energy policy swings across election cycles.

result of investing in generation (and as others also invest) market prices will change. New investments are exposed to post-investment prices not current prices.[5]

Some investment can go ahead, especially if it is displacing the dispatch of thermal generation that doesn't leave the market. This leads to an improvement in security of supply and, providing that forecasted baseload prices don't fall (WVs stay high), then investment will go ahead. This outcome, where generation will not exceed the level that would reduce baseload prices, is easy to ascribe to anti-competitive practice. However, as demonstrated in Figure 5, the lack of investment beyond that point would be the rational response of investors to the risk and uncertainty that prices will rise high enough in periods of scarcity to make new investment revenue adequate.

When an experienced New Zealand electricity market investor forecasts prices, they will forecast prices based on the best expectations of the costs of other generation that reflect current reality. Political and regulatory focus is on short periods of high prices rather than an efficient PDC. Therefore, the costs for low utilisation plant will reflect a fear, or inability, to lift prices significantly during times of scarcity. Therefore, when they model post-investment prices that start to push down baseload prices, they discover what is demonstrated in Figure 5, such investment will not be revenue adequate. The current market settings (and other external factors) will not reward a significant contribution to security of supply.

There is a lot of investment that is potentially financed by operators that are not experienced in the New Zealand market. However, they will identify that even with current high prices on average that there are still long periods of low prices. Some well capitalised projects may then go ahead, but many will seek to reduce risk to get financing. They will go to the market for PPAs.

There is a concern that PPA offers are not available. However, the other side to that concern is that PPA sellers are disappointed with prices when they are made. Again, depending on the forward view of investment and demand growth, this can be a rational response to post-investment revenue inadequacy, uncertainty, and external risks.

In section 4.2 we also draw out problems with PPAs, if renewable generation is to be used to contribute to dry year risk and dunkelflaute, that also make them less attractive to small/medium retailers.

Generation investment withholding

While the analysis suggests that there are market problems leading to low investment, particularly in security of supply, it is also worth considering whether a generation investment withholding strategy could be successful or stable.

To be a successful strategy then exercising the strategy would need to be expected to be more valuable in present value (PV) terms than not exercising it. As a long-term strategy this would mean lifting prices higher than they would be otherwise over the long-term. This clearly doesn't fit with

[5] New Zealand Electricity Futures are forward contracts but only up to four years ahead. This is insufficient price certainty for generation investment.

current market prices as a long-term strategy would need to maintain prices at a level that don't draw political or regulatory attention, or rise so high that a competitor response does occur.

As a short-term strategy, the pay-off would have to be high prices for a short period of time which then revert to normal. If this was a strategy, then it looks like a very risky strategy. Lifting prices to a level that invites political and regulatory response, with the chance of disruptive change, looks like a value destroying strategy for a long-term asset operator. It is possible that it is a strategy, but that is either very bold and/or poorly executed.

This raises the question of whether such a strategy could be stable. To be stable the four generator retailers would need to, simultaneously, have decided on a bold strategy and/or have poorly executed it. If any one of the four decided that prices were getting too high, in the face of political and regulatory risk, then they would have the opportunity to get ahead of the others on the investment curve and secure long-term volume, IF they believed the market would sustain that investment. If they don't believe the market could sustain that investment, then it's not a strategy to withhold investment, it is a market reality. This makes poor execution look less likely as it would require all four to have misplayed their hands.

It seems likely that the only way a bold strategy to lift prices high in the short run could be stable would be through explicit collusion. However, if the four companies were going to take the risk of collusion, then surely a long-term strategy would be more valuable, or at least a less bold, less risky short-term strategy. Surely, a collusive strategy would have considered the political, regulatory, and legal risks and would have adapted to the risk.

2.3 Wholesale price and competition conclusions

The one-part (energy only) market design in New Zealand requires that prices rise high enough at the right time, and fall low enough at the right time, to encourage investment in the right type of plant (suitable for the required utilisation) to meet demand at all times over time (subject to a reasonable security standard).

Factors outlined in (Reeve & Murray, 2024) have suppressed the top end of the PDC resulting in underinvestment in security of supply (both peak capacity and dry year reserve).

The scarcity of dry year reserve has resulted in higher WVs lifting electricity prices. This has lifted prices across the PDC but still not to a point that would encourage investment in plant with utilisation between 2 per cent to up to 40 per cent.

This results in high baseload prices that has encouraged some investment and is encouraging new investment. Historically, the lower investment than suggested by prices has been in response to external factors (particularly in this case the threat of Tiwai exit). However, we are of the view that the current structure of prices, with continuing external factors, will result in a lower investment than is needed to meet security standards (Winter Energy Margin). This is not due to the deliberate withholding of generation but rational response to price risk for low utilisation plant.

The problems for peak price signals are more acute (both revenue inadequacy and external factors) and the Winter Capacity Margin will further decline making demand curtailment inevitable and regular.

3. Retail

3.1 Margin analysis

In the following analysis of retail prices (through an assessment of retail margins) and retail competition we are focused on identifying issues with the retail market performance. We are trying to separate out competition issues that may arise from upstream markets (i.e. wholesale and contracts), although we do try to address where the upstream markets affect retail competition.

Our retail price analysis is done through looking at the retail margins between retailers in some detail. We have, in the time available, focused on the residential market. In our view, the correct benchmark for competition analysis is to assess retail margins based on revenue recovery compared to the variable cost of goods sold (which for convenience we generally refer to as cost). We explain our reasoning further in our assessment of competition below.

Upstream market problems

The difference between fixed and variable wouldn't matter if upstream markets were working as intended. In this case all parties would be ambivalent between wholesale prices and contract prices and contracting would occur freely. In this case the differences between wholesale prices and contract prices would be small, except for the case where there are high levels of contracting. In the case of high contracting levels then the contracts market is an available channel to all wholesale traders and creates an opportunity cost above the average wholesale price. Input costs would be the same for all parties.

In the market currently wholesale prices seem to have diverged from contract prices for at least some periods and, either because of the divergence of prices or other factors, a part of the market does not contract. Under these conditions then opportunity costs become different for different parties.

Variable costs

An important question, then, for this analysis is what is a variable cost and what is a fixed cost in the retail context? Variable and fixed costs must be defined in reference to a time frame. Costs that are variable are variable within that time frame and costs not variable within that time frame are fixed. In the extreme, in the very long term, all costs are variable; and, in the very short term, all costs are fixed.

Ideally, in this margin analysis we would do a continuous assessment of retail margins at the margin, i.e. the margins targeted by each retailer at the point of acquisition. However, we don't have time to do such an intensive analysis, and we do not have access to the data we would need. We have necessarily had to do some averaging.

Considering the period over which retail prices are variable, we note the market has generally settled on annual price increases for retail customers. However, retailers also try to minimise the rate shock to customers through trying to more consistent and averaged increases. Retailers also insulate retail customers from short run market impacts (such as dry periods). We think these are genuine services that retailers provide to small and medium customers. Therefore, we think the variable cost time frame for retailing to small and medium customers is over a few years. For these reasons, we have chosen five years, i.e. we consider that wholesale prices are a variable cost over a five-year averaging period. We have also looked at gross margins annually.

We also consider that network costs and metering costs are variable costs for retailers. If a retailer loses a customer, they lose these costs.

Fixed costs

The question then arises whether contracts and hedging instruments are fixed or variable costs. Reinforcing that this question would be moot if wholesale and contract markets are working as expected.

In our view this depends on the retail entity. For generator retailers, with long-life generation assets, the associated long-duration trading portfolio, and an enduring retail business, our view is that the implied retail contract is a fixed cost. At the other end of the spectrum, a new entrant retailer would have a more tentative hedging approach that is substantially at the margin, probably using New Zealand Electricity Futures. Here, contracts would be a variable cost. However, this may not be exclusively the case. The recent entry of Lodestone as a retailer is an example of a new entrant retailer entering the market as an existing generator to become a vertically integrated generator retailer. Here the implied contract is again a fixed cost. Historically, this is unique but with the low entry costs to solar generation it may become more prevalent.

The case for medium retailers is probably a mixture of the case for small retailers and large generator retailer. An established retail operation should have an enduring hedging strategy and would likely have a mixture of short-term arrangements, particularly for marginal acquisition, but are also likely to have longer-term Over-The-Counter (OTC) arrangements (especially as their operational resilience and creditworthiness improves).

This suggests to us that hedging costs, in a market where contracts are not freely available, tend to be a variable cost for small retailers that reduces as the retailer gets larger. Vertical integration, whether large or small, reduces variable hedging costs to zero.

Practical considerations for the margin analysis

The above conclusions mean that we should try to estimate the hedging cost functions as a function of retailer size. We do not have time for that, and we may not have sufficient data. Therefore, to apply a consistent benchmark and focus on the large generator-retailers, we have not included hedging costs in our analysis. We stress that this means that the margins for small/medium retailers will be overstated. We try to treat this qualitatively in the competition section.

3.1.1 Margins modelled for retail offerings in five EDBs

Five EDBs were chosen based simply on choosing offerings in Auckland, Wellington, Christchurch, a regional North Island centre (Whangarei) and a regional South Island centre (Nelson). Accessing retail price offerings is labour intensive and so a broader analysis was prohibitive.

Costs have been kept uniform for all retailers assessed. These costs are based on an 8,000kWh demand treated as a standard user. Controlled offers are preferred but where that leads to inconsistencies due to the prevailing EDB pricing then Anytime is used. The same approach is used for each retailer.

The biggest difference between offerings is that the large retailers strongly prefer single fixed and variable prices, where smaller retailers prefer single fixed prices and Time Of Use (TOU) variable prices. Therefore, these results are shown separately but the costs are still assessed on an identical basis.

Auckland

Figure 15: Retail margins and cashflows – non-TOU – Vector Northern

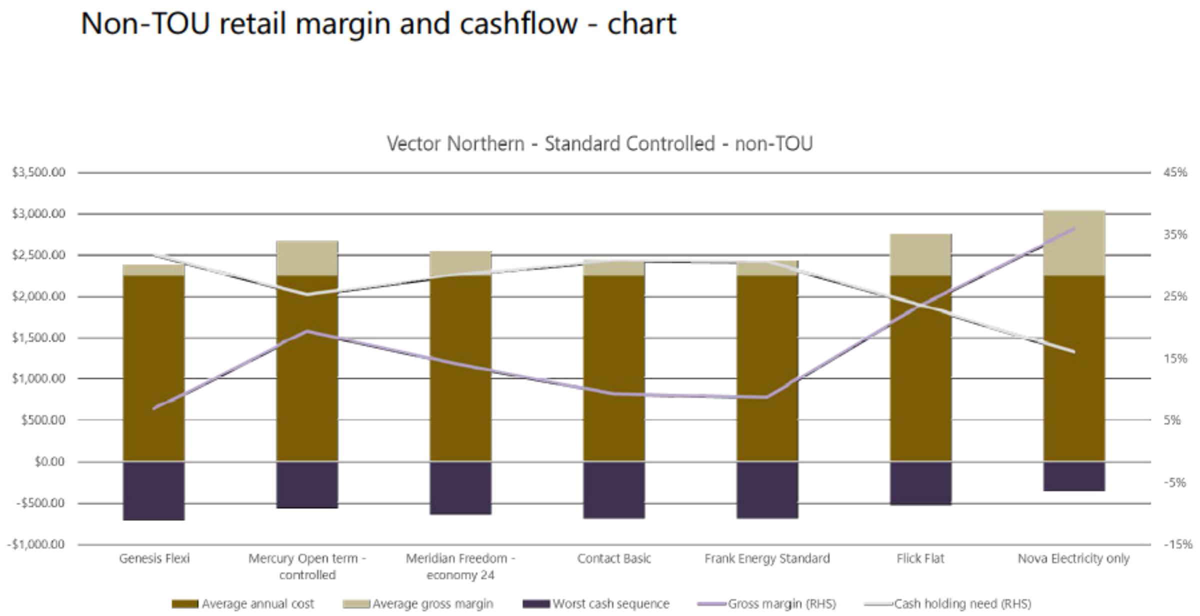


Table 1: Revenue, costs, margins, and adverse cashflows for non-TOU residential customers on Vector Northern

Non-TOU	Genesis Flexi	Mercury Open term - controlled	Meridian Freedom - economy 24	Contact Basic	Frank Energy Standard	Flick Flat	Nova Electricity only
Customer bill	$2,748.54	$3,074.17	$2,933.50	$2,813.15	$2,799.57	$3,177.75	$3,498.18
Effective rate (/kWh)	$0.34	$0.38	$0.37	$0.35	$0.35	$0.40	$0.44
Average annual revenue	$2,390.04	$2,673.19	$2,550.87	$2,446.21	$2,434.41	$2,763.26	$3,041.89
Average annual cost	$2,239.68	$2,239.68	$2,239.68	$2,239.68	$2,239.68	$2,239.68	$2,239.68
Average gross margin	$150.36	$433.52	$311.19	$206.54	$194.74	$523.59	$802.22

Non-TOU	Genesis Flexi	Mercury Open term - controlled	Meridian Freedom - economy 24	Contact Basic	Frank Energy Standard	Flick Flat	Nova Electricity only
Worst cash sequence	-$711.59	-$562.20	-$639.00	-$687.89	-$684.60	-$527.19	-$355.51
Gross margin (RHS)	7%	19%	14%	9%	9%	23%	36%
Cash holding need (RHS)	32%	25%	29%	31%	31%	24%	16%
GM per year							
2020	$422.52	$706.12	$583.60	$478.78	$466.94	$796.33	$1,075.40
2021	-$67.85	$215.03	$92.85	-$11.74	-$23.45	$305.04	$583.43
2022	$448.82	$731.71	$609.53	$504.94	$493.23	$821.72	$1,100.12
2023	$232.94	$516.43	$393.88	$289.20	$277.14	$606.54	$885.43
2024	-$303.60	-$106.18	-$186.88	-$265.63	-$259.60	-$39.47	$158.54

