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Review of Electricity Market Performance

Final Report to Ministers & MBIE | 23 May 2025

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1 Summary of our findings and recommendations

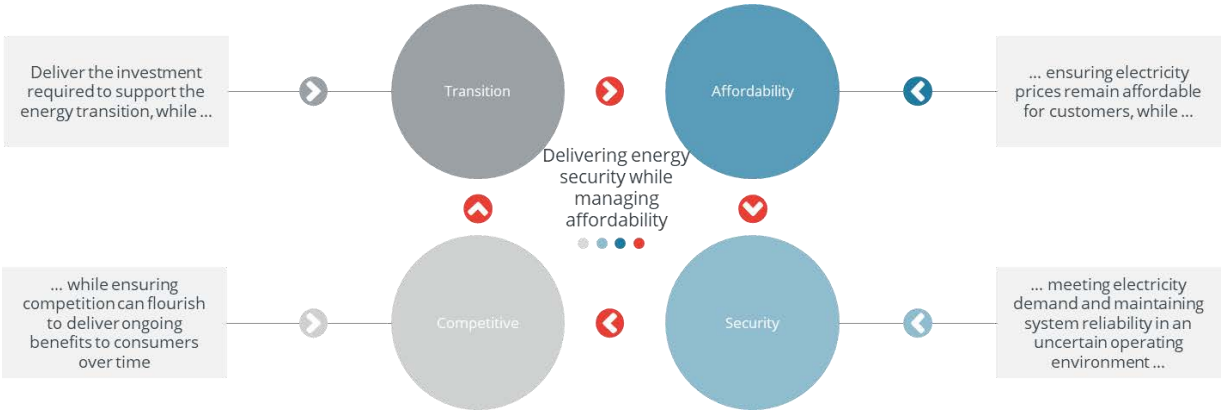
Electricity has a vital role in New Zealand's economic success

Electricity is essential to the success of the New Zealand economy, supporting key industries such as dairy, metal product manufacturing, and wood and paper production, while also driving the growth of technology-focused sectors, facilitating the transition to cleaner energy sources, and enhancing economic resilience.

Our review of the New Zealand electricity sector is timely as the country navigates the challenges of decarbonisation, rising demand, and evolving market dynamics that can threaten affordability, reliability, competition and investment in new generation capacity (Figure 1).[1]

Consistent with the Government's Policy Statement on Electricity,[2] in undertaking this review our primary goal is to deliver secure and reliable electricity services at their lowest cost. This outcome is essential to set up the country for future success.

Figure 1: Key challenges for the New Zealand electricity sector



Source: Frontier Economics

Substantial reform is needed to deliver lasting benefits

There are significant changes to existing arrangement required to achieve the Government's goals. We are concerned that if bold changes are not made now, irrevocable harm could be done to the New Zealand economy. Our proposed changes focus on:

- Addressing the key concerns in a way that minimises distortions to market signals and the efficient operation of the electricity market
- Reducing government's role in the energy market overall but refocussing its role to where it is most needed – to ensure system reliability, security and competitiveness
- Ensuring security of supply and reasonable prices during periods when water storage is low

[1] The terms of reference for this review is set out in Appendix F.

[2] Statement of Government Policy to the Electricity Authority Under Section 17 of the Electricity Industry Act 2010: New Zealand Electricity Industry - 2024-go5150- New Zealand Gazette

- Supporting competition by lifting-up independent retailers and generators to the cost efficiency level of the gentailers so they can compete on a level playing field
- Making it easier for industry to interact with the energy sector and thrive, and
- Ensuring an operating environment that is friendly to innovative energy solutions being rolled-out for all New Zealanders.

A solution to overcome policy uncertainty and dry year risk

As New Zealand's reliance on renewable energy increases to supply an increasing amount of electricity to meet the country's electrification goals, so does its vulnerability to dry year shortages. Without definitive action by the Government, dry year risk will lead to increased prices, loss of supply and economic disruption that will drive industry out of New Zealand.

We have identified that the core problem is one that has been caused by Government, and so it requires a solution by Government as the private sector has no means by which they can address this problem. Timely and sufficient investment in substantial new long-duration dispatchable capacity is not occurring, in large part, due to the considerable risk imposed by Government policy volatility. At the stroke of a pen the value of an investment can be destroyed. This is a risk the market is unable to manage efficiently.

Our proposed solution is designed to preserve the market signals and the operation of the existing energy-only market, while ensuring the dry year problem is resolved. While it is a bold proposal, it is also the one that we believe imposes the least disruption to the intended operation and market signals expected of the existing energy-only market.

We propose that the Crown refocus its involvement in the electricity sector to securing and selling thermal capacity, guaranteeing that New Zealand has the backup generation it needs when hydro resources are low and to fill any expected shortfalls in the supply of physically reliable power (i.e firm power) at all other times. In short, this ensures a secure and reliable energy supply for New Zealanders. Power will remain available in all conditions, supporting households and businesses alike. To deliver this outcome, we recommend establishing a new organisation, which we refer to as "New Co" in this report.

We also propose that independent retailers, generators, and large direct customers (referred to in this report henceforth as "independents") have priority over access to this firm capacity and energy at all times, with the aim of providing them with the opportunity to achieve the same cost efficiencies as their vertically integrated competitors. This approach, akin to providing Mum and Dad investors a dedicated allocation for an Initial Public Offering, will enable the independents to offer the same firmed up energy deals as their gentailer competitors and ensure that exiting gentailers cannot hoard this capacity. This move will immediately deepen and widen competition.

By taking primary responsibility for securing and selling dispatchable generation capacity, the Crown can act as guarantor of New Zealand's energy security and reliability. Achieving energy security and reliability will provide a more stable investment environment for investors and consumers.

This proposal is expected to be self-funding with cost recovered through wholesale market revenues, including contracts and spot prices, with the option to charge a levy to all customers if the existing owners of thermal capacity demand a price above the costs to operate. It is expected that substantial capital will still be required to develop deep sources of reliable fuel and new thermal capacity into the future.

We have also considered several alternative solutions; including those adopted internationally.[3] However, we found these solutions would not address the fundament issue of government policy risk, and so could not be expected to deliver the required capacity without substantial increases in electricity costs. Indeed, most of the options would impose material distortions to the market, embed the potential for substantial market power, and so ultimately see prices to consumers rise substantially.

Government ownership needs to be better targeted

We have found that, other than flexible generation capacity to support dry year risk and new firm generation to support more renewables, there are no major obstacles to investment in new renewable power assets. In general, the market design works well, provided there is enough capacity and energy, so we do not see a need for fundamental changes to the design of wholesale markets. However, we believe that majority Government ownership of the main gentailers is distorting market outcomes. This is primarily because Government ownership constrains the ability to invest in larger projects. This is because Government is unable to manage the budget implications of providing equity injections into large scale new investments – the gentailers can raise debt and they can apply retained earnings, but they struggle to obtain adequate equity injections.

We recommend divesture of the Government shareholding of the gentailers. Without the Government as the major shareholder the gentailers would have greater flexibility to raise capital, make larger investments and respond more dynamically to market demands.

We are not, however, recommending that the Government exit the wholesale market entirely. In fact, the opposite. Instead, we recommend that the Government use the funds generated from the divesture to invest in those things that are most critical to the proper functioning of the New Zealand electricity market. This includes the development of a secure and reliable source of fuel and appropriate generation assets described above. These are the things that the private sector is unwilling to invest in because of risks generated by the Government, which means only the government can manage these risks. The sale of Government shares in the gentailers will enable it to fund those specific projects that are essential to the future of New Zealand but the private sector, by itself, cannot manage. We note, however, that our proposal for Government control of thermal assets is not contingent on divesture of its ownership in the gentailers. The only difference is that the Government will need to directly fund the new entity.

Fragmented ownership of the distribution businesses is stifling innovation, raising costs and threatening reliability

There are too many electricity distribution businesses (EDBs) and many of them are operating below efficient scale (see Figure 2). This is limiting their ability to operate and invest efficiently and innovate to deliver services more efficiently to customers and to manage connection of large new supplies and loads.

We are recommending the number of EDBs be rationalised. We have identified three options for achieving this:

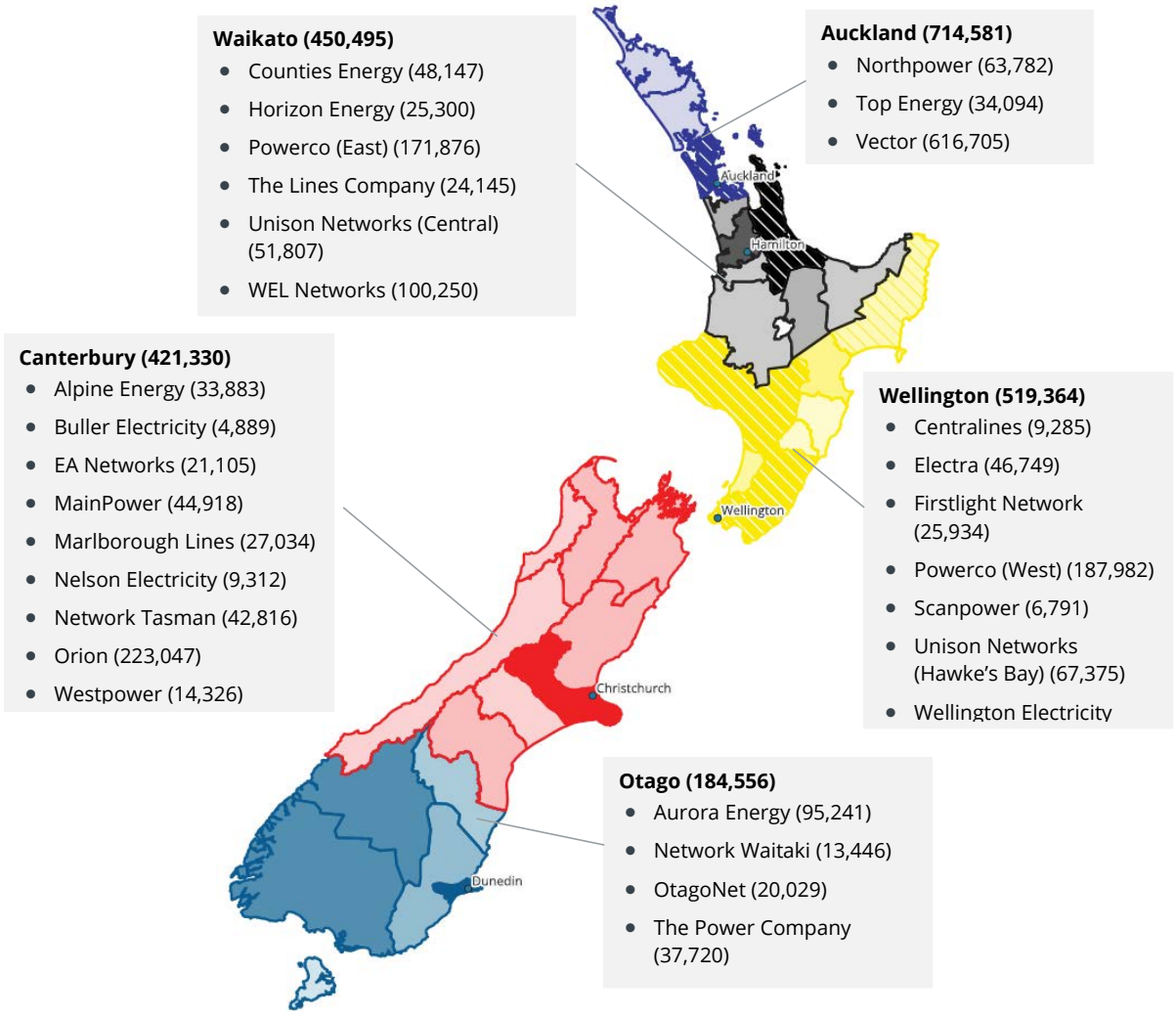
1. The first-best option would be to amalgamate the existing 29 EDBs into a small number (we recommend five) large regional EDBs,

[3] See Appendix A.2 for a description of international approaches to managing system security in markets with a high proportion of hydro generation.

2. The second-best option would be to require amalgamation for only those EDBs that do not currently have any private ownership, and
3. The third-best option would be to maintain the existing 29 EDBs, but require EDBs within defined regions to coordinate together to, for example, undertake joint procurement and share resources to generate efficiencies.

Given how fast the energy transition is occurring, the faster that that the number of EDBs is rationalised, the bigger benefits that can be delivered to consumers and to New Zealand's regional economies.

Figure 2: Potential model for aggregating exiting 29 EDBs into five Super EDBs



Source: Frontier Economics. Notes: Total number of customers (as of 2024) reported in parentheses for each EDB and region. Individual EDBs with larger customers numbers are shown in darker colours, and EDBs with fewer customers are shown in lighter colours. Hatched regions denote EDBs with at least some private ownership.

A new Energy Authority should be created combining gas and electricity regulation

We recommend establishing a new Energy Authority by amalgamating the functions of the Electricity Authority and the Gas Industry Company (GIC), reflecting the context that originally justified separate governance models for gas and electricity has changed. This change does not

reflect any concerns about the way the GIC has operated, but rather it reflects the opportunities that amalgamation brings. This new entity would streamline and harmonise regulatory functions across both sectors, enabling more consistent and urgent action on the energy transition while capturing cost efficiencies from integrated operations. The Energy Authority should replicate existing electricity arrangements for gas where suitable, and implement tailored approaches where necessary to reflect the sector's distinct characteristics. Internationally, combined energy regulators are common and demonstrate the potential for improved coordination and reduced costs, which we expect to be realised through this reform.

Top 10 recommendations

The sections above set out our five main recommendations. In summary, these were:

- For the Crown to take primary responsibility for security and selling on-demand dispatchable capacity and energy
- That independent retailers, generators and large direct customers have priority access to this firm capacity and energy at all times
- Government divesture of its shareholding of the gentailers, with these funds being used for investment in secure and reliable sources of fuel and generation capacity
- That the number of EDBs be rationalised, with our preference that this be achieved by amalgamating the 29 EDBs into five super distributors, and
- The Gas Industry Company should be amalgamated with the Electricity Authority to create a new regulator, the Energy Authority.

Recognising that you have asked us to provide you with our top 10 recommendations, we have identified the following additional changes to also be of high importance.

- That the ETS be removed from the electricity market given it is imposing additional costs to customers without delivering a corresponding environmental benefit.
- Exemptions for price and quality regulation for distributors should be removed and default price path regulation abolished. The implication being that individualised ex-ante price regulation applies to all EDBs. The intention being to ensure that the necessary investment is occurring to deliver the energy transition in New Zealand, and so avoid the prospect of a future bow wave of investment needs and reduced service performance in the interim.
- Existing restrictions on EDBs owning and controlling generation assets in their own service areas should not be relaxed. Relaxing these provisions would give EDBs the ability to exercise market power in a way that would harm consumers. This recommendation would not prevent EDBs from investing in generation assets outside their distribution area.
- The Electricity Authority should be subject to a formal code change process. Any person would be able to submit a request for a code change, and the Electricity Authority would be required to assess that proposal in accordance with a prescribed process.
- The Electricity Authority should urgently implement a program with retailers to achieve bill consistency so that customers are better able to compare retail offers and also identify ways to improve their electricity use. The template that has been developed by Consumers NZ for a consistent bill is a good starting point for achieving this.

Our additional recommendations

Additional recommendations that we have identified are as follows:

- A new streamlined version of the Investment Test should be introduced for Transpower that applies to augmentation projects that fall below the $30 million base capex threshold but above a nominal threshold of, say, $8 million. The key outcome will be additional public consultation on proposed augmentations and so additional confidence that the right investment is occurring at its lowest efficient cost.
- The proposals for non-discrimination of contracts and virtual disaggregation of the gentailers should not be adopted as these options will not resolve the underlying issue in the market; but will instead impose higher electricity costs onto consumers and industry.
- The Government recently passed the Customer and Product Data Bill to ensure customers have greater control over their data and to make switching retailer easier. To give effect to this Law a designation is required to designate data holders, classes of data to be regulated, and general requirements relating to regulated data services. In implementing this for electricity, the aim should be to permit customers to be able to agree to the release of their electricity usage data via a click of a button on a price comparison website.
- The Electricity Authority should make better use of the data it collects on hedging. This includes by preparing an annual report that identifies trends in contracting and the implications these trends are having on competition. A key objective for the use of this data should be to improve the sophistication of the market monitoring and assessment of competition in the market.
- There are benefits in centralising access to relevant gas market information in a single 'gas market dashboard'. This would make it easier for gas market participants to locate the information they need and to have a common understanding of 'point-in-time' supply and demand conditions in the market. We recommend that the Gas Industry Co be tasked with developing and maintaining the gas market dashboard.
- The Gas Industry Co currently prepares and publishes an annual supply and demand study on a voluntary basis. This publication is of high value to the sector and so there is benefit in codifying the requirement to produce this annual study.
- The Electricity Authority should be required to determine the scope of the Input Methodologies for electricity lines businesses. This would mean the Commerce Commission would not have the power to remove or exclude IMs that the Electricity Authority has determined that it must develop. This change would make the Commission more accountable for its decisions and provide all stakeholders with greater certainty over the regulatory framework.
- The prohibition of the Commerce Commission using comparative efficiency benchmarking as an input into setting prices should be removed on the basis that it overly constrains the Commerce Commission's decision making and its ability to assess the efficiency of lines businesses in New Zealand.
- A financiability test should be embedded within the regulatory framework to provide investors with certainty and confidence to commit funds to network investments.
- The Electricity Authority should expand its existing consultation on harmonising contractual terms for new network connections to consider more detailed matters. The aim being to bolster consistency across EDBs and so facilitate the entry of more innovative energy solutions across New Zealand.

- The North Island Winter Capacity Margin should be amended to provide greater flexibility to respond to factors that change the frequency, duration and magnitude of loss of load events.
- The Electricity Authority should be subject to a targeted review of how it performs its functions. The purpose being to identify if it is allocating its resources to the right areas of its functions, whether the resources it does have are well aligned with the delivery of its functions, and if its processes for internal decision-making have sufficient checks and balances to deliver robust outcomes.
- To assist the Electricity Authority with its market monitoring functions, Transpower should be required to maintain a data catalogue focused on data that is needed for market surveillance activities.

Response to specific questions

Our Terms of Reference asked us to address seven specific questions. While our report addresses these questions by focusing on the key issues we have identified, for completeness, we provide a response to each of the questions here.

Q 1 How does business ownership, structure or design of markets affect incentives or opportunities to invest in generation, storage, transmission and distribution

With respect to generation and storage, our view is that, except for investment to address dry-year risk and access to firming capacity for all market participants on an equal basis, the market is working to deliver new investment in generation.

Over recent years several factors have meant it was virtually impossible to invest in new firm capacity, these factors include:

- Demand uncertainty associated with the potential exit of the New Zealand Aluminium Smelter
- Supply uncertainty from the potential Government investment in the NZ Battery Project,
- Uncertainty associated with how New Zealand would meet a commitment to 100% renewables by 2030
- A ban on any further off-shore gas exploration, and
- A general negative attitude by lender support of any investment that wasn't a renewable or energy storage project.

There is however strong support and a pipeline of new renewable generation projects from both independent participants and the gentailers, suggesting a good environment for these investments to occur.

We believe that the number and size of distributors in New Zealand is a barrier to efficient investment in both network assets and innovative solutions that rely on networks. For transmission networks, there is a robust framework to deliver efficient new investment. However, we feel that the use of this framework could be adopted for a broader range of projects.

Q2 Since 2017, how have developments in the gas market and government policies including the offshore oil and gas exploration ban affected the availability of hedge contracts?

The ban on offshore oil and gas exploration saw major gas sector participants exit New Zealand and also sent a message that there was substantial policy risk associated with investment in finding additional gas and for new thermal generation capacity. While gas supply had already been in decline, for a range of reasons, before the exploration ban, the ban removed a conventional source of energy that could have been used to support the addition of more renewables and greater electrification. This aim cannot be achieved economically with intermittent renewables and batteries, together with existing hydro electric power, alone.

There is little doubt that the decline in gas exploration has contributed to concerns about future scarcity of firm energy. A consequence of reduced availability of firm energy, and the looming retirement of remaining thermal generators, is that there is less firm capacity available to back the hedging contracts that are sought in the market. The relative decline in the supply of available firm hedging contracts inevitably increases the costs of hedging as progressively more intermittent supply competes over the dwindling supply of firm energy to back their non-firm investments. Simply reallocating these dwindling supplies of firm energy to different parties either by regulatory mechanisms or other means does not solve the fundamental scarcity of this form of energy supply. The government must increase the supply of firm energy and the circumstances that itself has created that deters others from investing in this form of energy can only now be overcome by government itself. This is particularly important to support any plans to increase electrification.

It is important to emphasise, however, that the reduced availability of hedges is not solely due to the ban on offshore oil and gas exploration, it is merely one of a number of factors that meant that the firm capacity that is needed for contracts is less available.

Q3 Can an expectation that major electricity users are sufficiently hedged for dry years encourage greater investment in generation?

Under normal circumstances, the contracting for dry years would provide a market-driven mechanism that would drive investment in new generation capacity. This is because, where additional capacity is required to meet demand for contracts, investors would be expected to respond by developing new generation assets to meet that demand.

In this case, however, policy uncertainty risk means that the required investment will not be made by market participants, irrespective of the demand for contracts. The result of this aversion to invest in capacity and energy to manage dry year supply will cause relatively scarcity of contracts and rising prices.

Q4 What is the impact of market design and market rules on competition, market entry and expansion?

The market design and market rules in New Zealand appear to be facilitating competition by encouraging market entry and expansion in both the wholesale and retail electricity markets. A

significant number of independent participants have entered both wholesale and retail markets. This suggests participants view the market environment in New Zealand as positive for entry and expansion. In addition, having four vertically integrated entities of a similar size is also a positive indicator of effective competition.

We consider that there has been a lack of investment in customer and billing systems that are common in other retailing markets that could make it easier and cheaper for consumers to switch away from retailers that offer poor service and relatively high prices. The necessary reforms have been proposed and accepted before in New Zealand but never implemented. We can see no good reason for not expediting these changes for the benefit of consumers.

Q5 Do market participants have access to sufficient information (including gas and other fuel supply information) and risk management products to effectively manage risk?

We have access to confidential contracting data from all participants from 2010 to 2024. While we could not complete the analysis we wished to because of some critical missing data, our analysis shows the following:

- Gentailers are able to set their contract position for some years in advance
- Gentailers are major suppliers of hedging contracts to their competitors
- Small retailers appear to be able to also set their contracting position with some of these businesses operating active contract trading businesses which also involve them selling their over-contracted positions to the gentailers, and
- There appears to be a high correlation between prices of exchange traded and over the counter (OTC) hedging products, which means that there is a high level of transparency of contract prices within the market already, and in any case the information released on OTC contracts means that there a high degree of transparency of contract terms and conditions in the market.

None of the above suggests that small retailers find hedging contract terms and conditions acceptable and we have been advised as part of the engagement process that small retailers feel that they are paying too much for contracts. We note that our analysis of the retailing margins (see Section 5.3.3) shows that the smaller retailers generally have higher margins and lower energy supply costs than the gentailers they complain charge them too much.

Based on the above findings we do not consider that any of the existing contracting information disclosure arrangements need to be changed.

Q6 Do the regulator and system operator have the right roles and responsibilities to promote security of supply and affordable prices?

Overall, the split of roles and responsibilities between the Electricity Authority and the system operator appear to be working well enough for promoting prudent management of security of supply and affordable prices. While there may be opportunities for minor refinements, we do not see a need for fundamental changes to the existing framework.

One area of potential concern is the dual system operator and network operator function. While a conflict of interest could theoretically arise, there are also synergies that result from the

current structure. At this stage, we have not identified any specific problems that would justify the cost of separating the entities. Nevertheless, it is an issue worthy of ongoing monitoring and if this issue arises in the future it may be necessary to reconsider this position. The issues to monitor for include instances where there are network investment and/or operation decisions that result in unnecessary costs and risks imposed on market participants that may be disguised by the way in which the system is operated.

However, as noted above, it is our view that the effectiveness of electricity (and gas) regulation would be enhanced if the Gas Industry Company and the Electricity Authority were amalgamated into a single Energy Authority. Our view is that the current delineation between electricity and gas regulator is outdated and not fit-for-purpose given the current environment.

We note that market participants are dissatisfied with how the Electricity Authority is discharging its functions. To the extent that this because that participants feel the Authority is unresponsive to their concerns, we feel this can be addressed through more formal arrangements for code change proposals which involve strict processes and timeframes for considering proposed changes, recognising no formal arrangement exists at the moment. This should enhance regulatory transparency and accountability.

Q 7 How does our market monitoring and compliance enforcement system (roles and approach) compare with international best practice?

Our review of market monitoring and compliance enforcement has focused on the processes and tools the Electricity Authority adopts rather than whether it has made appropriate decisions and assessments. We have found that the Electricity Authority's broad framework to market monitoring is largely consistent with international best practice. However, it is our view that the meaningful improvements can be made to market monitoring by developing a more sophisticated approach to assessing market power and identifying and measuring barriers to entry so the Electricity Authority can determine where to direct pro-competitive changes to the market. Indeed, requiring the Electricity Authority to implement certain market power tests, or develop certain indicators, would fundamentally discount the challenges associated with monitoring for market power in electricity markets. Instead, while such tools may be suitable for screening purposes, far more detailed analysis is necessary.

Our approach to this review

To undertake this review we have brought together an international team of energy experts to bring fresh perspectives from around the world. The geographic coverage of the working experience of our team spans the Asia Pacific, Northern Asia, the United Kingdom and Europe, the United States, Canada, and the Middle East.

We have had a relatively short time to conduct a review where we were told to leave no stone unturned and that no option is off the table. To meet this timeframe, we have relied on the foundations of economics, our experience across global energy markets, input from the appointed New Zealand Expert for the Review, Concept Consulting, and conversations with sector participants. Between the draft report and this final report, we have also taken into account feedback from the Peer Reviewers, namely James Bushnell and team and NERA Consulting, as well as feedback provided to us from the Ministers.

By adopting an economic framework we are able to consider how participants are likely to react to market circumstances and the financial risks they face. That is, what incentives do participants face, how do they impact on their actual behaviour, and then given that behaviour, how do

competitors and consumers react to that. This framework is a key focus of applied game theory, where profit maximising participants seek to adopt strategies that are most likely to achieve their objectives, while reacting to other participants attempting to achieve their own profit maximising objectives.

In line with our terms of reference, we have considered the work of the Market Development Advisory Group, the Energy Competition Task Force, and other reviews conducted by the Electricity Authority. In this report, we discuss specific work or recommendations only where we have a relevant comment or recommendation to make.

Our ability to understand the issues and identify areas for recommendations was greatly enhanced by early workshops with Concept Consulting and discussions with market participants and stakeholders in New Zealand. We believe these interactions revealed a shared understanding of the main challenges facing the industry, noting perspectives differed on their root causes and the best solutions. In this respect, we came away from our discussions impressed with the sophistication of market participants and interested stakeholders in New Zealand. We would like to thank those stakeholders who were willing to meet with us.

We appreciated also input from the key market institutions in New Zealand, the Electricity Authority and the Commerce Commission. We held multiple meetings with these stakeholders in order to improve our understanding of the key issues. The Electricity Authority, in particular, also provided us with key data that was necessary for us to undertake this review and has been very responsive to requests for further information or explanation.

Finally, we have received invaluable support of staff at the Ministry of Business, Innovation & Employment (MBIE). Their professionalism and assistance — organising industry consultations, providing data and reports, and alerting us to key new market developments — have been invaluable.

Structure for the remainder of this report

After providing some contextual information that is relevant to how we have conducted this review, the remainder of this report steps through our findings in more detail. We address the questions above in terms of the main topics that arise from those questions, rather than the questions themselves. On that basis, the remainder of this report is structured as follows:

- Chapter 3 considers investment in new generation capacity, and particularly whether business ownership, market structure, or the design of markets affect the incentives or opportunities for investment.
- Chapter 4 focuses specifically on the question of investment to address dry year risk.
- Chapter 5 considers the impact of market design and market rules on competition.
- Chapter 6 addresses whether market participants have access to sufficient risk management products to effectively manage risk.
- Chapter 7 is focused on whether there is sufficient information and transparency about the gas market to support efficient decisions about its use and associated investment.
- Chapter 8 consider whether ownership, structure or design of markets are affecting the incentives for efficient investment in distribution networks.
- Chapter 9 considers whether the roles and obligations for the transmission network owner and system operating are delivering efficient outcomes.
- Chapter 10 discusses whether the regulators have the right roles and responsibilities to promote security of supply and affordable prices.

- Chapter 11 focused on market monitoring, particularly with respect to identifying the potential use of market power.

2 Context for the review

2.1 Introduction

In this chapter we briefly discuss some important context for our review, highlighting why security of supply and electricity affordability are so crucial to the New Zealand economy. We also identify that there has been substantial work already undertaken, and ongoing, in New Zealand that is focused on delivering better outcomes for consumers from the electricity sector.

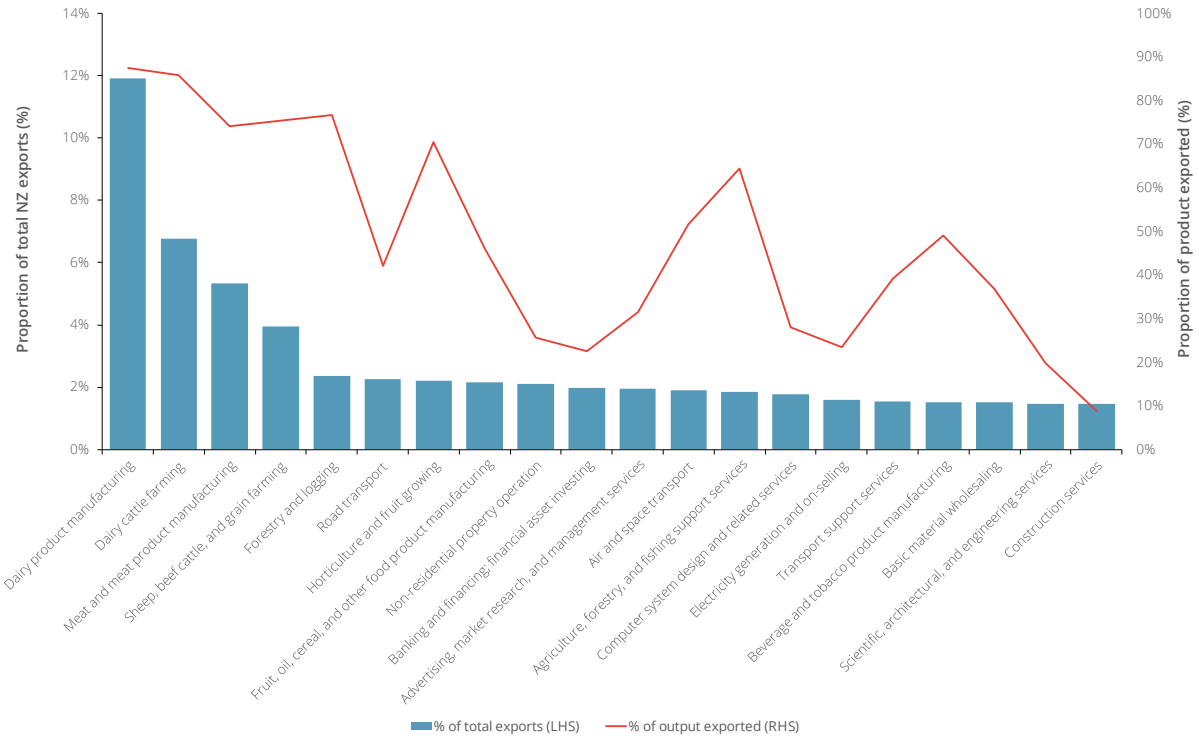
2.2 The importance of an efficient electricity system for New Zealand

2.2.1 An electricity reliant export economy

Like all modern economies, electricity costs and reliability in New Zealand have a crucial role in the success of the economy and so the well-being of people that live in New Zealand. However, the cost efficiency and reliability of the electricity market and system are particularly important in New Zealand. This is because New Zealand's economy is heavily dependent on export industries that are highly energy intensive. The result being that the New Zealand economy is vulnerable to higher and more volatile energy costs.

Analysis from New Zealand's Treasury National Accounts Input Output Table, shown below, highlight that agricultural sectors constitute a significant share of total exports. The chart also shows the proportion of each industry's products that are exported, demonstrating the economy's reliance on exports over domestic consumption.

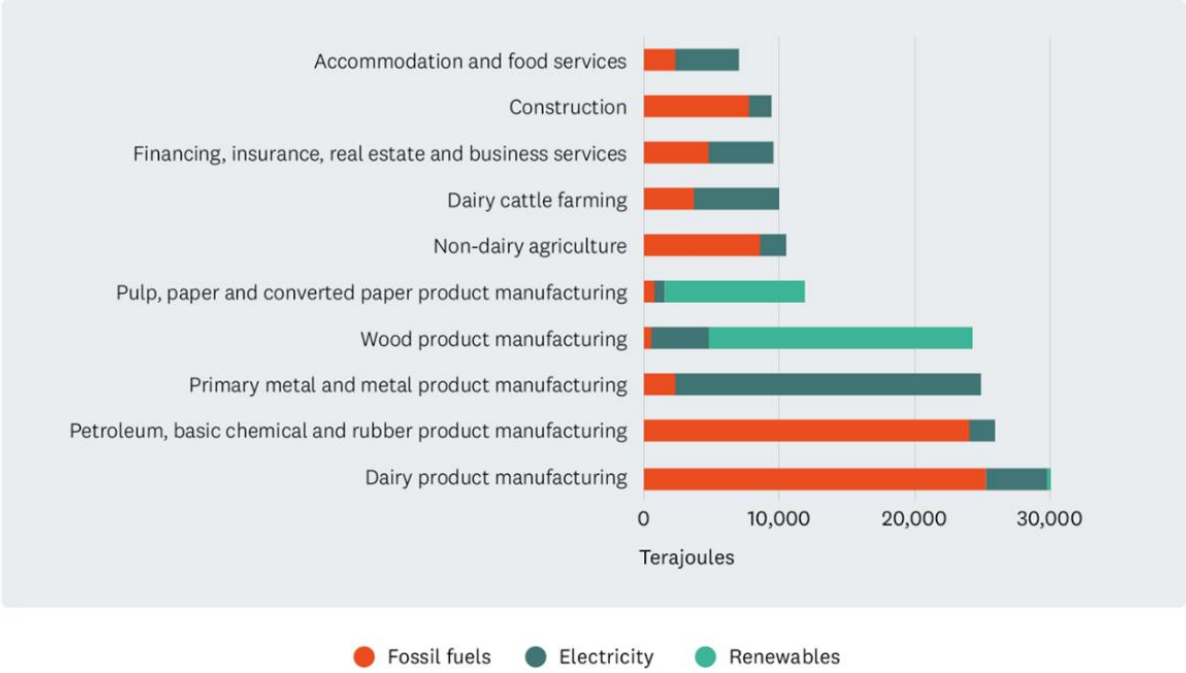
Figure 3: Proportion of total NZ exports (LHS) and proportion of output exported (RHS) - top 20 export industries (year ended March 2020



Source: New Zealand Treasury National Accounts Inputs Outputs Table – March 2020

The figure below demonstrates that these key export industries are also highly energy intensive industries, with the different colours indicating their fuel source. Given the New Zealand economy's reliance on energy intensive sectors, energy costs are clearly an important consideration for its long term sustainability.

Figure 4: Energy end use by top New Zealand Sectors



Source: Energy Efficiency and Energy Conservation Authority.

2.2.2 Transition away from fossil fuels

New Zealand has a domestic target of net-zero emissions (excluding biogenic methane) by 2050. This target is written into law under the Climate Change Response Act (CCRA). The principal tool to help achieve this is New Zealand's Emissions Trading Scheme (ETS).

Investment in renewable generation is projected to increase New Zealand's percentage of renewable generation from approximately 84 per cent today (corrected for mean hydrology conditions) to approximately 94 per cent by the end of the decade. The previous Government had an objective of ultimately achieving a 100 per cent renewable system by 2030. However, we understand that various projections of outcomes by the 2040s suggest that around 98 per cent renewables is realistically achievable.