Figure 16: Retail margins and cashflow – TOU – Vector Northern

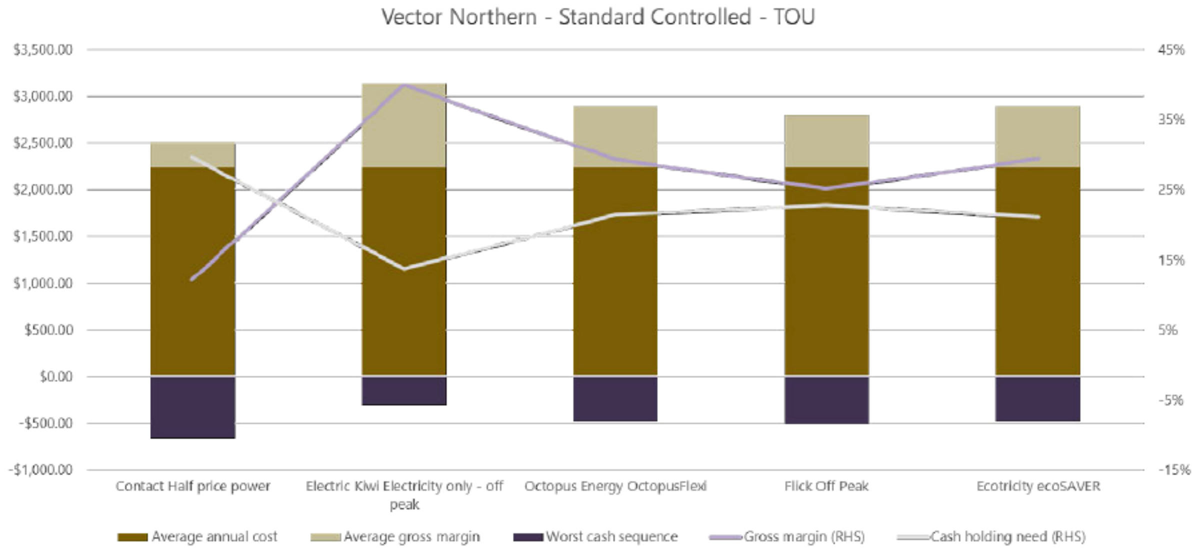


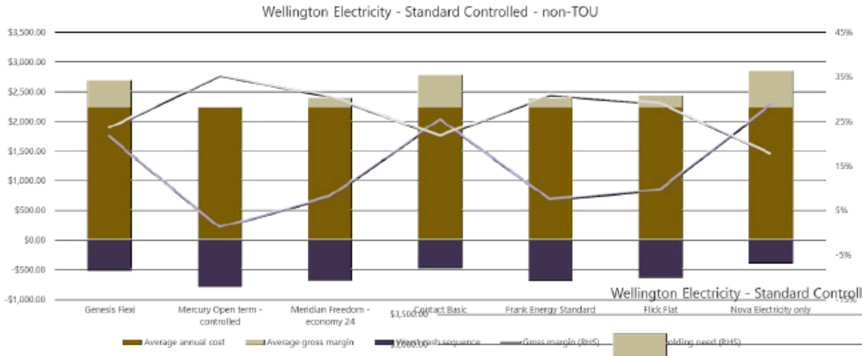
Table 2: Revenue, costs, margins, and adverse cashflows for TOU residential customers on Vector Northern

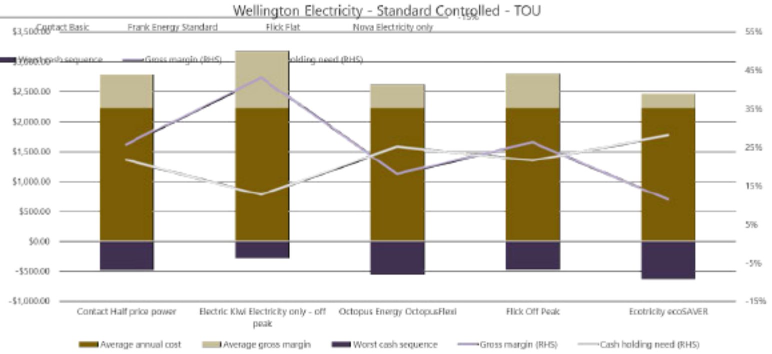
Non-TOU	Contact Half price power	Electric Kiwi Electricity only - off peak	Octopus Energy OctopusFlexi	Flick Off Peak	Ecotricity ecoSAVER
Customer bill	$2,886.27	$3,604.29	$3,328.93	$3,222.69	$3,333.64
Effective rate (/kWh)	$0.36	$0.45	$0.42	$0.40	$0.42
Average annual revenue	$2,509.80	$3,134.16	$2,894.72	$2,802.34	$2,898.82
Average annual cost	$2,239.68	$2,239.68	$2,239.68	$2,239.68	$2,239.68
Average gross margin	$270.13	$894.49	$655.04	$562.67	$659.14
Worst cash sequence	-$662.68	-$307.87	-$477.53	-$510.81	-$471.29
Gross margin (RHS)	12%	40%	29%	25%	29%
Cash holding need (RHS)	30%	14%	21%	23%	21%
GM per year					
2020	$542.48	$1,168.69	$928.34	$835.93	$932.63
2021	$51.77	$676.09	$436.51	$344.24	$440.70
2022	$568.44	$1,192.92	$953.24	$860.99	$957.46
2023	$352.94	$975.09	$737.27	$644.53	$740.82
2024	-$225.39	$255.50	$55.87	-$9.05	$65.13

Wellington

Figure 17: Retail margins and cashflow – Wellington Electricity

Charts only – Wellington Electricity

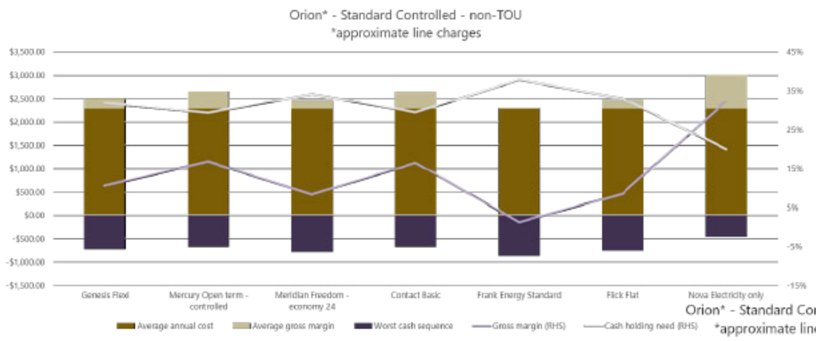




Christchurch

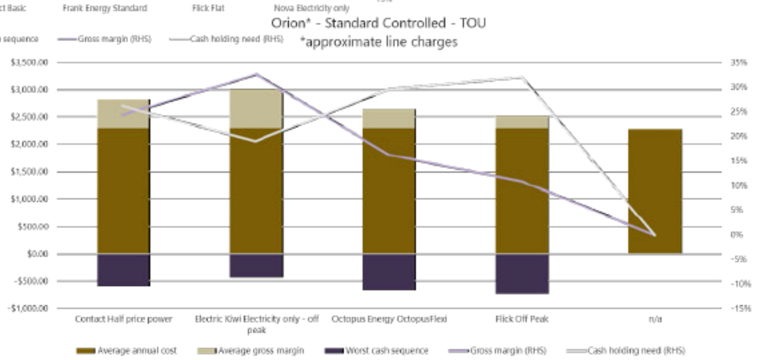
Figure 18: Retail margins and cashflow - Orion

Charts only - Orion



The model didn't anticipate the number of TOU categories for Orion. However, the lines charges are approximately correct and are consistent for every retailer.

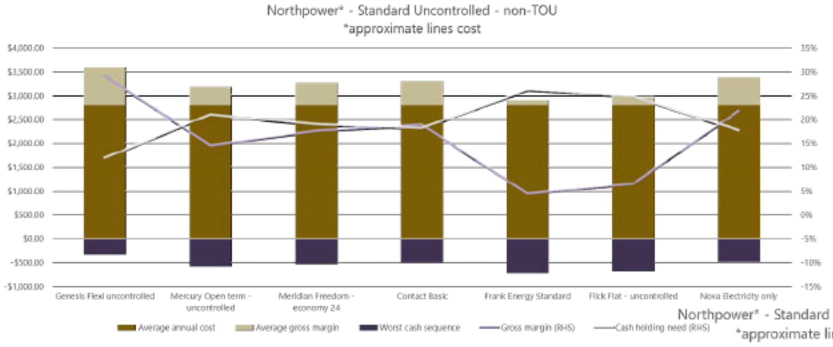
Ecotricity uses Orion's TOU structure and couldn't be reliably approximated.

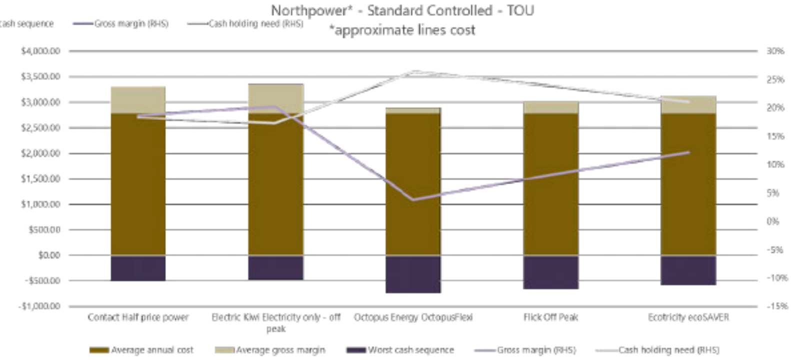


Whangarei

Figure 19: Retail margins and cashflow - Northpower

Charts only - Northpower





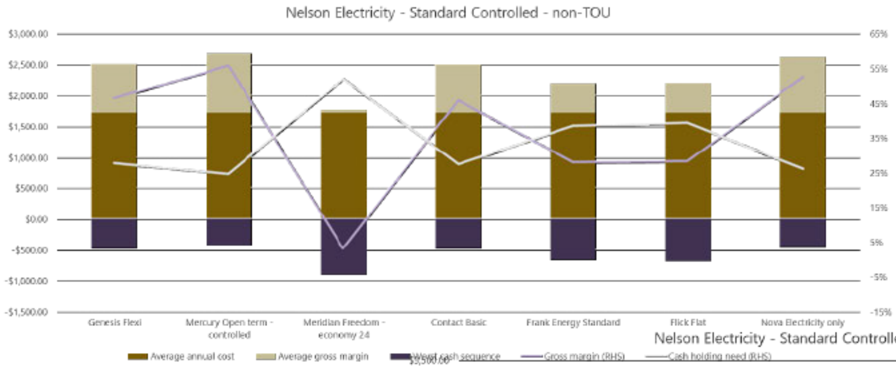
Again model would need to be modified for Northpower TOU structure. However, lines charges are approximately correct and are the same for every retailer.

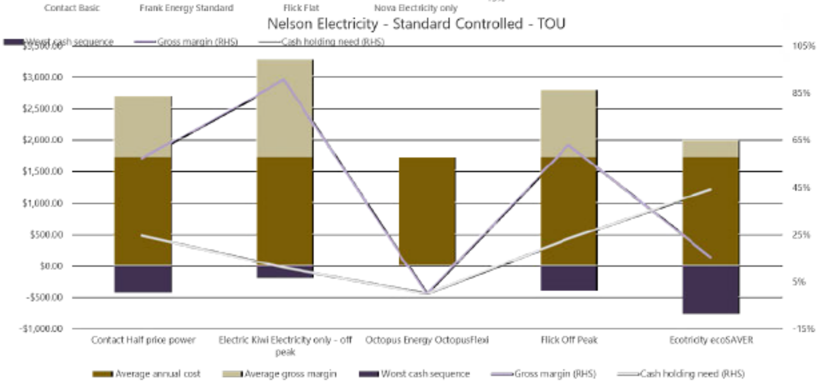
Ecotricity uses Northpower's TOU structure but was easier to adapt.

Nelson

Figure 20: Retail margins and cashflow – Nelson Electricity

Charts only – Nelson Electricity





Observations

The small independents are offering TOU and encouraging demand response, batteries, and solar (Pulse are the only ones that don't give online rates).

The profile was kept the same in the margin analysis so that results could be directly compared but, in practice, the small retailers would get some demand shifting and may look more competitive. Although, load shifting would change both cost and revenue and so margins may improve in practice.

Retailers can be inconsistent between networks. This could be due to regional acquisition targets, but it could also be due to the variety of network TOU structures. All five of the networks sampled had different TOU structures. All the retailers, except Ecotricity, maintained their own national consistency when it came to their pricing structure which doesn't always align well with the network price structure. Ecotricity seems to be the only retailer that tries to replicate each network price structure.

Big four margins tend to be smaller in the large centres. Margins seem to be healthier in smaller centres, e.g. Whangarei and, especially, Nelson.

Margins calculated here tend to be about double those calculated by the Electricity Authority (EA). We believe that is because the EA calculates the margins against total cost, whereas this analysis treats lines charges as a pass-through cost, i.e. the margin is assessed against variable energy costs.

3.1.2 Are the generator retailers losing money in retail?

The analysis above is for gross margins. The question is whether the generator retailers are negative profit at the net margin level, i.e. after cost to serve administration and directly attributable overheads.

The table below derives information the generator retailer operating reports. How the costs are bundled, what is and isn't included, and how common overheads are allocated is all opaque, and so the results are indicative at best.

Table 3: Large generator retailer gross margin, estimated cost to serve, and estimated net margin

Big four average gross margin and estimated cost to serve

	Genesis	Mercury	Meridian	Contact		
Average gross margin (flat reate)	$150	$434	$311	$207		
Estimated cost to serve	$190	$216	$211	$140		
Net margin/EBITDAF	-$40	$218	$100	$67		
Genesis notes	From interim report 2025, segment employee and operating expenses divided by number of residential customers					
Mercury notes	Price increase 1 April 2025. From 2025 Interim Report, segment total operating expenses divided by total customer connections					
Meridian notes	From Meridian Integrated Report 2024, segment employee expenses and operating costs divided by customer connections					
Contact notes	From operating report July 2022 to March 2025, declared cost to serve for 12 months to June 2024					

* Table is indicative only. It is unable to be determined what is or is not included in each cost to serve. Some may be electricity only, some may include gas, LPG, and bundled services.

Further observations (net margins and annual cashflows)

Big four margins are significantly lower than independents, although there is bit of variation between the large generator retailers.

Three of the large generator retailers appear to be recovering variable and fixed operating costs on average (they may not be recovering all fixed economic costs, i.e. return on capital, but capex should be small compared to generation).[6]

All the large generator retailers are recovering variable operating costs and some contribution to fixed operating costs (Genesis has the lowest margins in the regions assessed but is losing customers – maybe due to pricing in other regions).

The above results are true on an average basis but there are significant issues when looking at individual years and cashflow.

[6] The bulk of a generator retailer's gross margin comes from generation, but the capex costs are also orders of magnitude higher, i.e. economic overheads are significantly higher as well.

Even Mercury, that has the highest margins of the large generator retailers, has a bigger exposure to the worst cashflow sequence (for an unhedged retailer) than it expects from gross margin, i.e. the negative cashflows over adverse periods are higher than the eventual margins realised.

All the large generator retailers had negative gross margin in 2024 and two did in 2021, noting that the high prices over August 2024 occurred generally after the annual price increases for that year.

Generally, the pricing of the smaller retailers seems to be around the breakeven of 2024 costs and unhedged cashflow exposure is a lot less than for the large generator retailers. However, the cashflow exposure is still significant.