In addition to transforming the electricity sector, the ETS is aiming to drive a transition of the broader economy away from fossil fuels. This includes for heat production and transport. This requires electricity to replace the energy previously provided by those fossil fuels. There are projections that demand will grow by more than 50 per cent to achieve this change.

2.3 Government policy statement on electricity

A Statement of Government Policy to the Electricity Authority under Section 17 of the Electricity Industry Act 2010 was published on 11 October 2024.[4] Section 17 of the Act requires that the Authority must have regard to any statements of government policy concerning the electricity industry that are issued by the Minister.

The Policy Statement identifies that the Government wants an efficient electricity system recognising this is vital to a competitive and growing economy, as well as environmental

[4] Statement of Government Policy to the Electricity Authority Under Section 17 of the Electricity Industry Act 2010: New Zealand Electricity Industry - 2024-go5150- New Zealand Gazette

sustainability and social well-being. It expects that reliable electricity is delivered at its lowest possible cost to consumers to ensure security of supply and avoid excessive prices. It states that this is 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
- Efficient transmission and distribution networks, and
- Effectively competitive markets for electricity retail services.

The Statement then refers to several specific aspects of the market, stating:

- **Wholesale electricity market** – the wholesale electricity market must be updated, which means implementing the integrated package of measures set out in chapter 9 of the MDAG 'Price discovery in a renewables-based electricity system' report.
- **Transmission and distribution networks** – economically efficient investment is critical, while ensuring network reliability. To achieve this, efficient network pricing is essential, with the Electricity Authority responsible for setting principles for pricing structures and the Commerce Commission responsible for setting price and quality controls for Transpower and non-consumer-owned distributors.
- **Reliability and security of supply** – reliability requires enough investment. This, in turn, requires clarity of incentives and accurate wholesale price signals, and appropriate risk management. Further, the Government nor the Authority will step in to insulate participants from risk or the failure to manage risk. The Electricity Authority and System Operator have important roles in providing information, and signals for the efficient coordination and utilisation of electricity assets, albeit under a decentralised approach.
- **Spot prices** – it is important for spot prices to signal scarcity in order to avoid supressing incentives for investment, noting that stakeholders must be educated on the role of scarcity pricing to achieve this objective.
- **Demand-side flexibility** – efficient demand-side flexibility will deliver benefits for consumers and the system as a whole.
- **Competition** – effective competition is essential for delivering electricity at its lowest possible cost to consumers, such that the Electricity Authority should ensure that market arrangements facilitate competition, including in relation to flexible supply.

It identifies that the Electricity Authority should be aware of related policy elements, which include:

- The Government aims to streamline resource consenting for energy infrastructure.
- Fuel sector arrangements impact generation costs and reliability, with policy frameworks recognising their role.
- Carbon pricing rules drive decarbonisation, and thermal generation will be used if it remains cost-competitive.
- The Authority should not favour one supply type over another.
- The Government is reviewing thresholds for distribution businesses investing in generation.
- The Government is progressing the Customer and Product Data Bill to enhance market competition and consumer data access, aligning with the Authority's data initiatives.

2.4 Current reviews and work programs in New Zealand

2.4.1 MDAG review on pricing in a renewables-based electricity system

The Market Development Advisory Group (MDAG), established by the Electricity Authority in October 2017, proposed to the Authority in June 2021 that it undertake a project to understand how price discovery would work in the New Zealand wholesale electricity market under a 100 per cent renewable electricity system. The objective being to identify changes needed to ensure efficient price signals and to meet 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.[5] MDAG published its final recommendations paper, titled: "Price discovery in a renewables-based electricity system".[6]

The Final Recommendations paper set out a package of 31 measures for implementation over a four-year period. MDAG emphasised that it is not its intention that someone could pick and choose the measures they wanted to implement. Instead, its recommendations were an integrated package to be implemented as a sustained and coordinated program of action over the four-year period. It set out three tranches for this program of action arranged in order of urgency, with some measures in later tranches contingent on the effectiveness of prior actions.

MDAG categorised its measures under four topics, namely:

- Accurate price signals – spot and contract markets
- Tools to manage risks
- Ensuring adequate competition, and
- Public understanding and confidence.

2.4.2 Energy Competition Task Force

The Energy Competition Task Force was jointly established between the Electricity Authority and the Commerce Commission.[7] It has tasked itself with investigating ways to improve the performance of the electricity market in direct response to the fuel shortage and period of sustained high prices in August 2024. Its recommendations will go to the Authority's board for final decisions with any options that change market settings or regulations to follow the normal consultation process.

The work program for the Task Force is focused on two outcomes:

- Enabling generators and independent retailers to enter, and better compete in the market, and
- Providing more options for consumers.

In addition to developing its own initiatives, the Task Force is also progressing certain measures that were set out in the MDAG report. While it expects its work program to evolve as evidence emerges on the potential impact of different options, it identified eight initial options to pursue in two packages. Package one is focused on measures to assist new generators and independent retailers to enter and better compete in the market. Package two is focused on providing more options for consumers.

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5 MDAG, 'Price Discovery Under 100% Renewable Electricity Supply, Issues Discussion Paper, 2 February 2022, p.2.

6 MDAG, 'Price discovery in a renewables-based electricity system FINAL RECOMMENDATIONS PAPER, 11 December 2023.

7 https://www.ea.govt.nz/projects/all/energy-competition-task-force/

The package one initiatives are:

- Consider requiring gentailers to offer firming for Power Purchase Agreements
- Introduce standardised flexibility products
- Prepare for virtual disaggregation of the flexible generation base, and
- Investigate level playing field measures such as non-discrimination rules as a regulatory backstop

The package two initiatives are:

- Requiring distributors to pay a rebate when consumers supply electricity at peak times
- Requiring more retailers to offer time-of-use pricing
- Requiring large retailers to better reward consumers for supplying power, and
- Reward industrial consumers for providing short-term demand flexibility.

Several of these initiatives have progressed with firm recommendations. While the measure to introduce standardised flexibility products has already been implemented through the creation of a super peak product focused on high prices in morning and evening peaks.

2.4.3 Other reviews

We are aware that there are many reviews ongoing in New Zealand at the moment that relate to the operation of the electricity market. Many of these are focused on implementing the MDAG report recommendations. Much of this work is being done either by the Energy Competition Task Force or the Electricity Authority. We are aware also of work being undertaken by Transpower in its role as the system operator (for example, its work on renewable energy zones). In addition, market participants have been providing material to the market setting out their views of the pressing issues in the market with proposed solutions to those.

In the time we have had to undertake this review we have sought to have regard to as much of this material as we can. While we may not refer to this material directly in our report, this is not to mean we have not had regard to it or that it has not influenced our thinking.

3 Investment in new capacity

3.1 Introduction and summary of findings

This chapter considers whether business ownership, market structure, or the design of markets affect the incentives or opportunities to invest in generation or storage, i.e., new power supply.

Our main finding is that there are no major obstacles to investment in new renewable power assets, although there is a problem with investment in flexible capacity to support dry year risk. While uncertainty around demand, supply and policy has influenced investment in recent years, a strong pipeline of new generation and battery projects, driven by both gentailers and independent providers, is now underway. As a result, we see no need for fundamental market design changes. Specifically, we recommend the retention of the gross pool energy-only market and do not propose changes to the market structure.

Nevertheless, there are several factors that are constraining the efficiency of investment in new generation and battery projects, namely:

- The Government's ownership in three of the main gentailers limits the funding options available to these businesses. This constrains their ability to invest in larger generation projects. It may also influence the investment decisions of those entities that are fully privately owned.
- The information that is provided to developers about prospective investment opportunities could be improved to reduce search costs and improve the efficiency of new entry, and
- The approach to assessing whether there is sufficient capacity, or energy, to meet expected demand is not sufficiently dynamic to accommodate changes to the market over time. Therefore, it increases the risk of the measure under or over-stating the amount of capacity required for the market.

We have also found that the ETS is substantially driving up electricity prices without delivering a corresponding change in investment or operating behaviour and therefore little to no environmental benefit. It therefore acts as a tax on electricity consumer that reduces New Zealand's international competitiveness. We recommend the ETS be removed from the electricity market. An alternative would be to recycle Government revenues collected from the electricity sector back to consumers. However, customers would still remain significantly worse off even if this occurred given the impact the ETS has on wholesale electricity costs.

Recognising that we consider investment to address the risk of dry winters is a material issue in New Zealand, we address that topic separately in its own chapter below. This chapter is focused solely on investment in power supply other than for dry year risk.

3.2 What is the desirable market outcome?

3.2.1 Energy-only market

The New Zealand wholesale electricity market operates as a gross-pool energy-only market. In this market design all electricity is sold through a centralised pool and power supply assets are only paid for the energy they supply to the pool. This differs from capacity markets, where power supply assets can also earn revenue independently to the energy they produce by making their capacity available to the market.

In an energy-only market, the market clearing price is set by the most expensive bid required to meet demand, this is called the marginal unit of supply. This means generators earn the market

price minus their cost to generate the final unit of output.[8] Where there is a difference between the market price and their own generating cost, it permits power suppliers to contribute revenue to the recovery of the costs of investment in the plant.

As with any market, a generator or storage unit will only be willing to remain in the market where it expects it will be able to recover its fixed and variable costs. In an energy-only market fixed cost recovery can occur where the difference between the market price and its own cost to generate is large enough to compensate for its fixed costs over time.

3.2.2 Market entry and exit decisions

The pricing mechanism of the energy-only market is intended to provide signals that guide decisions on the entry of new types of supply capacity as well as the exit of older supply capacity. In terms of new entry, it will influence the timing of entry, their location, the size of capacity built, and the type of technology used to supply capacity. Price signals do this by harnessing the profit motive and financial incentives of the private sector. These financial incentives are generally considered more likely to produce economically efficient outcomes than central planning solutions. Not least, this is because profit motives mean firms are more likely to search for the least cost way of meeting the needs of the market.

For investment in new capacity to occur in an energy-only market it requires prices that reflect the scarcity of supply in the market. There is scarcity in the market when supply and demand conditions are tight. Further, these scarcity prices need to be sufficiently high and sustained so that if there is an investment response and new capacity enters the market the post-entry prices remain at a level that is sufficient to maintain the expectation of earning a normal return on investment – that is, pre-entry prices are expected to be higher than the long run marginal cost (LRMC) of new capacity for long and high enough that the risk adjusted costs and returns from entry are recovered over time. New supply will likely cause prices to fall to some extent. If post-entry prices are expected to fall below the level of new entrant costs, entry will not occur or it will be delayed.

The need for post-entry prices to be high enough to sustain entry will influence the size of new (and type) of capacity that is introduced to the market. A new very large increment of capacity might be expected to see a large fall in prices given it can substantially reduce the extent of scarcity in the market by creating a larger gap between demand and supply. Conversely, a smaller increment of new capacity may see prices fall relatively less, and so lead to post entry prices that remain at a level sufficient to sustain that new investment. Therefore, all things equal, the price signal should also lead to the right sizing of new investment.

The importance of scarcity price signals is evident in the scarcity pricing mechanism that applies in New Zealand. In circumstances where demand exceeds supply it is necessary to curtail some demand in order to prevent the system from collapsing. However, a reduction in demand in this instance reduces scarcity in the market with the result being a corresponding reduction in prices. So that price signals to generators are not diluted in a situation of actual scarcity, scarcity pricing aims to hold the spot price higher for a period of time. The scarcity price is set to reflect the value of lost load, which is the value customers place on continued electricity consumption.[9] The current settings for scarcity pricing are as follows:

- $21,000/MWh for the first 5 per cent of demand

[8] This is referred to as the short-run marginal cost (SRMC) of generation. The SRMC is the extra cost of producing one more unit of a good or service in the short-term, and so excludes any costs associated with expansion of capacity. Given it relates only to the final unit required to meet demand, it is different to concepts such as average cost.

[9] The value of lost load is typically determined via willingness to pay surveys of customers.

- $31,000/MWh for the next 15 per cent of demand, and
- $50,000/MWh for the remaining 80 per cent of demand.

Entry of new and more efficient technologies can also drive a fundamental change in the price in energy-only markets, and the extent to which prices permit the recovery of investment costs. For instance, wind and solar have very low operating costs, which can drive low spot prices when they operate. This can particularly impact on older thermal plant if their operation is being displaced by new plant. When owners of older plants have to make decisions about whether to make a forthcoming refurbishment or retirement of their plant, they will need to identify if expected prices will permit those refurbishment costs to be recovered in addition to the operating costs. Where this is not the case, the plant may choose to exit the market.

To provide increased certainty that the generator can achieve the revenue required to make the investment economic, developers will typically attempt to agree a price for electricity with buyers in advance – that is, backing the investment with customer load. This might be done contractually with an industrial participant or independent retailer, or through the investors own retail customer load – i.e., vertical integration. Such an arrangement also benefits the retailer, or industrial customer, given it provides certainty over the price of electricity. However, it is usually not possible to secure sales pre-commitments for the economic life of the plant or even for all of the plant's capacity over its early years. In these cases the developer has to bear the so-called merchant risk, or revenue uncertainty, over the economic life of the investment. If this risk is too high then investors will delay their entry decision so that the post entry price is high enough to account for this merchant risk and/or they will configure the plant size to minimise the risks of not being able to pay the debt on the investment and/or recover their equity and earn a commercial return.

It is important to note also that factors outside of the wholesale electricity market will influence investment decisions. These factors include:

- Access to fuel, or for renewable generators, access to land with suitable weather conditions
- Network access and the time taken to achieve that access
- Social licence, noting the impact that new large power supply assets, and the networks required to connect them, will have on local communities and therefore community acceptance or resistance to the investment
- Regulations, including environmental and local planning
- Government policy, or expected government policy, and
- The perspectives of shareholders, including with respect to factors such as environmental, social and governance (ESG).

3.3 Current market

3.3.1 Perceptions of a market failure

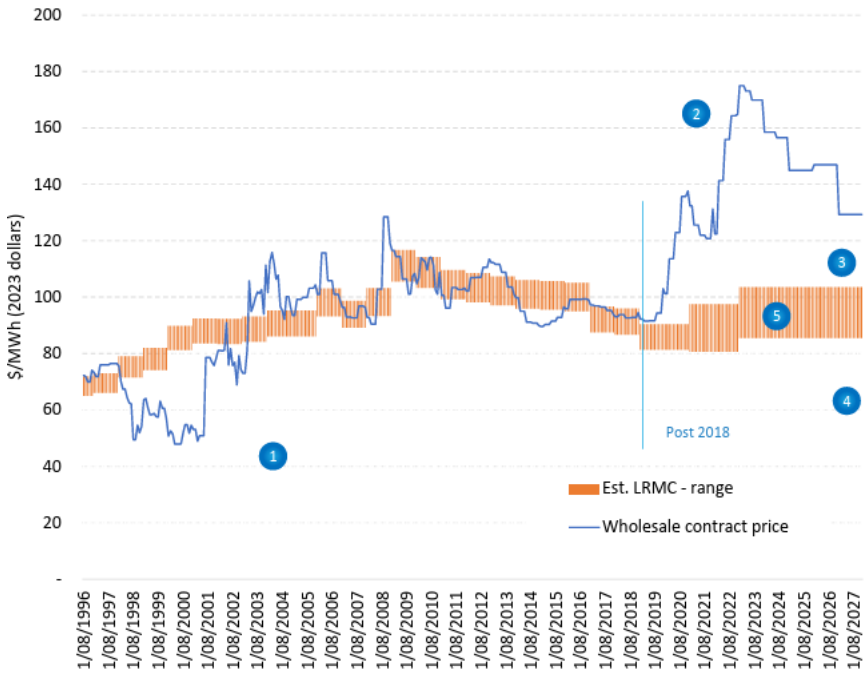
A chart that has been referred to by stakeholders several times as evidence of a fundamental problem with the New Zealand electricity market is one that shows the difference between forward contract prices and an estimate of the cost of investment in generation, referred to as the long-run marginal cost (Figure 5).[10]

[10] In this case, the cost of generation is the cost of a new geothermal project as this can provide reliable baseload energy.

The concern being the apparent gap between the pre-entry price for electricity being enduringly higher than the cost of generation entry. To some this gap suggest that there should be substantial new investment, and the concern that has been raised with us as part of our engagement with market participants and other stakeholders, is that the absence of investment indicates a failure of the market design and/or there is exercise of market power by incumbents by starving the market of new capacity so they can earn higher profits.

Figure 5 shows that the cost of new generation entry disconnected with forward contract prices around 2018. As of the time this chart was published, which was in 2023, the gap was starting to moderate, noting it was still above the estimated range of new baseload capacity.

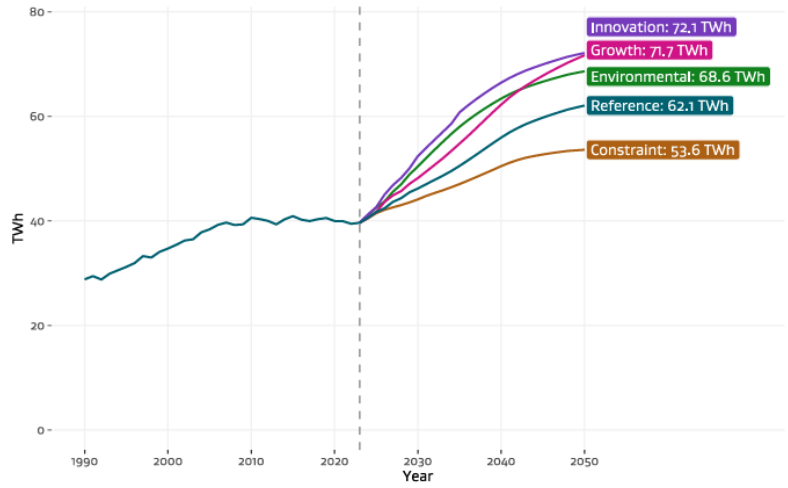
Figure 5: Contract prices and estimated costs for new baseload supply



Source: https://www.ea.govt.nz/documents/4414/Generation_Investment_Survey_-_2023_update.pdf p.6

The contention of some problem in the market is further argued based on projections of demand, which suggest there is a high level of future demand in New Zealand and that developers should be building capacity to meet this projected demand.

Figure 6: Total electricity demand

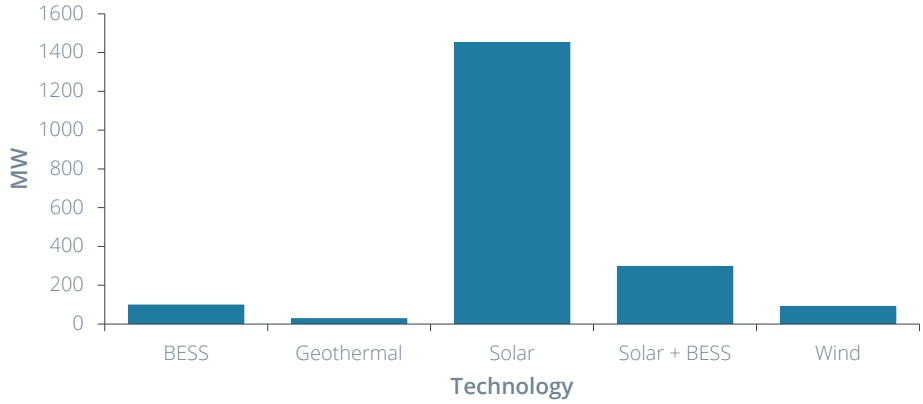


Source: EDGS 2024 Report, p.1

3.3.2 Strong pipeline of new investment

While it is true that forward contract prices have been above generation entry costs, there is, nevertheless, currently a strong pipeline of new investment that is being connected to the system. As shown in Figure 7, there is currently over 1,900 MW of capacity that is in delivery phase now in New Zealand. This capacity is primarily coming from grid scale solar projects.

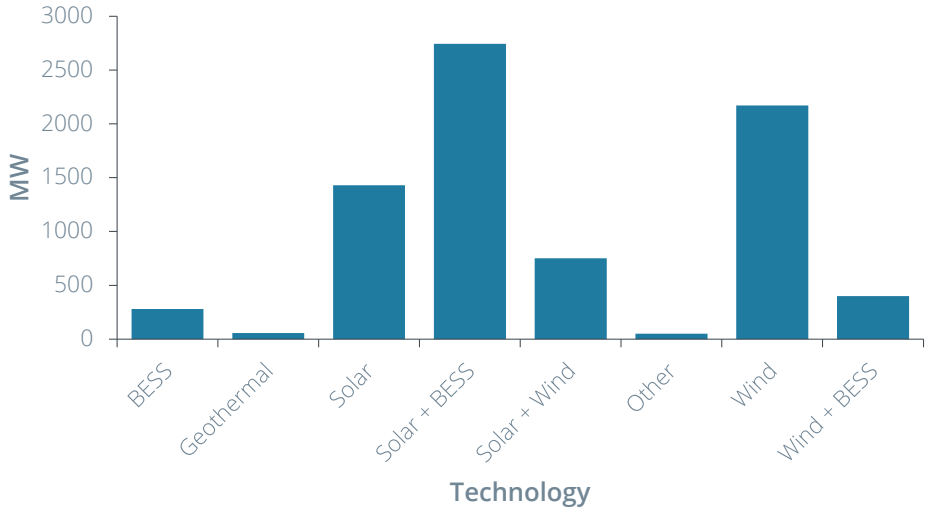
Figure 7: Sum of projects in delivery phase by technology



Source: Transpower New Generation Pipeline

There is also an extensive number of projects with a confirmed application for connection to the transmission network. While not all of these projects will make it through to completion, there is currently over 7,800 MW of capacity seeking to connect to the network. This is shown in Figure 8 below. In addition to this number, there is also another 5,000 MW of capacity that is under investigation for connection to the transmission network.

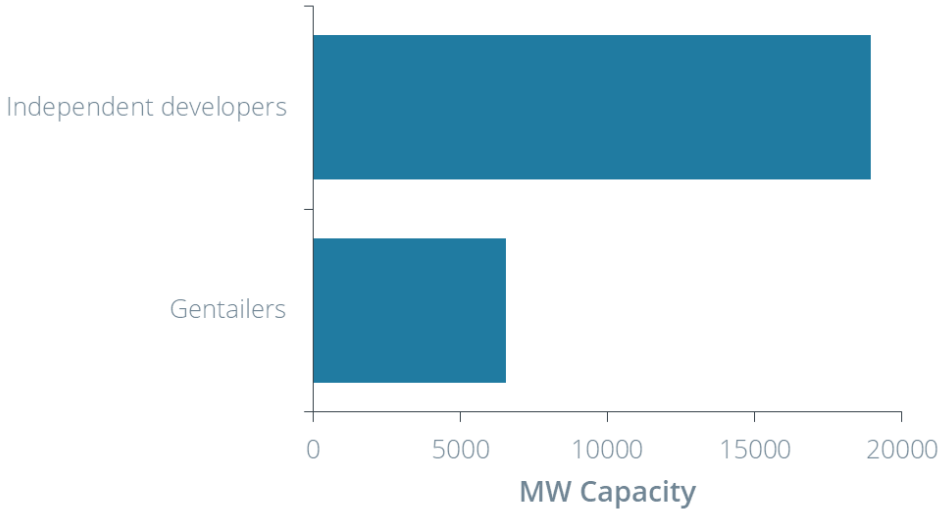
Figure 8: Sum of projects by technology with confirmed applications



Source: Transpower New Generation Pipeline

As shown in Figure 9 below, of the new capacity that is being added to the market, the majority of this is being added by independent developers.

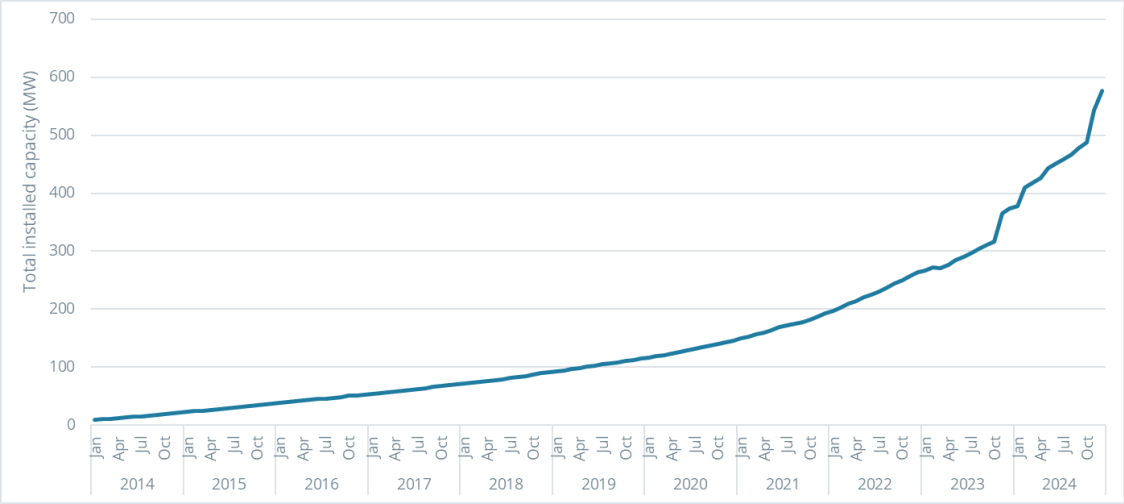
Figure 9: Proposed new capacity pipeline by developer type



Source: https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/GenerationFleet/Proposed

While its scale is still small, in addition to grid scale projects there is also increasing penetration of distributed generation in New Zealand, particularly in the form of roof-top solar. This growth in distribution connected solar capacity is shown in Figure 10 below.

Figure 10: Total installed distributed solar capacity



Source: Electricity Authority - EMI (market statistics and tools)

3.3.3 Role for demand management

Demand management can be substitute for new generation investment. That is, rather than supplying more energy, reducing demand takes pressure off the system so that less generation is required. It is important to recognise, however, that demand management is not a free option for an electricity market.

The prices under the scarcity pricing mechanism referred to above are based on the expected cost to customers from power cuts, or how much they are willing to pay to avoid those power cuts. While these prices would reflect the cost of an unanticipated power cut, prices of $21,000-$50,000/MWh are significantly higher than the cost of the generation required to avoid an outage. For this reason, it makes economic sense that the priority should be on ensuring sufficient generation capacity is available to meet demand, rather than relying on the curtailment of demand at times of scarcity. Indeed, having a reasonable assurance that supply will not be interrupted is crucial to modern industry and so the economy.

Despite the high value customers place on avoiding power cuts, the value to some customers of reducing demand can be much lower where they are given sufficient notice of the demand reduction requirement, or where it is undertaken in a controlled and pre-planned manner. In this instance, some customers – such as large industrial customers – will be willing to substantially reduce their demand for a fee. This fee may be a direct payment, or it could be a reduced price for their electricity to reflect that their supply is interruptible, noting also that the customer will benefit also through an avoided energy charge. The supply-side, such as retailers or generators, would be willing to pay for this demand management as a hedge against high spot prices.

Demand response played a key role during the dry winter in 2024. Specifically, an agreement between Meridian Energy, Contact Energy and the Tiwai Point smelter for large scale demand response. In June 2024 Meridian Energy called upon Tiwai Point to reduce demand so that it could conserve its water resources. According to the Electricity Authority, demand response from Tiwai Point saved around 330GWh of electricity over winter in 2024.[11]

[11] See: https://www.ea.govt.nz/news/eye-on-electricity/the-tiwai-point-smelter-demand-response-in-winter-2024/

In New Zealand, the demand-side can also participate directly in the wholesale market. There are three ways in which loads can participate in the wholesale market, namely:[12]

- **Dispatchable demand** – where loads compete with generators in the spot market such that large customers will reduce their demand based on their spot market bids. This form of demand-side participation requires that the loads are able to modify their consumption at short notice at the direction of the system operator.
- **Dispatch notification** – dispatch notified load is similar to dispatchable demand but requires a lower level of compliance. For this reason it is better suited to small-scale loads such as EV chargers, and solar and battery installations.
- **Difference bids** – this mechanism permits consumers to signal their price sensitivity in the forecast schedules. That is the prices at which they will reduce load when prices rise or increase load at lower prices.

3.3.4 Role of Government ownership in investment decisions

Three of the gentailers in New Zealand, Genesis, Meridian and Mercury, are owned under a mixed ownership model. This means they are publicly listed companies with the Crown owning at least 51 per cent of the company. The Public Finance Act requires that the Crown retains the 51 per cent shareholding and that no other party may own more than 10 per cent of shares.

We understand the Government's involvement in the day-to-day operations of the companies is relatively hands-off. Nevertheless, relevant Ministers must be consulted on transactions. When above a certain threshold, such as a major transaction under the Companies Act 1993 or in accordance with NZX listing rules, approval of the transaction requires the board to prepare a business case for Treasury analysis.

In terms of funding, Ministers may be asked to approve some financial operations such as investing and borrowing. Ministers also have the ability to approve the lending of money to entities or provide them with new equity. We understand new equity is only typically provided when companies are experiencing financial difficulty and cannot borrow from the private sector.

3.3.5 Emissions Trading Scheme

New Zealand has an Emissions Trading Scheme that has the objective of helping to reduce emissions. It was established in 2008 under the Climate Change Response Act 2002. It aims to reduce emissions through:

- Requiring businesses to measure and report on their greenhouse gas emissions
- Requiring businesses to surrender one 'emissions unit' (an NZU) to the Government for each one tonne of emissions they emit, and
- Limiting the number of NZUs available to emitters.[13]

The Government sets and reduces the number of units supplied into the scheme over time in order to limit the quantity that emitters can emit.

Participating businesses are able to trade carbon credits with the price then reflecting supply and demand in the scheme. The intention being that the price signal that results from trading will signal businesses to make efficient choices about their emissions, recognising that the amount of NZUs available is linked to New Zealand's emissions reductions targets.

[12] Transpower, 'GL-EA-1052 Guideline for Connection DD & DNL into the Electricity Market', 9 August 2023.

[13] https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/ets/about-nz-ets/

For trade-exposed sectors free allocation is granted based on output and intensity-based benchmarks. Eligibility follows a tiered approach:

- High emissions activities receive 90 per cent free allocation, and
- Moderately emissions-intensive activities receive 60 per cent free allocation.

The electricity sector is not considered trade-exposed and so is not eligible for free allocation. The Electricity Authority is required, however, to notify the Minister for Climate Change of the Electricity Allocation Factor (EAF) by July each year. The EAF is an estimate of the effect of the ETS on wholesale electricity prices and so is the uplift in electricity prices due to the requirement to place a price on carbon during the electricity production process.[14] For the 2023/24 financial year, the Authority determined the ETS impact on the price of electricity is 0.587tCO2e/MWh (tonnes of CO2 equivalent per megawatt-hour of electrical energy).[15]

3.4 Our assessment of the current arrangements

We acknowledge the argument that a gap between forward contract prices and the cost of new entry signals market failure. The logic is that if prices are high enough to support new investment, but investment is not happening, the market must be failing. However, we disagree. The pipeline of new investment suggests that New Zealand has relatively low barriers to entry, and the energy-only market has successfully driven renewable investment. Indeed, this pipeline of investment, once it is commissioned, can be expected to ease forward contract prices to some extent. The real issue is uncertainty, particularly due to policies of the former Government, which made new investment over the past four to five years highly risky. To the extent a gap remains between forward contract prices and the cost of new entry, this is likely due to lags of new capacity coming online and also due to forward prices reflecting the cost of managing dry year risks.

In terms of investment that is not related to addressing dry year risks, we consider that:

- There are compelling reasons for the absence of investment in recent years
- There is now a strong pipeline of renewable and battery storage investments from both the gentailers and independent developers, and
- The persistence of the gap between forward contract prices and the cost of new entry can be explained by other factors.

However:

- Government ownership in three of the gentailers may be distorting investment outcomes
- The ETS is adding costs to the market but not influencing investment or operational decisions to improve environmental outcomes, and
- Further, the efficiency of new generation investment could be enhanced through better forecasting and transparency of system needs.

We consider these issues in the remainder of this section.

[14] Electricity Authority, 'Determination of the 2024 Electricity Allocation Factor, p.3.

[15] Electricity Authority, 'Determination of the 2024 Electricity Allocation Factor, p.3.

3.4.1 Reason for the absence of investment in recent years

It is not surprising to us that there has not been significant investment in new power supply in recent years. Conversely, it would have been surprising for substantial new investment to occur in New Zealand given the circumstances presented to investors. These circumstances include:

- Demand uncertainty
- Supply uncertainty
- Policy uncertainty, and
- Fuel supply risk.

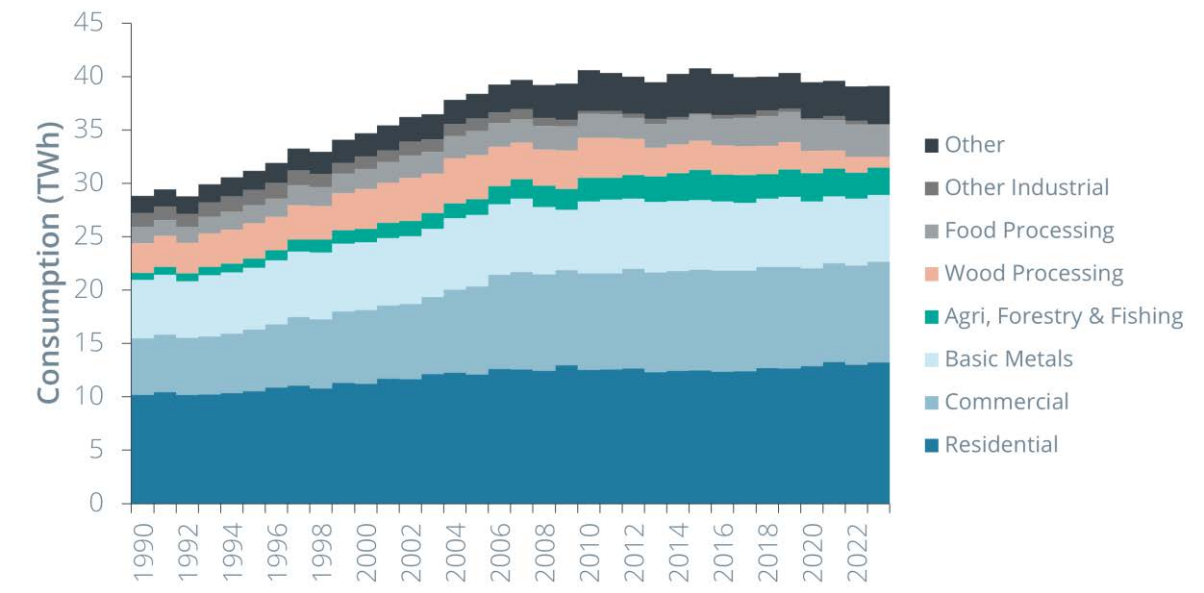
The presence of these factors is the major cause of the gap between forward contract prices and the cost of generation entry since 2018. That is, the risk caused by these factors meant that investment would not occur, even though there was sufficient price signal for that investment. For the most significant factors, demand and supply uncertainty, these were time-limited events and so are no longer having a material impact on investment decisions, at least with respect to renewable generation and batteries.

We discuss each of the specific factors here.

Demand uncertainty

Recent forecasts of demand have anticipated a large increase in electricity demand in the coming years.[16] This prediction is driven by the expected electrification of the economy to achieve climate change objectives. However, the opposite has occurred. In recent years demand has fallen as industry has exited the New Zealand market.

Figure 11: Annual electricity consumption by sector



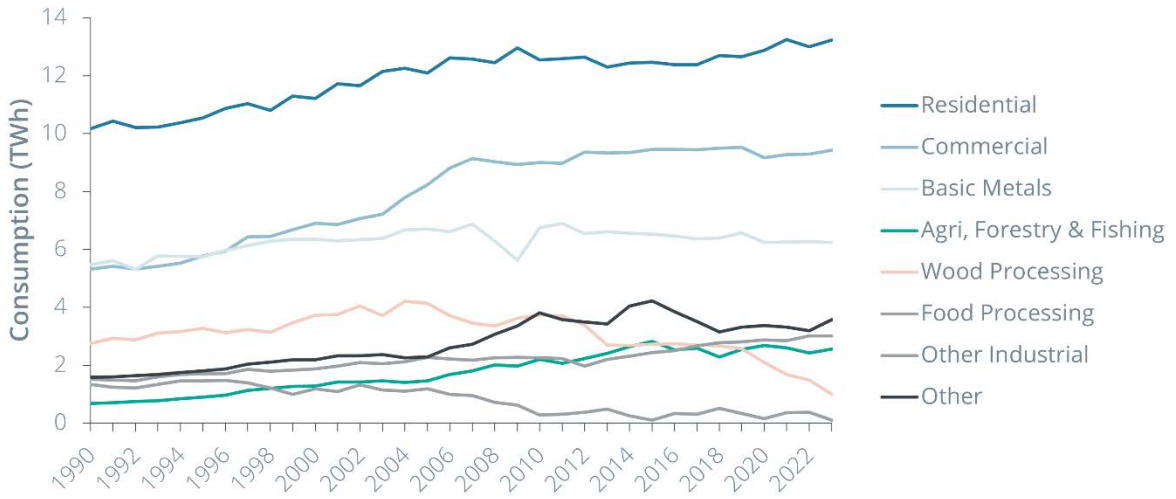
Source: MBIE Data, Frontier Economics analysis.

Overall electricity demand has been relatively flat since 2007. Consumption patterns across sectors have shifted significantly in the past three decades. Residential demand has grown steadily and now exceeds industrial use. Commercial consumption has remained relatively flat

[16] See Figure 6.

since 2007. The wood processing sector has seen a sharp decline – down over 50 per cent since 2020 – driving much of the fall in total industrial electricity consumption.

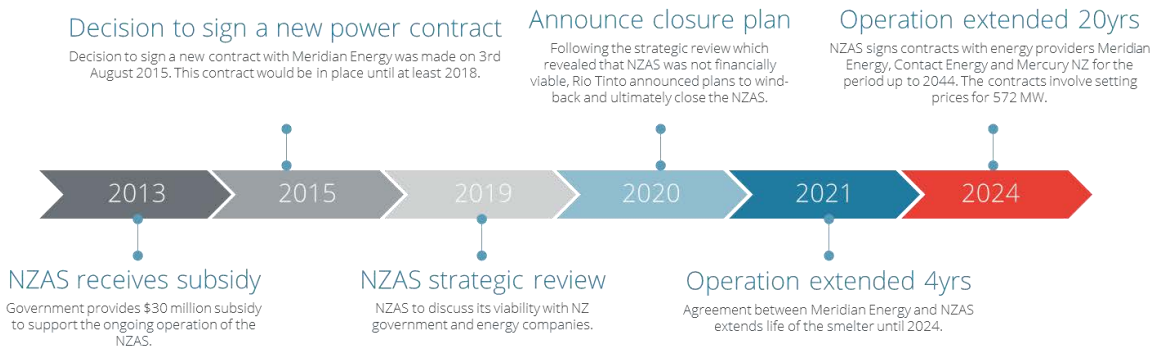
Figure 12: Sector-specific trends in annual electricity consumption



Source: MBIE Data, Frontier Economics analysis.

More telling has been the uncertainty over the future of the Tiwai Point Aluminium Smelter. As shown in Figure 13, the uncertainty around Tiwai Point has been a feature of the New Zealand market at least since 2018. The Tiwai Point Smelter is the largest consumer of electricity in New Zealand by a significant margin. In 2023 the Tiwai Point Smelter consumed the equivalent of 20 per cent of the North Island's electricity use[17] and the equivalent of over 30 per cent for the South Island.[18]

Figure 13: Timeline of Tiwai Point Smelter stay or go decision



If the Tiwai Point Smelter exited New Zealand it means that there would be substantial excess supply of electricity capacity in the country. The substantial excess of capacity would substantially reduce scarcity and cause a fall in spot prices. This fall could be sufficiently large that some supply capacity may choose to exit the market, or mothball plant, due to an inability for spot prices to support ongoing production. In an environment where prices could fall to

17 https://www.ea.govt.nz/news/eye-on-electricity/the-tiwai-point-smelter-demand-response-in-winter-2024/

18 https://www.emi.ea.govt.nz/MemberDashboards/Public/8b633342-ed77-458a-8597-9c4042881c84/2?_si=s|mdo,v|2

levels that would trigger market exit, it would not make sense for new investment in generation to occur, at least until there was some certainty about the future of the plant.

More generally, even with forecasts that predict large increases in demand, investment risks remain high without key market signals. Specifically, forecasts of demand won't drive a scarcity price signal, only actual demand increases will. Without this, new investment would likely be deemed too risky to proceed.

Supply uncertainty

Similar to the circumstances created by demand uncertainty, the potential development of a significant new supply of energy, the New Zealand Battery Project at Lake Onslow, would have raised concerns about the viability of other power supply investments.

The Lake Onslow project aimed to manage dry year risk through pump hydro storage, with the capacity to generate 5,000 to 8,000 GWh annually.[19] This is the equivalent to 20 per cent of New Zealand's total annual demand of 40,000 GWh. Such a large addition of storage would widen the gap between supply and demand, likely driving electricity prices down to below the level that would be needed to incentivise investment new supply capacity.

Ultimately, the Lake Onslow project, estimated to cost NZ$16 billion, was deemed too expensive and was cancelled in late 2023.[20] Noting that even at the time of cancellation that the considerable uncertainty about Tiwai Point Smelter remained present, such that the cancellation of this project alone would not have been sufficient to trigger a flurry of investment activity.

Policy uncertainty

The previous Government in New Zealand had an energy policy focused on decarbonisation but did not explain how this was to be achieved while maintaining security and electricity at reasonable prices. These policies included:

- an aim for 100 per cent renewable energy[21]
- the potential ban on new fossil fuel generators[22]
- a ban on off-shore gas exploration[23]
- a ban on using KiwiSaver funds for fossil fuel investments,[24] and
- the electrification of the broader economy, meaning that electricity demand would increase dramatically in a system that was already struggling to meet demand.

The current Government has reversed or is in the process of reversing some of these policies, including the deeply harmful ban on offshore gas exploration. However, if the Opposition was to again form government, it appears based on commentary while it is opposition, that it is likely

19 https://www.mbie.govt.nz/dmsdocument/28358-nz-battery-project-update-on-hydro-and-other-technologies-august-2021

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

21 https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/advancing-new-zealands-energy-transition-consultation-document/introduction

22 Regulatory Impact Statement: Banning new fossil-fuel baseload electricity generation

23 Planning for the future - no new offshore oil and gas exploration permits | Beehive.govt.nz

24 Default KiwiSaver changes support more responsible investment | Beehive.govt.nz

that the trend towards banning fossil fuels and offshore oil and gas exploration would recommence.[25]

Stakeholders we met with identified the policy uncertainty and sovereign risk this drives as a major factor negatively influencing investment in New Zealand. This is not only with respect to investment in supply capacity but also with respect to fossil fuel activities, such as drilling and exploration for gas. Even where developers prefer one Government's policy approach over another, where there are very large differences in policies between prospective governments investors will be concerned about the sovereign risks imposed on their investments. This is likely to particularly affect international investors who have a global market with which to invest their funds and so will prefer markets where policy outcomes are more stable. The result of these risks is a chilling of investment where developers perceive that the stroke of a pen could financially strand their investment.

Fuel supply risk

The ability to access a reliable supply of fuel over the life of plant is a factor that has influenced investment in fossil fuel generation. This is an issue that has affected primarily investments to address dry year risk. Therefore, we consider this issue further in the following chapter.

3.4.2 The pipeline of new investment indicates low barriers to entry

As identified above, there is about 2,000MW of supply capacity currently being connected to the Transpower network, 8,000MW of confirmed applications and over 5,000 MW of capacity under investigation. These investments have been proposed by both the gentailers as well as independent developers. The high levels of investment in the pipeline is evidence that there are no material barriers to entry, at least for renewable generation options.

Furthermore, the fact that a majority of the pipeline is made up of projects from independent developers suggests that barriers to entry are not too high.

3.4.3 Demand management has been used successfully

Given the substantial amount that customers are willing to pay to avoid supply interruptions, demand management should be used only where customers perceive the value of curtailment to be more than the value from using electricity. This is particularly important for New Zealand industry. To encourage industrial customers to enter and remain in New Zealand it is necessary that they have confidence that electricity supply will be reliable and secure, noting outages impose real costs. This is particularly true for data centres that require a highly reliable and secure supply of energy.

It is clear, however, that the electricity industry has been able to procure demand response from customers who are willing to reduce demand for payment. The primary example being Tiwai Point smelter. We note that while loads are able to participate in the wholesale market, and it is appropriate that this form of participation is available, the most likely form of large scale demand response will be from retailers paying for large industrials to reduce demand as a hedging mechanism. We expect also that in the future retailers will look to use their small customer load more efficiently too, particularly where customers install solar and battery devices. This can be achieved through IT systems that use customer resources to develop a virtual power plant (VPP). It is our view that one of the key barriers to VPPs in New Zealand is the high number of distribution businesses in New Zealand that makes it more challenging for the

[25] https://www.labour.org.nz/release_oil_and_gas_must_stay_in_the_ground and https://www.labour.org.nz/national_s_climate_strategy_undoes_good_progress

roll-out of enabling technology and for retail businesses or aggregators to develop scale across distribution regions. We discuss this issue further in Chapter 8.

3.4.4 Gap between forward prices and the costs of new capacity

It is our view that the gap between forward contract prices and the costs of new capacity was initially being driven by the material disincentive to invest in capacity given uncertainty of Tiwai and the Big Battery project. While price signals suggest that investment would have been profitable, the uncertainty of these events kept a lot of investment out of the market, which further inflated prices. If developers are unwilling to invest in the market due to non-market factors, it means that prices will remain above the cost of new entry.

More recently, with a pipeline of new investment emerging, to the extent a gap remains between prices and the cost of entry, this is likely to be driven by two things:

- First, it takes time for the pipeline of projects to be completed, meaning there is a lag until an effect is seen on prices, and
- Forward contract prices are also being driven by the cost of protecting against dry year risk and firming capacity more generally. Currently, this is a very high-cost option driven by the high cost of gas or liquids such as diesel.

Given our view that there are barriers to investment to address dry year risk and firming capacity generation, this gap between forward contract prices and the cost of new capacity is likely to persist.

3.4.5 Impact of Government ownership

The Government's ownership in the gentailers can distort investment outcomes in several ways.

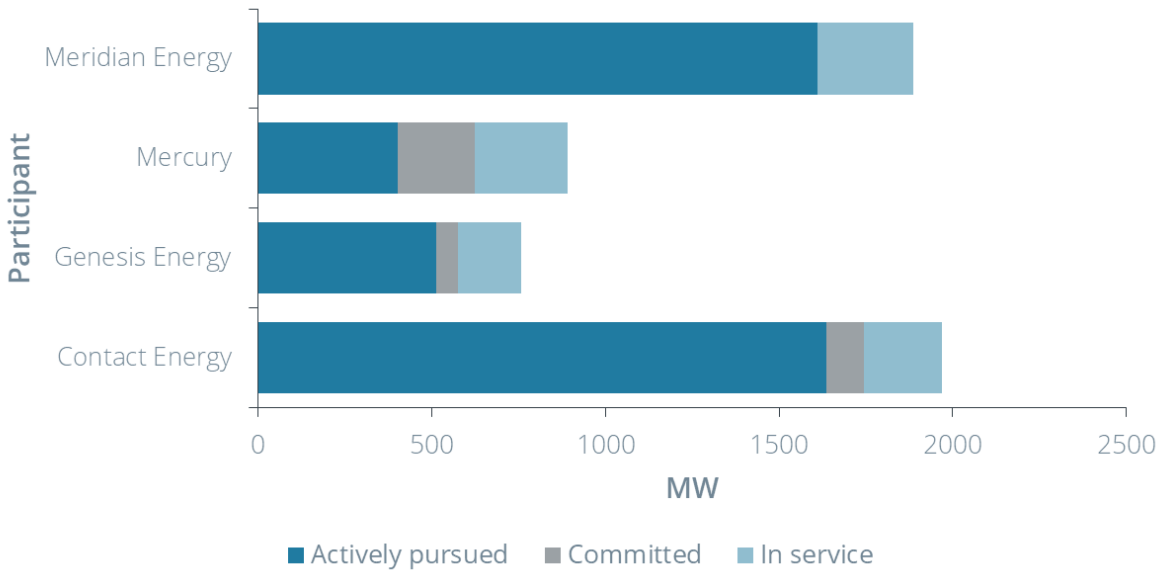
- **Investment constraints** – the current ownership structure limits the gentailers' ability to raise capital and invest in large scale projects. Government equity is effectively 'locked-in', preventing the attraction of additional equity funds. We were told by one genetailer that funding constraints meant it primarily relied on retained earnings for new investment, resulting in an overly incremental approach to project development. Another told us that the constraint on being able to source additional equity had limited their investment options.
- **Dividend pressure** – We were told that the Government prioritises stable and higher dividend payments to fund public budgets or social programs. We have not observed evidence that dividend payments are higher and more stable for the gentailers with Government ownership compared to, say, Contact Energy. Nevertheless, if management believes that the investors are attracted to the business because its Government investors reduce the risk that dividends would be harmed as a result of large capital investments, they would be discouraged from undertaking those investments. This reflects what is known as clientele effects. Clientele effects explain why different categories of investors prefer specific alternative dividend policies.[26]
- **Competition for capacity** – The investment constraints on the gentailers mean they rely more on purchasing output from independent developers rather than investing in their own assets given a PPA can be expensed rather than require upfront capital. This practice reduces market competition and allows gentailers to control supply from independents who could otherwise emerge as competitor to the gentailers rather than suppliers to the gentailers. That is, this approach means that independent operators and industrial

[26] See, for instance: Andrey Golubov, Meziane Lasfer and Valeriya Vitkova (2020), "Active catering to dividend clienteles: Evidence from takeovers," Journal of Financial Economics, 137, pp.815-836.

customers must remain dependent on the gentailers for capacity rather than being able to go directly to the developers of that capacity. We were told by one large industrial customer that this practice also makes it more difficult for them to obtain PPAs for new capacity, as gentailers have the ability to price them out of them market.

While it is not possible to know how the Government ownership has actually impacted on management decisions, we do know that stakeholders have told us that these limitations exist, at least to some degree. These limitations appear evident when looking at recent investment in new generation over the last 5 years, as well as the pipeline for new capacity. This shows that the private gentailer, Contact Energy, is investing more than the other gentailers with government ownership. From a total MW capacity perspective, only Meridian rivals Contact Energy (Figure 14), however, in terms of actual energy that will be delivered to the market, Contact Energy is clearly investing more than the gentailers with Government ownership (Figure 15).[27]

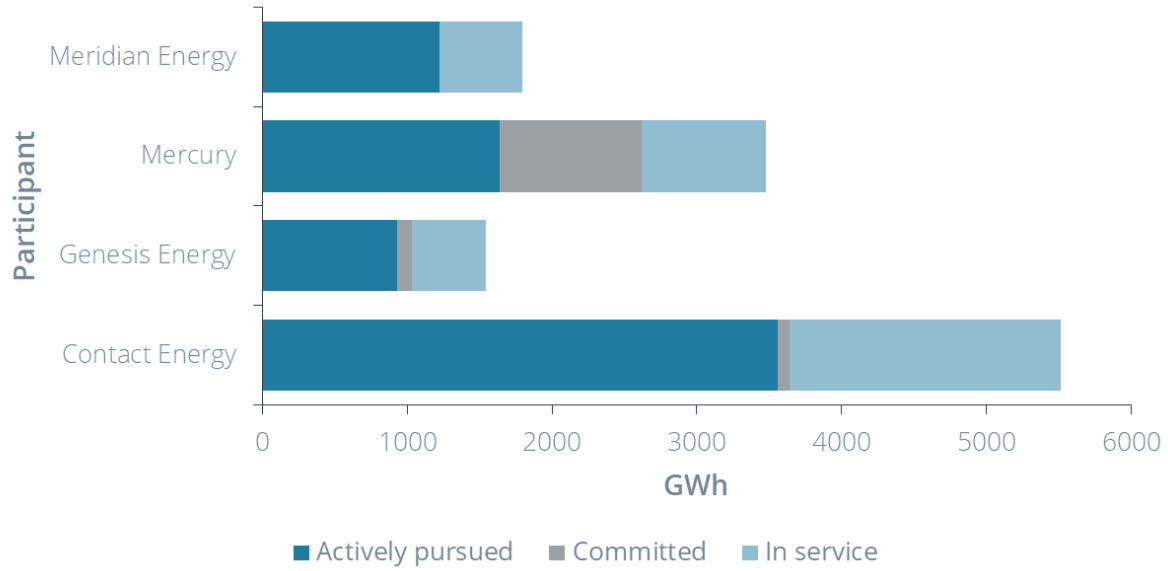
Figure 14: Gentailer commissioned projects since 2020 and investment pipeline, MW



Source: Frontier Economics, various sources

[27] This is primarily a result of Contact Energy's investment in geothermal capacity compared to others who have invested predominately in solar, wind or batteries.

Figure 15: Gentailer commissioned projects since 2020 and investment pipeline, GWh



Source: Frontier Economics, various sources

While successive Governments have not sought to involve themselves in the day-to-day operation of the businesses, which is rare and to be commended, this does not mean there is not an understanding of the limitations that exist for the businesses. This includes asking for additional equity for very large investments or diluting dividends.

As it is a topic that has come up during our review, we do not think that Government ownership, without additional measures, acts to prevent against the use of market power where it exists. We are aware of many examples of government owned businesses being investigated for the misuse of market power.[28]

3.4.6 Impact of the ETS

The ETS substantially increases the cost of electricity to consumers without delivering a corresponding environmental benefit. This is because the ETS does not have any meaningful impact on investment incentives, or change when and how long thermal generation operates. However, it does substantially increase the cost of electricity for New Zealanders and delivers a wealth transfer from New Zealand electricity consumers to renewable energy providers.

In New Zealand the decision on thermal generation investment decisions is driven mostly by factors outside the market rather than the ETS. As will be explained further in the following section, policy uncertainty is the primary factor limiting investment in thermal generation. This means that the effect the ETS could have is severely muted, at best.

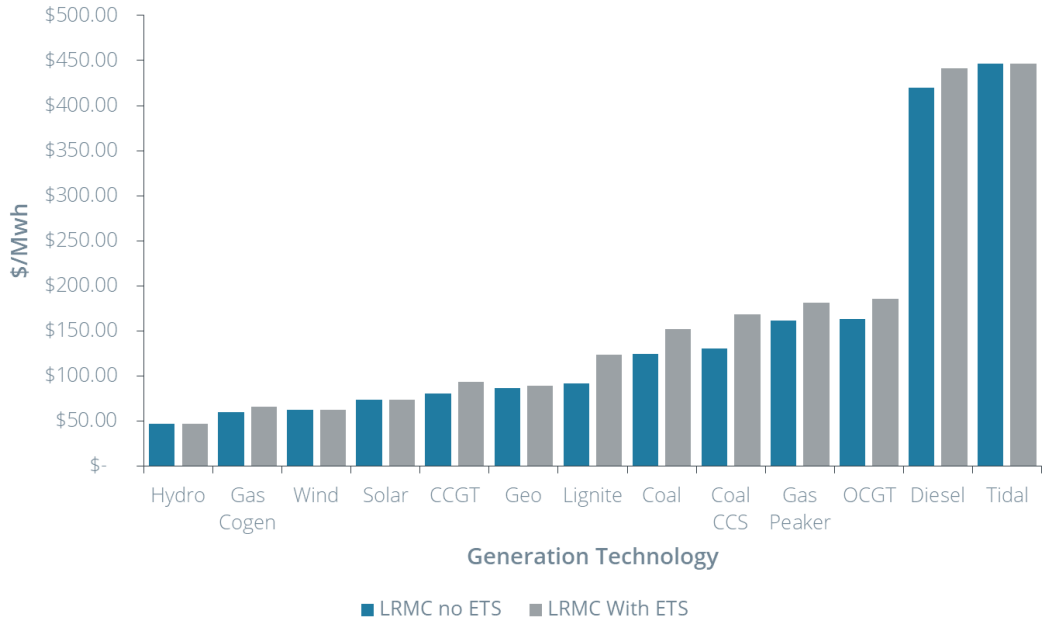
Nevertheless, we have analysed 2021 data on generation costs provided to us by MBIE to identify the change in the long run marginal cost of electricity with or without the ETS.[29] As shown in Figure 16 below, the relative cost of each generating technology remains broadly the same with or without the ETS. The implication is that, setting aside the other disincentives for investment in

[28] See, for example: https://www.erawa.com.au/electricity/wholesale-electricity-market/market-behaviour-investigations/2017-investigation-into-synergys-pricing-behaviour

[29] The MBIE data forms the basis of its levelized cost of electricity comparison tool: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/interactive-levelised-cost-of-electricity-comparison-tool

thermal generation that we discuss in Chapter 4, the ETS is unlikely to be a material factor influencing developers' generation investment decisions.

Figure 16: Long-run marginal cost of generation with or without the ETS, 2021 data

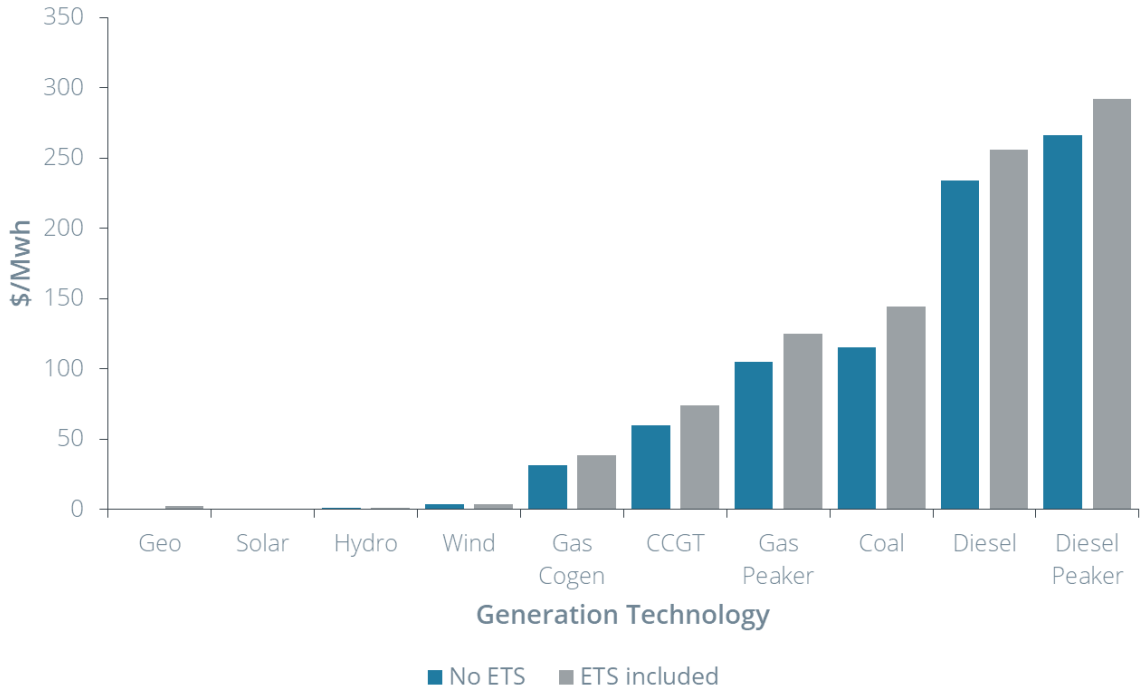


Source: Frontier Economics analysis of MBIE data

In principle, the ETS is intended to also influence the operational decisions of thermal generators by increasing their cost to generate, thereby reducing the amount of time they are dispatched to meet demand, or at least ensuring they are only dispatched when the benefits exceed the costs of generation and emissions. However, the operating costs of renewable generation is extremely low, and often close to zero. This means that even without an ETS thermal generation already sits at the top of the cost stack. As a result, the ETS merely increases the total cost to the market of meeting demand, without materially altering when or how often it runs.

To explore this further, we used the MBIE data referred to above to reconstruct the generation bid stack for currently available technologies in the New Zealand market, with and without the ETS. The results show that thermal generation does not displace renewable generation in either scenario, indicating that the ETS has no practical impact on whether renewable generation is dispatched (see Figure 17). In fact, the analysis suggests that the ETS does not change the bid stack at all for any of the generating technologies operating in New Zealand that were available in the data. Implying that it also does not impact on which form of emitting generation technology is dispatched.

Figure 17: Short-run marginal cost of New Zealand Generation without an ETS, 2021 data



Source: Frontier Economics analysis of MBIE data

What the ETS does do, however, is substantially increase the price consumers pay for electricity. Using analysis undertaken by the Electricity Authority when determining the Electricity Allocation Factor[30], and based on approximately 41TWh of electricity use in 2024,[31] the ETS caused New Zealand electricity consumers to pay almost $1.5 billion more for electricity in 2024. In contrast, MBIE data provided to us shows that the Crown collected only $223 million in ETS revenue from the electricity sector that year. We note that these values represent only 2024 amounts, while the ETS has been in effect since 2008.

Exacerbating this economic cost on New Zealand is a so-called tax interaction effect that the ETS – this is the additional loss of economic surpluses caused by the ETS charge/tax being on top of other taxes being paid for by producers. The ETS cuts into higher value consumption and lower cost production, silently destroying New Zealand's economic wealth.[32]

The disparity between the cost imposed on electricity consumers from the ETS and the amount collected by Crown arises because only emitting generators are liable for ETS costs. Yet, because these generators set the wholesale price for electricity, including when they do not generate due to their impact on the opportunity cost of hydro generation, it means the price of wholesale electricity is elevated for all consumers.

The need for thermal generation for firming in New Zealand,[33] and the fact that hydro generation is priced based on its opportunity cost, and so will shadow the price of thermal

30 Specifically, its analysis of the load weighted average price of electricity with and without the ETS. Electricity Authority, 'Determination of the 2024 Electricity Allocation Factor', p.13.

31 www.emi.ea.govt.nz/r/10zcg

32 For example, see Figure 2 on page S5 of Goulder, L.H. (2013), "Climate change policy's interaction with the tax system", Energy Economics 40, Weblink: https://web.stanford.edu/~goulder/Papers/Published%20Papers/Climate%20Change%20Policy's%20Interactions%20with%20the%20Tax%20System.pdf

33 "To ensure enough firm capacity to reliably meet peak demand, new gas peakers are required to provide firming in all scenarios." MBIE, Electricity Demand and Generation Scenarios: Results summary', July 2024, p.2.

electricity, means that more solar and wind electricity will not reduce the cost to customers from the ETS. That is, hydro generation is priced not based on their very low operating costs, but based on what it could earn by withholding generation now and selling later when prices are higher. These expectations are influenced by the expected cost of alternative generation sources. In a market where some level of thermal generation is expected, the offer price for hydro generation will always be inflated by the presence of an ETS.

Non-emitting generators earn a windfall due to the presence of the ETS. Generators earn the benefit of the difference between their own operating costs and the cost of the highest cost generation required to meet demand. Where the ETS artificially inflates the electricity spot price, it also means a larger benefit is given to renewable generators (recognising they do not incur an ETS cost). This is, effectively, a $1 billion plus transfer of wealth every year from New Zealand electricity consumers to renewable generators with no meaningful impact on generator output or investment decisions.

While a significantly higher ETS might make some technologies, such as carbon capture and storage, more economic, this will come at a massive cost to customers, recognising that an increase in the ETS to make such technologies economic will lead to further increases in the cost of electricity. To the extent that the New Zealand government wants to encourage specific technologies, it would cost New Zealander's far less to directly subsidise that technology rather than to impose the ETS on all electricity consumers.

Given the ETS, as applied to the electricity market, is doing very little to change behaviour in a way that improved environmental outcomes, it really is just a tax that transfers wealth from consumers to producers and the government. There are more efficient taxes than an ETS if the government is dependent on the ETS revenue.

3.5 Our recommendations

3.5.1 The energy-only market should be retained

Since we see no significant barriers to new supply capacity—aside from those related to managing dry year risk and firming supplies—we do not recommend substantial changes to market design or structure concerning supply investment. More directly we are not recommending a move away from the energy-only market design. Further, given the extent of investment from independent participants, we do not believe that structural separation of the gentailers would lead to more investment in new capacity.

3.5.2 Divestiture of Government shareholding in the gentailers

Selling the Government's stake in the gentailers will lead to more efficient market outcomes. Without the Government as the major shareholder the gentailers would have greater flexibility to raise capital, make larger investments and respond more dynamically to market demands.

We are not, however, recommending that the Government exit the wholesale market entirely, indeed the opposite. Instead, we recommend that the Government use the funds generated from the divesture to invest in those things that are most critical to the management of security and competitiveness of the New Zealand electricity market. This includes the development of a secure and physically firm sources of fuel and appropriate generation assets. These are the things that the private sector is unwilling to invest in themselves for the reason explained. The sale of Government shares in the gentailers will enable it to fund those specific projects. We discuss this proposal in the following chapter.

3.5.3 Better information to facilitate better investment decisions

We have identified some enhancements that could be made to the information that is made available to potential investors. We address these specific recommendations in our chapter focused on transmission planning and system operation.

3.5.4 The ETS should be removed from the electricity sector

Based on the ETS not driving behavioural change in the market, and it acting largely as a tax on electricity consumers, we recommend that the Government remove the ETS from the electricity market.

If the Government chooses to retain the ETS on electricity, we recommend that it recycle revenue collected from the electricity sector for the ETS back to customers. We note, however, that given there is a large disparity between the revenue collected and cost impact on customers from the ETS, that customers will remain significantly worse off.

4 Managing dry year risk

4.1 Introduction and summary of findings

New Zealand's high reliance on hydro power creates security of supply vulnerabilities when rainfall is low, particularly before or during winter when electricity demand is at its highest. In this chapter we discuss whether business ownership, market structure, or the design of markets affect the incentives or opportunities to invest in power supply to address the risk of insufficient energy in dry years when water supplies for hydro generators are low.

Our finding is that from the perspective of managing dry year risk and providing firming capacity, New Zealand's energy security and reliability hangs in the balance. As the system's reliance on renewable energy increases to meet new demand for electricity and as existing sources of thermal capacity declines, so does its vulnerability to dry year shortages and renewable energy droughts.

Without definitive action by the Government, dry year risk will lead to increased prices, loss of supply and economic disruption that will drive industry out of New Zealand. Therefore, dry year risk also represents a significant economic and social risk for New Zealand.

We have identified that this is a problem caused by Government policy driven risk that requires solutions by Government – there is no point waiting for a market response to these Government induced risks. Indeed, the market has demonstrated it is not willing to respond. Investment in new dispatchable capacity is not occurring, in large part, due to the considerable risk imposed by Government policy volatility. At the stroke of a pen the value of an investment can be destroyed. This is a risk the market is unable to manage.

Our proposed solution is designed to preserve the market signals and the operation of the existing energy-only market, while ensuring the dry year problem is resolved. While it is a bold proposal, it is also the one that we believe imposes the least disruption to the intended operation and market signals expected of the existing energy-only market, particularly compared to the other options that are available.

We propose that the Crown refocus its involvement in the electricity sector to securing and selling thermal capacity, guaranteeing that New Zealand has the backup generation it needs when hydro resources are low and to provide access to firm power at all other times. In short, this ensures a secure and reliable energy supply for New Zealanders, power remains available in all conditions, supporting households and businesses alike. To deliver this outcome, we recommend establishing a new organisation, which we refer to as "New Co" in this report.

We propose that independent operators have priority over access to this capacity with the aim of making them less dependent on the gentailers for firming services. This is by providing retailers with virtual vertical integration and generators a firming product that does not rely on the gentailer's firm generation backed contracts. Fair access to firm capacity for all participants will enable other participants to compete at the same level as the gentailers. By taking responsibility for securing and selling thermal capacity, the Crown can act as guarantor of New Zealand's energy security and, hence, market competitiveness. This will ensure the system and price stability regardless of rainfall patterns.

We have also considered several alternative solutions; including those adopted internationally. However, we found these solutions would not address the fundament issue of government policy risk, and so could not be expected to deliver the required capacity without substantial increases in electricity costs. We are also aware of similar ideas to our proposal that have been

put forward by the sector. However, again, these options do not address the policy risk issue while also entrenching the prospect of market power in the hands of a few players.

4.2 What is the desirable market outcome?

In a well-functioning market, wholesale prices will signal the need for investment in additional flexible capacity, ensuring sufficient supply to meet demand even during periods of reduced hydro generation. Additionally, this should include a safety margin so that there is adequate capacity to withstand the failure of the largest flexible unit that is relied upon during a dry winter.

Importantly, the amount of reliable capacity should be enough to meet all demand from household and industry so long as customers value the use of that energy more than the cost of supplying it. Having a system that is designed to meet all demand does not mean that there is no role for demand response. Where demand response is offered, it is because the customer benefits more from avoiding consumption than it does using electricity. It is critical for the success of the New Zealand economy that customers can expect to rely on the availability of electricity supply.

It is important to also be clear about the security of supply service that is the focus of this chapter, and so what we mean by firming capacity. We are focused on a dispatchable long duration service. This is a service that is required for a period of months rather than hours or even days. It is one that can be called upon when needed, subject to start-up notification requirements. Batteries are not capable of providing this service. It needs to be dispatchable supply that can operate continuously for long periods of time for there to be an assurance that energy will be available when needed. There also needs to be enough of this energy to compensate for the power that is typically provided by hydro generation in wet years. This means the capacity needs to be provided by geothermal, or thermal generation such as coal or gas fired generation.[34]

We do not suggest that additional renewable energy doesn't help manage dry year risk. It does assist the system to manage this issue to a degree by allowing hydro generators to limit their use of scarce water resources for electricity generation when solar and wind farms can generate. As more renewables are connected to the system it will help meet the expected growth in demand from greater electrification and also, at times, allow the hydro generators to preserve their water to generate more at times when the energy is more valuable. The extent to which renewables can be used to stretch water supplies will depend on the extent of water spill.

4.3 Current market

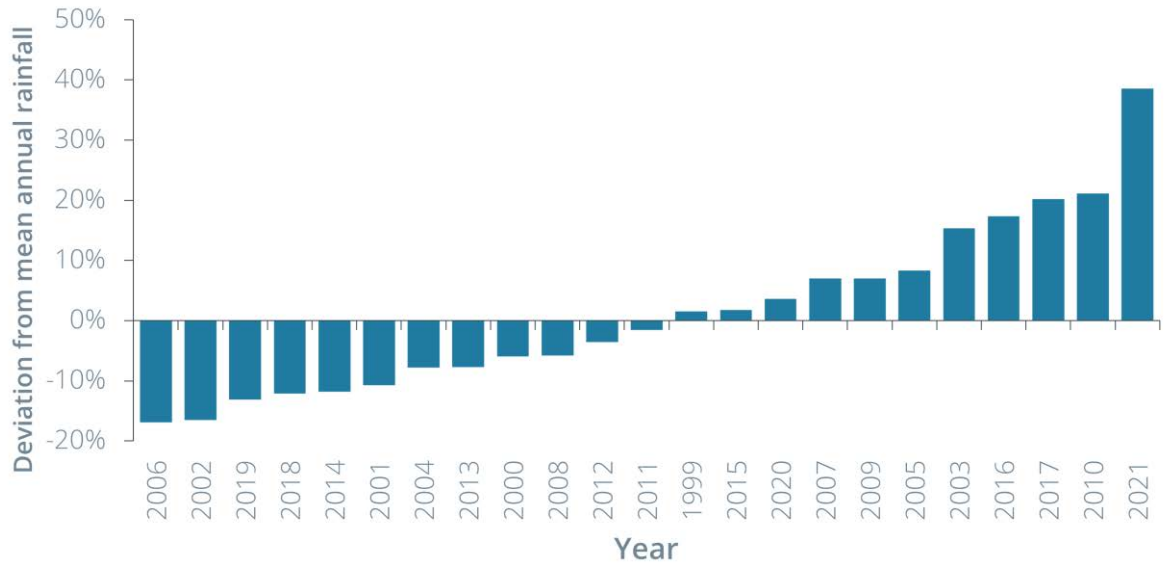
4.3.1 Dry years occur infrequently

The New Zealand hydro generators are highly dependent on rainfall and snow melt to ensure sufficient water is available to produce electricity. This is because, unlike some other hydro dominated market, the lakes used to supply water in New Zealand are relatively small. With only 4.5 TWh of storage capacity, these lakes are capable of only supplying water for a period of weeks to months.