3.2 Retail competition

3.2.1 Is there 'retail squeeze'?

One of the key competition concerns in the level playing field is the margin squeeze on small/medium retailers. Margin squeeze is also a result expected from strong competition, so for the margin squeeze to be an anti-competitive action it would have to be attributable to a predatory pricing strategy. In such a strategy the large generator retailers would be deliberately setting prices at unsustainably low levels for the purpose of causing the exit of competitors and then benefiting from longer-term prices with far less downward competitive pressure.

An associated concern is that the margin squeeze has led energy intensive industry to be forced to take wholesale market exposure and then fail financially with the high wholesale prices of August 2024. We look at this issue first but to explore these associated issues it is worth understanding how wholesaling and retailing works in New Zealand.

3.2.2 Did 'retail squeeze' play a role in the exit of energy intensive customers over August 2024?

Wholesale and retail customers

Obviously, retailers are wholesale purchasers of electricity that then sell to others (retail customers) whereas wholesale customers purchase from the wholesale electricity market. However, there are some subtleties to be aware of for both retail and wholesale.

The Code permits a wide range of purchase and contract arrangements. The only rule that is somewhat restrictive is that grid connected customers must purchase from the wholesale market. There is no restriction on who can be a wholesale customer, or even a retailer, providing that the Code obligations to be that class of market participant are met.

Generally, code obligation costs are too high for small commercial and residential customers to be economic wholesale customers and, as stated above, grid connected customers must be wholesale customers. Nevertheless, the variety of arrangements can still permit some crossover. Some retail customers can choose retail plans that make them 'spot customers' and wholesale customers can contract with a retailer for all services provided by a retailer even though they remain the purchaser of wholesale electricity.

There is a significant difference between customers, however, when it comes to the form of contract.

Retail services and contracts

Before getting into the contract forms, it is useful to understand the services that are provided by retailers. The retail services that can be purchased are:

- Metering services
- Reconciliation services
- Compliance services
- Credit services
- Trading services for a wholesale customer/electricity purchases for retail customers,
- Risk management, and
- Billing.

Wholesale customers can choose which of these services they wish to contract for and which to do themselves. The retailer provides all these services to mass-market retail customers, usually through bundled prices. However, there is a difference between the nature of the bundled contracts offered to different customer groups.

From residential and small business customers through to medium commercial and industrial customers the contract tends to be a simple price, full-service contract with an enduring term. The small/medium customer retail contract does not have a termination date, but allows periodic price rises.[7] As small/medium customers can switch whenever they want, then retailers seek to smooth price increases as best they can to avoid a rate shock that would cause customer dissatisfaction.

Larger Commercial and Industrial customers (C&I) are not offered standard price based enduring contracts but are usually on fixed term contracts. The C&I contracts are often Fixed Price Variable Volume contracts (FPVV) with TOU price structures tailored for the C&I customer.[8] C&I customers tender these contracts and there is usually competitive pressure on each contract renewal. C&I volumes are significant, and their profiles can be favourable for electricity purchases leading, generally but not always, to good competition for them.

During the term of an FPVV contract the C&I customer has no electricity price risk and low transaction costs. However, C&I contracts can also expire during periods of market stress leading to weak competition, significant price increases and rate shock at these times. Multisite C&I customers can spread the re-contracting risk by contracting different sites at different times, but the re-contracting risk is significant for a single site C&I customer.

[7] Fixed retail contracts are offered but these are not fixed term contracts but fixed price terms for a fixed period. Breaking the contract can attract a break fee although, increasingly, this is usually structured as a variabilised discount and price guarantee for the fixed period. If a customer switches during the fixed period, then they do not receive the whole discount. At the end of the fixed period the contract does not terminate but reverts to flexible terms.

[8] Small retail contracts are also FPVV but with a simplified TOU price structure – often just a single price.

Such customer then has the option to become a wholesale customer, or choose a retail spot price, and use financial contracts to layer cover.[9] Being financial contracts, not physically linked, contracts can be for part of the demand and the customer can manage re-contracting risk by having different expiry dates for smaller parts of their demand. However, now they must actively manage electricity price risk, which grid connected customers must do as they are required to be wholesale purchasers.

Price risk theory

In a theoretically perfect one-part (energy only) market it can be shown that wholesale prices, without contracts, will clear, on average, at the price needed to incentivise investment to meet demand in all periods. It can also be shown that, with 100 per cent contracting, wholesale prices will clear at the variable cost of supply and the risk premium on contracts will equal the fixed costs of generation. That is to say, both approaches are equal, on average, and will recover the total cost of any generation needed to meet demand over all time periods.

In this theoretical market all parties are ambivalent between contract or wholesale prices and preferences should be based on cashflow preferences, which should lead to high levels of contracting as price outcomes are genuinely equivalent on average.

Such a perfect market would only result from:

- 'Perfect' prices, everyone having perfect market information and no ability to make their position better in the market (ideal competition) and no external factors affecting price formation, and
- Trust in all prices, critically important for contract prices as settlements will be, on average, paid out to generators.

While at the outset of the electricity market in 1996 no-one expected a 'perfect' market, and that imperfect information and less than ideal competition would lead to inconsistencies between 'perfect' outcomes and actual, it was still thought that symmetrical market understanding, workable competition, and trust in prices would lead to natural contract liquidity. Experience has shown that this isn't the case.

Imperfect information

The natural barriers to perfect outcomes are significant enough. Electricity markets, and particularly New Zealand's electricity market being over 50 per cent hydro, are exposed to the weather and climate. Weather and climate are significant sources of imperfect information in the electricity market. However, there are other sources such as the gas market, which has significantly affected electricity prices in recent years.

Demand is also a significant source of imperfect information. While individual customers understand their current and intended consumption, aggregate demand is poorly understood. It is generally

[9] Such a customer can also opt for financial versions of FPVV TOU contracts and so this option gives a lot of flexibility, but the transaction costs are higher.

poorly understood internationally, but New Zealand is particularly poor in demand statistics below major demand classifications.

Information access is also asymmetric with the supply side having significantly more information about generation costs and the power system than the demand side.

Less than ideal competition

In this section the term ideal competition has been used rather than perfect competition. The difference is semantic, but the definition of perfect competition used here is the level of competition that would cause the market to clear at variable cost. Such competition would lead to market outcomes that don't recover the fixed cost of generation and result in no generation investment. This would occur until demand is curtailed at which point scarcity prices should encourage generation but, after investment and only if wholesale prices are the only source of revenue, if perfect competition remained the new generation would not have adequate revenue. The term ideal competition is used here to mean competition that ensures that prices do recover all generation costs but rise no higher than needed to do that.

In theoretically perfect markets, i.e. not electricity markets, market outcomes are the result of a series of Short Run Marginal Cost (SRMC) curves that intersect with a Long Run Marginal Cost (LRMC) curve. At each market stage a continuous SRMC curve is followed, with increasing demand always met by supply at an increasing cost that intersects with the LRMC. At the point of intersection new investment is economic and new long run supply establishes a new SRMC curve.

In the real world the variable cost of supply often doesn't intersect with the LRMC curve. In electricity, for example, once supply capacity has been reached then no amount of money spent will increase supply in the short-term. While supply can't be increased, demand can respond (for compensation) or, ultimately, be curtailed with the attendant lost value of load. As supply approaches its limits, and demand potentially responds at higher levels of compensation until the risk of demand curtailment increases then the expected value of supply (including Demand Response (DR) costs and risk of curtailment) increases to the point where the Value of Lost Load (VoLL) is met. This creates a Short Run Opportunity Cost (SROC) of scarcity curve, which are short run marginal costs. This concept is well understood in the mathematics of hydro water values.

The SROC curve extends the SRMC curve so that it intersects with the LRMC curve. However, this means that electricity market prices must, as the limit of supply is approached, lift above the variable cost of supply. For those used to markets where there is closer to perfect competition (clearing close to the variable cost of supply) then a one-part (energy only) electricity market looks less than ideally competitive at best, and highly uncompetitive at worst. For some, the concept of some market power being critical to efficient price formation is difficult to come to terms with. But it is directly a result of increments of supply not being perfectly divisible in the short run.

Market power

Market power has a defined meeting in market theory but also has legal and emotional connotations. In market theory, market power is the term used to define where a market participant has a unilateral ability to affect the market clearing price by any amount. In practice, most markets have some degree of market power, but the degree of influence is usually small.

Market Development Advisory Group (MDAG), in its paper on trading conduct (Baldwin et al., 2020) has thoroughly covered the issue of market power. In summary, the conclusions are:

- Market power is ubiquitous in electricity markets
- Market power is a design feature of one-part (energy only) markets, so that prices can lift above variable cost and signal the SROC of scarcity[10]
- Market power is only a problem when it is abused (or becomes significant to use the MDAG and Code terminology).

Significant market power is defined by MDAG, and in the Code, as the point where market power causes inefficient price outcomes. That is to say that market power is significant if the resulting market prices,

- Don't incentivise production efficiency gains
- Incorrectly allocates supply to less valuable uses or arbitrarily curtails demand, and/or,
- Does not incentivise innovation and investment.

It should be noted, though, that market power cannot, and is not intended to, correct for market design or functional problems with markets.

Highly problematically, for the issue of trust in prices, it is extremely difficult to determine if market power is significant.

Imperfect market outcomes

Imperfect information leads to some disconnect between whether market participants are genuinely ambivalent about contracting or taking wholesale market price risk. Information asymmetry can lead to very different perceptions between market participants about the efficiency of either contract markets and/or the wholesale market. This can lead many participants to the conclusion that they are better off, from a purely value perspective, to take wholesale market risk.

This incentive towards risk taking can be the natural outcome through just real-world market imperfections.[11] The incentives can be amplified if there are external factors affecting price formation, and particularly if parties think they can affect the external factors, e.g. through political lobbying.

[10] The missing money problem is a problem in all electricity markets, where the variable cost of supply curve is unable to intersect with the LRMC and new generation is revenue inadequate. In a one-part (energy only) market, market power is tolerated to recover the 'missing money,' but other markets can use direct interventions (e.g. capacity markets or mechanisms), or combinations of both approaches.

[11] In particular, the concept that contracts where settlements are predominantly to sellers is equivalent to wholesale price outcomes if there were no contracts is poorly understood. Even where it is understood, if a party believes that others will contract and incentivise wholesale prices down then they can get a relative benefit by remaining uncontracted—a form of hold-out and free-riding.

External factors

How external factors appear to be affecting wholesale price formation is discussed in section 2. The conclusion from that section is that WVs are high because of eroded security of supply in both peak capacity and firm energy, and that focus on short periods of high prices rather than the long-term PDC, and some other factors, has led to revenue inadequacy in security of supply investment. The same factors that elevate WVs are likely also lifting the risk premia for contracts.

Nevertheless, the Taskforce considers that prices for OTC baseload and peak hedge contracts are likely to be competitive. The main contracts market concern from the Taskforce appears to be the premium over New Zealand Electricity Futures for super-peak hedge contract prices. Our assessment of the PDC required to meet security of supply and give revenue adequacy at all load factors leads to peak prices substantially higher than average, even with elevated average prices. Anyone offering super-peak hedging, in a market where the WCM is already critically low, would do so on the basis that the contract would underpin investment in peak capacity over the relevant contract duration. Recovering capital costs over short duration does yield high prices. Our analysis suggests that wholesale prices are not sufficient to recover investment costs for peaking plant (including for plant that would improve weather related security, i.e. dry periods and/or long periods of still wind and/or cloud). As such any peaking type of contract, that does recover costs of investment, will be at a very large premium to wholesale prices, that don't recover investment costs.

If contract prices are perceived to 'trade at a substantial unquantified premium' then any purchaser of electricity will consider they would be better off taking wholesale market risk if they could manage that risk.

Price risk management

Price risk management is a financial choice based on value and risk trade-offs. If electricity markets work as intended, then purchasers of electricity would trust that they are ambivalent to contracting over taking wholesale prices. If the market isn't working as planned, or even is perceived to be not working, then a purchaser would start to evaluate the value and risk trade-offs.

The first thing to do would be to assess the maximum quantum and period of adverse cashflow outcomes the purchaser could accept. Once the value of tolerable risk is established then the purchaser can think about managing the residual risk. Traditionally, this would be done through electricity contracts but, when the assessed divergence between contract prices and wholesale prices becomes large, then self-cover could well be considered.

Self-cover involves ensuring short-term financial assets are available, and suitably liquid, to meet the worst anticipated cash settlements. If the cost to carry the required short-term assets is less than the cost of risk premia in electricity contracts, then self-cover becomes viable.

Of course, for this to work a purchaser needs to trust that they can forecast the worst anticipated cash settlement. Uncertainty about being able to do this leads most purchasers to prefer electricity contracts. However, for purchasers for whom electricity is a significant input cost, and where contract prices might exceed their financial viability, then self-cover may be the only viable option.

Now, if price sequences occur that cause cash settlements that are higher than the worst anticipated, then such a purchaser finds themselves in an untenable financial position.

It should be noted that the stress testing regime was introduced for the purpose of trying to ensure that purchasers understand how bad the worst outcome could be, and to record that all purchasers understand this. The Authority sets stress tests that market participants are required to assess through defined process. They are then required to get sign off that the Board understands the results and consequences of the tests and submit that to NZX. However, if a purchaser perceives that the stress tests are not robustly assessed then they may rely primarily on their own assessments.

Market problems

Naturally, an entity self-covering for wholesale market risk that gets caught out by a market outcome worse than they anticipated would contend that the market isn't working. They would have a point but not because of the price outcome, necessarily, but rather because this could indicate that:

- Market imperfections are too acute
- Too much information is missing
- Information asymmetry is too large
- Competition is not workable
- Expected scarcity costs are too high and/or security of supply is too low
- External factors are exacerbating the above, and/or
- The stress testing regime is not functional.

While any of the above could be a factor, it would only take two or three of the above factors to cause significant market problems. However, diagnosing the actual problems is difficult. It is far easier to make assumptions about which of these factors are causing the problems.

Stress testing regime

In many ways a workable stress testing regime must have the same features as a workable contracts market. It must be well understood, and it must be trusted.

No opinion is offered on whether the current stress tests are correct. The only observation is that the prices over the third quarter of 2024 (including August) were less than stress test E1 ($400/MWh time weighted at OTA2201 for the quarter). Yet, major risk exposed purchasers shut down claiming that the electricity prices were unexpectedly large.

The general reaction to prices over August 2024 when, for the first two months of quarter three, prices had been averaging close to the level of stress test E1 with a month left to run (where September then dropped the average price for the quarter significantly), suggests that few parties believe the E1 stress test is credible.

To be useful we suggest the following attributes are needed for a functional stress testing regime:

- Constantly assessed, robust stress tests with participant engagement
- Trust in the stress tests and commitment to their integrity.