Dry years are unpredictable and do occur relatively infrequently in New Zealand. However, they are frequent enough to have a material impact on market outcomes even in wet years. The figure below shows that dryer years are just as likely to occur as wet years.

[34] As demonstrated in the previous chapter, the current energy-only market is working well to provide an incentive for capacity such as batteries to provide security of supply when it is not windy or sunny.

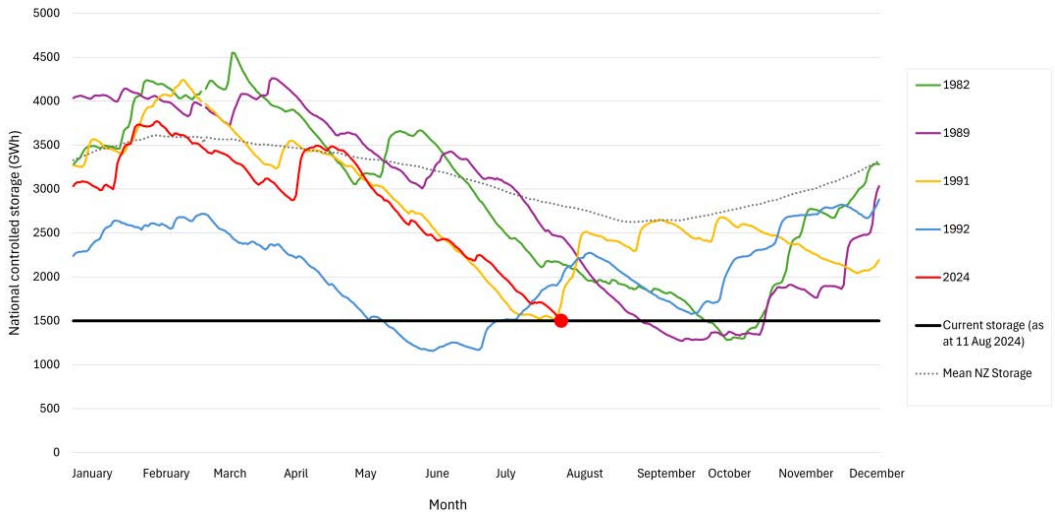
Figure 18: Rainfall difference to mean



Source: Frontier Economics analysis of rainfall data from StatsNZ. Mean rainfall calculated as the average annual rainfall from the entire sample period 1960 to 2022. Data displayed on the chart above is from 2000 to 2022 for illustrative purposes.

Figure 19 below shows how much lower storage levels can fall in years that are classified as 'dry years'. It is clear that there can be a material difference between average and dry year storage levels, which impacts on how much electricity can be produced from hydro generation.

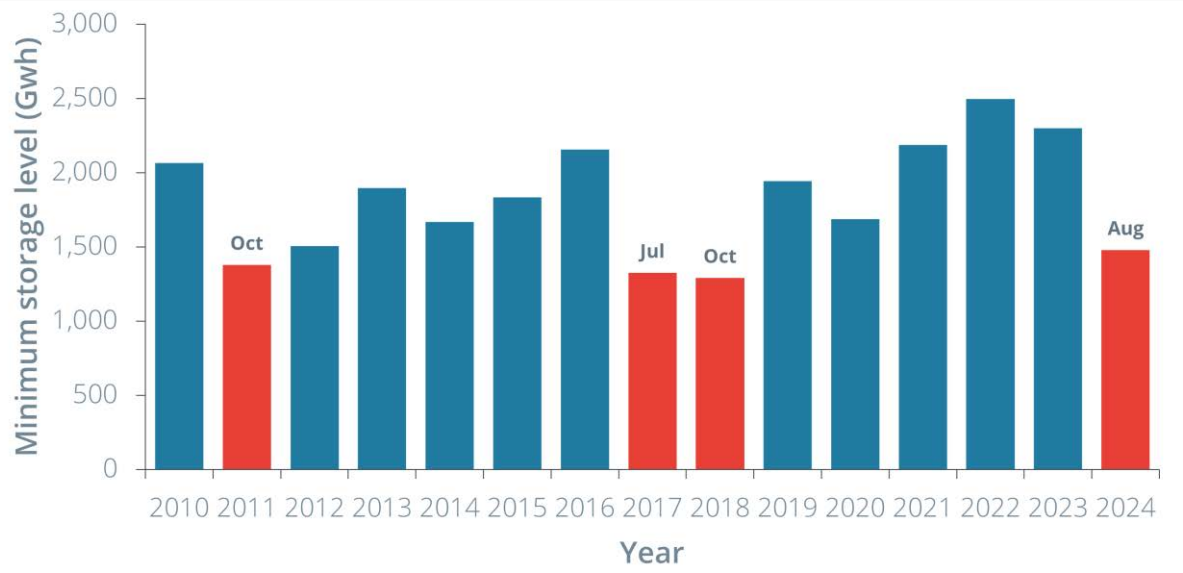
Figure 19: Controlled hydro storage levels during 'dry years'



Source: Transpower – Weekly Market Movements – 11 August 2024

Figure 20 below sets out the minimum hydro storage levels in each year, expressed in GWh. The years shaded in red are ones where minimum storage levels were lower than normal and could be considered 'dry years'. In these years, minimum storage levels are reached in the higher demand winter months, typically between July and October.

Figure 20: Minimum annual controlled hydro storage levels

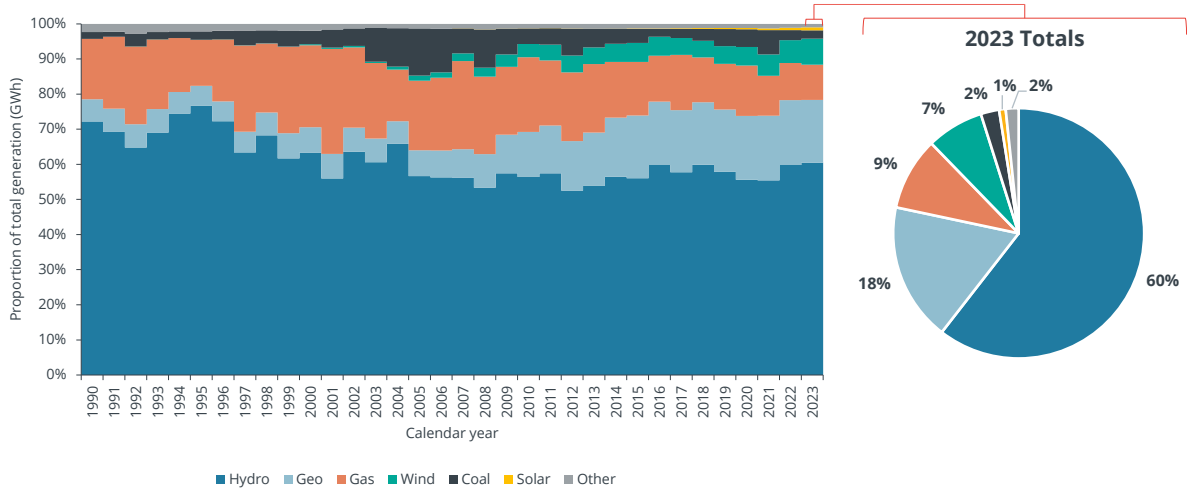


Source: EMI Data, Frontier Economics analysis.

4.3.2 The changing generation mix is increasing the dry year risk

While the proportion of electricity that comes from hydro generation has been falling over the years, it still makes up over 60 per cent of New Zealand's electricity supply. The supply of hydro generation has been replaced primarily by other renewables, in the form of geothermal energy, wind and solar. At the moment there is limited battery capacity. This change in generation by fuel type is shown in Figure 21: Generation by fuel type below.

Figure 21: Generation by fuel type

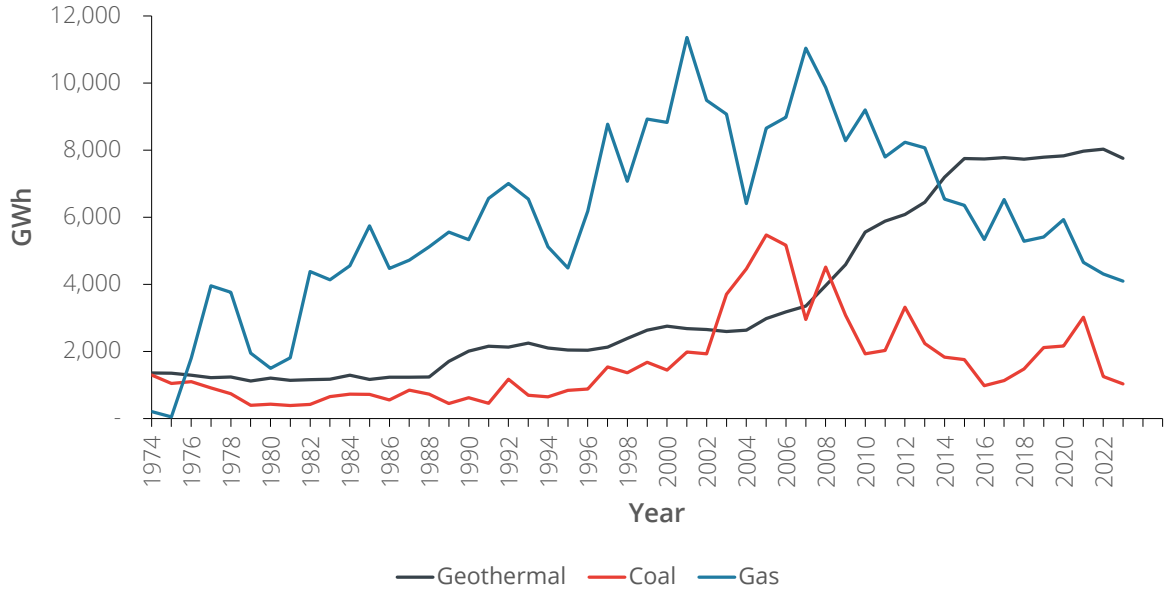


Source: Frontier Economics using data from MBIE

Figure 22 and Figure 23 below show that supply by thermal capacity has been decreasing over the years in terms of both output and capacity. This is the firm, secure and reliable capacity that can be used when hydro generation is constrained. In particular, the contribution from gas has been reducing over the past decade or so, while coal provides only a small percentage of supply.

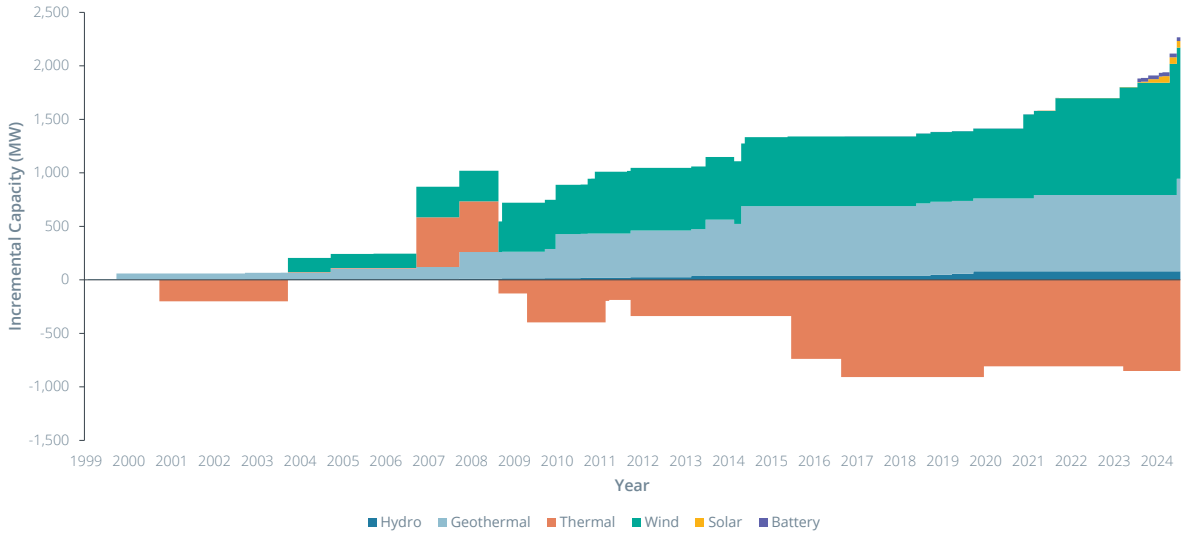
This has been somewhat offset by an increase in geothermal capacity. However, we understand the ability to install additional geothermal capacity is constrained by land access issues. In addition, Todd Energy Corporation has made relatively recent investments in two 100MW peaking gas power stations, opening McKee power station in 2014 and Junction Road in 2020. We note, however, that it has unique position of having a 100 per cent interest in the Kapuni gas field, which means it has more control over the supply of gas for these generators.

Figure 22: Output from dispatchable generation sources



Source: Frontier Economics analysis of MBIE Annual electricity generation and consumption data

Figure 23: Change in utility scale generation



Source: Data provided by Concept Consulting

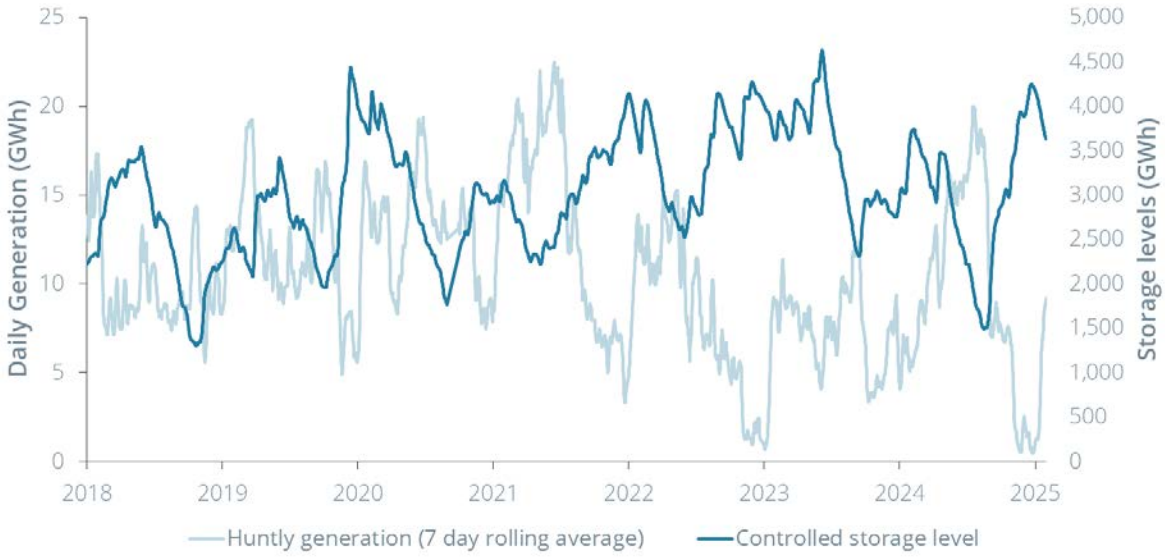
Increasing the dominance of intermittent generation, and reducing supply from dispatchable thermal generation, intensifies dry year risk in New Zealand. This is compounded by the fact that

output from wind generation is positively correlated with rainfall. The implication being that there tends to be less wind output in a dry year.

By implication, for wind to make up a shortfall in hydro capacity it would require substantially more wind resources than is needed for any other time. The expectation being that this volume of wind would cause a spill in either wind or hydro capacity. Such overbuilding also increases the resource cost of supplying electricity, which is ultimately paid for by customers.

The role that needs to be played by thermal generation is demonstrated in the figure below showing the relationship between generation from Huntly, which can use both gas and coal as fuel, and water storage available for electricity generation. It shows that output from Huntly is inversely related to water storage availability. This means, historically, Huntly has been used to compensate for low water supply.

Figure 24: Huntly generation and water storage

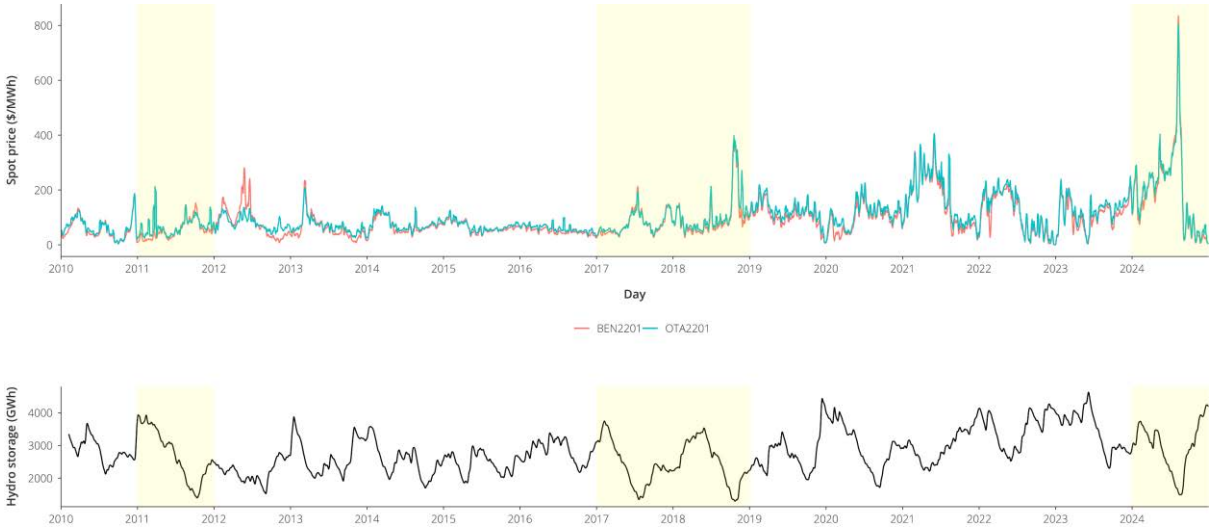


Source: EMI Data, Frontier Economics analysis.

4.3.3 Dry years have a material impact on prices

Figure 25 below shows that average spot prices are considerably higher when storage is low, while more moderate in wet years – the shaded areas represent years of low water storage.

Figure 25: Spot prices, water storage and demand

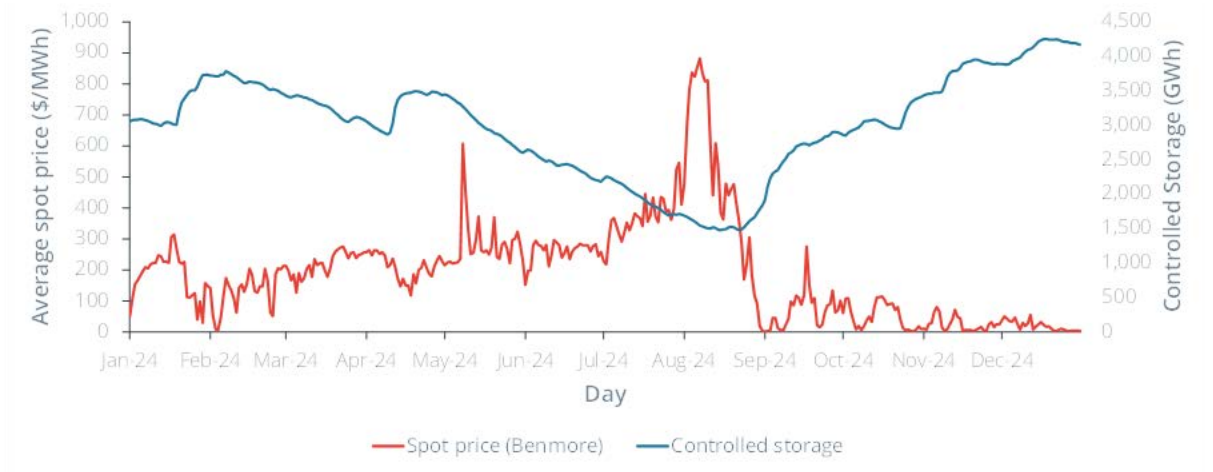


Source: EMI Data, Frontier Economics analysis.

Prices tend to rise even before the peak of a dry winter, as hydro generators seek to conserve water for the period of highest demand. By holding back water, they drive up spot prices because the opportunity cost of using that water today—when future prices are expected to be higher—increases. The resulting higher cost of hydro generation incentivises greater use of thermal generation, which in turn helps to preserve water reserves.

It is evident that spot prices were particularly high in the most recent dry year in 2024. This is shown more clearly in Figure 26 below.

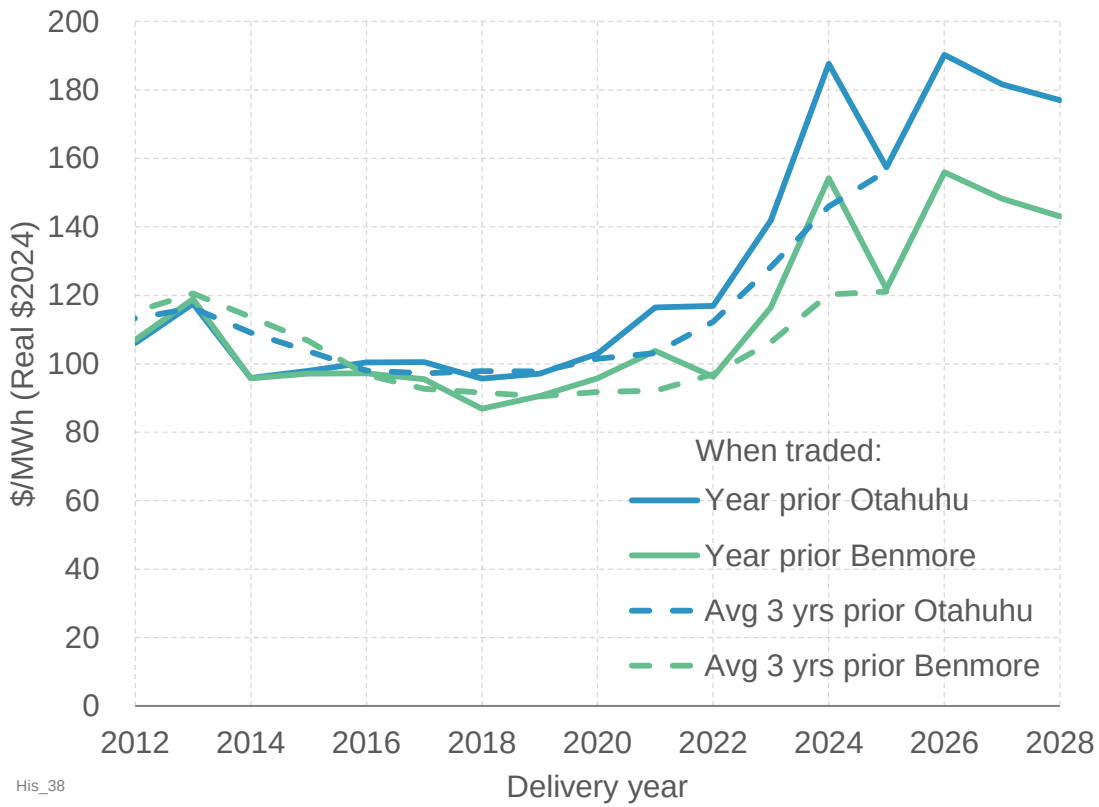
Figure 26: Average spot prices and storage levels in 2024



Source: EMI data, Frontier Economics analysis

Figure 27 shows that future contract prices have been increasing substantially since just before the 2024 dry year. The risk of high prices during a dry year appears to be the primary driver for higher futures contracts. Specifically, the main driver for futures prices is the marginal fuel required to meet demand in a dry year. That is, either gas, including from Methanex, or diesel. Lack of supply of key fuels such as gas means also that the input costs of generation to address dry year risk has also been increasing. This is a key difference from previous dry years where thermal generation was more abundant and cheaper to run.

Figure 27: ASX annual prices traded one year in advance of delivery year



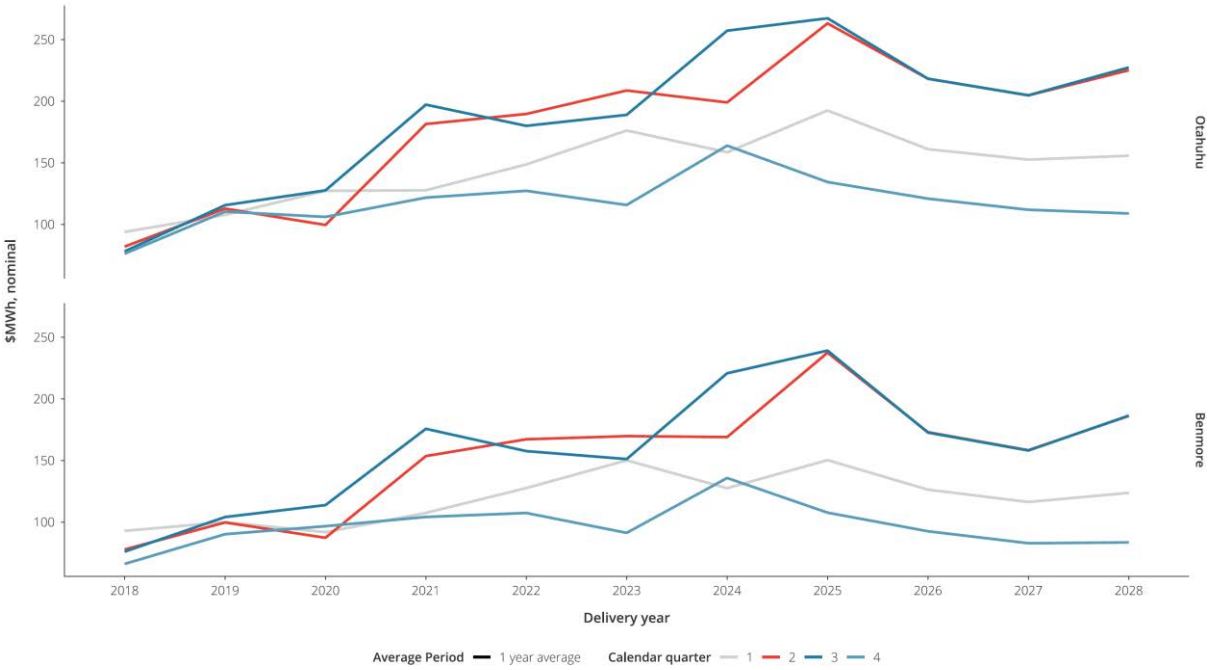
Source: Concept Consulting

While contract prices across the year give an indication on the market's expectation of the average annual price of wholesale electricity, it is worth noting that the recent increases since 2020 seen in Figure 27 above are largely being driven by increases in the price of Q2 and Q3 quarterly contracts. That is, the contracts that cover from March to June and July to September.

Below in Figure 28 we set out the recent contract data received from the Energy Authority on ASXEnergy contract trades. For each reference node and contract quarter, we calculate the volume-weighted average base swap price for the twelve-month period leading up to the active contract quarter.

Both in the North Island (Ōtāhuhu) and South Island (Benmore), it is evident that the price of Q2 and Q3 contracts (represented by the dark blue and red lines) are substantially higher than Q1 and Q4 contracts (represented by the light blue and grey lines).

Figure 28: 12-month volume-weighted average quarterly base swap prices



Source: EA data, Frontier Economics calculations. Note that trade data is limited up to 24 March 2025 and therefore averages for latter years typically won't have 12 months of trading data available yet.

Declining gas supply has caused prices to spike higher than usual

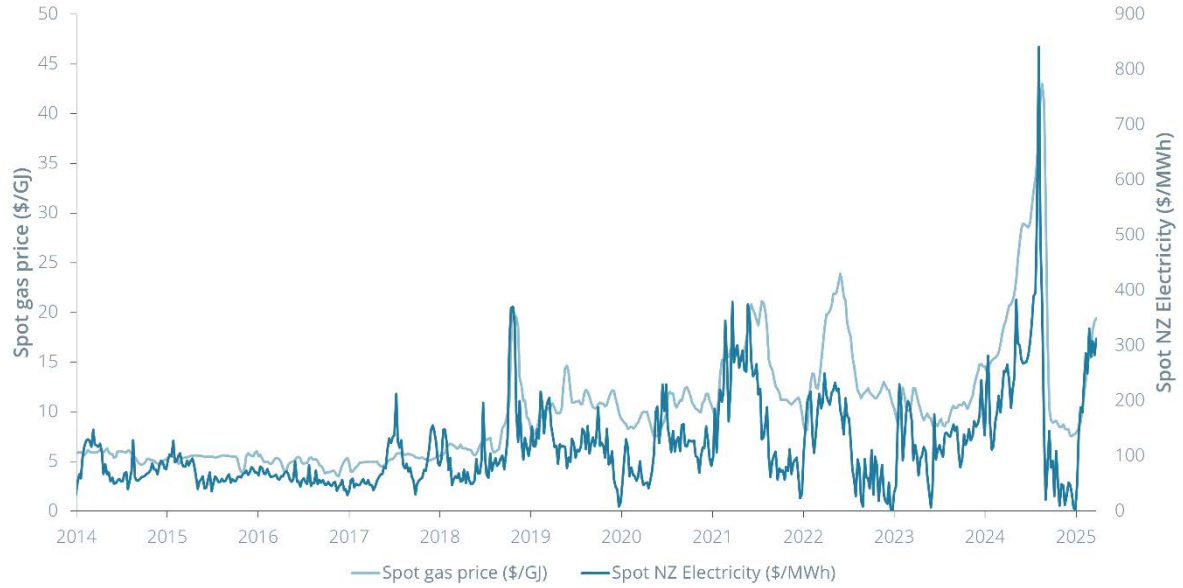
As discussed further in Appendix A, gas supply has been well below forecast in recent years. However, gas is crucial for addressing dry year risk given it provides fuel for dispatchable thermal generation that can be relied upon when water levels are low. Dwindling supplies of gas mean higher gas prices, which in turn means the cost of generating electricity with gas is also higher.

Last winter, with a dry year, much of the gas used for electricity generation was supplied by Methanex. Rather than use gas to produce methanol, Methanex sold this gas to generators at high prices. We understand that there was a requirement to rely on short-term, higher-priced, contracts with Methanex in part because existing contracts were void following the triggering of 'force majeure' provisions. That is, we understand that long-term contracts held by generators, with a relatively lower gas cost, were suspended due to the triggering of a 'force majeure' clause, with the 'force majeure' event being linked to the severe gas shortage. Nevertheless, it is possible that better contracting of gas may have meant the cost of gas during winter 2024 may not have been has high as it was.

Figure 29 shows the impact of dwindling gas supplies on gas prices, and the impact this had on the cost of generating electricity.

In Appendix A, section A.7, we set out the current and prospective situation for supply and demand in the gas sector in further detail.

Figure 29: Weekly average gas and electricity spot prices



Source: Spot gas prices from emsTradepoint; spot electricity prices from EMI data; Frontier Economics analysis.

4.3.4 Currently Genesis is providing firm capacity to the market through various mechanisms

The primary means for industry for addressing dry year risk has been through the use of the Huntly generator, which is owned by Genesis. Genesis appears to indicate that, but for dry year risk, it would not continue to operate the Huntly generator and would prefer to remove it from its portfolio.

Its use for managing dry year risk over recent years has been through an arrangement referred to as the Huntly Firming Option (HFO). The HFO is a derivative product designed to provide eligible counterparties with a flexibility product. The HFO is backed by the Huntly's Rankine units and offers notional call options on generation capacity during periods of both capacity and energy scarcity over a two-year period. The four call profiles, which are being sold 6 months to 18 months out, are:

- Baseload long duration (00:00 to 23:59 ≥ 5 days duration)
- Baseload short duration (00:00 to 23:59 ≤ 4 days duration)
- Peak (any 15 hour block during a day), and
- Superpeak (any two non-contiguous 3.5 hour blocks during a day).[35]

Genesis runs a capacity allocation process to allow the market to determine the market value for the Rankine units. This then sets the annual premium to be paid per MW of capacity by those eligible market participants that receive an allocation. That is, the marginal successful bid price sets the annual premium for all participants.

More recently Genesis, in conjunction with the other gentailers, announced their intention to develop a Heads of Agreement for the use of Huntly. We understand that the Heads of Agreement will be a 10-year arrangement that will permit the gentailers to toll fuel through the generator. While independent retailers have not been included in the Heads of Agreement

[35] Firming Options Genesis Energy Limited May 2024, p.7

discussions, we understand there is an intention for some portion of capacity to be made available to other parties. This could be through a new version of the HFO.

4.3.5 ThermalCo was a failed attempt at a commercial solution

In 2021 Contact Energy proposed ThermalCo as a consolidated ownership model of thermal generation assets between Contact, Genesis and Nova. Other than consolidation, the main feature of the proposed approach was a transparent platform for the trading of thermal capacity. We note that the proposal for ThermalCo was not focused on investing in new capacity for flexible generation. Instead, it was presented as allowing one entity to plan and stage the shutdown of thermal plants.[36]

Ultimately, agreement to established ThermalCo could not be reached and so this option did not progress any further.

4.3.6 Energy required to address dry year risk

Analysis undertaken by the previous Government for the Big Battery projects suggests that dry year risk is somewhere in the range of 3 to 5 TWh.[37]

4.4 Our assessment of current market arrangements

A failure to address electricity supply limitations for dry years has driven higher spot and forward contract prices than otherwise would be. This is not caused by market structure problems or a lack of oversight on participant behaviour. It is caused by a lack of flexible and firm long-duration capacity in the market. The primary cause for the failure of investment in the type of assets needed is policy uncertainty and shareholder aversion to investment in thermal assets. There is also a fuel supply risk issue and a free-rider problem that exacerbate the issue.

Furthermore, the proposals that have been put forward by the industry, including the current Heads of Agreement for the Huntly generator, are anti-competitive and will entrench any competitive market concerns that exist. They will also not address the impact policy risk is having on the capacity for the market deliver long-term fuel supply options.

In the remainder of this section we discuss the key barriers to investment to address dry year risk and firming generation more generally. We also consider the solution that has currently been put forward by the gentailers regarding the Huntly generator and why a solution focused on more renewables is unlikely to be an efficient solution.

4.4.1 Policy uncertainty risk

The policy uncertainty created by the New Zealand Government more directly impacts on investment in thermal capacity than any other investment. However, this is precisely the capacity needed to address dry year risk. In New Zealand no investor is willing to invest in a new thermal generator, or even in developing the fuel resources needed for a thermal generator, when a stroke of the pen could either ban that technology or irrevocably harm the ability to recover costs. This was a consistent theme across stakeholders we met with as part of our engagement

[36] Contact Energy, 'Crafting a path for New Zealand's 100% renewable electricity market. Proposal for industry-wide engagement on the future of New Zealand's thermal assets', p.5

[37] https://www.mbie.govt.nz/dmsdocument/23346-update-on-the-new-zealand-battery-project-proactiverelease-pdf p.3.

process. It was also raised as a key issue in the 2023 Generator Investment Survey for the Electricity Authority where the following was identified:[38]

> *Some interviewees commented that policies relating to thermal generation are a key area of uncertainty – due to conflicting signals between ETS settings, renewable targets, biofuels, hydrogen, gas and coal policies.*

Investors know that the former Government sought a 100 per cent renewable system, banned gas exploration and was investigating how to phase out thermal generation and thermal energy for industrial processes. They also know the Government was, for a time, willing to seriously consider investment in a very large dry year solution, in the NZ Battery Project at Lake Onslow, that would swamp the supply market and so make almost all other investments uneconomic.

Traditional risk management tools are incapable of address government policy risks. There is no way market participants can hedge against policy risk (except by reducing equity exposure to the sector), noting whether that risk eventuates is entirely in the hands of the Government. For assets where cost recovery occurs over a 20-to-30-year period, this makes the risk exposure for thermal generation untenable. The result being the investments will simply not proceed.

4.4.2 Business specific factors

Our discussion with stakeholders revealed that policy uncertainty was the single biggest factor hampering investment in assets to address dry year risk and firming requirements. However, they also identified that the detrimental impact that investing in thermal assets would have on their share price as another significant factor. This share price impact is likely driven by two things:

- Investor preferences for businesses to focus on environmental, social and governance (ESG) considerations means they prefer investing in low-carbon assets and renewable energy projects.
- A recognition by the share market of the stranded asset risk associated with thermal assets, influenced by both the Government policy risks and also the difficulties associated with recovering fixed costs in a highly renewable electricity system (i.e., the market failure issue identified above).

There are numerous examples that demonstrate that that the market is reluctant to invest in thermal assets, including:

- Investors have told the Electricity Authority that they are concerned about the difficulties of obtaining funding for non-renewable projects, stating with respect to the negatives in terms of capital availability: "*Concern that non-renewable projects may face undue hurdles to obtain funding*".[39]
- The former Government banned KiwiSaver default funds from investing in fossil fuels. Particularly telling, that in making this decision the Commerce and Community Affairs Minister at the time indicated that stranded asset risk was a key reason justifying the ban, stating: "*It also makes sense for the funds themselves given that* ***there is a risk of investing in stranded assets as the world moves to reduce emissions***." [emphasis added][40]

[38] Concept Consulting, 'Generation investment survey, 2023 update, Prepared for the Electricity Authority', p.48.

[39] Concept Consulting, 'Generation investment survey, 2023 update, Prepared for the Electricity Authority', p.45.

[40] Default KiwiSaver changes support more responsible investment | Beehive.govt.nz

- NZ Super Fund has a deliberate strategy to reduce the carbon emissions from their investments.[41]
- Participants with thermal assets are seeking to remove those assets from their portfolio. For example, Contact Energy has identified that its ambition is to have net zero energy generation by 2035.[42]
- New Zealand banks have demonstrated they are reducing lending to the fossil fuel sector, including a 10 per cent reduction in lending to the sector between 2023 and 2024, equivalent to $100 million.[43] We note, for instance, that ANZ has indicated it is actively encouraging its customers with thermal generation assets to focus on low carbon transition plans, stating:[44]

  > *Since 2018, ANZ has been engaging with its largest emitting business customers, including 12 that own or operate power generation assets. Our engagement with these customers has been focused on encouraging them to strengthen their low carbon transition plans, and we have seen a number of customers improve their plans over this period. While improvements in our customers' emissions performance made a small contribution to the overall decline in the emissions intensity of our portfolio during 2023,* ***we expect larger declines to come in future as our customers gradually bring online new clean generation capacity and retire their existing fossil fuel assets.*** [emphasis added]

- Analyst reports we have access to have identified that a key risk for gentailers with thermal generation is their exposure to ESG risks. We also noted that the equity beta for a gentailer with thermal generation implied it was a riskier business than one that had no thermal assets. Indeed, one analyst report identified that "*regulatory threats to thermal power stations*" was a key factor for its fair value estimate of the business.

4.4.3 Impact of fuel availability

The reduced supply of gas made the price impact of a dry year more pronounced in 2024 than in previous years. We believe this, combined with the use of diesel for generation, rather than market power, is the primary driver of elevated dry-year prices. However, the decline in gas supply also weakens incentives for investment in new gas-fired generation. Investors may be deterred by concerns that sufficient fuel may not be available over the asset's lifetime or that fuel costs could be prohibitively high, making the investment uneconomic.

This risk is further heightened by uncertainty over the future of New Zealand's largest gas consumer, Methanex. Methanex plays a critical role in supporting gas development and drilling activities, effectively underwriting investment in the sector. If the company were to exit New Zealand, the absence of a stable, large-scale gas purchaser would significantly diminish the incentive for further gas exploration. We discuss gas market issues further in section A.7.

4.4.4 Market failure

A market failure is also constraining the incentive for investment in assets that provide security of supply during a dry year. The key problem is that, given the size of the New Zealand electricity market, under the current market design, investors struggle to capture sufficient returns for investment in assets to address dry year risk and, to a lesser extent, firming. This is because competitors, and industrial customers, can free-ride on the investment made by someone else

41 https://nzsuperfund.nz/how-we-invest/sustainable-finance/climate-change/

42 https://contact.co.nz/about-us/our-story/netzero

43 Major NZ banks cut $133m in fossil fuel lending amid climate push - NZ Herald

44 ANZ, 'Climate-Related Financial Disclosures', 2023, p. 52

that has the effect of suppressing prices. In other words, those who do not invest still gain from the added capacity, as its presence lowers prices by reducing energy scarcity during dry years. This creates an underinvestment problem, as private entities have little incentive to build assets that may be rarely used, and so have limited revenue opportunities, but are essential during periods of high supply risk.

As indicated in the previous chapter, the existing market design has been successful in providing an incentive for investment in new renewable generation. However, unfortunately, this also intensifies the market failure and risks associated with investment in the type of assets needed to address dry year risk. This is because solar and wind have very low operating costs, which means that they depress wholesale spot prices when they produce electricity. The result is that there are fewer opportunities for flexible thermal capacity to earn revenue to contribute to fixed cost recovery.

Forward contracting of the output to manage the risk of a dry year is a potential mechanism for investors to ensure they earn sufficient revenue to invest. However, a market failure can exist here also. The incentive can be to free ride on the contracting of others, to the point that there is insufficient incentive for any individual party to bear the cost of contracting for new capacity to be built. We consider the contracting position of participants further in Chapter 6. However, the evidence suggests that retailers, at least, are covering their loads with contracts. Conversely, stress testing data suggests that other parties, such as large industrials, may be exposing themselves to the spot price, perhaps in the expectation that other participants will contract and so reduce the likelihood of spot price volatility.[45]

The outcome of these market failures, where they occur, is higher prices and lower reliability during dry winter periods.

4.4.5 Existing market price signals are not sufficient

Evidence from the behaviour of market participants demonstrates that market participants do not perceive that market price signals are sufficient to encourage them to provide capacity that addresses dry year and firming risks. Two particular examples are telling. If market price signals were sufficient:

- Genesis would not be implementing the Heads of Agreement. That is, if the price signals were sufficient it would not share the spoils of those scarcity prices with its competitors, it would hold onto them for its own benefit. The more likely reality is that Genesis has been providing an insurance product to the market and has decided it is no longer willing to do this on its own given the costs of doing so do not outweigh the benefits it can obtain during the infrequent dry years.
- Contact Energy would keep TCC in the market, and it would have been refurbished before now. However, in 2019 Contact Energy told the market that it was not convinced the market would pay the higher pow cost that would be required to recover the next refurbishment of TCC, which was due in 2022.[46]

If there is a desire to rely on price signals to drive a response, given the challenges described here and the evidence of the actual behaviour of market participants, it is our view that all this will do is lead to prices to rise to very high levels without further investment. It will also mean more market power will be in the hands of those participants that do have thermal assets during dry years. We cannot see that this would be an outcome that would be tolerated by New Zealanders and so the New Zealand Government.

[45] https://www.emi.ea.govt.nz/r/g2yk5

[46] https://www.scoop.co.nz/stories/BU1902/S00280/contacts-tcc-plant-may-give-way-to-rankines.htm?utm_source

4.4.6 The role of Huntly

The proposed 10-year agreement between the gentailers regarding Huntly is anti-competitive and will entrench any market power that exists. This is because it effectively ensures that the gentailers have preferred access over flexible capacity and ensuing independent parties are dependent on the gentailers for firming capacity. We understand that due to a desire to reach an agreement quickly that the arrangement was limited to the gentailers. While we also understand that a portion of capacity will be made available to independent retailers, we were told that the way this product is packaged and priced means it is unsuitable for those participants. For instance, we understand the products offered were larger than what is needed by smaller retailers. Arguably, the gentailers have limited incentive to package the product in a way that improves the ability for others to compete against them.

Furthermore, while the Huntly solution addresses the near-term dry year risk, it does nothing to address the lack of incentive to invest in new capacity or to underwrite long-term fuel supply options. The current solution works in the short term because someone already owns a suitable generator and there is available fuel. However, it will not overcome the policy uncertainty risks, shareholder reluctance or free rider issues that are preventing new capacity being built and the substantial investment needed to develop new fuel sources over the long-term.

While we also note that ThermalCo was another proposal that would have incorporated Huntly, again, this solution does not address the incentive issues for new capacity or the underwriting of long-term fuel supply options. Furthermore, it appeared this solution was more focused on an orderly exit of thermal generation rather than ensuring it was available to address dry year risk into the future. The fact that the relevant companies were unable to reach agreement on this proposal also shows the frailty of commercial solutions to address this significant security of supply issue.

4.4.7 Relying on renewables in a dry year

Some commentators, including MDAG, have proposed that the best way to address New Zealand's dry year risk is to increase the amount of renewable energy in the system.[47] The premise is that if enough wind and solar generation is built across geographically diverse locations, the variability in output will average out, so when the wind is not blowing or the sun is not shining in one place, it will be elsewhere. Excess generation during favourable conditions could then be stored, for example using batteries, for use when output is low.

While this approach may seem appealing in theory, we consider it both prohibitively expensive and insufficient to provide a reliable and secure supply of electricity.

It is our understanding that if renewable energy was to be the primary source for addressing dry year risks that hydro generation would not be a key feature. For example, the 2023 Generation Investment Survey identified that: "*hydro consenting perceived as too difficult to pursue by most parties*."[48] As a result, the bulk of additional renewable energy would need to be sourced from intermittent generators, such as wind and solar.

The fundamental challenge with intermittent renewables is their low and unpredictable capacity factor. That is, the proportion of time they generate electricity relative to their maximum capacity. Wind and solar typically have low capacity factors, meaning they produce far less electricity over time than their rated capacity suggests. For example, current estimates suggest

[47] MDAG, 'Price discovery in a renewables-based electricity system, FINAL RECOMMENDATIONS PAPER', 11 December 2023, p.34.

[48] Concept Consulting, 'Generation investment survey, 2023 Update, Prepared for the Electricity Authority', p.29.

wind in New Zealand has an average capacity factor of just 40 per cent,[49] and solar performs even less reliably, with an average capacity factor of 14 per cent.[50]

The Electricity Authority analysed a nationwide rollout of wind and solar, including scenarios focused on the top-performing sites. It found that wind output exceeded 50 per cent of installed capacity only about 9 per cent of the time, and that total wind generation is around 20 per cent lower in winter, when electricity demand is highest, compared to spring. Even when focusing on the best locations, solar capacity factors remained low.[51]

The implication of these low capacity factors is significant. To ensure a secure and reliable supply during a dry winter, the system must be massively overbuilt, with far more wind and solar capacity than would be needed in an average year, just to ensure enough energy is available when conditions are unfavourable. This overbuild drives up costs dramatically.

MDAG has estimated that transitioning to a 100 per cent renewable electricity system could cost between $27 and $37 billion by 2050.[52] This estimate already assumes a large role for demand response, meaning industries would be required to reduce or stop production when energy is scarce. This would have serious economic consequences, particularly during extended periods of low renewable output. In our view, given the reliance on demand response, this approach underestimates the true cost of ensuring reliability in a dry year and risks significant lost economic activity.

Some also point to batteries as a solution for storing surplus renewable energy. However, current battery technology is not suited to addressing dry year risk, which requires the ability to provide electricity continuously over a period of months, not just hours, days, or even weeks. Batteries capable of this kind of seasonal storage do not exist today, and even if they did, they would need to be built at enormous scale, representing assets that would sit idle in most years but must be fully available when needed. This would be an extremely costly and inefficient use of capital.

4.5 Our recommendations

4.5.1 Summary

Action is required to address the reliability of supply and pricing issues that arise in dry New Zealand winters. It is clear to us that the current market will not deliver the necessary capacity on its own; especially given thermal generation is what the market requires.

Our proposed solution is designed to preserve the market signals and the operation of the existing energy-only market, while ensuring the dry year problem is resolved. While it is a bold proposal, it is also the one that we believe imposes the least disruption to the intended operation and market signals expected of the existing energy-only market.

Our proposal is for the Crown to refocus its involvement in the electricity sector to securing and selling thermal capacity, guaranteeing that New Zealand has the backup generation it needs when hydro resources are low and also provide general firming capacity for the market. This means that no matter the weather, the lights stay on, and businesses keep running and New Zealanders have confidence in their energy supply. We are proposing a new entity be

[49] See: https://www.windenergy.org.nz/onshore-wind/#:~:text=Because%20of%20Aotearoa%20New%20Zealand's,wind%20energy%20is%20more%20efficient.

[50] See: https://www.mbie.govt.nz/assets/energy-in-new-zealand-2023.pdf

[51] Electricity Authority, 'New Zealand Wind and Solar Generation Scenarios', Executive Summary.

[52] MDAG, 'Price discovery in a renewables-based electricity system, FINAL RECOMMENDATIONS PAPER', 11 December 2023, p.52.

established for this purpose. For the sake of this report, we will refer to the new entity as "New Co".

Our recommendation is a significant but pragmatic approach to ensure that the energy system remains resilient, fair and future ready. We have designed it so it can be implemented quickly and so have a swift and significant impact on the market. However, we have also identified what is needed over the medium to longer terms so that the New Zealand electricity system is future proof to weather risks.

The key features of the proposed solution are:

- **A smarter approach to energy security** - the Crown will fund thermal generation resources in New Zealand through either contracting or ownership of assets, with a primary goal of underwriting the sourcing of fuel for thermal generation and other forms of dispatchable generation. Initially through coal and gas but also by identifying potential green options such as biomass or green gas/hydrogen.
- **Level the playing field** – independent retailers, generators and battery owners will be empowered by ensuring they have priority access to capacity – effectively providing them with virtual vertical integration. This will work in a similar way to the dedicated allocation that might be given to Mum and Dad investors for an Initial Public Offering and is not intended to provide capacity on more favourable terms or prices. This will level the playing field and boost competition by ensuring the gentailers cannot hoard capacity, while ensuring consumers can benefit from the cost efficiency of vertical integration.[53] This will result in a more dynamic market that drives further innovation and better prices for customers.
- **A competitive market-driven approach to market participation** – the entity will bid into the market in the same way as all other generators would in a highly competitive energy-only market, namely, by capping its offer at the avoidable (variable) cost of supply. It will also contract like all other generators, noting a portion of contracts will be reserved for independent operators to have first right of refusal. New Co will bid to the level of its contracts, which will also ensure it has an incentive to bid at its variable cost in order to guard against unfunded difference payment risks. This also provides an incentive for participants to contract with the entity given, absent a contract to defend, it has no incentive to generate. This market and incentive based mode of operation is a key point of difference between this proposal and the former Whirinaki reserve energy scheme.
- **Sustainable and self-funding** – the solution is designed to be self-sustaining, with cost recovered through wholesale market revenues, including contracts and spot prices. Because, at the outset, the owners of existing thermal generation may demand a price that is above the cost to operate, any difference between the efficient operating costs of the plant and the contract price can be recovered transparently through a levy on network tariffs, reflecting the social benefit of the service with maintaining financial stability.
- **Robust governance arrangements** – robust governance arrangements will be essential to ensure that New Co only procures sufficient capacity to address dry year and firming shortfalls. The Crown, as the residual risk holder, would be responsible for transparently setting this parameter, based on advice from MBIE and other market agencies such as the System Operator and the Electricity Authority. These arrangements will maintain discipline, prevent market distortion and safeguard against unintended mission creep.

Investment to underwrite the sourcing and future development of fuel supply, and ultimately in new firming capacity, will require substantial capital. We propose that this capital come from selling down the Government's current share in the gentailers. This option preserves

[53] We discuss the efficiency benefits of vertical integration in Box 3.

Government ownership in the sector but ensures it is focused on that aspect of the market where it is most appropriate, namely insurance against dry year risk. However, should the Government choose not to divest its ownership in the gentailers, this option could still proceed, just with a different source of funding. The key objective being to provide confidence to the market that there is someone putting in real capital where it belongs.

Conversely, if the status quo persists the likely outcome will be a sustained escalation of prices and the continued exit of industry from New Zealand. This trajectory can be expected to trigger a more reactive and potentially heavy-handed intervention by Government. Such an intervention, while it will be well-intentioned, is unlikely to be one that addresses the underlying issues that the sector is facing and may instead embed further distortions, ultimately leading to worse outcomes from New Zealanders

Benefits of the proposed approach

It is our view that the proposed solution will:

- **Deliver security of supply** – by placing an obligation on New Co to procure, either through contractual arrangements or direct ownership, the amount of firm capacity required to address dry year and general firming requirements.
- **Moderate spot and contract prices –** which will occur because the Crown will deliver the exact form of capacity that has been absent from the existing market and that has been causing prices to rise, particularly during dry years.
- **Constrain the ability for the exercise market power** – as identified by multiple stakeholders, including MDAG, the primary source of market power risk in New Zealand relates to the provision of firming capacity. The governance and operating arrangements for New Co are designed to ensure that its resources cannot be used to exercise market power.
- **Improve competition in both the retail and wholesale and contract markets** – providing independent operators with first right of refusal on capacity from New Co ensures that firm capacity cannot be locked-up by the incumbent generators. This the provides confidence to current independent operators, and potential new entrants, that they will not need to be dependent on their gentailer competitors for firming services.
- **Provide confidence to the market to develop local fuel supply options** – investment to identify new sources of fuel, or extract more from current known sources, can occur with increased confidence given Crown backing can ensure the investment does not become stranded. We note, however, that resolving the fuel supply issue is not sufficient on its own to address the dry year and firming problems in New Zealand. This is because the barriers to investment in thermal generation that we have identified above remain even if there is abundant fuel.
- **Ensure the energy-only market can continue to provide efficient signals for all other investment and use of electricity** – the proposed solution delivers the least market intervention of all the options that we have assessed or that have been proposed to us. By minimising the extent of market intervention, and ensuring the market behaviour of New Co remains consistent with what would occur in a highly competitive market, including through strong governance arrangements, private investors can have confidence in the price signals that the market delivers.

Alternative options

In reaching our recommendation we also undertook a detailed consideration of several other options, including:

- Implementing the status quo (i.e., the gentailer Heads of Agreement and level playing field measures),
- Obliging Genesis to be a regulated default provider of firm capacity
- A strategic reserve, similar to the former Whirinaki solution[54]
- A capacity market
- Mandatory contracting, and
- Tradeable certificates.

Our assessment was that none of these options are suitable because they are not as effective at overcoming the policy uncertainty risk that exists in New Zealand and the reluctance for private investment in continuous operation thermal capacity.[55] Indeed, we believe that some of the alternative options would make the situation far worse than it is today, and ultimately lead to higher prices and less security of supply.

Box 1: Comparison to the Whirinaki reserve energy scheme

The proposal for the establishment of New Co has been likened to the 2004 development of the 155MW aero derivative diesel fuelled Whirinaki power station. This power station was developed in response to power shortages in 2001 and 2003 due to drought, which also led to high prices.

Whirinaki was developed and operated by the privately owned Contact Energy, but owned by the government. Its market operations was controlled by the then Electricity Commission (the predecessor of the current Electricity Authority).

The stated aim of Whirinaki was to "govern the electricity industry and to improve security of supply". More specifically, the additional capacity of Whirinaki together with the price controls established by the Electricity Commission aimed to moderate extreme spot prices in dry years.[56] Originally, the plant was intended to be a last resort generator that did not interfere with normal market operations. The costs of plant was recovered through a levy on all wholesale purchases.

In reality, the structure and operation of Whirinaki distorted market outcomes and as water supplies for hydro electric generation returned to more normal patterns, Whirinaki was considered to be unnecessary and was sold in 2009 to Contact for a fraction of its purchase costs.

Twenty years on from the decision to develop Whirinaki as a reserve generator, the circumstances in which New Co is being proposed is fundamentally different. Twenty years ago:

- there was not the reluctance to invest in fossil fuel power station that exists today. Debt and equity was happy to invest in new fossil fuel power stations then, but now they are not
- there was substantial reserves of gas to operate the power station, but now gas reserves are low and quickly depleting

54 See: https://www.beehive.govt.nz/release/further-government-decisions-reserve-energy

55 As distinct from peaking or short-duration capacity.

56 https://www.beehive.govt.nz/release/further-government-decisions-reserve-energy

- the availability of firm generation was higher then than it is today and so dry year events are now likely to have a more severe effect on reliability and security of supply and prices than when Whirinaki was developed, and
- there was almost no intermittent generation that needed to be firmed when Whirinaki was developed and now there is, and this is a growing problem, and the lack of availability of the means to firm up these intermittent projects is causing greater generator concentration.

Aside from the differences in circumstances, the proposed arrangements for New Co are also fundamentally different to the Whirinaki arrangements. For example:

- The aim of New Co is two-fold – to overcome the barriers that face the development of firm generation and energy in New Zealand, and to ensure that the contracts that are backed by this capacity is fairly allocated across the market to promote more long-term competition. Whirinaki was focussed on being a generator of last resort
- New Co is to be operated as a business that recovers its costs through normal contract trading. As a backstop, it has been proposed that if there is a funding shortfall resulting from normal contract trading, over time, then to limit the exposure to government finances, any shortfall would be funded by a broad based charge on customers. This is similar to Whirinaki except that it is not the default funding option, it is a fail-safe funding option, and the charge is applied at the retail or network level rather than on wholesale, to limit efficiency distortions [57]
- A regulator will not be setting bid rules for the plant. The bidding will be governed by the terms of a standard contractual instrument used in the market. This will eliminate the possibility the plants under contract to New Co will be bid in an abnormal manner. In fact, given the plants will be covered by financially firm contracts, there is a natural incentive for it to be bid at the short run marginal cost to avoid any unfunded difference payments. This is generally consistent with how other market participants operate in the market
- The projects that are sponsored by New Co do not need to be owned by the state, as was the case for Whirinaki. These projects can be owned and operated by the private sector, if they are prepared to. New Co needs to have contractual control over the plant so it can fulfil its roles
- New Co will be owned by the state and fully accountable to two shareholding Ministers. Contact – the owner of Whirinaki - was a private firm that pursued the interests of its private shareholders.

4.5.2 Implementing the proposed solution

New Co's core objective would be to secure dispatchable, reliable and secure supply to mitigate energy shortfalls caused by low hydro availability in New Zealand and to ensure there is sufficient firming energy for the whole market. This includes ensuring sufficient fuel reserves for generation during shortages. Additionally, New Co would be required to reserve a portion of capacity for priority access to independent retailers or generators.

[57] Double marginalisation – this refers to the harm to consumers where margins are added to charges applied upstream.

While urgent action is needed to address dry year risk, a long-term solution is equally critical. Therefore, our recommended implementation identifies actions to be taken now and into the future.

Short-term actions

New Co would effectively take over the operation of the Huntly Firming Option by procuring all the Huntly capacity from Genesis. Genesis would remain responsible for the operation and maintenance of the generator, as well as sourcing the fuel, for a fee.

By taking over the Huntly Firming Option New Co can control how capacity is sold and traded in the market. Currently Genesis allocates capacity to participants at its absolute discretion.[58] Under our proposal the Crown would be permitted to quarantine an allocation of contracts for independent participants, and so also ensuring that these products are packaged in a way that is desirable for independent parties. Further, the Crown could accept a level of prudential support and credit worthiness from independent participants that may have been rejected by Genesis.

Initially New Co would negotiate with Genesis on commercial terms for the service. If agreement is reached the generator would operate under the agreement. If no voluntary agreement is reached, the Minister(s) can mandate the operation of the generators for the Crown by applying a regulated pricing solution through mandatory acquisition. The existence of the mandatory acquisition option will discipline the negotiations and so increase the prospect of a fair price being agreed. This approach is modelled on the approach taken in Australia for the Orderly Exit Management Framework (OEM Framework). This is a model, which is prescribed in the National Electricity Rules, that pays thermal capacity to remain in the market to support reliability and security of supply in a highly renewable system.[59] It is our view that the presence of this backstop should ensure that it is not needed and a reasonable commercial agreement can be reached.[60]

The contractual arrangement would need to ensure that the plant was made available when required by New Co in a similar manner to currently exists under the HFO.

Medium-term actions

New Co would either enter a long-term tolling arrangement for Huntly and/or buy the generator from Genesis. It could also contract with, or acquire, from Contact Energy the Taranaki Combined Cycle (TCC) generator, which has limited life but could be refurbished. Again, a fall-back mandatory acquisition option would exist to discipline negotiations.

The nature of the tolling agreement would allow New Co to toll coal or gas through the Huntly and/or TCC generating units, meaning that:

- New Co would procure the fuel, e.g., coal or gas
- The toller, namely the power plant operator, converts the fuel into electricity,
- New Co owns the electricity that is produced.

Under this option, with a strong assurance of fuel availability, the System Operator would then have additional confidence to use water resources, including the strategic reserve. This would then see a reduction in spot and contract prices during a dry year than might have otherwise been the case.

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58 https://www.aspecthuntley.com.au/asxdata/20240513/pdf/02805893.pdf , p.7.

59 See: https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/system-planning-working-group/orderly-exit-management-framework

60 This is because Genesis should prefer to reach a negotiated agreement than be subject to a determination by arbitrator or regulator.

We note that procuring the fuel is a critical function for New Co. This is something that is essential to provide fuel security for New Zealand. This means that over the medium term, the primary function of the entity is to provide long-term assurance to the gas sector, and potentially coal sector, that they can develop resources and explore fuel supply options with confidence that there is someone available to put real capital behind this investment over a long-term horizon.

Currently coal and domestic gas appear the most affordable options for fuelling thermal capacity. The key risk is whether new gas supply can be found to take some of the price pressure off fuel and also to remove the reliance on sourcing coal from outside of New Zealand. We think considerable resources should be employed to provide New Zealand fuel security through domestic options. This means underwriting gas field drilling and exploration, as well as investigating the ability to mine additional coal at Rotowaro.

If economic supplies of domestic gas is not possible, it may be necessary to develop an LNG import terminal, although this is unlikely to be as economic as domestic gas. It would make no economic sense to develop an LNG import terminal to meet just dry year risk as the large fixed costs would be spread over a relatively small amount of output. If an LNG terminal is contemplated as a last resort to provide NZ with a secure energy system, this should be considered as part of a wider gas supply strategy for communities and industrial users where gas is the most economic source of energy, having regard to the higher operating costs of imported gas but also to the avoided costs of electrifying domestic appliances and industrial heat processes. Consideration of the LNG import terminal ought to be a task that is undertaken by New Co, and with the government as their owner.

While it is clear that securing fuel supplies is critical, we emphasise that resolving fuel supply issues will not be sufficient to address the issues identified in this chapter given the disincentive for participants to own and invest in thermal generation assets.

Longer-term actions

Over the longer-term New Co would identify and invest in new physical generation options having regard to:

- The amount of capacity that is required, and
- The fuel options that are available.

Investment can be in the form of long-term contracts with developers of generation assets. However, New Co should retain the option to own the assets itself given this ensures the capacity can be built even when no other party is willing to, or at least not willing to do so at a reasonable price.

Over the longer term, the focus should be on ensuring fuel supply security for New Zealand.[61] Once there is a clearer picture of domestic gas and coal supply, further consideration can be given to options such as an LNG terminal or the use of biomass and green gas/hydrogen. We consider that an LNG terminal should be considered a last resort, recognising that doing so exposes New Zealand to the global price of gas, which would have implications for the competitiveness of industry with high gas demand.

[61] We are aware that the Government has announced a tagged contingency of $200 million over four years for co-investment in new gas fields. Given this was announced on the day before our report was due, we have not undertaken detailed analysis of this initiative. See: $200m set aside for Crown stake in new gas fields | Beehive.govt.nz

4.5.3 The proposed Huntly Heads of Agreement and the Huntly Firming Option

Based on our view that the currently proposed Heads of Agreement for Huntly would entrench the potential for market power in the market and would not solve the long-term issues of fuel supply and investment in new capacity, our recommendation is that this agreement does not proceed. Furthermore, to the extent that Genesis recommences the Huntly Firming Option, it is our view that this option will not drive new investment in the market for assets that provide the necessary firming service and also means that independent operators remain dependent on gentailers for firm capacity.

4.6 Alternative options

In developing our proposed solution we have considered several other options that have been adopted internationally and that have been raised with us during the course of this review. In our view, these options would not resolve the underlying problem, and in some cases will lead to reduced security of supply and higher prices over time.

Box 2: International approaches to capacity planning for system reliability

Capacity planning and investment for system reliability is a critical function in power systems worldwide to ensure that electricity supply meets demand under varying conditions. Different countries adopt diverse approaches, ranging from centralised, government led planning to market based mechanism that rely on price signals and competitive auctions.

Table 1: Market summary of international approaches to identify resource needs (2023, unless stated otherwise)

	Brazil	Columbia	CASIO	ERCOT
Population (million)	211	52	39	31
Peak demand (MW)	100,900	11,475	44,534	85,199 (2024)
Installed Capacity (MW)	225,952	19,918	87,753	138,069 (2024)
Hydro capacity (MW)	109,922	13,206	14,045	572 (2024)
Method to identify resource needs	10-year demand/supply forecasting	15-year demand/supply forecasting	Demand/supply forecasting to 2040	Equilibrium RM estimate 4-yr ahead, reliability assessment (past and 3-yr ahead), resource adequacy (5-yr ahead)

Mechanisms to secure firm capacity	New/existing energy auctions (regulated market, obligations to be fully contracted (regulated or unregulated)	Reliability charges, energy expansion auctions, early entry incentives	LSE obligation to procure 100% of projected load + reserve margin	Reliability Unit Commitment, Reliability-Must Run, Long-term additional ancillary service and financial support

Source: Frontier Economics

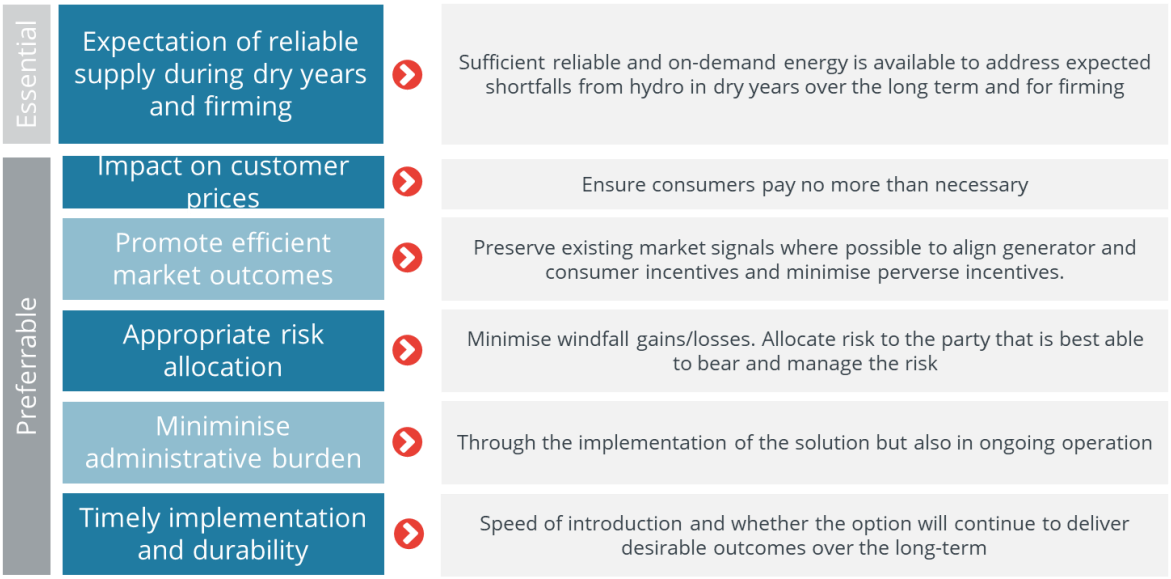
We set out these international arrangements in more detail in Appendix A.

The alternative solutions we considered in detail for New Zealand are:

- **Implementing the status quo** – this would be progressing with the Heads of Agreement, further developing the Huntly Firming Option and implementing the level playing field proposals.
- **Default regulated provider** – under this option, Genesis Energy would be formally designated to provide a pre-determined amount of firm capacity to the market under a regulatory scheme.
- **A strategic reserve** – similar to the previous Whirinaki reserve generation solution, this solution would see the System Operator procure capacity that is kept outside of the market and used only in specific emergency situations when hydro capacity is low. The capacity is procured through competitive tenders and paid for through an industry levy.
- **A capacity market** – this form of market pays generators for making capacity available regardless of actual electricity generation. This option represents a major market overhaul of the existing market design with extensive regulatory and administrative costs.
- **Mandatory contracting** – this would require retailers to have contracts for firm supply that would cover a dry year risk.
- **Tradable certificates** – under this option retailers and large users would be required to procure certificates for secure supply based on their market share.

We compared each of the options against assessment criteria. We note that one criterion, that the solution deliver an expectation of reliable (and secure) supply during dry years and for firming, is an essential criterion, while the others are preferrable. Our assessment criteria is set out in Figure 30 below.

Figure 30: Assessment criteria for options to address dry year risk and firming



Source: Frontier Economics

We have scored each of the models against the assessment criteria, where a full circle reflects that the option meets the criterion very well, an empty circle very poorly, and gradients in between that reflecting the degree the criterion is met or not.

Table 2 below provides a summary of our assessment of the models against the criteria.

Table 2: Assessment of models to address dry year risk and firming

	Reliable supply	Customer prices	Efficient market	Risk allocation	Admin burden	Timely and durable
Implementation of current proposals	◔	◔	◔	○	◑	◑
New Co	●	●	◕	●	◑	●
Regulated Genesis	◕	◑	◑	○	◔	◕
Strategic Reserve	◑	◔	○	◕	◕	◑
Capacity Market	◑	◑	◔	○	○	◔
Mandatory Contracting	○	○	◔	○	◔	○
Tradable Certificates	○	○	○	○	◔	○

Source: Frontier Economics

Our assessment shows that the proposed New Co option best meets the criteria. Notably, a key limitation of the alternative options is that they do not adequately achieve the essential criterion

to deliver secure and reliable supply during dry years and for firming. The key reason for this is that the alternative options do not fix the core problem in New Zealand. This is that the policy risk and preferences of shareholders mean that there is a disincentive to invest in the thermal assets needed to support dry year risk. Furthermore, in most of the alternative models certain generators would likely exhibit substantial market power that would drive up prices. To attract addition investment in new capacity with some of the alternative models the price would need to be so high to overcome the risk that it would drive electricity prices to higher levels than they are today.

We present a detailed assessment of each of the options in Appendix B.

5 Competition and market outcomes

5.1 Introduction and summary of findings

In this chapter we discuss the impact of market design and market rules on competition having regard to conduct and performance in the New Zealand electricity market.

We are aware that there has been significant debate in New Zealand about whether the gentailers are misusing market power and if they should be broken up or regulated. However, the real issue is not competition, it is investment. It is the lack of investment in new firm capacity over recent years, including for firm capacity to address dry year risk, that has been the driver for market outcomes rather than anti-competitive behaviour. There is no doubt that the market power of all incumbents – small and large - increases when there is greater capacity and energy scarcity, but this increase in market power is a symptom of the underlying problem and not the cause of the problem.

In fact, there is evidence that rather than the gentailers misusing market power at the expense of consumers, they are shielding consumers at the expense of their own margins (see Section 5.3.3 for a discussion on retail margins).

The New Zealand electricity market has a structure to support effective competition, with multiple large and small players and concentration rates below internationally recognised thresholds or below concentration rates seen in other electricity markets. Further, electricity costs to households and commercial customers have been declining in real terms in recent years. While some industrial customers have faced higher costs, in some cases this seems to be a consequence of customers making decisions to be exposed to more spot electricity price risk rather than paying the price of hedging. Almost certainly customers have made this choice because of the elevated cost of hedging due to the high value of hedges in dry years.

Our proposal for Crown investment in firm thermal capacity will further bolster competition. It will level the playing field between independent operators and gentailers without diluting the efficiency benefits that come with vertical integration.

Although we do not have material concerns with competition in New Zealand, some issues exit:

- Independent generation developers struggle to sell their capacity without firming products, making them dependent on the flexible generation owned by the gentailers. This is also an issue for large industrial customers. However, this issue will be addressed by our proposal for New Co.
- Retail switching for residential and small-business customers is more difficult than it needs to be due to:
  - A lack of immediate access to customer data to permit easy and quick price comparisons, and
  - No standardisation of bill formats which makes price comparisons more difficult.

  These issues should be resolved as quickly as possible for the benefit of consumers, noting that new legislation has recently passed that will enable the access to customer data.

Two of the current Energy Competition Task Force initiatives focused on competitive outcomes – the non-discrimination rules and virtual disaggregation – will cause increased costs for electricity

users and will not address the underlying problem of a lack of new firm capacity in the market. We recommend they do not proceed.