The Authority may well have achieved the first point, I haven't assessed this, but the second point is a clear problem.

We note the improvements suggested for the stress testing regime in (Hansen, 2025).

Conclusion on the role of competition in the exit of energy intensive industry

Our best estimate is that energy intensive industry observed contract premia in the market that led them to consider self-cover for wholesale market risk. This is a valid approach if the entity taking risk can assess the worst-case cash settlements and make current asset provisions available.

That the energy intensive industries then faced wholesale prices and cash settlements that were worse than anticipated can be attributed to market problems, such as lack of information, information asymmetry, and lack of precedent for such peak prices in the observable record (where there probably should have been). The prices over August 2024 are consistent with a PDC that recovers the total cost of security of supply and should be occasionally expected in dry periods.

The problem with the above commentary is that the prices over the quarter ending September 2024 had been averaging equivalent to the E1 stress test over that period. This means that the industries in question must have signed off that they had assessed and understood the risk.

3.2.3 Is the 'retail squeeze' anti-competitive?

Taskforce comments on competition and innovation

In the LPF paper the Taskforce makes the following comments about competition and innovation.

> "The limited growth of competing retailers and generators suggests there may be barriers to entry and/or expansion in retail and generation. For example, we would typically expect to see small to medium retailers vigorously competing to grow their share, as occurred until 2020, including through innovation, agility and/or highly competitive pricing. That competitive impact appears to have stalled. This highlights a competition risk, particularly given that a group of small to medium retailers are pointing to a specific issue (as they see it) as a barrier to expansion"
>
> "Whilst the 80 innovations from the past decade may sound productive, innovation in the New Zealand electricity retail sector may still have potential to be more impactful.
>
> Innovation in electricity retail markets in comparable countries also seems to be more advanced or disruptive. A number of innovations seen overseas have not yet arrived in New Zealand at scale. We set out three examples of innovations from other markets below"

This gives rise to the question, what would be the expectation of competition and innovation. What is an efficient level of both? These questions need to be asked together as they are somewhat interdependent. Competition is, after all, one type of innovation.

Competition expectations

The Taskforce's expectation, if taken to the extreme to make the point, is that any new entrant should be able to enter the retail market and compete until every party has equal market share. Which would have to mean that there is infinite ability to innovate, 'be agile,' and compete away margins.

Actual market shares depend on each party's cost functions, and where these functions intersect, i.e. the point where no party can be better off or worse off by changing market share. Even if we ignore current market problems and assume that input energy costs are equivalent, large generator retailers likely have high fixed costs to serve, and significant economies of scale which makes them difficult to compete against at scale. 'Agile' new entrants likely have lower fixed costs and lower economies of scale, which would tend to make them competitive at lower customer numbers. While technology is reducing both the fixed costs to serve customers and economies of scale, you would still expect the point of competitive equilibrium to result in differences in market share with the large generator retailers retaining larger number of customers.

The increase in wholesale price and volatility from 2018 does seem to have affected the growth in small/medium retailer market share, but it is incorrect to expect that the growth in market share for small/medium retailers would have continued unabated or at the same rate.

However, if there is a distortion in the relative input costs of energy, which we are suggesting there is, then this would result in distorted market shares.

Is there evidence of predatory pricing?

The predatory pricing problem the Taskforce is concerned with seems to be, simultaneously, that generator retailers are withholding generation investment to lift wholesale costs, are also lifting costs through the contracts markets, and are predatory pricing in retail.

The generation withholding argument doesn't make sense for retail competition issues. If generator retailers can exercise this strategy, then it is inherently valuable, it doesn't require a retail book to benefit. The argument seems to be that excess generation profits enables the retail businesses to exercise predatory pricing. This seems unlikely, normal generation profits are sufficient to enable predatory pricing if such a strategy was viable. If they are strategies, they are independent strategies. In any event the assessment in section 2.1 is that wholesale price outcomes are best explained by external factors affecting security of supply and misshaping of the PDC.

Neither is there obviously predatory pricing in retail. The analysis in section 3.1 shows that the generator retailer margins are lower than the small/medium retailers but are not, on average, below cost. It could be argued that very low margins could be the result of predatory pricing, but this is also the expected outcome from near perfect competition. Theory suggests that, where a product is homogenous and search and switch costs are low, that a small number of competitors can approach perfect competition and lead to price falling to the level cost. The evidence is consistent with this outcome.

For predatory pricing to be a successful strategy it must drive competitor exit over a timeframe that the aggressive pricing party can sustain. Prices must then be able to rise to a level where, in present value terms, future revenue offsets current losses.

In fact, the number of retailers has increased.

Figure 21: Number of retailers (parent) over time

Although, the picture does look different for retailers with higher number of customers.

Figure 22: Number of retailers (parent) with over 1,000 customers over time

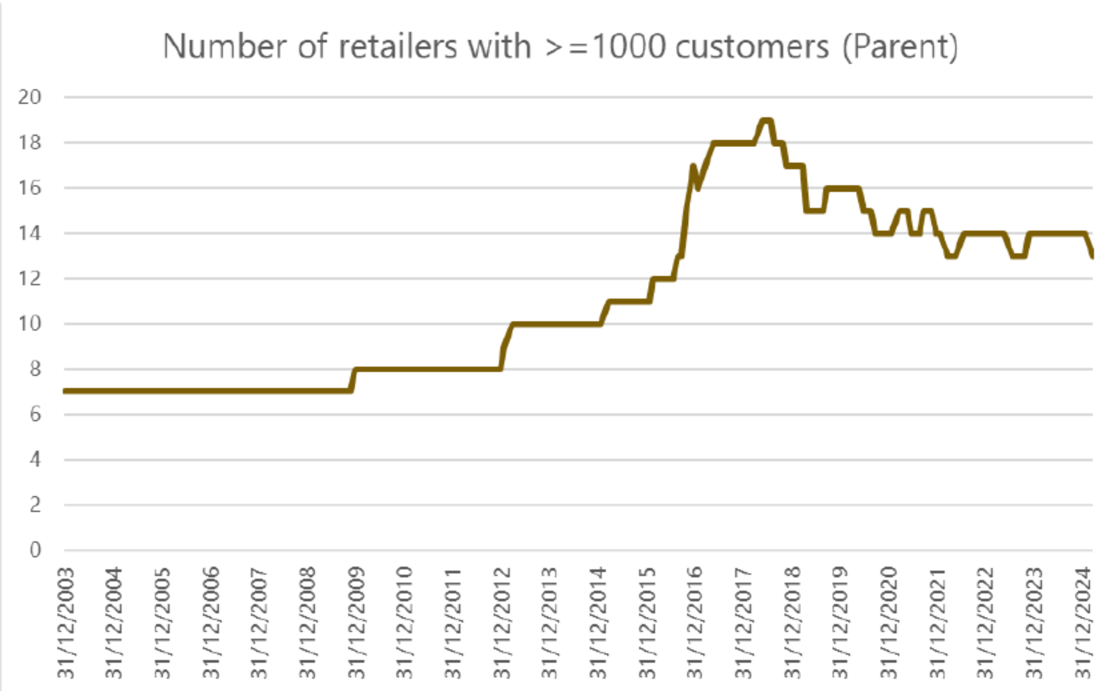
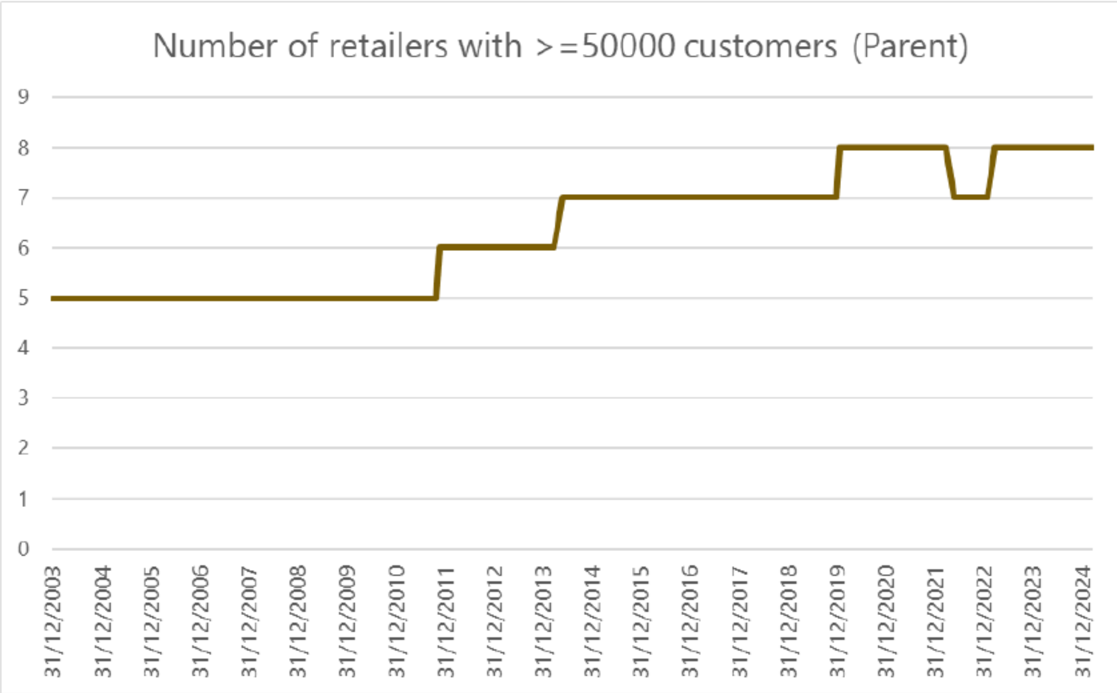
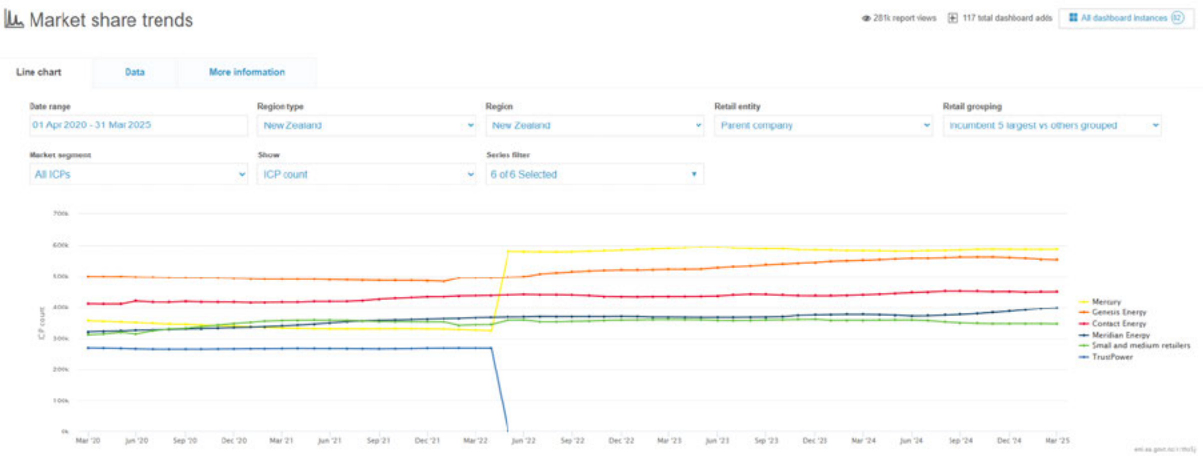


Figure 23: Number of retailers (parent) with over 50,000 customers over time



Collectively, small/medium retailers remain a significant competitor to the large generator retailers.

Figure 24: Market share of generator retailers vs small/medium retailers by ICP count



While there has a been a little loss in small/retailer market share it seems unlikely that any exit will be significant, while there are still new entrant retailers entering the market. Conventional wisdom suggests that, with very low barriers to entry, a predatory pricing strategy will not pay back even if such a strategy could be maintained between four large generator retailers. Even if competitors could be driven from the market, they would eventually come back.

The evidence suggests strong competition rather than predatory pricing in the retail market.

However, this is not to say that there aren't problems in the retail market. If there are distortions in the relative input costs for retailers, which we think there are, then there will be distortions in retail market shares.

Innovation expectations

The Taskforce seems to have a narrow definition, and expectation of, innovation. Not all innovation is obvious. Innovation around cost reduction and competitive advantage, where retail margins are already low, would not be obvious to an external observer.

Market conditions and market prices are key drivers in the type of innovation that is incentivised. Generally, market adversity and high prices are the strong drivers of innovation, which demonstrates that obvious innovation should not be a regulatory objective. Very little innovation occurs quickly. Most innovation takes time to move from proof of concept to early adoption, to early followers to critical mass. Given that the retail market environment was benign up until 2018, and uncertainty has plagued the market since then (including early commentary that the gas market problems were temporary), then the path of innovation in New Zealand is not obviously impeded. The Taskforce itself identified a lot of innovation in the retail market.

From a purely innovation perspective, current market conditions and prices would seem to be ideal for encouraging innovation. There is little ability to compete away margins further, consumers are more engaged in reducing cost, and there are marginal opportunities to increase market share. Our analysis shows that the large/generator retailers compete for sticky mass-market while the small/medium retailers actively compete for more price sensitive customers. There is a significant variety of TOU pricing approaches and quite different ways of balancing fixed daily and variable prices. Some small/medium retailers also engage with customers, and often offer tools, to assist them to reduce their electricity costs.[12]

If the Taskforce were to arbitrarily levelise the playing field, rather than address the issues with relative input costs, then surely this would be a regulatory setting that would discourage innovation. Bearing in mind that innovation should be the result of productive and dynamic efficiency rather than an objective in its own right.

[12] The taskforce definition of innovation seems to be focused on tools rather than what is meaningful for customers.

4. Contract markets

We haven't specifically looked at contract markets. We defer to (Carlson, 2025) for that assessment. However, we have noted a few theoretical problems for the contract markets that we elaborate on here.

4.1 Wholesale market preference

The theory for a working one-part (energy only) market, with working contract markets, is that parties should be ambivalent between wholesale market prices and contracts, and trust that they are ambivalent.[13]

Noting that energy intensive industries chose wholesale market risk rather than contracts, even when they had also signed stress tests acknowledging the risk, shows an extremely strong preference for wholesale.

The evidence provided by the Taskforce that three generator retailers do not offer on all contracts, shows that even generators prefer the wholesale market.

Without any specific analysis this tells us that some, at least, contract markets aren't working.

Standard contract markets problems

We note that standard problems for contract markets are likely at play here, i.e.:

- Too much information is missing
- Information asymmetry is too large
- Concerns that competition is not workable.