5.2 What is the desirable market outcome?

Competition refers to the rivalry between two or more firms selling identical or similar products or services to customers. The rivalry between firms is what constrains their behaviour in a market. Rivalry ensures firms cannot arbitrarily increase prices or reduce service quality without the risk of customers choosing a more affordable or superior alternative. Crucially, this rivalry is driven not only be current firms in a market but also by the potential for new firms to join the market as rivals.

When a market operates competitively, it is expected to deliver outcomes that benefit society as a whole. This is because competition fosters cost efficiency and encourages optimal investment. Together, with fair and efficient pricing, these factors promote the efficient use of goods and services by consumers.

In practice, markets do not match the textbook ideals of competition. The aim, therefore, is for markets to be 'good enough' at promoting efficient outcomes for consumers. Terms such as 'workable' or 'effective' competition have been used to describe situations where competition is sufficient to promote economic efficiency. What this means in practice is that even where markets are considered 'effective' there can be times when participants possess a degree of market power over the short term – known as transitory market power. However, it is these periods of transitory market power in an energy only market that are highly influential in investor entry decisions. That is, new entrants will enter the market to capture those higher prices with the outcome that prices then revert down to competitive market levels after new entry has occurred. At times where prices are too low higher cost operators will be forced to exit the market where market prices fall below their avoidable cost. The implication of these outcomes being that competition needs to be assessed over the long term, not based on a dry year sequence.

Measures of competition that may be adopted by competition regulators includes the following:[62]

- There are active participants in the market with a market share sufficient for them to operate sustainably in the market
- Prices over the long term, by and large, reflect underlying costs rather than market power, accepting that one or more firms may hold market power from time to time
- It is sufficiently easy for firms to enter the market so that when prices rise above competitive market levels this occurs only on a temporary basis, and
- There is evidence of independent rivalry between firms in terms of their prices, and products or services offered in the market.

5.3 Current market

When analysing the effectiveness of competitive markets, it is common to focus on several dimensions of a market, namely:

- The structure of the market, which is the number and type of participants and how easy or difficult it is for new firms to enter or leave the market

[62] In chapter 11 we consider competition analysis and market monitoring in further detail, including highlighting the challenges and limitations associated with focusing on these types of indicators.

- Market conduct, which refers to the behaviour of market participants and customers. This includes how firms compete and interact with other firms in the market, and
- The performance of the market, which refers to the outcomes of the market with respect to prices, profit and service performance.

The following sets out the current market with respect to these focus areas. For market structure we consider both wholesale and retail markets, while conduct and performance in the wholesale market has been addressed, at least indirectly, in Chapters 3 and 6, which address generation investment and the extent that contracts are made available to market participants, we consider only retail market conduct and performance in this Chapter.

5.3.1 Market structure

Retail market

The current retail market structure is currently made up of 38 retailers. The majority of the market is comprised by the four large gentailers, being Genesis, Contact, Meridian and Mercury and their subsidiary retailers. The gentailer subsidiary retailers typically operate as low-cost, low service providers.[63] Together with Powershop, the gentailers and their subsidiary retailers provide for 89% of the retail customer base as of February 2025. The 27 independent retailers account for the remaining 11% of the share of retail customers. The structure of the retailer ownership as at February 2025 is set out below:[64]

Table 3: Retailer structure summary as at February 2025

Retailer type	Brands	Customers (ICPs)	Proportion
Gentailer	5	1,760,499	76%
Gentailer subsidiary	6	314,990	14%
Independent	27	254,780	11%
Total	**38**	**2,330,269**	**100%**

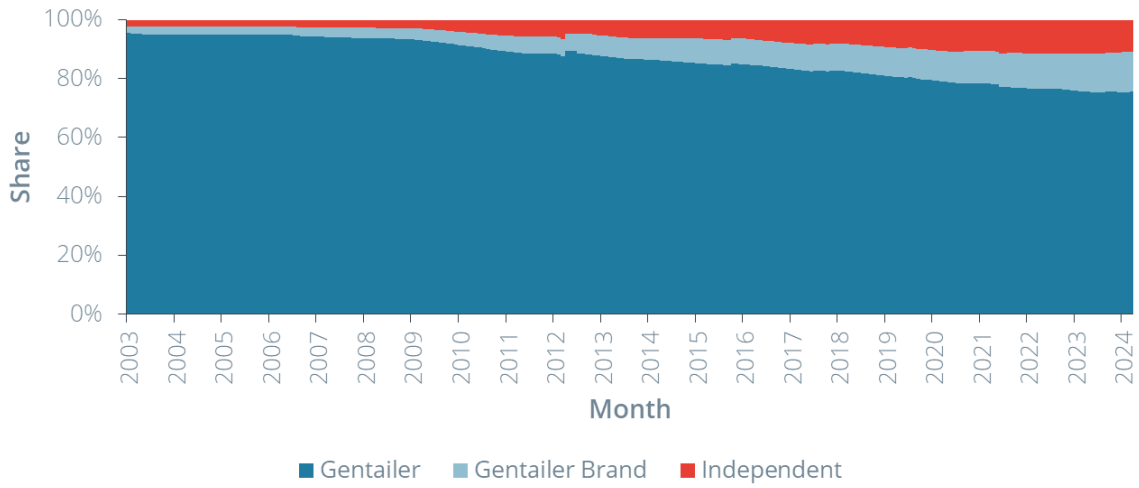
Source: Frontier Economics analysis of the EMI 'Market share trends' data on the EMI website

Notably, however, the independent retail market share has increased significantly between 2010 and 2020, rising from 3 per cent to around 11 per cent. Figure 31 shows the change in the share of customer connections (ICPs) for the gentailers compared to gentailer brands and independent retailers over time. We note that while independent retailers have grown their share, the large gentailers and their subsidiary companies have typically maintained over 90% share.

63 For instance, all billing and customer interaction may be online and there is no call-centre available to resolve issues.

64 We note that since this data was produced there have been several key developments in the retail market. First, a new Gentailer was formed with Lodestone entering the retail market. Second, Meridian acquired customer contracts from Flick and Z Energy, subject to conditions and regulatory approval. We have not updated the data recognising Loadstone only has one commercial customer at present and the Meridian purchase of customer contracts remains subject to conditions.

Figure 31: Retail market share by ICP



Source: Frontier Economics analysis of the EMI 'market share trends' data on the EMI website

The changes in retail market share are reflected in the retail customer switching data. Over the decade between February 2015 and February 2025 larger gentailers Genesis, Contact and Mercury have all seen a net negative of customer switches, resulting in a positive switch for smaller independent retailers. The only exception from the gentailers was Meridian, who had a net customer switch volume comparable to independent retailers Electric Kiwi or 2degrees.

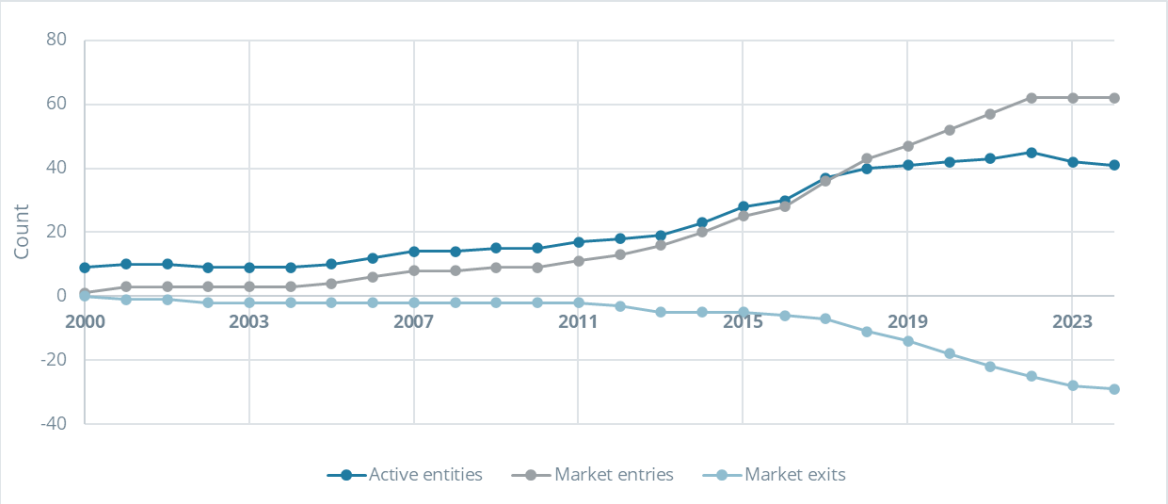
Table 4: Retailer customer switching summary (Feb 2015 – Feb 2025)

Entity	Gains	Losses	Net
Genesis Energy	920,366	1,026,566	-106,200
Contact Energy	727,776	784,520	-56,744
Mercury	697,516	804,013	-106,497
Meridian Energy	680,860	602,222	78,638
Electric Kiwi	215,444	155,364	60,080
2degrees	161,558	104,918	56,640
Flick Electric	118,648	76,951	41,697
Other retailers	473,612	409,034	64,578

Source: Electricity Authority - EMI (market statistics and tools)

There have been 62 businesses enter the retail market since the year 2000, with a corresponding exit of 29 retailers. Market entry has outpaced exits, suggesting incentives exist for market participants to enter the New Zealand retail market and seek to expand. As demonstrated in Figure 32, the bulk of the market entry occurred from 2017, with the market exits occurring after 2019.

Figure 32: Retail market entry-exit since 2000



Source: Frontier Economics analysis of EMI retail 'entry and exit' data from the EMI website

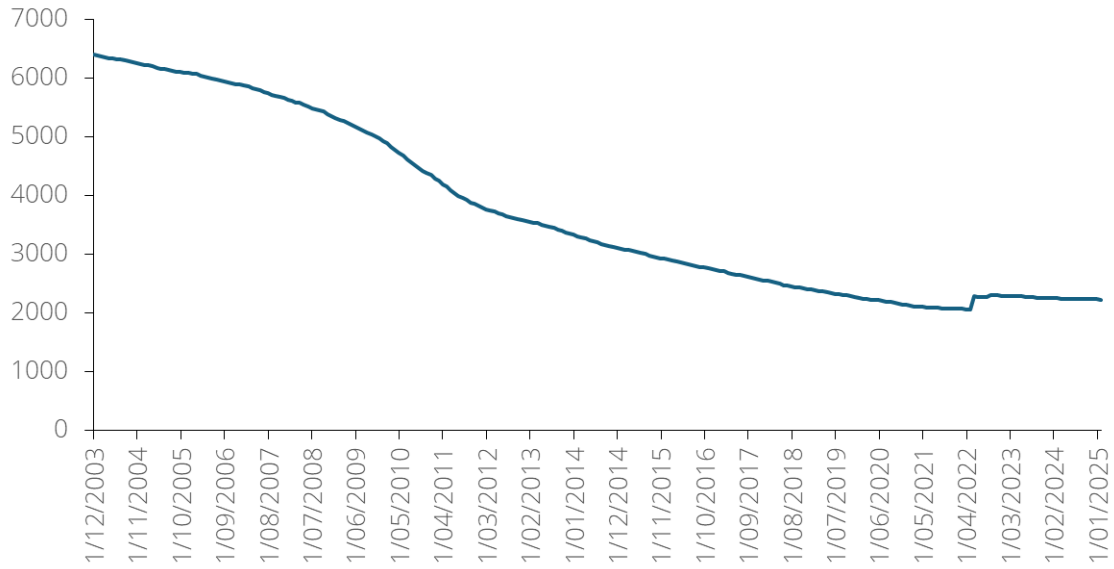
An indicator that is commonly used in competition analysis to assess the extent of concentration in a market is the Herfindahl Hirschman Index (HHI), which is the sum of the squares of the market shares of all firms in the market. The Australian Competition and Consumer Commission (ACCC) cites that it is less likely to be concerned about concentration when the HHI is less than 2,000, or where, in the context of a merger, above 2,000 with a post-merger change of less than 100.[65] The European Commission also adopts 2,000 as a threshold.[66] The Australian Energy Regulator (AER), when reporting on electricity and gas retail markets, formerly reported a threshold of 2,500 as highly concentrated, however, in its most recent report it cited a figure of 2,000. Importantly, while the HHI is a valuable screening tool, the thresholds must be contextualised with market realities. This means that the threshold signals potential concerns rather than definitive anti-competitive outcomes, with the implication that additional analysis is required on structural and behavioural factors before conclusions can be reached.

As shown in Figure 33, while the level of concentration was lower in 2022 than it is today reaching a low of 2,054, it has been consistently falling over the time. The step change in 2022 would reflect the transfer of customers from Trustpower to Mercury, which has bumped the HHI to a figure that is well above the HHI threshold of 2,000. Even though this is the case, since 2022 the downward trend in concentration has continued.

65 ACCC, 'Merger Guidelines' November 2008, updated November 2017, p.35

66 https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52004XC0205(02)

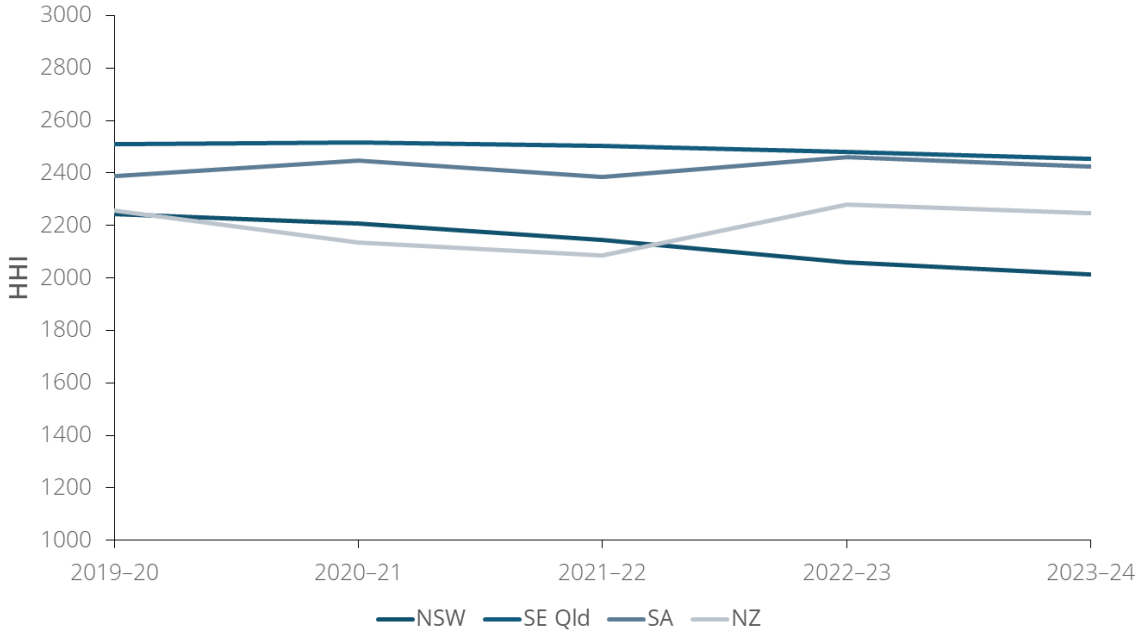
Figure 33: HHI for the New Zealand retail market



Source: www.emi.ea.govt.nz/r/3kw5l

As suggested above, the AER compares HHI figures across Australian NEM jurisdictions (with the exception of Victoria). This shows that the retail concentration is lower in New Zealand than all Australian regions in the AER data other than New South Wales. Noting that the Australian Capital Territory and Tasmania have substantially higher HHIs, with 5,699 and 8,736 respectively for 2023-24 financial year. Indeed, before the Trustpower customers were transferred to Mercury, New Zealand had superior HHI figures than all of the regions reported on by the AER. We also note, as identified above, that prior to the most recent analysis, the AER adopted a threshold of 2,500 as demonstrating highly concentrated, and only reduced this to 2,000 for its most recent report.

Figure 34: Comparison of New Zealand HHI to Australian Jurisdictions



Source: www.emi.ea.govt.nz/r/3kw5l and https://www.aer.gov.au/documents/schedule-2-quarter-4-2023-24-retail-performance-data

Wholesale market

On the supply side, we considered two key market concentration indicators, namely:

- The HHI, and
- The three firm concentration ration (CR3) – which is the sum of the shares of the three largest firms in a market, with a ratio above 70-to-80 per cent indicating a highly concentrated market.

For each concentration indicator we considered three scenarios. This was to identify if there were particular market conditions where there was a high level of concentration in the market. These scenarios were: all capacity, all capacity minus peaking generation, and all capacity minus wind and solar generation.

The analysis shows that, except for all capacity minus peaking generation, for HHI and CR3, the New Zealand wholesale market does not breach the thresholds for a highly concentrated market. For the one scenario above 2,000, this is only by a small amount. While this suggests a moderate level of concentration, this is not unusual for the wholesale electricity sector given the high capital costs involved.

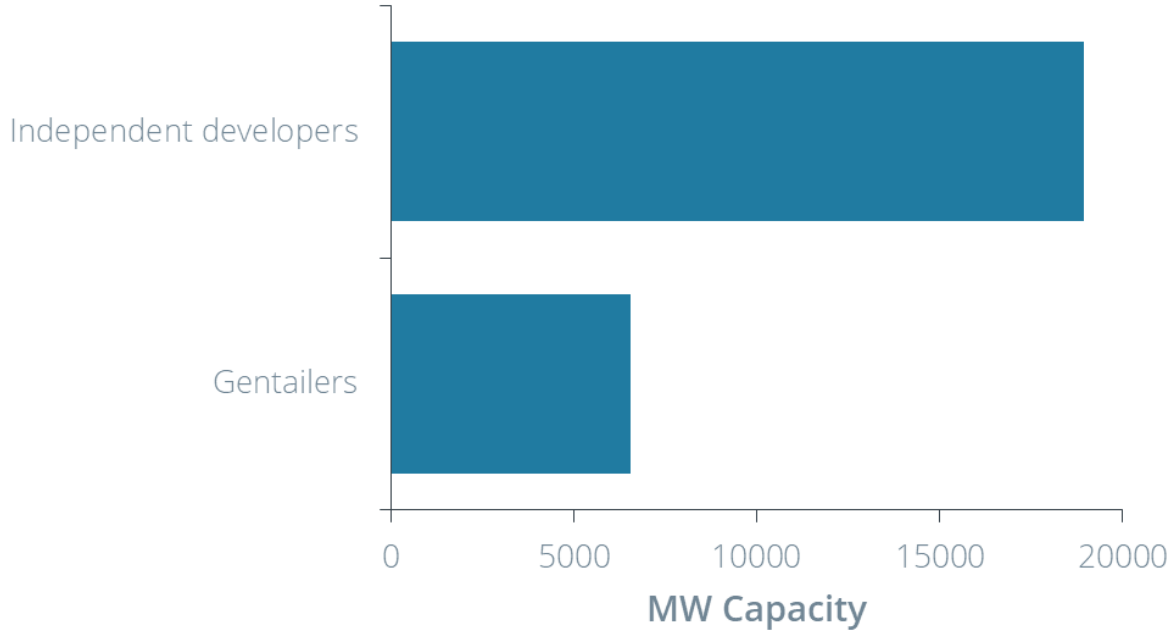
Table 5: Market concentration indicators

Scenario	HHI	CR3
All capacity	1,929	67.52
Minus peaking generation	2,009	68.97
Minus BESS and wind and solar generation	1,917	69.60

Source: Frontier Economics analysis of the EMI Generation Fleet dataset and Generation MD datasets on the EMI website

As identified previously, a large proportion of proposed investment in generation is being undertaken by independent developers.

Figure 35: Capacity pipeline by developer type



Source: https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/GenerationFleet/Proposed

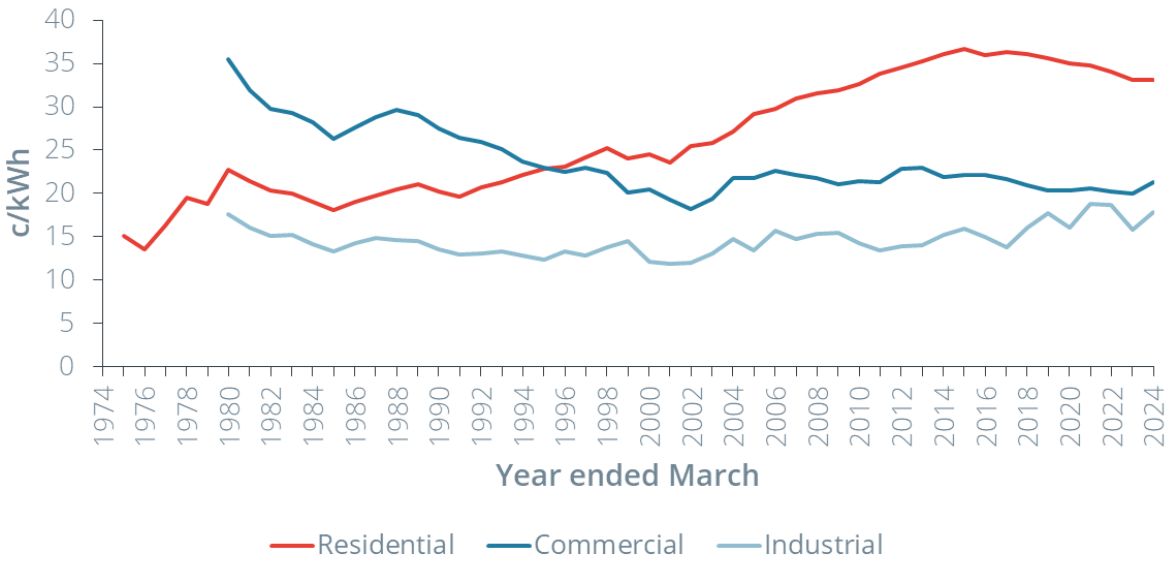
Other methods commonly used to test for market power in wholesale electricity markets include pivotal supplier tests and residual demand analysis. These techniques assess whether a generator becomes pivotal, that is, total demand cannot be met without its output, once the capacity of all other generators capable of responding has been exhausted. When a generator is pivotal, prices become highly sensitive to its bids, and it may be able to set the spot price unconstrained by effective competition.

We have not applied these techniques in this report because, to perform them accurately, they require detailed knowledge of each generator's contract position for every trading interval. Without knowing a generator's net contract position, it is impossible to determine its incentive or ability to influence the spot price. For example, a generator that is fully hedged in a given interval faces no commercial incentive to bid above its short run marginal cost.

5.3.2 Market conduct

There is limited data available on final retail prices over time in New Zealand. Nevertheless, it is possible to infer price outcomes for consumers based on data that is available. Figure 36 shows that the cost of electricity for residential customers has been falling in real terms since approximately 2014. Commercial electricity costs have also been falling over a similar period. Given this data is total energy cost divided by demand, this could be caused by increased use or the structure of prices shifting more to daily fixed charges. Irrespective, the cost to customers on a per kWh basis is falling. For industrial customers, electricity costs appear to fluctuate year to year, which may reflect the extent they are exposed to spot prices or not.

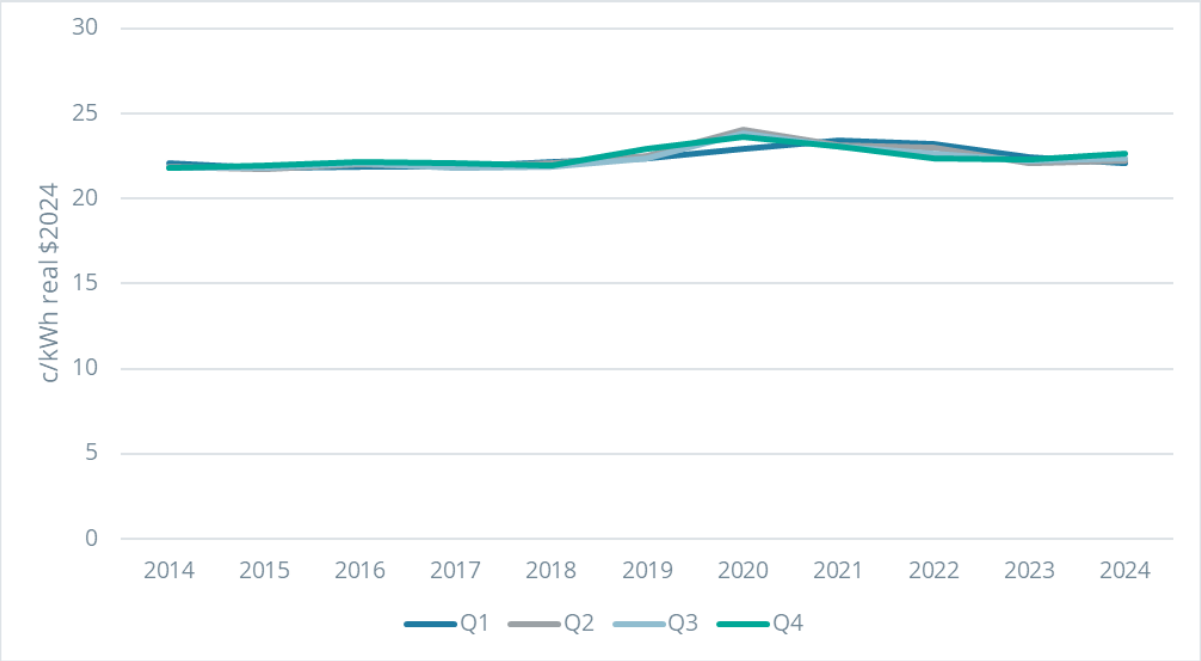
Figure 36: Real (2023) electricity costs 1974 to 2024



Source: MBIE Quarterly Price Update

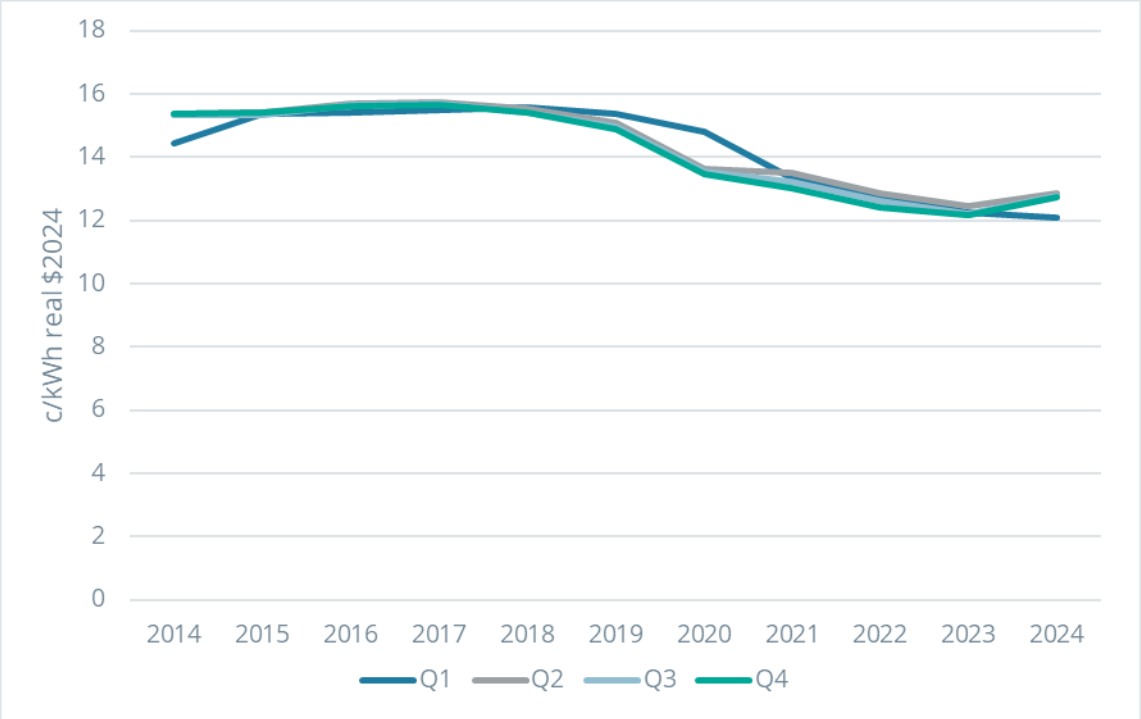
The stability or decline in residential electricity costs aligns with trends in the cost of supply, which drive retail prices. Specifically, while the wholesale and retail cost components of average residential electricity prices have remained relatively steady in recent years, overall cost reductions have been driven by decreases in the lines component. This is shown in Figure 37 and Figure 38 below.

Figure 37: Quarterly wholesale and retail cost to serve component of average residential electricity prices



Source: https://www.rbnz.govt.nz/statistics/series/economic-indicators/prices

Figure 38: Quarterly lines component of average residential electricity prices



Source: https://www.rbnz.govt.nz/statistics/series/economic-indicators/prices

Figure 39, sourced from the Electricity Price Review undertaken by the New Zealand Government over 2018 and 2019, shows the variation in electricity bills across residential customers. The distribution shows that while many customers pay close to the average annual bill, there are

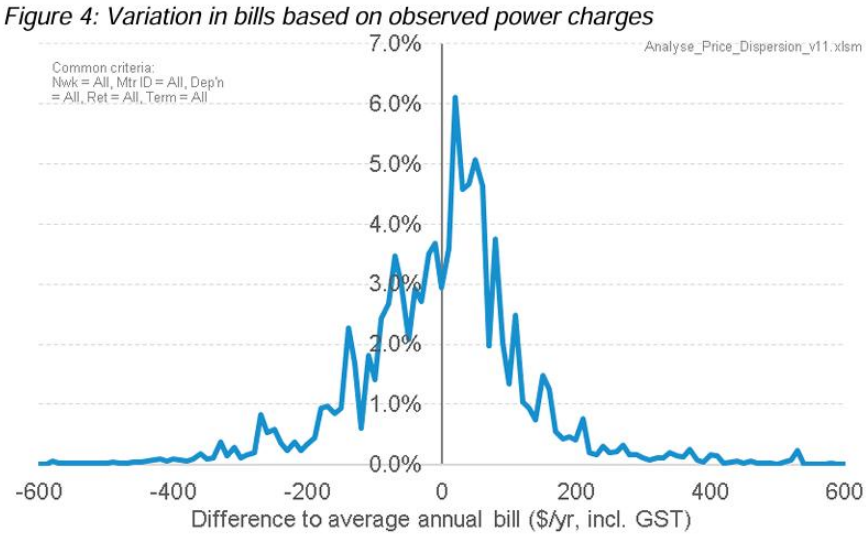
long tails on both sides. This indicates that some customers benefit from lower prices, while others pay significantly more.

The spread of outcomes for customers has several implications. First, it suggests that many customers could achieve substantial savings by switching to a more competitive retail offer. Secondly, it highlights the likelihood that at the time this data was gathered that retailers could identify and retain 'sticky' customers – i.e., those customers less likely to switch – and charge them higher prices.

A key factor enabling this practice at the time the data for Figure 39 was gathered was the ability of retailers to 'win back' customers when they attempted to switch. This meant retailers could delay offering competitive rates until a customer was actively leaving. With the banning of win-backs in New Zealand following a recommendation in the Electricity Price Review, it is likely that price dispersion has narrowed, as retailers now need to offer better prices upfront to retain customers. However, we do not have data to confirm this.

While we do not have access to the latest price dispersion data, we were informed that material savings remain available for those who switch. Specifically, we were told in discussion with stakeholders that 90% of customers could save at least $100 per year, with an average potential saving of around $500 per year. This suggests conditions may have improved since 2018, though there is still room for further progress.

Figure 39: Variation in bills based on observed power charges



Source: Electricity Price Review, Initial Analysis of Retail Billing Data, 15 October 2018, p.13

Innovation in a market is also an indicator of competitive conduct. The Electricity Authority has identified that there is considerable innovation occurring in the retail market in New Zealand. This finding was made in the Authority's Issue Paper for its review of risk management options for electricity retailers. It identified around 80 innovations that had been introduced over a 10-year period.[67] Table 6 below replicates a table in the Authority's Issues Paper that includes what it considered to be significant shift innovations over the past 10 years.

[67] Electricity Authority, Reviewing risk management options for electricity retailers – issues paper, 7 November 2024, p.9.

Table 6: Electricity Authority's assessment of significant innovations over the past 10 years

Year	Innovation example	Context and magnitude	Innovation type	Type of retailer
2014	Usage monitoring	Architectural	Technology	Gentailer
2014	Solar buy-back	Architectural	Network	Gentailer
2014	First app	Architectural	Marketing	Gentailer
2015	Mass market customer access to spot price	Architectural	Network	Independent
2015	"Free hour of power"	Disruptive	Customer engagement / retention	Independent
2016	Time of use charging	Disruptive	Customer engagement / retention	Independent
2019	Internet of things connectivity	Disruptive	Network	Gentailer
2020	First 'roaming' EV charging	Disruptive	Network	Gentailer
2022	Virtual solar	Radical	Technology /Network	Independent

Source: Electricity Authority, Reviewing risk management options for electricity retailers – issues paper, 7 November 2024, p.10

Customer interaction with the market

There is significant variation in billing information provided by New Zealand electricity retailers. We understand that these differences include:

- Differences in what information is presented
- Differences in how usage and cost information is broken down, and
- The terminology that is used in bills.

In addition, we were told that some electricity bills are missing important information that would make electricity purchase decisions easier. This might include historical consumption data or information to assist in price comparison. The 2018 Electricity Price Review identified that customers indicated that more understandable bills would help them to compare plans and switch to retailers offering better deals.[68]

[68] Electricity Price Review, 21 May 2019, p. 1.

Currently retailers are required to give customers their usage data within five working days for no fee. This means that customers cannot get instant access to their usage data. This is data that could be used to identify market offers that would save the customer the most money. In the 2018 Electricity Price Review there was a recommendation that the Electricity Authority give retailers six months to agree on a quick and simple procedure for processing customer requests for consumption data, and if that does not occur, it should impose a procedure.[69] We understand that this recommendation has not been implemented. We can see no good reason why this important change has not been made.

5.3.3 Market performance

Profitability is often a key focus when assessing competition in a market. However, this is a metric that is difficult to assess due to data limitations and variations in how profit might be reported for a regulatory purpose versus for an accounting purpose.

In New Zealand the Electricity Authority reports on retail gross margins. In this case, the retail gross margin represents the revenue received by the retailer after its costs, which include energy purchase costs, metering, levies and distribution costs. The energy cost for the gentailers is an internal transfer price, which for most of the gentailers is determined using a 3-year rolling average of historical ASX prices, for independent retailers it is the actual cost of energy.[70]

We recognise that the three-year rolling average of ASX electricity futures is an imperfect proxy for gentailer costs. However, in a well-functioning market the ASX price will reflect the opportunity cost of their generation and therefore the market value of that output. Furthermore, our experience suggests that a three-year rolling average is not inconsistent with how retailers actually buy contracts. For this reason, we conclude that ASX contract prices will at least be indicative of wholesale costs for gentailers and provides a market-based price for electricity. While for independent retailers the wholesale cost is their actual cost, so we do not see any issue with the appropriateness of relying on that data. The margin in this case includes both the retail cost of service, so billing systems and marketing costs, and any retail profits. The implication being that the actual profit earned will be less than what is reported as a margin.

We are aware of comments that it would be more appropriate to use spot prices to assess retail margins because forward contracts do not represent the retail opportunity cost of selling retail electricity. It is our view that using actual contracting costs, or a suitable proxy, is appropriate for estimating retail margins. This is because fixed-price retail contracts oblige retailers to supply customers for the agreed term. As a result, a retailer cannot withhold supply, divert the electricity to another customer, or freely re-sell the volume into the spot market without breaching its contractual and regulatory obligations. If an opportunity cost analysis was to be used, the most accurate measure would be the contract price at the time that a retail contract is agreed. However, we accept that this does not reflect how retailers actually hedge, with most retailers adopting a longer-term approach, as noted above.

The data shows that across all the years where data is available, the independent retailers achieve higher margins than the gentailers. In 2024, the difference in the margins between the independent retailers and the gentailers widen considerably, with the gentailers exhibiting a material fall in their gross retail margin.