We also have a concern that participants don't generally understand that they are ambivalent about being highly contracted with settlements to generators on average, to cover fixed costs and an uncontracted market where the fixed costs are recovered through wholesale prices. However, that is not the primary issue at play here.

Wholesale market problems

(Carlson, 2025) has recommendations for improving the contract markets. Nevertheless, even if contract markets were working correctly in every other respect a wholesale market that isn't revenue adequate across the whole curve will cause problems.

If contract prices are expected to recover investment costs for the contract periods they cover, and wholesale market prices don't, then there will be a divergence that will tend to encourage wholesale

[13] Although, we have overlooked a complicating factor in nodal pricing. The presence of basis risk (a different price at different locations) should also be addressed, although we are not aware of the current debate being related to nodal price differences.

market preference. If those contracts are then unable to be backed up by physical generation, due to barriers to entry then the price divergence will be extreme.

4.2 Problem with standard PPA contracts for renewable energy

In considering how New Zealand might meet its firm energy requirements it looks probable that intermittent renewable energy will provide some contribution. Having considered how wholesale prices might support the contribution of intermittent renewable energy to security of supply we have identified the features that would be necessary for the contract form to encourage the contribution of intermittent renewable energy to security. The conclusion is that standard PPAs are not ideal.

To encourage contribution from renewables a contract would have to:

- Be revenue adequate
- Provide regular cashflow
- Incentivise maximum plant availability during periods of scarcity
- Incentivise innovation to firm supply during periods of scarcity, and
- Make the plant ambivalent to spill during periods of relative surplus.

Standard PPAs do not incentivise plant availability and firming innovation during scarcity. They also create an incentive to run in periods of relative surplus regardless of underlying short-run costs and location in the grid. If the wholesale market doesn't clear at SRMC during periods of surplus then any spill allocation will be inefficient, transmission losses may be increased, and incentives to improve production efficiency are reduced.

It should be noted that a renewable energy contract form with incentives to contribute to security of supply would be more useful for retailers. Such a contract would be better correlated to wholesale market prices and a better risk management instrument.

4.3 Contract competition

We have considered an anti-competitive explanation for the withholding of contract prices by the large generator/retailers. The only way such a strategy could be valuable, where revenue is foregone in one market, is if larger returns could be made in other markets that offset the foregone revenue. We don't consider this is the case in the retail market, where no rational competitor should expect a long-term payoff for the loss of retail margin.

This is also inconsistent with a wholesale strategy where writing contracts would still be more valuable even if they were deferring generation, i.e. the strategies would not be mutually exclusive.

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Level Playing Field – Hedging Considerations

Report prepared for Independent Expert Submission

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6 May 2025

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1 INTRODUCTION

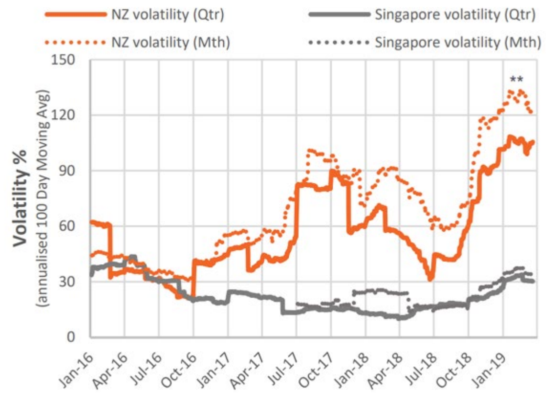
This paper is not intended to be a self-contained examination of the level playing field situation in the New Zealand Electricity Sector. Rather it is the development of some thoughts relating to the current hedging options available in New Zealand and where potential areas for improvement lie, that if addressed may improve the environment where participants are able to take greater responsibility for addressing and meeting their risk management requirements.

2 CURRENT HEDGING OPTIONS AVAILABLE

2.1 VOLATILITY

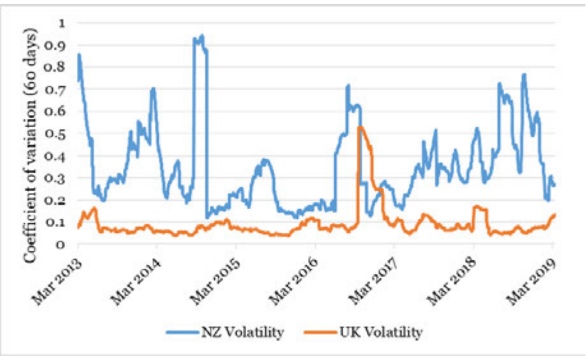
A fundamental characteristic of wholesale electricity spot markets is that they are volatile. This is particularly the case in New Zealand's energy-only market where spot prices are influenced by, inter alia, hydrology (with limited storage), wind flow, iridescence, and gas supply availability. The NZ electricity price is highly volatile even by comparable jurisdictions (see Figure 1 and Figure 2).

Figure 1: Contract volatility New Zealand vs Singapore



Source: Genesis Energy Limited submission to EPR, 2019

Figure 2: Coefficient of variation in UK and NZ wholesale energy prices



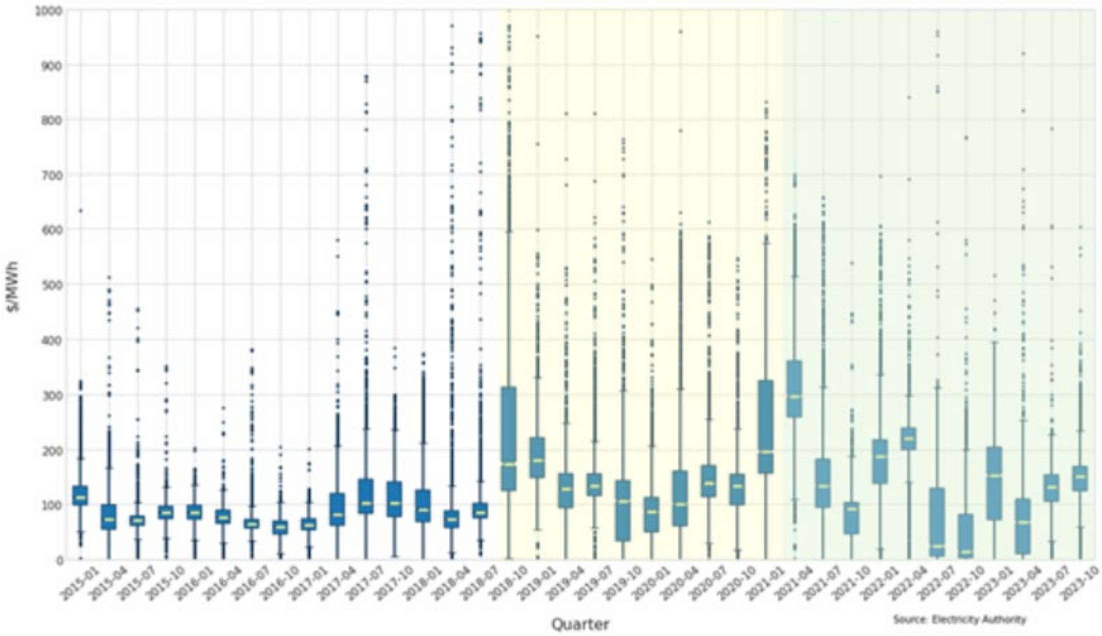
Source: Meridian Energy submission to EPR, 2019

The level of volatility has further increased since 2018 as noted by the Authority:

> *From 2018 onwards spot price volatility increased, as shown by the larger inter-quartile range and greater number of outliers (see yellow highlight in Figure 1). In 2018, New Zealand's largest producing gas field, Pohokura, began to decline. This caused volatility as gas buyers, including those who use gas to make electricity, and gas sellers became less certain about future gas availability. Since early 2021 (see green highlight in Figure 1), spot price volatility increased even further, with a greater variation in quarterly spot prices*[1].

[1] Energy Authority, Eye on Electricity, Past and future spot market volatility, 8 April 2024

Figure 3: Box plot distributions of nationally averaged spot prices adjusted for inflation per quarter 2015-23



Given this level of volatility some form of hedging is important. As well as physical hedging through vertical integration between generation and retail businesses and long-term Power Purchase Agreements[2], New Zealand also has OTC trading and large customer contracts (commercial and industrial) with embedded hedging elements (i.e. fixed price variable volume (FPVV) and fixed price fixed volume (FPFV) contracts).

Additionally, battery storage, demand response and new ‘standardised’ OTC products (such as the recently launched super-peak flexibility product[3]) are now seen as contributing to the overall possible hedging portfolio.

2.2 ASX Products

ASX has the following New Zealand electricity derivative products (each priced against Otahuhu and Benmore nodes).

- Base Load Monthly Futures
- Base Load Calendar Quarter Futures
- Peak Load Calendar Quarter Futures (not actively traded, if at all)[4]
- Base Load Calendar Quarter Average Rate Options (similarities with a contract-for-difference)

[2] While used extensively in other jurisdiction, PPA contracts have never been popular in New Zealand. This is partly due to a general reluctance for parties to take a long-term view on electricity prices given potential stepwise changes in the future supply/demand balance e.g. uncertainty with ongoing renewals of the Tiwai smelter.

[3] “New standardised flexibility product trading begins on 28 January”, Energy Authority general news, 22 January 2025

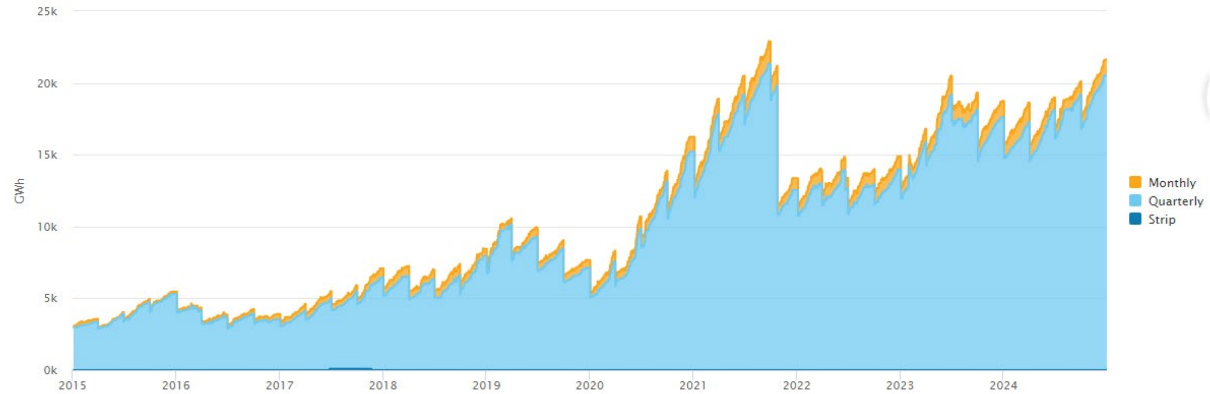
[4] The peak load profile is defined as the period from 07:00 hours to 22:00 hours Monday to Friday excluding Public holidays and any other days as determined by ASX) over the duration of the Contract Quarter.

There is nothing overly noteworthy/unusual except the relatively small unit size (0.1MW) which is targeted for smaller participants[5].

We note that ASX were planning to introduce two cap products to the hedge market, but this did not proceed. The cap products were intended to enable sellers of electricity to gain more stable income for infrequently used plants and to help to underwrite or support new investments[6].

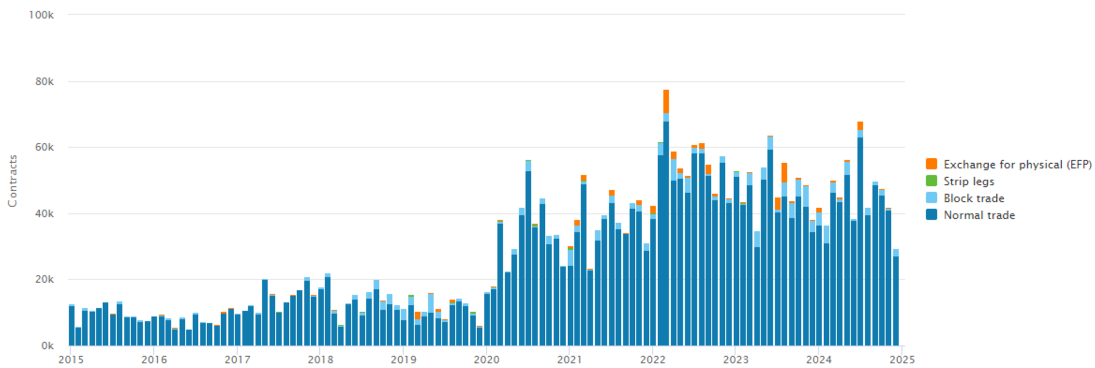
Overall, volumes traded and open interest have remained high on the ASX, especially since 2020.

Figure 4: ASX Open Interest – all electricity derivatives



Source: EA Electricity Market Information website (EMI)

Figure 5: ASX Trade Volumes – all futures



Source: ASX, New Zealand Electricity Market Making Update, March 2025

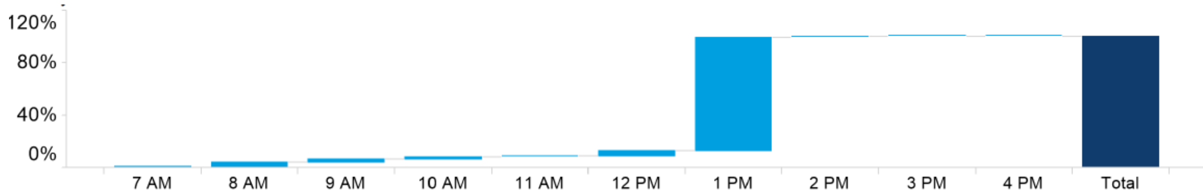
At the current time only base load monthly and quarterly contracts are supported by market making. While market making is a relatively common practice for exchange traded derivatives it is more normal to see these services in smaller markets or in the early phases of product establishment. It is thus a little unusual to see the high volume of market making still taking place in New Zealand. However, as can be seen in Figure 6, the vast majority of trades take place during the market making window.

---

5 These were initially traded in 1MW contracts but moved to 0.1MW contracts in 2015 in order to make it easier for the smaller players to participate.