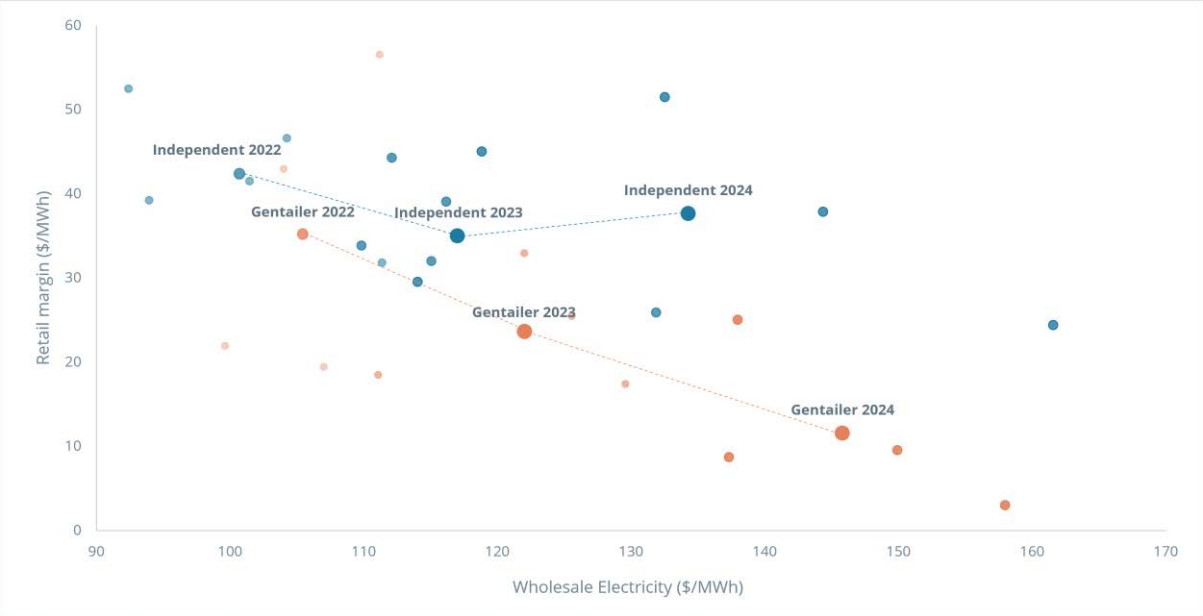
It is apparent, from Figure 40 below, that the gentailers are also incurring significantly higher energy purchase costs compared to the independent retailers. This is likely to be due to differences in hedging strategy, and so hedging costs, between the retailers. We note that the gap is sufficiently large such that even where the gentailer's energy purchase cost is lower than

[69] Electricity Price Review, 21 May 2019, p. 34.

[70] Electricity Authority, Internal Transfer Price and Retail Gross Margin post implementation review', 7 November 2024.

reported, there is likely to be some gap still between their margins and those of the independent retailers.

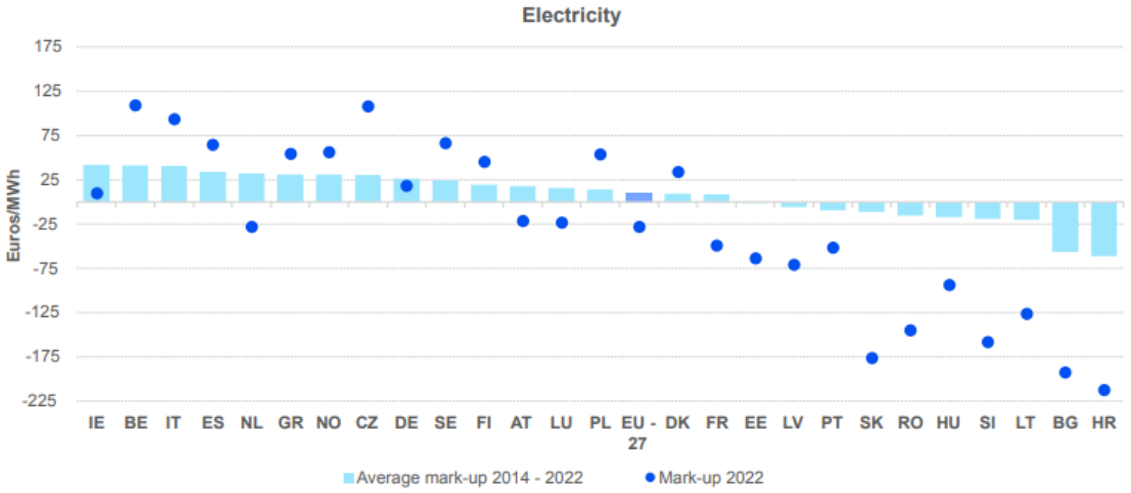
Figure 40: Retail gross margins 2022-2024



Source: Frontier Economics analysis of Electricity Authority data

Whether the margin outcomes in New Zealand are consistent with other retail electricity margins in other jurisdictions is difficult to ascertain. Even within a single jurisdiction undertaking margin analysis can be difficult given there is a lack of transparency around actual costs, when comparing to other jurisdictions additional complications arise, including how to normalise differences in accounting and cost structures across businesses and jurisdictions. Nevertheless, Figure 42 shows reporting on gross margins across Europe for electricity retailers. Over the period of analysis, it shows in some regions the average margin has been negative, while in others positive. While we do not have access to the underlying data, it appears the EU average was around $19.00 based on current exchange rates (around 10€). This result is consistent with the margins earned by gentailers in New Zealand, but below those reported for independent retailers in New Zealand.

Figure 41: Average annual mark-up in retail electricity and gas markets for household consumers in European Union Member States and European Economic Area Member Norway from 2014-2022, and annual mark-up in 2022 (euros/Mwh)



Source: Figure 37, European Union Agency for the Cooperation of Energy Regulators, and Council of European Energy Regulators, Energy Retail and Consumer Protection, 2023 Market Monitoring Report, September 2023.

We note that margins that are earned in the wholesale market are another relevant metric. In this case, in the time available, we have had difficulty in calculating a sufficiently robust estimate of the margins, recognising reporting differences across businesses is a material limitation in this respect. Furthermore, while the Electricity Authority does report on an 'energy margin', this does not take into account the opportunity cost of water, and so assumes this resource is free. Nevertheless, it is clear from reviewing the annual reports of the gentailers that, unlike for the retail sector, they are earning positive margins on the wholesale side of the business.

5.3.4 Energy Competition Taskforce

The Electricity Authority and Commerce Commission have jointly established the Energy Competition Task Force to investigate ways to improve the performance of the electricity market following sustained high wholesale prices in August 2024. The Task Force's work program is directed towards two outcomes, namely:

- Enabling new generators and independent retailers to enter, and better compete in the market, and
- Providing more options for consumers.

It is considering new initiatives as well as some that have already been proposed, for instance, those included in the MDAG report. Initiatives relevant to market competition that have recently been implemented, proposed, or are in train, include the following:

- Non-discrimination arrangements for electricity supply contracts, and
- Virtual disaggregation of the flexible generation base.

Other initiatives go more directly to risk management tools and so will be addressed in Chapter 6 that deals specifically with hedging and risk management.

Level playing field options

On 27 February 2025 the Task Force published an Options Paper on Level Playing Field measures. The key finding from that Options Paper was that there should be mandatory non-discrimination obligations on the gentailers. The expectation being that this would give non-integrated retailers and generators access to products (such as hedge contracts) on substantially the same terms as gentailers supply themselves internally. Initially this proposal would be implemented with principles-based rules, with the ability to escalate the obligation through more prescriptive measures if necessary.

Virtual disaggregation of the flexible generation base

The option for virtual disaggregation would be a form of 'virtual' break-ups of the gentailers rather than a requirement for divestment of physical assets. While the initiative is yet to be fully formed, we understand that it would require gentailers to auction a minimum volume of their flexible generation base to buyers in the form of risk management contracts. The intention being to mimic the effect of physical disaggregation. Ownership and generation dispatch rights would remain unchanged.

5.4 Our assessment of current market arrangements

Effective competition, including through the success of smaller independent operators, is integral to the success of the New Zealand electricity market. Aside from presenting a threat to gentailers, independent operators can lead the way on better, low-cost and innovative services for consumers. In turn, they motivate the larger businesses to innovate and offer lower prices themselves to retain customers. Equally, it is beneficial that there are enough larger competitors to ensure no single firm is able to dominate the market.

The survival or demise of independent operators is an indicator to potential new entrants of the barriers to entry in the market. Successful independent operators are therefore harbingers for other new potential entrants. The evidence of substantial new entry in the market, both on the retail and supply side, is therefore a strong indicator of attractive operating conditions in New Zealand. Indeed, we have identified the following factors as indicators of an effective market:

- A large number of market participants, including four large gentailers and many independent retailers and generators
- Low barriers to entry and exit, with market participants apparently able to enter the market with little effort
- No evidence of a concentrated market in either the retail or wholesale market
- Evidence of positive outcomes for customers, with retail costs steady or falling and extensive innovation in market offers.

Rather than misusing market power, we believe the gentailers are likely acting to protect residential customers at the expense of their own margins. This view is based on conversations we have had with stakeholders as well as observed behaviour. We expect this behaviour is partly driving concerns from independent retailers about margin squeeze and indeed a decline in the margins can be seen in Figure 40 above. That is, they view retail prices not tracking up with costs, but this ignores that the gentailers appear to be absorbing these costs and taking the hit on their margins.

With respect to the concerns about margin squeeze, it is important to understand that for a margin squeeze to be anti-competitive it would require market power in the upstream activities (in this case the supply of wholesale electricity) and the ability to obtain market power in the

downstream market (electricity retailing) because of the margin squeeze. With four individual gentailers this prospect seems highly unlikely. It would require each of the gentailers to be acting in a highly coordinated and so illegal manner. In addition, it would require high barriers to entry to maintain market power in the downstream market, which is evidentially not the case given the apparent ease of entry and exit in the retail market in New Zealand. Furthermore, the size of the reported margins for independent retailers does not present evidence that margins have been squeezed.

While we find that the New Zealand electricity market exhibits the characteristics of an effectively competitive market, we have identified some opportunities to enhance competitive market outcomes. In contrast, we believe the Competition Task Force's current proposals, intended to address perceived competition issues, are more likely to drive up prices for customers and will not resolve the underlying issues that caused higher prices in 2024.

We discuss our views on the opportunities to enhance competitive market outcomes and the Task Force proposals in the remainder of this section.

5.4.1 There are barriers to customer switching

Switching retailer is harder than it needs to be in New Zealand. There are two factors that contribute to this difficulty:

- An inability to access electricity use data quickly, and
- An inability to make simple comparisons using electricity bills.

We think the presence of a dedicated price switching website in New Zealand, such as the one currently provided by Powerswitch, is a positive step to reducing the costs of switching. It means customers can be directed to a single site that can be trusted and that directly connects to retailers. However, this service is constrained, unnecessarily, by limitations in access to data. Without the ability for customers to receive instant access to their metering data at the click of a button it is not possible to provide an accurate comparison of the expected cost to customers from different market offers. This is because the expected benefit has to be estimated. Indeed, the only criticism we heard about the Powerswitch service was that it did a bad job at estimating usage for customers. However, this is the fault of a lack of data and not Powerswitch. The service should be able to use actual customer metered data to identify real potential savings. Noting this is an issue that has previously been identified in the Electricity Price Review, it is surprising that it has not yet been resolved.

The issue of bill complexity was also raised in the Electricity Price Review, but again no solution has been developed for this. The incentive for current retailers is to avoid bill simplification if it raises the costs and frustrations for customers who want to switch suppliers. Indeed, comments from the retail side of the market suggested a reluctance to resolve this issue. We think that the absence of more uniform provision of billing information is making it harder for customers to make price comparisons and deters customers from shopping around.

5.4.2 The Competition Task Force initiatives will increase prices for consumers

At the outset, it is unclear what specific issue the Task Force aims to address with its initiatives. The market currently exhibits significant entry from independent participants in both the retail and wholesale sectors, and independent retailers enjoy higher gross margins than the gentailers. In addition, as will be demonstrated in Chapter 6, it appears that all independent retailers are able to fully set their contract position. This suggests that competition is functioning, and market power is not driving high prices. While electricity prices were elevated in 2024, this does not

appear to be a result of market power. If gentailers used substantial market power, we would expect them to extract higher margins in retail rather than experiencing depressed retail margins relative to independent retailers.

Our view here reflects a general concern we have with the analysis by the Task Force. This is that it has not undertaken sufficiently robust competition analysis to first ascertain that a competition problem exists. Indeed, the approach from the Task Force appears to be that the potential for the presence of market power is sufficient for action to be taken. Given the proposals will have very material impacts on gentailers, and potentially material costs to consumers, it is our view that it is preferrable to first establish that a problem exists that warrants the size of the intervention that has been proposed.

This is not to suggest that no issue exists at all. As discussed in our chapter on investment for managing dry-year risk, the primary concern in the market is the lack of firm capacity, driven by policy uncertainty that discourages new investment. This is not a problem of a lack of competition and so will not be resolved by breaking up the gentailers or imposing the level playing field measures. The Task Force's proposed measures do nothing to address this underlying problem. Instead, they are likely to increase prices for consumers.

Level Playing Field measures

With respect to the proposed "Level Playing Field" measures, if the Task Force's concern is market power in the provision of contracts, its proposed solution will have the unintended effect of raising prices for customers. If gentailers indeed possess market power, they could respond to a non-discrimination obligation by increasing the price of internal contracts—thereby also raising the price of contracts they offer to the broader market so that they are 'non-discriminatory'. Since gentailers would not risk losing supply or retail customers in this scenario (assuming they possess market power), they could comply with the non-discrimination requirement without compromising their competitive position.

Competitors of the gentailers are likely aware that this solution will increase prices. When we asked an independent retailer whether they were more concerned with achieving cost parity with gentailers or with ensuring lower prices for customers, they stated that their priority was cost parity—and so were indifferent to the level of the wholesale price so long as all retailers faced the same price.

A further concern we have with the proposal that contracts be offered on non-discriminatory terms is that it will be extremely difficult to monitor. Participants contract at different times, over different time horizons, for different shapes, and using different products. Further, the price for a contract today can change tomorrow as more information becomes available. The point being that the gentailers and independent parties can still have entirely different hedging costs simply due to choices made by the participants rather than discriminatory pricing.

Virtual disaggregation of the flexible generation base

We do not support the Task Force developing a proposal for virtual disaggregation of the flexible generation base. Our concerns with this proposal is that it would remove the efficiency benefits that come with vertical integration because it would increase the cost of risk management in the market. Ultimately, this increased cost would be passed on to customers. In addition, requiring gentailers to hand-over a portion of their capacity to other participants would reduce the total

volume of contracts that are made available to the market because outage risk would need to be spread across a smaller portfolio of assets.[71]

Given these concerns, it is our view that this proposal is more likely to increase costs for consumers. Furthermore, it does not address the central issue in the market that there is insufficient incentive for any party to invest in firm physical capacity.

5.5 Our recommendations

Even though we have found that the market is working well, we have identified several opportunities to enhance competition. These are focused both on the supply-side and at a customer level. These enhancements are:

- Crown ownership of firming capacity
- Access to consumer data, and
- Bill reform.

5.5.1 Crown ownership of firming capacity will enhance competitive outcomes

Our recommendation to address dry year risk and firming supply generally was for the Crown to invest in assets capable of replacing hydro generation during a dry year through the New Co entity. We also recommended that priority access to capacity from those thermal generation assets be provided to independent retailers and generators.

The intention behind quarantining capacity from the Government-owned thermal generators for independent participants is to support those participants without dismantling the benefits that vertical integration brings to customers. That is, independent retailers and generators will be able to procure capacity that suits the size of their business without needing to rely on the gentailers for this service. This will enable them to manage risk in the same way that the gentailers do, recognising that the gentailers will retain firm capacity within their portfolios and so the participants that require firm capacity the most are independent players. The quarantining will ensure that the gentailers do not attempt to hoard the capacity in order to freeze competitors out of the market. It does not mean that independent retailers are subsidised or can procure capacity at a discount. For retailers, this means protection against high price periods through firm thermal capacity, while for owners of intermittent generators, they will be able to offer a fully firmed product to retailers and industrial customers without needed to obtain that firm capacity from gentailers.

We have taken this approach based on our view that it is preferrable to lift up the independent providers rather than to tear down the gentailers to level the playing field. The approach allows the independent participants to harness the efficiency benefits of vertical integration rather than removing those benefits from the gentailers. Noting that in a competitive market those benefits are ultimately passed through to customers in the form of lower prices. The benefits of vertical integration are set out in Box 3 below.

[71] A further concern with the proposal is that it would send a poor signal to investors of new firm capacity, with the prospect that capacity is taken off them at any time following a regulatory decision, with the outcome that the investment will not occur. However, given we have identified that there is already minimal incentive to invest in firm capacity we do not consider this is a material issue in the specific context of this proposal.

Box 3: The benefits of vertical integration

There are several ways that vertical integration between retail and generation can increase operating efficiency. Some of these include:

- **Risk management**. Electricity markets face extreme price volatility. Vertical integration provides firms with a natural hedge against price risks. A gentailer can offset wholesale purchase costs for its retail arm with revenues from generation during price spikes, and in turn, stabilise revenue and profit.
- **Lower transaction costs**. Integrated firms avoid the costs associated with searching for counterparties, negotiating contracts, enforcing contract terms and dispute resolution between separate entities.
- **Investment incentives**. Vertical integration strengthens incentives for investment in generation capacity by providing a guaranteed demand from retail operations. In addition, investment can be supported where an integrated entity has improved creditworthiness and so lower borrowing costs.
- **Addressing inter-firm externalities**. Vertical relationships can reduce or eliminate 'double marginalisation' that occurs where an independent downstream firm does not take account of the profits of an upstream firm when it sets it price. Vertical integration internalises this externality. In practical terms, the benefits can arise in the adoption of a coordinated trading approach that recognises both generation and retail commercial interests.

In a competitive market, these are benefits that are passed onto customers in lower prices.

5.5.2 Task Force virtual disaggregation proposal should be abandoned

We recommend that the Task Force not proceed with its proposals for non-discrimination of contracts and virtual vertical disaggregation on the basis that these options will not resolve the underlying issue in the market and will impose higher electricity costs onto consumers and industry.

5.5.3 Immediate access to data needed to improve switching decisions

We are aware that the Government has recently passed the Customer and Product Data Bill, which establishes an economy-wide consumer data right.[72] The intention being to give customers greater control over their data and so make it easier for them to switch providers for electricity services. To give effect to this Law a designation is required to designate data holders, classes of data to be regulated, and general requirements relating to regulated data services. In implementing this for electricity, the aim should be to permit customers to be able to agree to the release of their electricity usage data via a click of a button on a price comparison website. In doing so, customers will gain accurate information about what market offer best suits their circumstances and will remove the barriers to switching that would come with having to wait up to five days for this data.

[72] Customer and Product Data Bill 44-2 (2024), Government Bill – New Zealand Legislation

5.5.4 Bill consistency will help customers to compare offers

The Electricity Authority should implement a program with retailers to achieve bill consistency. This should include obligations for retailers to include certain information on their bill in a similar or identical form and location. This should include:

- Revealing if the customer is on the best deal for that retailer, and the savings that could be made if they are not
- How current consumption compares to historical consumption and also to households of a similar size
- The structure and form of prices.

We are aware that Consumer NZ has undertaken extensive work on developing a billing template. We recommend that this work be the starting point for the Authority's development of a standard bill.

6 Risk management

6.1 Introduction and summary of findings

The purpose of this chapter is to consider if market participants have access to sufficient information and risk management products to effectively manage risk.

We have access to confidential contracting data from all participants from 2010 to 2024. Data that is critical to undertaking a comprehensive assessment of risk management in New Zealand was not available to us. While this has limited the analysis we have been able to undertake, our analysis shows the following:

- Gentailers are able to set their contract position for some years in advance
- Gentailers are major suppliers of hedging contracts to their competitors
- Small retailers appear to be able to also set their contracting position with some of these businesses operating active contract trading businesses which also involve them selling their over-contracted positions to the gentailers, and
- There appears to be a high correlation between prices of exchange traded and over the counter (OTC) hedging products, which means that there is a high level of transparency of contract prices, and in any case the information released on OTC contracts means that there a high degree of transparency of contract terms and conditions in the market.

None of the above suggests that small retailers find the terms and conditions acceptable and we have been advised as part of the engagement process that small retailers feel that they are paying too much for contracts. We note that our analysis of the retailing margins (see Section 5.3.3) shows that the smaller retailers generally have higher margins and lower energy supply costs than the gentailers they complain charge them too much.

Based on the above findings we do not consider that any of the existing contracting information disclosure arrangements need to be changed.

As noted in Section 4.5, we are recommending that independent parties be provided with priority access to capacity that is held by the proposed new Crown entity that would have responsibility for securing and selling on-demand dispatchable capacity and energy. This option will substantially improve the ability for independents to manage risk and to do so in ways similar to the current gentailers. The effect should be to immediately deepen and widen competition in the market, which will have flow on effects for lower electricity prices.

We recommend also that the Electricity Authority makes better use of the data it collects on contracting. This includes by preparing an annual report that identifies trends in contracting and risk management behaviour. Undertaking this analysis will then also have important implications for assessing competitive outcomes in the market.

6.2 What is the desirable market outcome?

6.2.1 Purpose of risk management and contracting

Energy-only electricity market are, by design, comparatively volatile, with prices rising quickly in the face of capacity and energy scarcity. Therefore, risk management in all its forms – namely, financial and physical - is a central feature of these forms of competitive wholesale markets.

Hedging against spot price volatility is a risk management strategy that is adopted to offset potential future losses that might be incurred. It involves taking an opposite position in relation

to an asset or security that is being hedged. Mostly hedging is done to reduce downside risk, however, it can mean that future gains are also lost. This is acceptable where it allows for more predictable outcomes overall. Obviously reducing risk comes at a cost, either through the cost of the hedge itself or the opportunity cost of not fulling benefiting from favourable price movements.

Hedging is critical to improved market outcomes in the following ways:

- **Generation** – hedging helps to manage the revenue risks for generators would otherwise face a highly volatile revenue stream to cover their largely fixed costs. The greater revenue certainty that hedges provide generators the more likely it is that they will be able to access lower cost capital, and this lowers the cost of providing wholesale electricity.
- **Retailers** – customers generally prefer fixed prices over time. To provide these to customers retailers need a high degree of certainty of their energy purchase costs. Hedging provides retailers with greater energy purchase cost certainty which then allows retailers to more vigorously compete for customers.
- **Price discrimination**- hedging allows buyers and sellers to agree to a price that was different to the single spot price in order to maximise economic welfare, for instance, through encouraging customers to consume more electricity than they would be if they had to purchase off the spot market. For instance, there are likely to be customers willing to buy more electricity if the price was lower than the prevailing spot price, and suppliers willing to supply more at a price lower than the spot price (because they are inframarginal). If these two parties can come to agreement about the price to be paid and received price outside the operation of the spot market they can both benefit economically.

In a well-functioning market, hedging contracts act as an informal capacity mechanism. By providing revenue certainty, they incentivise investment in new supply. Rising demand for contracts should signal the need for additional capacity, guiding efficient investment decisions. Furthermore, a liquid contract market lowers barriers to entry and exit for retailers. Participants should be able to secure suitable contracts at fair prices, while businesses exiting the market should be able to liquidate their positions without disrupting prices.

6.2.2 Risk management tools

There are several ways that participants can hedge their exposure to spot prices. The most common are the following:

- Vertical integration through the ownership of both a retailer and generator. This is known as a natural hedge because when the spot price is high, while the retailer pays the higher price, as the owner of the generator it will also receive the high spot price for its generation – the cash flows offset each other automatically. The comprehensiveness of this form of (natural) hedging and the avoidance of having to pay premiums for financial hedging contracts that they may never need are the main reasons businesses vertically integrate. Vertical integration is not pursued to build market power, although in some circumstances, vertically integrated businesses gain market power, especially where rivals cannot achieve the same cost efficiencies in different way as the vertically integrated businesses. We believe that there is an element of this occurring in New Zealand.
- Power purchase agreements (PPA) with a generator. PPAs provide a similar hedging benefit to vertical integration but achieve this through contracts rather than ownership. Importantly, a PPA with an intermittent generator is not financially firm because the generator cannot commit to producing output at particular times.

- Financial derivatives. There are a range of financial derivatives that are available to retailers, industrial customers (and generators) to hedge their exposure to volatile spot prices. Common contracts include spot contracts (which lock-in a spot price for the counterparties) and cap contracts (which cap the spot price). These are traded both on the stock exchange and over-the-counter (OTC) between participants.
- Financial transmission rights (FTR) – these manage the risk of buying and selling energy at different locations. In a nodal market, like New Zealand has, the wholesale price will be different depending on the node and the effect of transmission losses. FTRs provide compensation for congestion costs when transmission lines are constrained, and so there are price differences between regions.

6.2.3 Risk management strategies for retailers

If a retailer serving fixed price customers is under-hedged (i.e. have less MW hedge cover than the MW of their customer demand – quantity risk) at times when the spot price rises above the energy purchase cost embodied in the fixed price contract (price risk), the retailer is exposed to additional energy costs that they won't be able to recover from customers (energy purchase cost risk). These additional costs will have to be met from the retailer's margin.

Smaller independent retailers, lacking generation assets and scale, generally face higher hedge costs and may struggle to pass these costs onto customers in a competitive market. In contrast, larger retailers benefit from a more diversified customer base, reducing their exposure to volume risk. Geographical diversity further stabilises their energy purchase costs.

Vertically integrated retailers (gentailers) may be even better placed to manage the risks that emerge from these energy purchase cost risks as they have the benefit of large and diversified customer bases as well as the benefit of a natural hedge in that they are selling and buying at the same price. The more balanced the gentailer in terms of how much electricity they sell compared to how much they purchase, the more efficient the natural hedge.

6.2.4 Risk management considerations for generators

Generators' ability to offer hedging contracts depends on their technology type and operational flexibility. To provide financially firm contracts, a generator must have dispatchable capacity (e.g., hydro, geothermal, thermal, batteries). However, contract offerings vary by technology:

- Batteries cannot supply long-duration baseload power, limiting their role in firm contracting.
- Peaking gas plants are expensive to run continuously.

However, batteries and peaking plants are very well suited to cap and option contracts that protect against short duration high priced periods.

Aging thermal generators may reduce their contract offerings due to increased outage risks. If a contracted generator experiences an outage, it must buy replacement energy from the spot market—potentially at high prices—creating substantial financial risk. To mitigate this, aging generators may lower their contract commitments to maintain contingency reserves.

In a market with a high penetration of intermittent and hydro generation, risk driven by weather fluctuations becomes a significant factor for risk management. The timing and size of this exposure will be difficult to predict. This uncertainty about the generation profile may encourage a generator to rely more on its own generation as a hedge against this risk rather than making it available to the market. By keeping their generation in-house, retailers may consider they are able to offer more competitive and stable prices to their customers. Furthermore, these retailers may consider there is value in being able to access the high spot prices at times when renewable generators are not producing.

The pricing of contracts also reflects opportunity costs. A generator selling a super peak period hedge may forgo the ability to sell a broader baseload contract (which overlaps with the super peak period hedge), meaning the hedge price must account for lost alternative revenue opportunities.

6.3 Current market

6.3.1 Contract market

In terms of contracting for risk management, there are five key sources for contracts, these are:

- **The ASX** – which trades in futures and options. These are standardised contracts structured as cash-settled contracts for difference against two grid reference nodes, Ōtāhuhu in the North Island and Benmore in the South Island. The ASX is also where market making is undertaken for the electricity market. For a product like a baseload monthly or quarterly futures contract, participants are able to trade 0.1MW/h at the relevant reference node.
- **OTC market** – where parties negotiate between themselves to agree on a price. Unlike for the ASX, there is no requirement for the contract to fit a standardised form. The implication being that the contracts can be better shaped to the requirements of the purchaser. Nevertheless, we understand that the majority of contracts are contracts for difference and cash-settle each month. A voluntary code of conduct exists for the OTC market that commits signatories to a number of underlying principles and behaviours for participation.[73]
- **Standardised 'super peak' contract** – this standardised contract was introduced in January 2025 with the aim of providing a contract option for the high-priced morning and evening peak periods. The morning peak trading period is between 7:00am and 10:30am, while the evening peak trading period is 5:00pm to 9:00pm. Buyers can purchase cover for calendar months or calendar quarters up to 3 years ahead.
- **Financial Transmission Rights (FTR) market** – these are products aimed at managing the risk of price differences between pricing locations in the market. FTRs are bought through an auction process that is managed by the FTR manager; which is Energy Market Services, a division of Transpower.[74]
- **PPAs** – these are bilateral contracts between a generator and a retailer or industrial customer. They generally apply over a much longer time period than other contracts, for instance over 10-years and generally provide the purchaser with the rights to the value of energy sold by the generator for the volumes agreed in the contract.

Marking making obligations

Mandatory market making obligations apply to the four gentailers, with the option for voluntary commercial participants to also provide a market making function.[75] The market making obligation is provided through the ASX. The intention of the marking making function is to provide a transparent forward price curve on which participants can benchmark their OTC arrangements, while also ensuring that there is an avenue available for participants to manage risk without needing to rely on OTC arrangements.

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73 Hedge market | Electricity Authority

74 FTR manager | Electricity Authority

75 The market making requirements are set out in Subpart 5B of the Electricity Industry Participation Code. The Electricity Authority awarded VivCourt with a two-year contract to act as the commercial market maker on 1 July 2024. See: https://www.ea.govt.nz/news/general-news/commercial-market-making-services-contract-awarded/

Market making occurs in four products, namely:

- Benmore base load quarterly futures
- Otahuhu base load quarterly futures
- Benmore base load monthly futures, and
- Otahuhu base load monthly futures.

The market making session runs from 3:30pm to 4:00pm each trading day with the market maker required to make markets for at least 25 minutes.

The limited spread on market maker buy and sell quotes applies. The maximum spread is the greater of 3 per cent or $2.00. Before January 2020 a wider spread was permitted, with it being the greater of 5 per cent or $2.00.

The market making obligation requires that the gentailers provide quotes for a minimum of 24 months of NZ electricity futures for the Otahahu and Benmore reference nodes for the current month and each of the five months following the current month.

Price disclosure obligations for OTC contracts

A Hedge Disclosure Obligation Scheme applies in New Zealand. The intention being to provide increased transparency and deliver price signals for investment decisions.

Hedge disclosure obligations commenced in 2009, but in 2024 these obligations were broadened with a particular focus on improving transparency of new contract types and shapes.[76] The broadening of these arrangements was intended to align with recommendations from the MDAG report which recommended improving the transparency of hedge information covering offers, bids and agreed prices. The current arrangements achieve the following:

- A broader scope of information is collected to capture more risk management contracts, including PPAs. Further, a more detailed subset of information about these contracts is required so that key terms in any novel contracts are disclosed.
- A broader scope of information is published to increase transparency and confidence in the market, noting commercially sensitive information remains confidential.

In addition to basic contract information such as the parties to the contract, relevant trade and effective dates, and the volume of a contract, the following information must be provided:[77]

- Whether the contract is a CFD, fixed-priced physical supply contract, an options contract (and what type of options contract), or other type of risk management contract
- The premium specified in the contract
- The node at which the price is set
- Whether the price is linked to consumption or generation of electricity
- Whether there are other relevant clauses such as an adjustment clause, force majeure clause, special credit or suspension clause.

The Electricity Authority may also prescribe additional information that must be submitted.

[76] Electricity Authority, 'Improving Hedge Disclosure Obligations Decision paper', 6 June 2004, p. 2.

[77] The hedge disclosure obligations are set out in Part 13 of the Electricity Industry Participation Code.

Liquidity and trading volumes in contracting markets

The depth and liquidity[78] of contracting markets are of key concern to the Electricity Authority.

- ASX baseload swaps benefit from significant market making, leading to substantial depth and liquidity in the market that allows for forward price discovery, and allowing any market participant access to baseload hedges.
- ASX peak contracts are traded in low volume, partially due to a lack of suitability of these contracts.
- Standardised Super-peak contracts are a relatively new product developed as a result of MDAG recommendations. These are traded in centrally run auctions, with significant volumes offered by both buyers and seller, owing to the fact that this in an effective risk management tool for retailers.
- OTC contracts make up the majority of hedging contracts signed by independent retailers, as they are not traded in a defined market, it is difficult to measure the liquidity of these contracts. However, they are able to trade at high volumes, and use the market made baseload contract price as a source of truth. The Electricity Authority raised that the response rate to OTC RFQs may be a concern, but this is not the correct measure of assessing an OTC market, as there are legitimate reasons requests may not be accepted. Instead, we should focus on market outcomes, being the price and volume at which participants are able to settle contracts.
- PPAs are traded on an as developed basis, for variable renewables, these contracts may be difficult to sell as the purchaser must be able to manage the risk of output fluctuation in this contract, potentially crowding out their ability to sell other contracts with that generation. Geothermal PPAs are essentially baseload contracts and will be easier to find suitable customers for, with there being instances of independent retailers acquiring these projects.

6.3.2 Electricity Authority Risk Management Review Preliminary Findings

The Electricity Authority commenced consultation on a risk management review in November 2024, publishing 'Reviewing risk management options for electricity retailers – issues paper'. It has since received submissions to that Issues Paper and so confirmed its preliminary review findings. These findings are:

- Retailers use a mix of risk management strategies to hedge against wholesale market volatility, with no single best approach
- Several alternatives to OTC hedge contracts exist (e.g., baseload hedges combined with battery renting, demand response, or retail tariffs), but these are still emerging in New Zealand and may take time to influence OTC hedge prices.
- Retailers have secured substantial shaped hedge cover via OTC contracts, but the market remains thin and illiquid, with over a third of requests receiving only one offer.
- Fuel or capacity scarcity is a key factor behind the limited availability of shaped hedge contracts.
- OTC baseload and peak hedge prices appear competitive, but super-peak hedge contracts trade at a significant premium, suggesting potential market power concerns.

[78] Liquidity refers to how easily a contract can be bought or sold in a market without significantly affecting its price. This can sometimes be confused with trading volumes, noting that high trading volumes tend to correlate with strong liquidity.

- While scarcity is a likely driver of high prices, the possibility of anti-competitive behaviour — such as refusing to supply key products to competitors — cannot be ruled out.

6.3.3 Energy Competition Task Force PPA workstream

Workstream 1A for the Energy Competition Task Force is to focused on the role of PPAs. The intention behind the workstream is a view that a deeper and more active market for PPAs will enable more generation investment.[79]

The Task Force published a Working Paper seeking input from the sector on various issues associated with PPAs in New Zealand titled: 'Entrant generators – context, headwinds and options for power purchase agreements, Working paper'. The Task Force only recently published the submissions that were provided in response to that Working Paper and so has not yet reached any views on the ongoing role of PPAs for the electricity market.

6.3.4 Current hedging practices

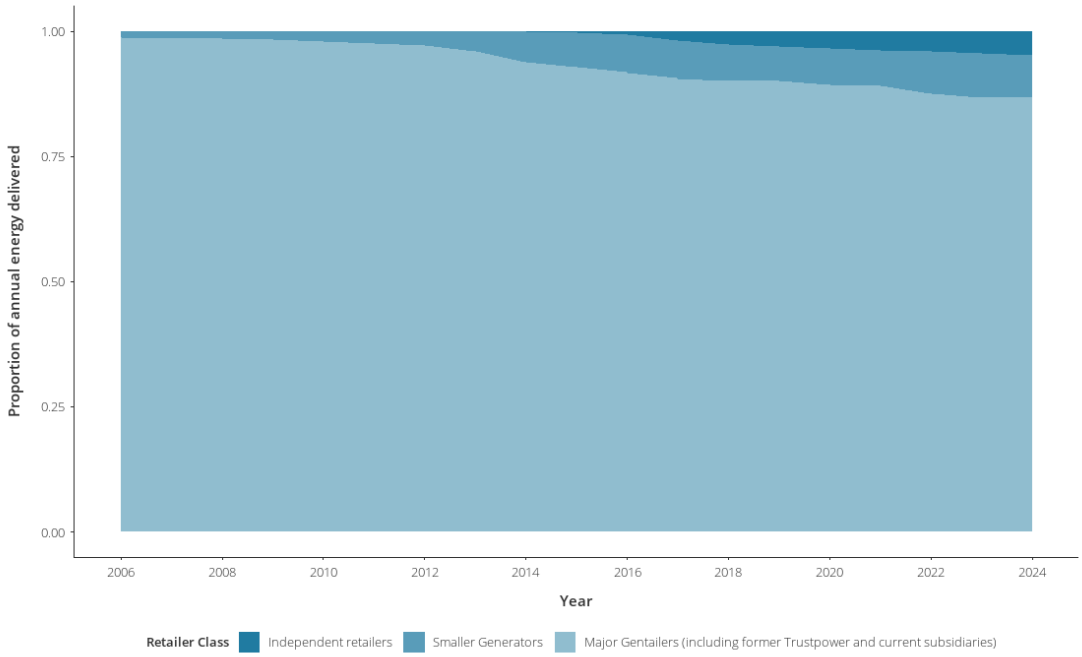
Hedging strategies of market participants are dominated by the use of OTC contracts. Given the limited form of the old hedge disclosure obligations, it is not possible for us to know the precise form of these contracts, however, the updated regime will allow for more accurate analysis of participants market positions and increase understanding of each participants ability to manage risk.