6 Tim Street, Electricity Authority, Hedge Market Breaks Records, 14 December 2017

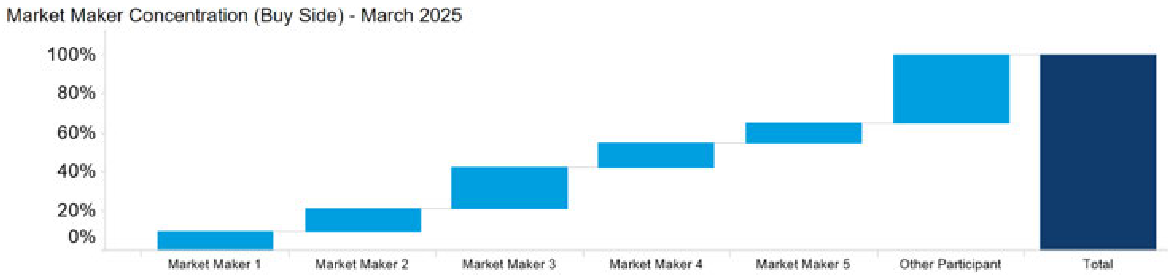
Figure 6: Time of Day Execution



Source: ASX, New Zealand Electricity Market Making Update, March 2025

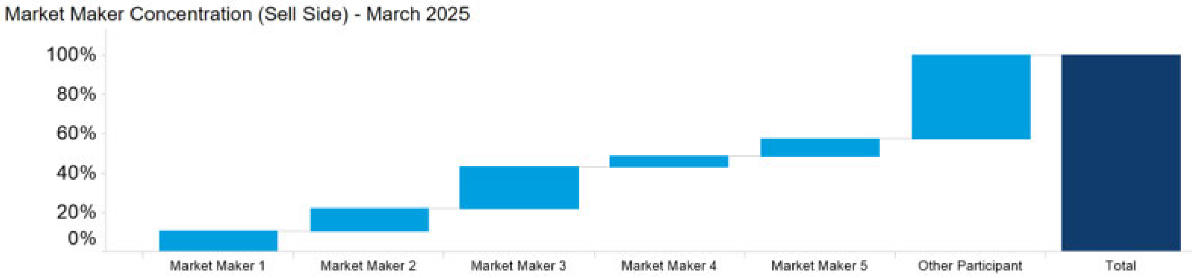
Interesting to note is that a significant proportion of trades (~30-40%) involve a non-market maker counterparty on both the buy and sell sides (see Figure 7 and Figure 8). In the context of New Zealand, where all the large Gentailers are market makers, this points to a good level of trade on the part of the non Gentailers (being independent retailers and generators) and to a reasonable level of market depth.

Figure 7: NZ Market Maker Concentration – Buy Side



Source: ASX, New Zealand Electricity Market Making Update, March 2025

Figure 8: NZ Market Maker Concentration – Sell Side



Source: ASX, New Zealand Electricity Market Making Update, March 2025

2.3 ASX Market Making

The 2018/2019 Electricity Price Review clearly highlighted the need for hedging by Independent Retailers and raised concerns that when stressed the market can become "illiquid"[7]:

> *The Review found that the voluntary wholesale hedge market does not always work effectively.* ***An effective hedge market is necessary to manage risk, and to support***

7 Electricity Price Review: Government Response to Final Report, Office of the Minister of Energy and Resources on behalf of Hon Dr Megan Woods, 3 October 2019

> ***independent retailers and retail competition****. It does this by allowing generator-retailers to manage their risk exposure in the wholesale and retail electricity markets by trading hedge products. It also* ***allows independent retailers*** *(those without generation assets)* ***to*** *purchase hedge products and* ***manage their exposure to volatile spot prices****.*
>
> *The current hedge market can become "illiquid", especially when the system comes under stress, such as during dry hydrological conditions. This can result in some* ***independent retailers becoming exposed*** *to purchasing wholesale electricity at high spot prices, and/or losing confidence that the price of hedge contracts offered in the market is reasonable. In recent times, some independent retailers have gotten into financial difficulty and left the retail market, thus reducing competition. This situation may also be holding back independent retailers from expanding, also limiting retail competition.*

Following this review market making on the ASX was strengthened, initially on a voluntary basis but then moving to a mandatory requirement being placed on the 4 larger gentailers. Presently there are 5 market makers – 4 regulated market makers (Contact Energy Limited, Genesis Energy Limited, Mercury NZ Limited and Meridian Energy Limited) and 1 commercial market maker (appointed by the Authority through competitive tender).

Market making obligations are to:

- Offer a two-way price for 25 minutes[8] in each 30 minute market making session (window) with an exemption to not make markets in 5 sessions per 20 trading-day period
- Provide 24 contracts in 12 lots in front six (6) months and 24 contracts in 12 lots in all calendar quarters
- Have a maximum bid/ask spread of 3% or NZD$2.00

2.4 OTC Products

As already commented on, ASX is not the only form of hedging taking place in the New Zealand market. Over-the-counter (off market) trading also takes place with what is often referred to as 'shaped' products. In New Zealand's context, 'shaped' is used very broadly to mean almost anything that is not a standardised baseload product. This ranges from participants looking to fill specific gaps in their overall hedge portfolio; looking to backout risk from (or by) larger customers with a specific usage pattern; right through to long term contracts to underwrite new generation investment decisions.

Typically, in other jurisdictions, the OTC market is used for non-standard products (be it shape, tenure, reference nodes or counterparty risk) on a willing buyer, willing seller basis.

It is also not uncommon to see OTC as the place where innovation takes place, with new products emerging around common needs being faced by the industry or parts of the industry. Once these new products begin to build volume, the financial exchange may look to replicate these products as

[8] If an offer or bid is lifted within the window, then the market maker will need to reload a new offer or bid in order to provide 25 minutes of window coverage at the required volumes.

new standardised products (thus avoiding the risk of launching a product with initial liquidity uncertainty).

2.4.1 New Flexibility Product

In January of this year, a new 'standardised' OTC product was launched as an initiative of the Energy Competition Task Force. The contract is a 'super-peak' broker facilitated product with twice monthly, one hour, trading events. It has been aimed at hedging morning and evening peaks.

Table 1: Standardised flexibility product 2025 as recommended by the Standardised Flexibility Product Co-design Group

Feature	Specification
Product style	Contract for difference for electricity
Nodes	Otahuhu 2201 grid reference point Benmore 2201 grid reference point
Contract unit	0.1 MW
Contract profile	• All days • Morning peak trading periods: 15 to 21 (7:00am to 10:30am) • Evening peak trading periods: 35 to 42 (5:00pm to 9:00pm)
Contract durations	Offered as calendar month contracts for the current quarter and next two quarters (6 to 8 months total), not including the current month. Offered as calendar quarter contracts for the following 9 quarters (when including the front 6 months, a total of 12 quarters, or 36 months offered).

Source: Energy Authority product specification sheet

While the new product is voluntary there is an implied threat of regulatory intervention if the product is not traded. The Chair of the Standardised Flexibility Product Co-design Group noted in his recommendation letter[9] to the Authority that:

> *Creating liquidity in the product is vital to its success and underpins price discovery. The Authority has decided that the product will trade voluntarily initially, and that they will monitor the liquidity of the product as it begins to trade. If the liquidity needs to be improved, then it is up to the Authority to consider how best to do that.*

2.5 OTC vs Exchange Traded

Trading through exchanges will incur higher working capital costs through the margin requirements on exchange participants, while the OTC trade will require the rationing of trades with counterparties according to their credit worthiness.

However, one key advantage to exchange traded products that is often undervalued is the development of a transparent and robust future price curve. Large consumers can use this future price curve to evaluate the competitiveness of fixed price contracts being offered by suppliers. In addition, longer term price signalling assists investment decisions by participants (although this should be balanced with the recovery period of most significant investments extending well beyond the price curves possible from future markets, which in any case get quite thin in the out years).

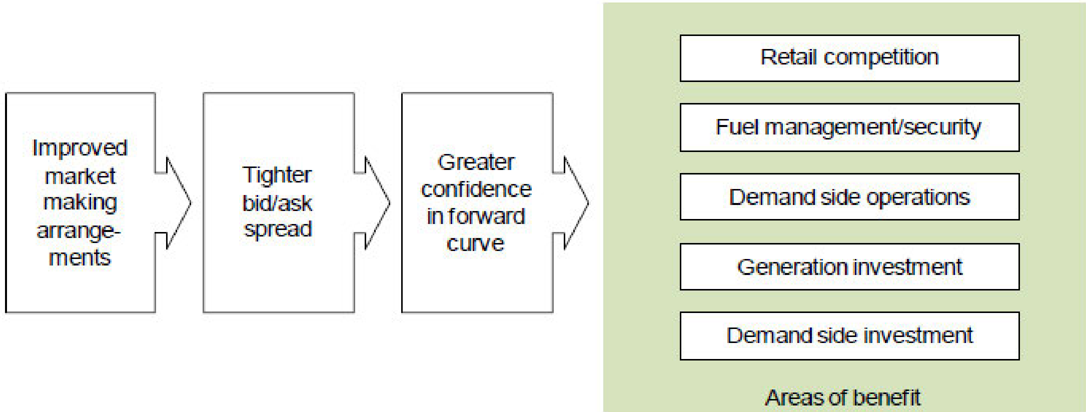
9 Standardised Flexibility Product Co-design Group Recommendations, 18 December 2024

The other key advantage that exchange trading can offer over OTC is the provision of liquidity and depth through a) concentrating trading around a small group of standardised products, and b) the use of market makers.

Market making on exchanges also provides greater confidence in the prices being offered, as subject to the required market making spreads, these are the prices that the market maker would be willing to both buy and sell against.

The economic benefits of exchange trading and market markers in New Zealand have been highlighted by the Authority in the past (refer Figure 9).

Figure 9: Linkage between market-making and economic benefits



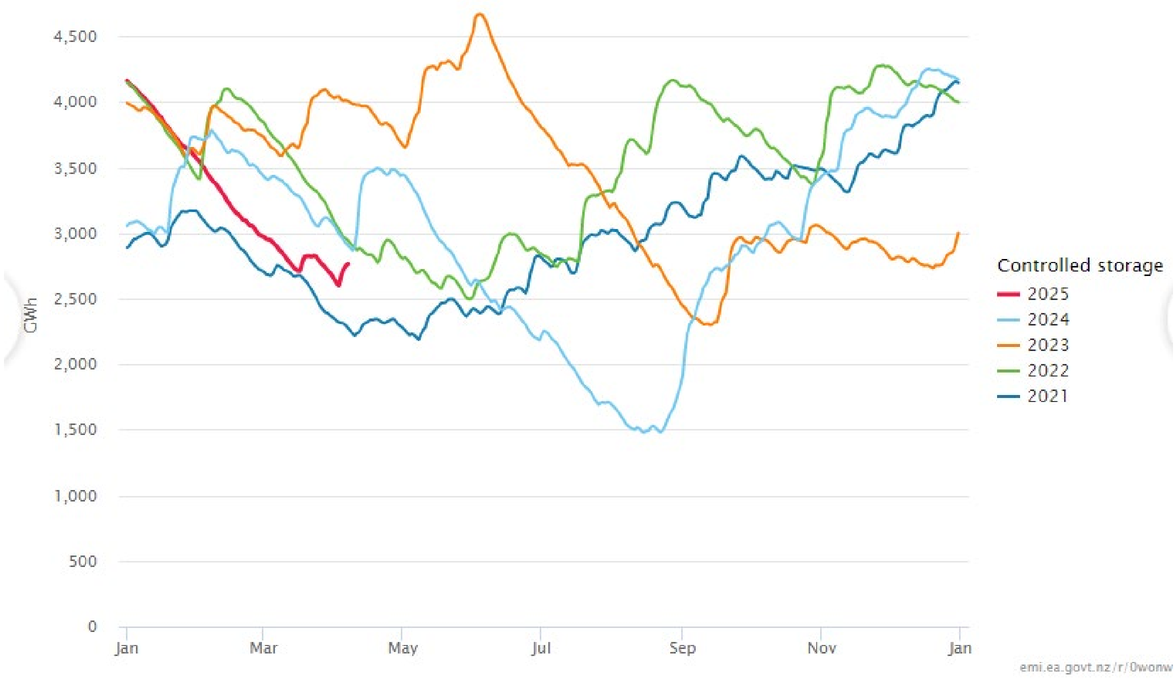
Source: Electricity Authority, Cost Benefit Analysis – Market-Making Obligations, 21 November 2011.

3 MARKETS IN STRESS - WHAT HAPPENED IN 2024?

3.1 THE SITUATION

Much attention is focused on how markets respond when they are under stress as this is one of the key reasons why participants have hedging in place in the first place. We only need to look back to the winter of last year for an example of this. So, what actually took place?

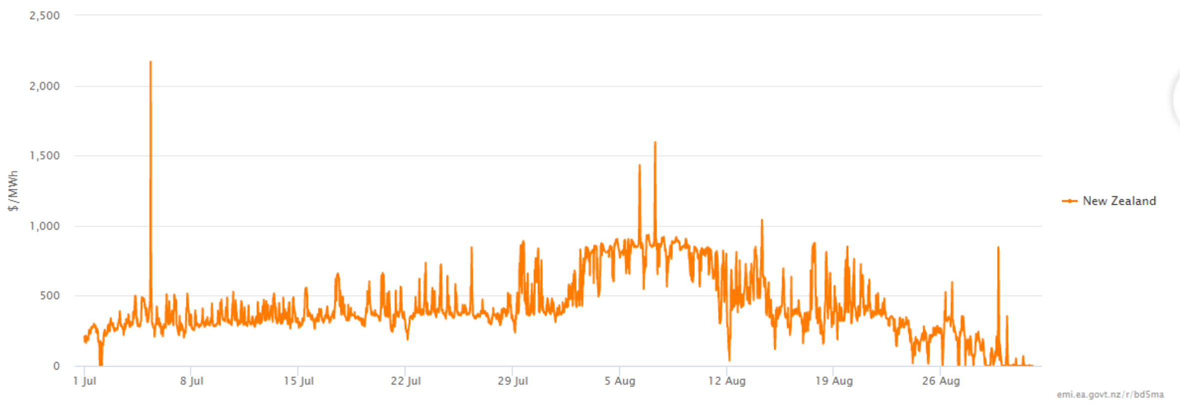
Figure 10: Hydro storage – last 5 years compared



Source: EA Electricity Market Information website (EMI)

The sector entered the 2024 winter with major gas supply issues and terrible hydro conditions (refer Figure 10). This resulted in higher prices in late July through early August (see Figure 11).

Figure 11: Wholesale price trends (underlying) – 1 July to 31 August 2024



Source: EA Electricity Market Information website (EMI)

In New Zealand, where wholesale prices are strongly (inversely) correlated with hydro storage levels, this outcome should have been fairly predictable without even considering the worsening impact of the low gas availability heading into the 2024 winter. The gas availability was subsequently eased with Genesis and Contact's deal to buy 3 months of Methanex's gas supply commencing in mid-August 2024. Ironically, this timing also coincided with decreasing hydro storage correcting.

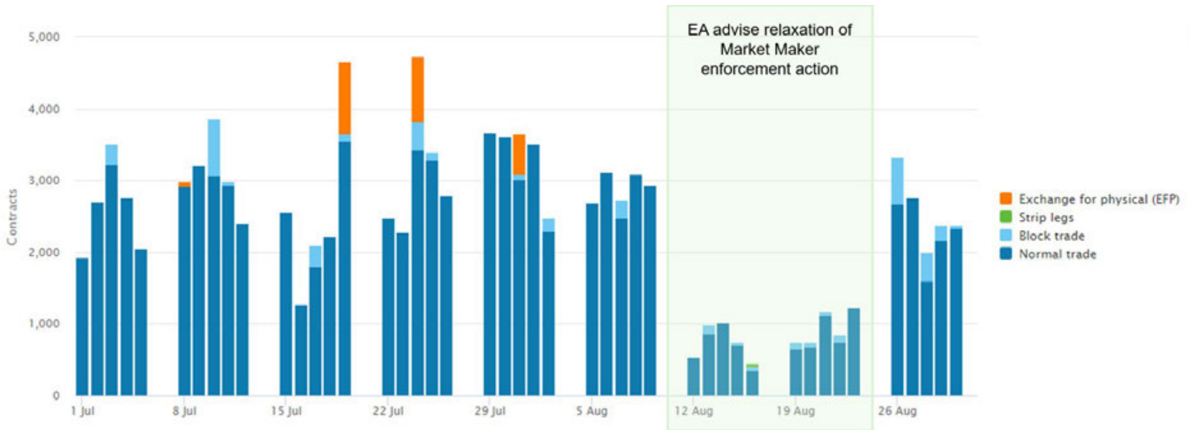
3.2 Electricity Authority Chasing Shadows

The Authority, claiming concern that without urgent and immediate relief, market makers would cease their market making on the ASX exchange due to the rising wholesale spot prices (the underlying). The Authority wrote to market makers on 12 August advising them that it would relax its enforcement action of market maker requirements, thus allowing market makers to reduce their contract volumes and widen their spreads. This letter was not issued contemporaneously to the wider market. The only public issuance we could find was from the 20 August Authority press release “Guidance for market-making requirements revised”.

> *The Electricity Authority Te Mana Hiko has revised the guidance on its enforcement approach to market-making settings that were introduced last week.*
>
> *The original guidance took effect on Monday, 12 August 2024 as an urgent measure in response to conditions in the forward market traded on the ASX. It allowed for widening of spreads and halving of lot sizes before the Authority would exercise its discretion to take enforcement action.*
>
> *From Wednesday, 21 August 2024 the conditions outlined in guidance will change to allow market makers to apply spreads up to 8% and offer minimum total lots of 18.*
>
> *As previously indicated, the guidance will be removed completely after trading on Friday, 23 August 2024 and the Authority will no longer exercise its enforcement discretion under the guidance.*
>
> *From Monday, 26 August 2024 market-making requirements will revert to spreads of up to 3% of minimum total lots of 24.*

The impact of the Authority’s actions on market maker volumes was immediate (refer Figure 12).

Figure 12: ASX Trade Volumes (all NZ futures) – 1 July to 31 August 2024



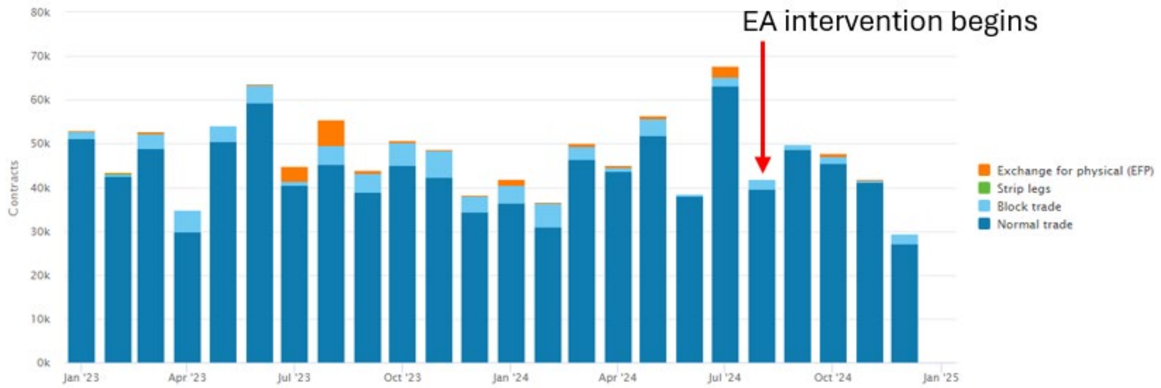
Source: EA Electricity Market Information website (EMI) – Annotations added

The Authority then went further to issue an urgent code amendment to reduce market making requirements under periods of high stress. The urgent code amendment increased the bid-ask spread from 3% to 5% on contracts when the wholesale spot price exceeds $500/MWh. This urgent Code amendment is due to expire on 12 June 2025 unless made permanent following a consultation process.

While a number of letters and emails exchanged around the time of these events were made public on 18 November 2024 pursuant to a request under the Official Information Act, we could see no evidence that the EA undertook any analysis to support the actions it took. Additionally, the way the EA communicated its intervention into the financial markets on 12 August 2024 falls far from what we would expect of a competent financial regulator. This raises concerns about the dual role of the Authority when operating outside of its more core physical (spot electricity) market regulation.

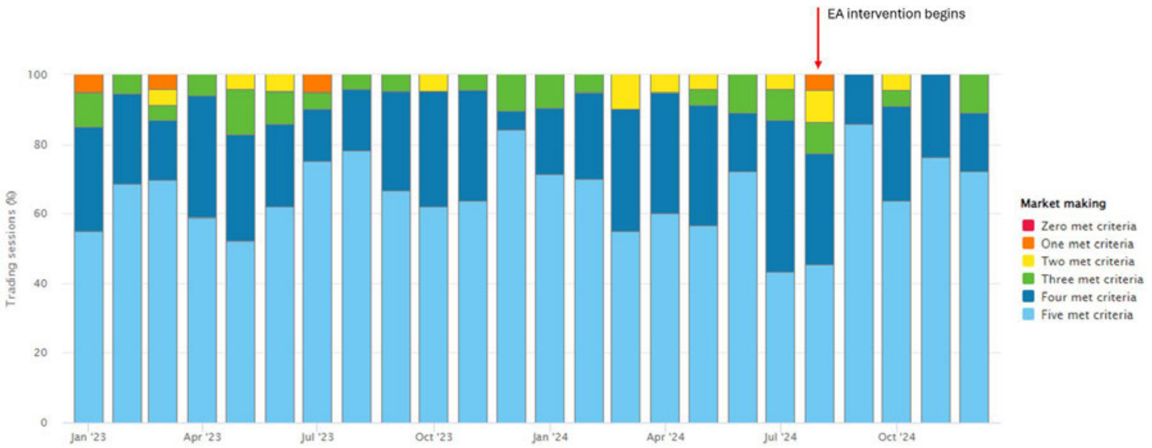
Hindsight can be a cold and ruthless judge of action. Looking at the overall impact on ASX traded volumes before, during and after the period of claimed "high stress conditions" (refer Figure 13) it would appear to us that the Authority was chasing shadows. This is further evidenced by the adherence to market making requirements immediately prior to the claimed event[10]. Even by their own admission the EA has stated that "The Authority's analysis of events around and subsequent to winter 2024 do not support making the urgent Code permanent..."[11]

Figure 13: ASX Trade Volumes (all NZ futures) – 2023 and 2024



Source: EA Electricity Market Information website (EMI) – annotation added

Figure 14: ASX Market Making Activity



Source: EA Electricity Market Information website (EMI) – annotation added

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10 ASX market makers are only required to meet requirements in 15 of each 20 market making windows. However, despite this loose requirement it appears that there was always at least 1 market maker present, thus liquidity would always be available but at reduced market depth.

11 EA consultation paper, Expiry of Urgent Code regarding market making under high stress conditions, 17 March 2025

However, one further concern we note during this period of market stress was that an ASX clearing member withdrew, thus limiting participant access to the ASX market during a time that adjusting hedge positions may have been necessary.

4 MARKET MAKING REQUIREMENTS

4.1 DOES NEW ZEALAND HAVE A FAST MARKET RULE?

Circuit breakers (first introduced after the 1987 stock market crash/correction) were designed to help prevent a panic in the event of a fast market and sharp decline in values. However, a complete halt to trading was not viewed as healthy so circuit breakers were generally replaced with fast market rules. The key difference being that fast market rules allow for the exchange to keep trading but with less restrictions on trading.

Prior to the Electricity Price Review (EPR) in 2018/19 market makers were voluntary with very little transparency on how ASX managed their fast market conditions. Consequently, fast market provisions were a key point raised by the EPR Panel in their recommendations[12]:

> *The mandatory market-making obligation should include definitions of the parties on which the obligation applies, the maximum permissible spreads between prices quoted for buying and selling contracts, the contract volume obligations* ***and the conditions that would trigger a relaxation or suspension of the obligation (see safety valve mechanisms below)****.*
>
> *The Electricity Authority's prime goal should be to develop a scheme that is well-structured and will therefore pass the test of time. We expect this work to take 12 months, given the* ***time needed to design safety valve mechanisms that strike the right balance between costs and benefits****.*
>
> ***We do not expect market-makers to assume undue risks****, but they have been withdrawing from their obligation without publicly stating either the decision or the reasons for it.*

While fast market rules may relieve pressure on markets makers to quote at defined spread requirements, they can also serve to add to the cost of market makers (and other traders) to trade out of adverse positions they may already hold.

We also note that fast market rules are in the interest of the Exchange operator who will want to protect the viability of their market makers while ensuring that accelerated trading does not destabilise the market, create an overly onerous burden on clearing members and cascade to the broader financial community (e.g. banks) that support the exchange's orderly operation.

The design of the fast market rule is also important to ensure that it does not remove liquidity completely from the market at critical times thus leaving market makers (and other traders) with exposed positions.

12 Electricity Price Review, Final Report, 21 May 2019

Take your pick

At the current time New Zealand effectively has three quasi fast market rules – none of them particularly well designed. These three 'rules' are:

i. The discretionary powers of the Electricity Authority to relax enforcement action against Code breaches, as it did so from 12 August to 23 August 2024 (refer Section 3.2),
ii. A general 'get of jail free' option with each market maker receiving 5 cards to play for each block of 20 market making windows (refer Section 2.3), and
iii. The urgent Code change regarding market making under high stress conditions due to expire on 12 June 2025 unless taken through the normal Code change process (refer Section 3.2).

4.2 Back to Basics

At its most basic ***the aim of a market maker is to collect bid-ask spreads***. It is not about taking an open position (although it is not uncommon for market makers to have a view on market direction and take a directional position). The most important thing to do as a market maker is to ***manage inventory within limits***.

Risk limits will dictate how exposed a market maker will be to one side of the market and may require the market maker to close out positions unprofitably.

Thus the ***principle risk*** to a market maker is not having a large open position when the market moves but ***lies in trading to manage open risk limits*** and incurring the bid-ask spread cost when the market is volatile and has rapid price directional movement within a market making window, and between the closing position of one window and the opening position of the next. Generally, ***as spreads tighten, market makers face higher risk while their opportunity to earn revenues reduces.***

However, while tighter spreads increase the likelihood that a market maker will have their bid or offer lifted, they also reduce the cost to the market maker to offload an adverse position they do not wish to hold.

4.3 International Practice – UK market

Mandatory market making in the electricity sector is not a common practice. The UK is one of the few other jurisdictions that have undertaken this. This was implemented under the Secure and Promote licence condition which also contained a 'fast market' rule designed to reduce the risk of market makers suffering significant losses in periods of volatility[13]. It allowed licensees to withdraw from posting bids and offers in the remainder of the designated market making windows if prices for a product increased or decreased by 4% compared to the first trade in the window.

However, feedback from licensees suggested the threshold had been hit too infrequently, and it was insufficient in preventing licensee costs from escalating during market volatility. OFGEM analysis showed the then current threshold had only been triggered in 0.7% of windows between the

[13] Mandatory market maker requirements were removed from the UK in November 2019 following a period of participant consolidation. This had created only two remaining participants that fell within mandatory market making requirements thus creating a disproportionate market making burden that was no longer considered viable.

beginning of 2015 and July 2017. This was well below the 'couple of percent' of windows initially intended[14].

Table 2: Proportion of windows incurring fast markets at various thresholds, UK

Proportion of windows where a fast market would be triggered, by fast market threshold, 2015 – 30 Jun 2017

	Month+1	Month +2	Quarter +1	Season +1	Season +2	Season +3	Season + 4
1% threshold	7.1%	5.1%	5.7%	2.2%	1.8%	1.3%	2.2%
2% threshold	2.8%	1.9%	2.1%	0.5%	0.2%	0.3%	0.3%
3% threshold	1.3%	0.9%	0.8%	0.2%	0.0%	0.0%	0.1%
4% threshold	0.7%	0.4%	0.3%	0.1%	0.0%	0.0%	0.1%

Source: Ofgem analysis of ICIS transaction data

Source: OFGEM, Secure and Promote review: Consultation on changes to the special licence condition, 13 December 2017

OFGEM accepted concerns about increasing costs on licensees from complying with the market maker obligations. Licensees provided evidence that these costs were increasing beyond the original estimates during periods of market volatility. These costs broadly arise from restrictions on bid-offer spreads during volatile market periods making price discovery more difficult.

OFGEM then proposed two measures to help mitigate these costs:

- A soft landing period of ten minutes at the beginning of each market making window with wider bid-offer spreads
- A new fast market rule to widen bid-offer spreads in the market making windows when the price moves by ±1% from the first trade of the window

Table 3: Proposed bid-offer spreads for fast markets and soft landing, with the earlier spreads in brackets

	Baseload	Peak
Month+1	1.0% (0.5%)	1.0% (0.7%)
Month+2	1.0% (0.5%)	1.0% (0.7%)
Quarter+1	1.0% (0.5%)	1.0% (0.7%)
Season+1	1.0% (0.5%)	1.0% (0.7%)
Season+2	1.0% (0.5%)	1.0% (0.7%)
Season+3	1.0% (0.6%)	1.0% (1%)
Season+4	1.0% (0.6%)	N/A

Source: OFGEM, Secure and Promote review: Consultation on changes to the special licence condition, 13 December 2017

It is important to note when looking at the UK example that while market maker spreads are much tighter than New Zealand and a relatively low (1%) price variation threshold is used within the window, that this is in part possibly due to the lower volatility in their underlying spot market (refer Figure 1).

4.4 SO WHAT SHOULD A FAST MARKET RULE LOOK LIKE FOR NEW ZEALAND?

Looking at the features of the current fast market rules in New Zealand we would suggest that something more akin to the modified UK fast market rules should be followed (but allowing for

[14] Useful to note that this 2% guideline is vastly lower than the 5 in 20 (25%) window obligation used for market makers in New Zealand.

wider spreads and possibly a higher intra window price variation threshold as we have already noted). The advantage this has over the current 'rules' in New Zealand is that:

- There is a single unambiguous rule
- Its workings are published and defined as opposed to being discretionary
- Fast market conditions are measured based on price volatility (not an absolute price threshold)
- It has a reasonable target frequency of occurring (~2%) as opposed to a 5 in 20 (25%) frequency
- Market making still occurs during fast market conditions (albeit at wider spreads) as opposed to the risk that all market makers play one of their many "get out of jail free" card at the same time
- It is enforceable (although uses license conditions rather than the Market Code)

Of the current fast market 'rules' seen in New Zealand the urgent rule change is the closest to being sensible, meeting all of the above points except for not using price volatility as the trigger.

The Electricity Authority currently has a consultation paper out where it recommends allowing the urgent code change to expire on 12 June 2025. Given this will be in the midst of the most volatile time of the market, the middle of winter 2025, would seem at odds to us.

5 INDEPENDENT RETAILERS

5.1 ARE THEY ABLE TO HEDGE?

As noted in Section 2.2 there appears to be a good level of trading taking place from independent players on ASX baseload products. We also noted that this trading is concentrated during market maker windows highlighting the importance (dependence?) on market makers to support liquidity and depth.

However, there is a lot of commentary around whether independent participants are able to find sufficient competitively priced 'shaped' hedging to address exposure outside of that provided by baseload hedge cover.

The Authority noted in their review of Winter 2024 that:

> *Most electricity consumers, including all residential households, **were sheltered from these high prices through retailer hedging**. However, some retailers removed promotions or all their offerings from websites such as Powerswitch and some stopped taking on new customers. This may have reduced consumer choice at this time. There was a small decline in the number of ICPs with a small- or medium-sized retailer during July and August, as more consumers switched to larger retailers[15].*

Despite the Authority's view on this we would argue that some improvement in providing a liquid and deep addition to baseload hedging is required. Relying on the OTC market to provide this is not something we would recommend - we discuss a more viable approach to achieving this in Section 6.1.

[15] Electricity Authority, Review of winter 2024, paragraph 1.12, 8 April 2025

5.2 NEED FOR CONTINUOUS HEDGING

The anecdotal claims that independent retailers find difficulty in accessing the hedge markets at times of market stress is concerning. Participants should not be seeking hedge cover during periods of market stress but rather to adjust positions they already hold.

While the hedging strategy of each retailer will vary depending on many factors such as risk appetite and the portfolio and nature of customer contracts, one factor remains constant and that is that parties need to hedge themselves in advance of unexpected events occurring. Remaining unhedged or attempting to hedge in the midst of such an event, when the market is stressed, should not be resolved (nor entertained by regulators or officials) through playing the moral hazard card in hindsight.

Hedged retailers are exposed to the cost of the hedge when the spot price is below the hedge price. It's only in the event when the spot price exceeds the hedge price that the hedged retailers realise the benefit of the hedge. If retailers are able to hedge against a high spot price during a market stress event then there is less incentive to hedge earlier. This claim by independent retailers may lead to a less liquid market as it doesn't reward early and prudent hedging.

Independent retailers, especially during their start up phase, may find the financial requirements to access exchange traded contracts prohibitive, or such contracts may not provide sufficient granularity. Such retailers will typically rely on bilateral OTC arrangements with larger players. Ideally, the necessity of bilateral contracts under these circumstances should already form part of a new entrant's business case and be identified in stress tests (refer Section 5.3) which should also form part of a new entrant's plans.

However, regardless of how hedging is undertaken it should be a deliberate process that takes place over a long period of time, as described below.

Figure 15: Retail hedging strategy

Most retailers start hedging for a particular period about two years in advance of that period commencing. However, prudently managing forward exposure to prices is a balancing act, with benefits and costs to hedging too far in advance or not far enough. For example, a retailer would not want to enter into hedges to cover their entire (forecast) load two years in advance of a particular period because:

- their load might change in the intervening two years
- in two years' time, contract and spot prices might be lower (and competing retailers may set lower retail prices based on those lower spot/contract prices).

In this sense, contracting too much load too far out might increase the retailer's exposure to risk.

Similarly, a retailer would prefer not to hedge their entire load just before a particular period commences because such a strategy would mean they are completely exposed to the prevailing spot and contract prices. Their retail prices for the period will be largely locked in already, so any wholesale price increases will negatively impact the retailer's margins.

By building up a portfolio of contracts over time, a retailer is best able to balance these different risks.

Retailers that pursue this hedging strategy generally do not own generation, or only own small amounts of generation that do not provide adequate protection from wholesale price volatility.

Source: ACCC Retail Electricity Pricing Inquiry—Final Report, June 2018

We believe that ongoing education of market participants on the role of hedging is important and should be conducted as part of the regular stress test arrangements currently taking place.

5.3 EXPAND ROLE OF STRESS TESTS

The market has a stress testing regime that requires retailers and direct wholesale customers to apply a set of standard stress tests to their market position (net of 1hedging) to assess the impact of high price events.

Clause 13.236F of the Code requires each disclosing participant to submit a certificate to the Authority that:

1. verifies their Board has considered the disclosure statements for the certification period and the projected change in net cash flows from operating activities as a result of applying the stress tests
2. confirms that they have provided information about the stress tests to any of their customers who entered into or renewed a supply contract with any spot price exposure, so as to allow the customer to consider their own stress test outcomes.

Stress tests should be extended to be a required part of a new entrant's process for joining the market if this is not already the case.

Additionally, some consideration should be given to expanding point 2 above to include a level of disclosure to all customers, similar to that required for claims paying ability in the general insurance industry. This would a) provide a level of assurance to customers that their chosen retailer has the requisite level of financial substance and/or hedging to support the contract they have entered into, and b) help to self-limit the retailer from growing its retail portfolio beyond its hedge cover. The alternative to this is to have a greater acceptance that a normal part of a free market is that participants will come and go.

5.4 HOW SHAPED DOES HEDGE COVER NEED TO BE?

It is relatively easy to look at the risk profile of one's spot electricity portfolio and design a perfectly shaped product that provides a matched hedge. However once one looks beyond the naivety of this approach it quickly becomes obvious that such products don't exist with any liquidity behind them. A liquid imperfect hedge will usually provide a better solution than an illiquid perfect hedge. It is very hard for some level of basis risk not to exist such that a trade-off is inevitable between the level of residual risk versus the availability (liquidity) and depth of the risk management solution. A range of building-blocks (portfolio approach) can be considered and provided they provide a 'good enough' fit then the decision should swing on price and availability.

The Authority's review of risk management options for electricity retailers[16] notes that a number of these 'good enough' hedge solutions exist:

> *The results of our modelling suggest that risk reduction is currently similar to a portfolio of shaped hedges (baseload, peak and super-peak hedges) using the following products:*
>
> *(a) A portfolio of baseload hedges with peak hedges.*
>
> *(b) A portfolio of baseload hedges with demand response.*
>
> *(c) A portfolio of baseload hedges with battery investment.*
>
> *(d) A portfolio of baseload hedges with C300 cap hedges.*

[16] Reviewing risk management options for electricity retailers, Update paper following submissions, 27 February 2025

From a regulatory perspective, the reasonable and necessary approach in our view, is to ensure that at least one 'good enough' option is readily available to market participants (supported by the Authority) and that should they wish to explore what they might believe to be a better fitting solution, then they are free to do so without any additional regulatory intervention being necessary.

We note that option (a) already exists on the ASX, albeit that the peak product is only available for quarters and is not actively traded (near zero liquidity and depth). This is also the same product set that was used in the UK to provide market making coverage.

Table 4: Market Making Obligation Product Set, UK

Baseload	Month +1 Month +2 Quarter +1 Season +1 Season +2 Season +3 Season +4
Peak	Month +1 Month +2 Quarter +1 Season +1 Season +2 Season +3

Source: S&P Licence Conditions, Schedule A

6 POTENTIAL AREAS OF IMPROVEMENT

6.1 Better Product Range and Liquidity for Exchange Traded Futures

We believe that the answer to providing a sufficient hedging solution, supported by the Electricity Authority lies in offering an exchange traded baseload and peak contract supported by market making, to ensure a minimum level of liquidity and depth. This is consistent with studies already undertaken by the Authority as noted in Section 5.4.

In this context, we would recommend that:

(a) a monthly peak product (against each of Otahuhu and Benmore) be added, and

(b) the current market making volumes be split over base load (~ 2/3^{rds}) and peak load (~1/3rd).

A simple look at Figure 8 suggest that all non-market maker trades could be more then met by existing market marker volumes thus allowing existing volumes to be split over baseload and peak market making. However, this is an area that should be scrutinised and confirmed.

We would also suggest that the time periods that define the peak product could be relooked at to see if a hybrid between peak and super peak would better serve hedging requirements as a whole (when combined with base load hedging). We do not believe it is advisable or necessary to have both a dedicated peak and super peak product. In looking at the spot trading intervals that define this product, consideration should also be made to any expected change in the pattern of peak trading intervals that may arise with any significant shift to solar generation entering the market in the near future.

This product set could be further enhanced in the future with a cap product, as earlier planned by ASX and promoted by the Authority. However, we would caution that this be further reviewed (refer Section 6.4). In our view, based on the earlier experience of launching a peak product on the Exchange, there is little value in launching a new product without some level of market maker support. We would also strongly caution that given the small size of the New Zealand market that growing the product set too quickly (such as moving the OTC super peak product to the Exchange) runs the risk of cannibalising existing liquidity and placing too much strain on market makers. Market making comes at a cost, whether or not this is explicit (as in commercial market makers) or imbedded (as in the case of regulated market makers)[17].

6.2 Review of Market Making

We have already discussed that a single and sensible fast market rule needs to be adopted in New Zealand (refer Section 4.4) and that market making needs to be broadened by splitting current baseload volume requirements across baseload and peak (refer Section 6.1).

Additionally, we would question what value a commercial market maker brings ***in addition*** to the existing 4 regulated market makers other than to provide some price discovery (through competitive tender) of what the costs are to a market maker. We have argued in the past of the benefits of commercial market making, but from the viewpoint of moving regulated market makers to a commercial basis.

In its current consultation on the expiry of the urgent market making code change the Authority states that (emphasis added):

> *"It also seeks feedback to inform **a wider review of market making settings**, to commence in 2025. The Authority is undertaking this consultation to assist with improving the market making framework, to achieve the Authority's Statutory Objective".*

We would recommend that this wider review includes the relevant suggestions made in this paper.

6.3 Stop trying to make OTC do all the Heavy Lifting

As already discussed, we believe the role of OTC trading should be to provide additional and more customisable options to exchange based trading where parties are free to contract (or not) on a willing buyer willing seller basis.

Given the small size of the New Zealand market, new products without market making support have a much-reduced chance to build liquidity. We thus believe that exchange traded products with market making support is the preferrable option to establish a core set of products that can be used to provide a sufficient building block approach to meet hedging requirements.

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[17] We are somewhat dismayed to see the Authority acknowledge in its current consultation that successful market making is a trade-off between cost of service, service levels and reliability yet goes on to say that "The Authority's primary objective in considering the urgent Code amendment is to consider reliability" – Expiry of Urgent Code regarding market making under high stress conditions, Consultation Paper, 17 March 2025.

6.3.1 Adjust the voluntary OTC code

Since 2023 the industry has been operating under a voluntary code of conduct for OTC trading. The code centres around non-discriminatory behaviour – "…treating all parties fairly and in objectively justifiable ways, and in good faith without prejudice"[18].

There is no explicit obligation to quote or trade under the code itself - specific relevant clauses being:

> *21.3 All parties (subject to laws and regulations) have the right to determine at any point in time the risk management features of the trades they want to transact, the requirements they have on counterparties to complete these trades, and the terms and conditions they are willing to accept.*
>
> *21.4 Request for Proposals (RFPs) in the OTC market may not get transacted for a number of reasons, including parties having different opinions on the value of a trade, or because one party considers the other party is unable to satisfy their credit or capability requirements.*

However, to better manage expectations of the parties involved, we would suggest that the code expands clause 21.4 to include the cases where a party may decline to quote when the potential trade would exceed the physical limits of the party to back-up the trade or be overly inefficient for the party to trade counter to its net natural position (i.e. there is little overall value if one of the party enters into a trade only to immediately seek to trade out of its position through a further trade).

Additionally, building greater disclosure requirements into the OTC code should be the first point of call to provide greater confidence and assurity in how the OTC market is operating before any more interventionalist regulatory action be considered. With our recommendation that a more complete set of exchange traded products be provided (refer Section 6.1) we believe that the OTC market as a whole will require much less regulatory scrutiny.

6.4 A Permanent Industry Based Financial Market Working Group

As already discussed, a careful balance needs to be maintained between extending a hedging product set while preventing the diluting or cannibalizing of liquidity and depth. The removal of basis risk often comes at the expense of compromising liquidity. Also, the New Zealand electricity sector has some specific features, such as the pricing of hydro resources into the spot market, that need to be understood and considered when prioritizing what additional standardised risk instruments would be beneficial to the market as a whole.

In this regard, we would recommend that a financial market working group be established by the industry to work with the ASX to give guidance and advice on these matters. The role of this group should be in the nature of a hands-on working group with a secretariat (under the directions of the group) to provide analytical support.

It is also anticipated that such a group, working with the ASX, will help strengthen the relationship with the Australian exchange and increase their focus on the New Zealand market.

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18 Paragraph 24. Voluntary Code of Conduct For participants in New Zealand's Over the Counter Electricity Market

6.5 STRENGTHEN STRESS TESTING

As noted in Section 5.3 we believe that stress testing could be extended to cover disclosure to all end customers and to form part of market joining (registration) requirements.

Additionally, we would strongly urge some basic market training on the need for hedging to be a continuous activity. This will hopefully put a stop to the facile claim that “New Zealand’s hedge market works except when you need it [in times of market stress]”.

7 ABOUT THE AUTHOR

Dave Carlson is an experienced energy market operator, designer and change manager with a track record spanning Asia, Africa, Australia and New Zealand.

Before returning to New Zealand in 2016 he was a Senior Vice President at SGX (Singapore Securities Exchange), responsible for new initiatives in the gas and power sectors. Prior to that he served for 10 years as the CEO of the Energy Market Company, EMC, the national electricity market operator for Singapore.

Dave has served on and chaired many industry and governance panels in Singapore to further liberalise energy markets including market rule evolution, the implementation of retail contestability, developing gas trading and introducing electricity derivative products.

Dave continues to work with a number of national utilities, regulators, market operators, private generator-retailers, and government clients in Southeast Asia, Australasia and the Middle East. He has a BSc in Mathematics from Victoria University in Wellington and passed the Associate Examinations of the Institute of Actuaries, London.