The energy composition of the retail market is shown in Figure 42, the major gentailers are responsible for 87 per cent share of retail load, with smaller vertically integrated retailers responsible for an 8 per cent share. This means that most of the load in New Zealand will be supplied through the gentailers own generation assets.[80] This has consequences for the amount of contracting that is undertaken.

[79] Electricity Authority, 'Entrant generators – context, headwinds and options for power purchase agreements, Working paper', p.7.

[80] 78.89 per cent of energy was delivered through vertical integration in February 2025. See the EMI Vertical integration trends dashboard. https://www.emi.ea.govt.nz/Wholesale/Reports/BLKL4U

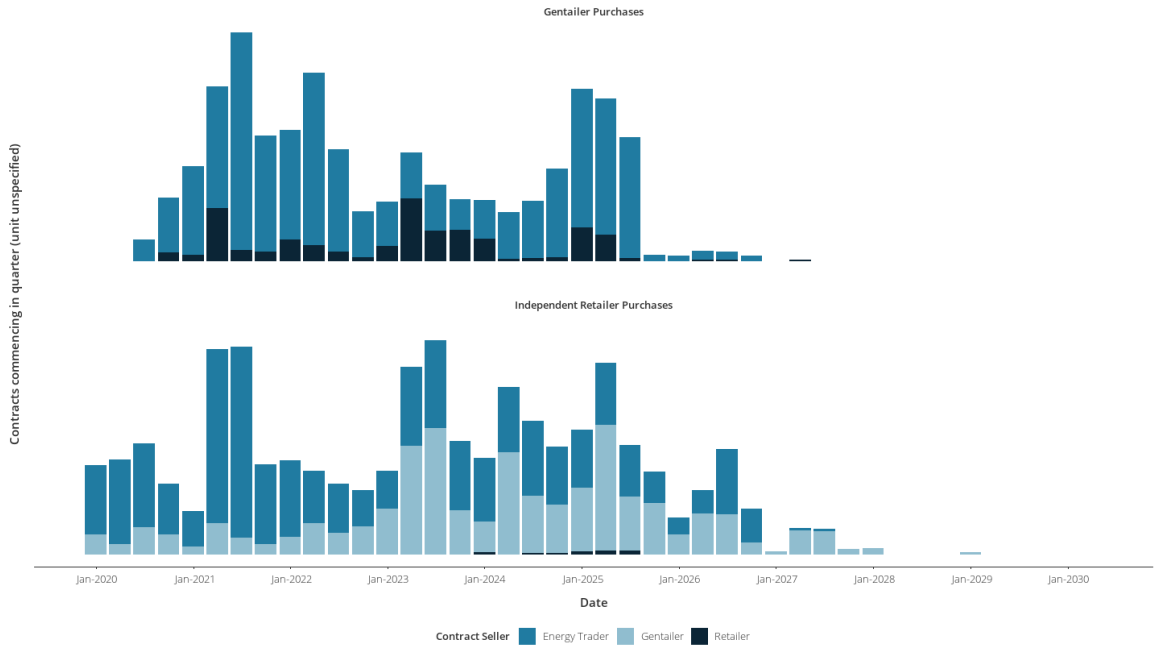
Figure 42: Retail energy share by participant type



Source: Frontier Economics analysis of retail load data

Importantly, as shown in Figure 43 below, gentailers are selling contracts to their competitors, and are also purchasing contracts from energy traders and other independent retailers. We note that the gentailers purchase the bulk of their contracts from each other, but this is not shown in the figure below.

Figure 43: Contract flows between gentailers, independent retailers and energy traders



Source: Frontier Economics analysis of Electricity Authority contract data

ASX

The ASX contracting market shows strong volumes and liquidity, largely driven by the presence of mandatory market making by the four largest gentailers, and the more recent addition of a contracted commercial market maker, with each of these five participants required to offer 20 per cent of market making volume. The intention of these arrangements was to:

- Increase depth and liquidity in the ASX contracting market
- Increase confidence in the forward pricing curve, and
- Improve access to contracting markets in the New Zealand electricity market and increase competition in retail markets.

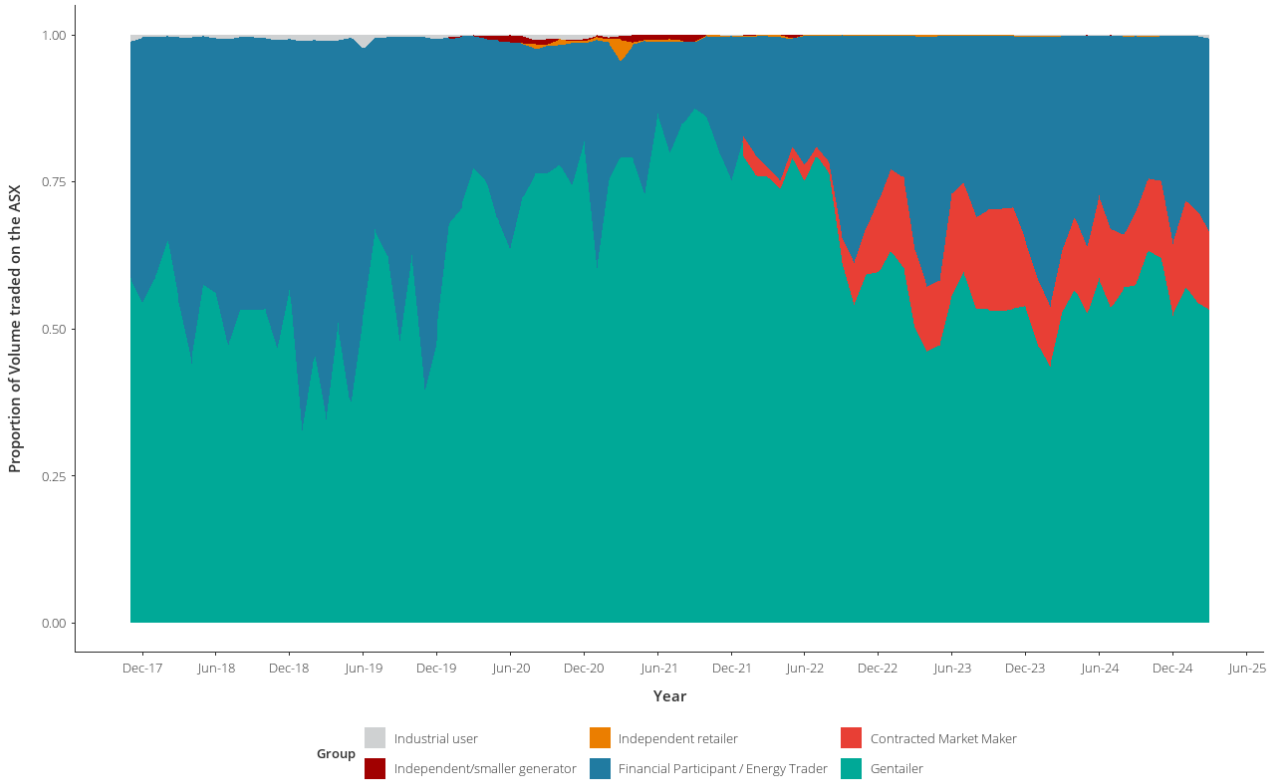
The figure below shows that trading volume in market made contracts increased substantially after the introduction of the mandatory market making regime in September 2022[81], with forward price curves for contracts increasing in responsiveness to events and providing a clear average price benchmark for the sale of OTC contracts. The increase in volumes is largely driven by trades made by market makers, that is, the gentailers and the commercial market makers comprise the largest proportion of ASX trade volumes. There was also a marginal increase in retailer, or electricity trader market share in the ASX from this time.

We note that participation in the ASX requires participants to meet substantial prudential obligations in order to manage counterparty default risk. We expect that this is a factor that influences the participation of interdependent retailers. As a result, these independent retailers often trade OTC contracts with energy traders, or their parent firm, in order to hedge their retail position. Nevertheless, Electricity Authority analysis has shown that forward contract prices are

81 https://www.ea.govt.nz/news/press-release/electricity-authority-awards-commercial-market-making-contract/

an unbiased estimate of actual spot prices over the period 2011-2023, so participants can be confident in this as a measure of future expectations.[82]

Figure 44: Share of trading volume on the ASX by participant type



Source: Frontier Economics analysis of Electricity Authority contract data

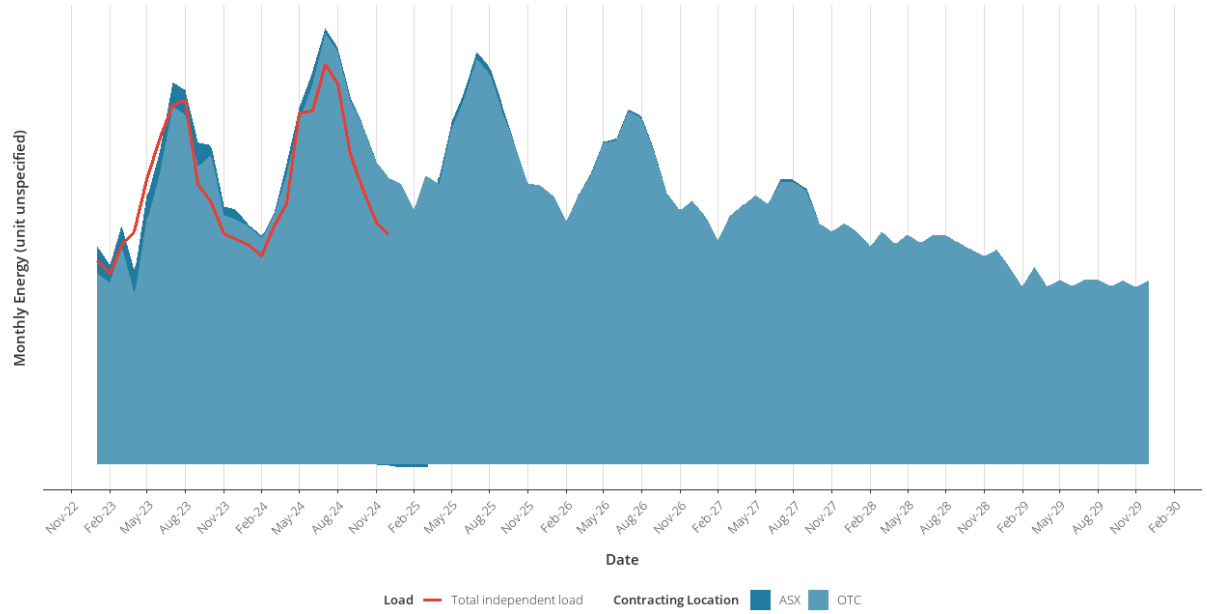
Hedging strategy for independent retailers

It appears that the primary hedging strategy from independent retailers is to purchase shaped hedges that closely resemble a residential load profile. This involves the purchase of long dated baseload OTC contracts, with the addition of peak and super-peak products. Figure 52 shows the proportion of contracted volume by independent retailers that are purchased OTC versus via the ASX. It shows that the vast majority of volume is obtained in OTC markets.

It appears also that independent retailers often source contracts from energy traders, rather than directly from the gentailers. These energy traders trade in ASX, FTR and OTC markets and resell contracts to independent retailers. The main contracts being sold appears to be long dated baseload contracts, with seasonal shaped contracts being acquired closer to the time the energy is needed. This is likely because shaped contracts can be more accurately priced based on expected market conditions as more information is revealed.

82 https://www.ea.govt.nz/documents/5976/Appendix_A._How_we_calculate_competitive_risk_management_prices.pdf

Figure 45: Final contracting position of major independent retailers



Source: Frontier Economics analysis of EA hedge disclosure and retail load data

Figure 45, shows the total hedge position of independent retailers, displaying contracted energy on a monthly basis, differentiated by which contracts are transacted on the ASX and in OTC markets. The red line represents the total energy demand of customers of independent retailers, demonstrating that this cohort is able to fully hedge for their energy positions. This is confirmed also with discussions we have had with independent retailers and also commentary in the Electricity Authority's Risk Management Review.[83] However, due to limitations with historical hedge disclosure data, we are unable to determine seasonal shape that may exist in long term contracts and have limited visibility of the form of many shaped hedges. Nevertheless, on an energy basis, the independent retailers are able to cover their position well. This may be supplemented by other mechanisms such as retail tariff structure and demand response. For instance, independent retailers, such as Flick, have a retail plan that exposes customers to the wholesale market, along with demand response options.

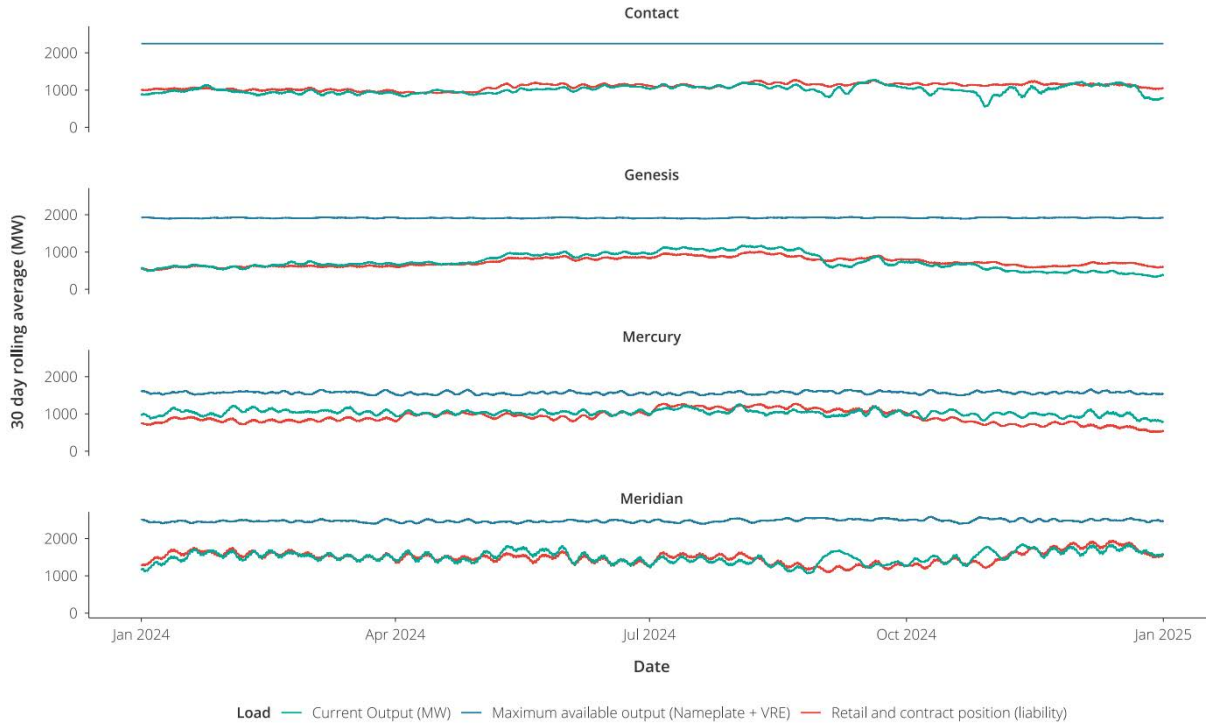
Hedging strategy for gentailers

Major gentailers are hedged for the majority of their energy production, spread across the vertical hedge of their retail book, and the sale of ASX and OTC contracts to other market participants. With their final position after accounting for their all production and obligations being approximately neutral. Figure 46 implies that they are fully contracted for their expected energy position. Therefore, it does not appear that the gentailers are withholding contracts from the market in order to benefit from spot price exposure during high priced periods. While exposure to high spot prices in a dry winter may be beneficial to generators, similar downside risks exist if an influx of water reduces spot energy prices.

It is apparent also that gentailers trade frequently between each other. This is likely to be as insurance against the risks of outages and potentially low hydro storage conditions.

[83] "Retailers have been able to acquire substantial shaped hedge cover", Risk management options – issues paper, p. 2, https://www.ea.govt.nz/documents/5980/Reviewing_risk_management_options_for_electricity_retailers__issues_paper.pdf

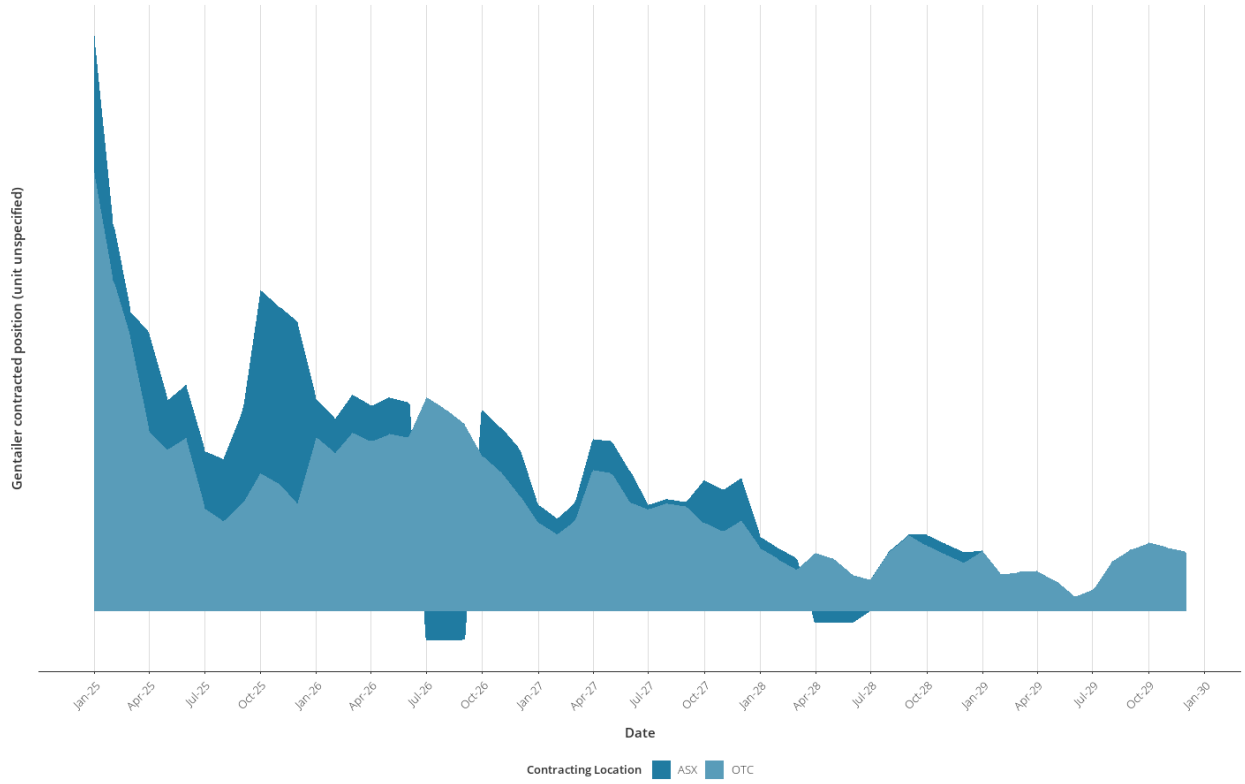
Figure 46: Gentailer generation and liabilities in 2024



Source: Frontier Economics analysis of public and private Electricity Authority data. Note – seasonal shape in long term hedges may not be captured under old hedge disclosure data.

Figure 47 demonstrates how Gentailers taper their hedging portfolio over time, with internal hedges to their retail book and long-term hedges being offered on their guaranteed energy position, and more contracts being offered as hydro conditions materialise.

Figure 47: Aggregated gentailer forward contracting position



Source: EA data, Frontier Economics analysis. Excludes options and PPAs.

6.3.5 Super-peak hedges

Formalised super-peak hedges were introduced following a recommendation of the MDAG report, noting these contracts were already being widely contracted on OTC markets before this time, and appear to be the primary instrument used by retailers to cover their positions in extreme peak periods. In its Risk Management Review, the Electricity Authority found that while other OTC products were competitively priced, it could not reach the same conclusion for super-peak products.[84]

In their review, the Electricity Authority outlined a range of premia that will be factored into the price of a shaped hedge focused on the highest price period, these included:

- **Spot price premium**: The spot price premium is the floor for risk premia, with the premium on the spot price in super-peak periods being around 30 per cent in Q2 and Q3[85]
- **Volatility premium**: In periods of higher spot prices, the premium on super-peak hedges is likely to be higher, as the most upside price risk exists in these windows, elevating the potential value of these contracts beyond just the average spot price premium.

In addition to this, as noted above, selling a super-peak product means other contracts that would have been sold with an overlapping time period, such as a baseload or peak contract, cannot be sold. The implication being that there is a foregone opportunity that also needs to be

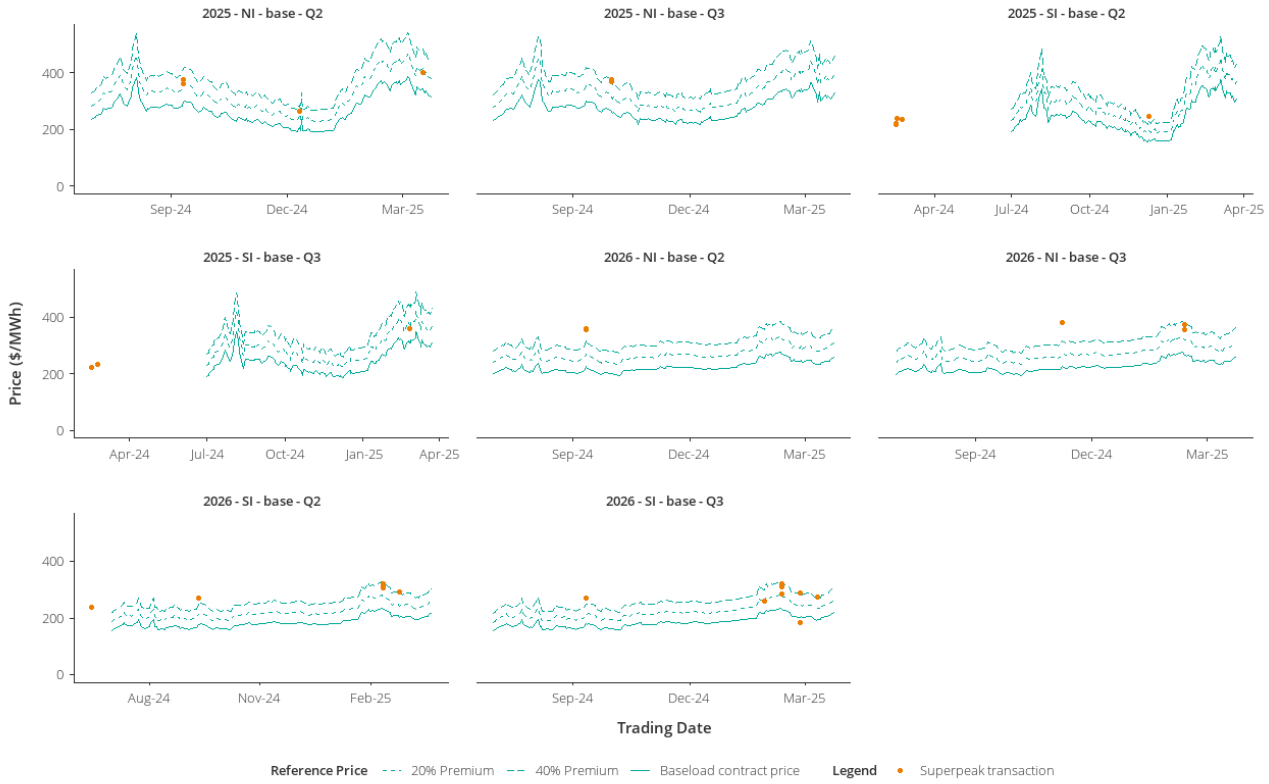
84 https://www.ea.govt.nz/news/press-release/review-identifies-risk-to-retail-electricity-competition/

85 34% in Q2 and 29% in Q3, How we calculate competitive risk management prices, Table 2, https://www.ea.govt.nz/documents/5976/Appendix_A._How_we_calculate_competitive_risk_management_prices.pdf

factored into the price. The implication of this being that it should be expected that super-peak contracts trade a higher premium than other traded contracts, especially at times of scarcity.

Figure 48 shows the premium for quarterly super-peaks when compared to ASX baseload swap prices in 2025 and 2026 winter quarters. It demonstrates that the premium on different contracts varies but is almost entirely within a 40 per cent premium of the relevant baseload contract price at the same time, with trades of the new standardised super peak in February and March 2025 appearing to reflect the level of the futures price. Indicating the additional premia attached to the super-peak contracts from sources other than the spot price premium is under 10 per cent.

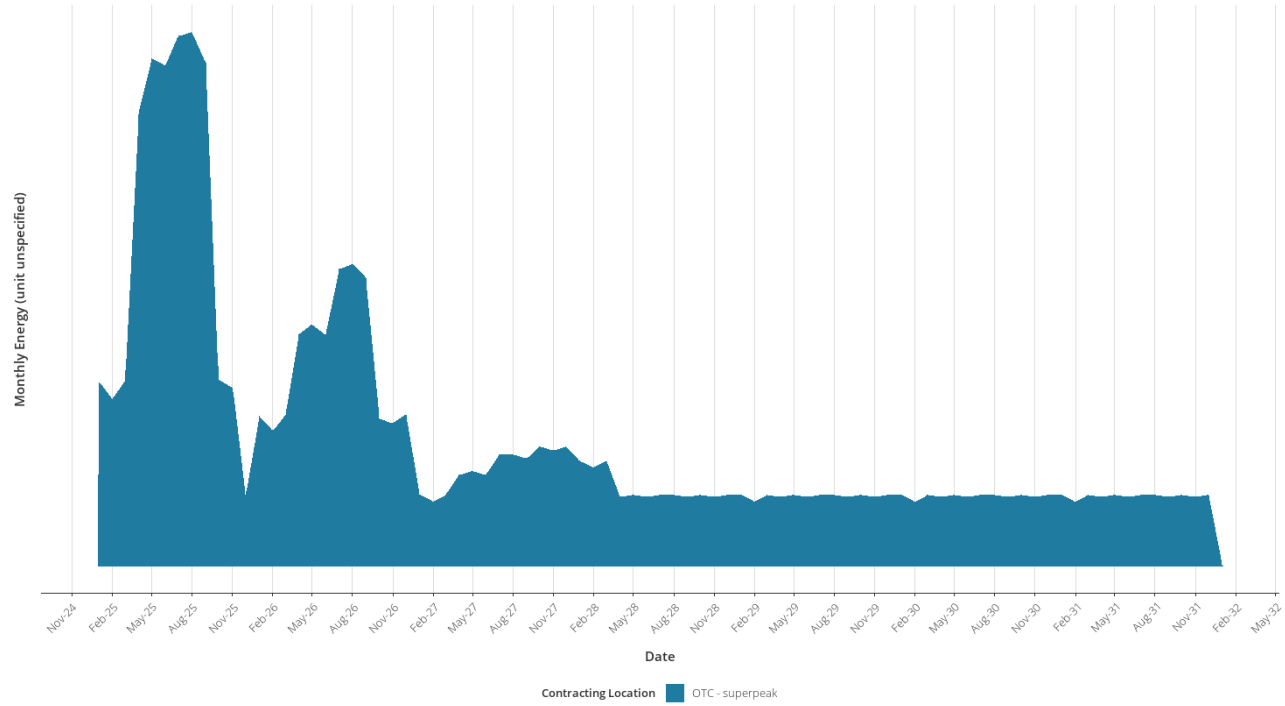
Figure 48: Super peak premiums



Source: EA contracting data, Frontier Economics analysis. The dots represent the price of super-peak contracts settled on a given day, and the lines represent the price of the relevant ASX baseload swap price.

Gentailers who have high generation capacity, and substantial storage capabilities are the primary provider of these super peak products. In addition to quarterly products, Figure 49 shows there have also been long-dated super-peaks purchased by independent retailers, there may be additional contracts for which the shape is unknown due to the old hedge disclosure obligations. these contracts shown in are difficult to price as they reflect years of uncertainty about the future of the New Zealand electricity system, with hedging against this uncertainty being mutually beneficial for retailers and generators.

Figure 49: Forward super-peak contracting



Source: EA data, Frontier Economics analysis

6.3.6 Power Purchase Agreements

Power Purchase Agreements involve the purchase of a power stations output, with these arrangements typically being entered into by variable renewable generators who wish to hedge against future spot price risk and receive a fixed energy price on a long-term basis. This market in New Zealand is far less developed than in other jurisdictions, with PPA's signed also being of shorter duration (Table 7) than in other locations (such as Australia[86]).

86 Based on our knowledge, Australian PPAs signed with Utility scale renewable energy are often of 10-20 years long, with available information showing that these are longer than those signed in New Zealand

Table 7: Select PPA's above 1MW signed in 2023-24

Date	Buyer	Seller	Technology	Length	Size (MW)
Jan-2024	Pulse (Small vertically integrated generator)	Inchbonnie Hydro Ltd	Run-of-river hydro	1 year	1MW
Oct-2022	Pulse (Small vertically integrated generator)	Lodestone Energy	Solar	5 years	19MW
Sept-2022	Prime (retailer – defaulted and defunct)	Lodestone Energy	Solar	7 years	25% of output
May-2024	Spark (large user)	Genesis	Solar	10 years	63MW
May-2023	NZ steel	Contact	Undisclosed	10 years	30MW
Jun-2024	Meridian	NZ Wind Farms	Wind	1-2 Years	46MW
April-2024	Amazon (Large user)	Mercury	Wind	15 Years	51.5MW

Source: Electricity Authority, Review risk management options for electricity retailers – issues paper, pg. 60

Participants who may purchase PPA's include:

- Generators who want access to additional energy, and are able to firm variable renewable energy supplies
- Large energy users who would like to decarbonise their electricity supply, or
- Retailers who would like access to additional generation.

PPA's can be bought for different types of generators which are suitable for different participants.

- **Geothermal:** Geothermal PPA's are essentially access to baseload hedges, providing consistent cover, with the exception of outages. This can be used by generators who would like to add firm generation to their portfolio, or retailers who want access to firm energy.
- **Variable renewable PPA's (wind and solar):** These options are most suitable for vertically integrated or independent generators with firming capacity who are able to turn variable output into a firmed product that can be used to hedge against a retailer's load profile. The Electricity Authority found that wind and solar PPA's were not as useful a product to reduce exposure for retailers that typical CFD based products in their review of risk management

options.[87] If large energy users purchase these PPAs to meet internal decarbonisation goals, the obligation to firm this PPA will lie with their retailer, in Table 7 we can see agreements with large customers are made with major Gentailers who possess generation to sleeve this PPA.

6.4 Our assessment

6.4.1 Outcomes in the hedge market

We have not found evidence of material issues in New Zealand's contract market or with the ability for participants to manage risk. However, our ability to reach this conclusion has been limited by the quality of available data and the relatively short time we have had to undertake analysis. Nevertheless, we feel some confidence reaching this view given market participants have indicated to us and the Electricity Authority that they can secure contract cover. Concerns appear to be more about the price of cover rather than availability. Furthermore, evidence also suggests that gentailers are not systematically withholding contracts. The volume of contracts offered is naturally influenced by their views on hydro storage levels and their risk appetite, as they must ensure sufficient energy to meet their own load requirements. We are also not aware of any evidence of market manipulation in the market maker function. We note, however, that it is a competitive market for market making where real trades are required, including with a commercial market maker that is not a gentailer. This reality constrains the ability for manipulation in this market.

It is self-evident that contract prices rise significantly as dry years approach. Independent retailers that secure hedging closer to execution in such periods face increased costs due to heightened spot price expectations and a shrinking share of firm capacity in the market. Distinguishing between higher prices reflecting genuine scarcity versus market power is challenging, particularly given the data and time constraints of our assessment. A particular complication here is that realised spot prices can be below forward prices given the need for generators to defend those contracts and avoid difference payments. However, the identified barriers to investing in new thermal capacity suggest that, without intervention, the risk of market power misuse during dry years will only increase. As noted in section 5.4.2, proposals such as non-discrimination requirements will not resolve this issue and will likely lead to higher consumer prices.

Our analysis of the contract market has revealed that more needs to be done to gain a clearer picture of hedge market outcomes over time. While the Electricity Authority has collected extensive hedge market data, it does not appear to have fully utilised this information to assess market liquidity and competition in the market. The format in which data is provided has been a key limitation, but this is not an insurmountable issue. It is concerning to us that this data has been collected for so long without the Electricity Authority seeking to identify what it means for the market, which would have driven it to request the information in a different form much earlier. The additional data now being collected on over-the-counter contracts makes such analysis far more feasible. However, the Electricity Authority needs to ensure that the way it collects this information makes comparison across participants as easy and as useful as possible to justify the industry and Authority's costs of collecting this data.

6.4.2 Market maker obligations

The market maker provisions impose additional costs on the market, not only due to the expense of the commercial market maker but also the costs incurred by gentailers participating

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in the ASX. Therefore, it is important to be sure that this function is delivering additional benefit to the market. It is our view that while independent retailers conduct minimal trading on the ASX, the market maker function appears to serve as an effective price discovery tool.

We note that with the introduction of additional disclosure requirements for OTC products, these could potentially replace the ASX market maker obligation. However, one challenge is that OTC products are sometimes non-standard, making it more difficult to establish a reliable benchmark for price discovery. However, we consider there to be sufficient standardisation that the revelation of this OTC information could be a reasonable replacement for the market maker function.

6.4.3 Super-peak contracts

Currently the average super-peak contract trades at a below 40 per cent premium on ASX baseload futures. At this level, it cannot be definitively concluded that super-peak contracts are not fairly priced, recognising that there is substantial variation in spot price outcomes during this time and generators are also foregoing the opportunity to sell other forms of contracts by offering a super-peak product. In addition, because the opportunity cost of offering a super peak product is the ability to offer some other form of contract that would have otherwise covered the same period, such as a peak period, this is something that also needs to be factored into the premium paid for this product.[88] Therefore, in our view, time should be taken to confirm the performance of the new standardised super peak product.

We are aware of commentary that consideration should be given to market making obligations for super peak products. We consider it is too early to have such a requirement on this product. In this first instance, it is not yet obvious that this is a product that the market actually wants. However, it is important to appreciate that having an obligation to offer super peak products harms the ability for generators to offer peak products, which already have market making obligations associated with them, recognising there is an overlap between peak and super peak periods. The implication being that a super peak market making obligation could cannibalise liquidity from broader peak products unless total obligations are managed carefully.

6.4.4 Power purchase agreements

A key difference between Australia and New Zealand in terms of PPA volumes is that, in Australia, renewable generation is entitled to certificates which non-renewable participants must purchase. This creates a strong incentive for participants with non-renewable assets to enter long-term PPAs to secure access to these certificates. Indeed, we understand that the term for many Australian PPAs will end once the requirement for certificates ends.

That renewable PPAs in Australia are driven by climate regulation obligations, and that there is a limited volume of PPAs in New Zealand for intermittent generation demonstrates that PPAs for unfirm energy may be of limited value to the market. If customers do not see substantial value in a PPA for non-firm energy, it cannot be expected that these contracts will drive substantial new investment in capacity and energy in New Zealand.

We believe that the proposal for the Crown owned New Co to provide preferential access to its capacity can provide a material boost to customers agreeing to PPAs for renewable power. This is because access to this capacity will permit independent generators to firm up the energy from their intermittent generation sources such as solar or wind. The result being more renewable capacity than may have otherwise been the case.

[88] That is, the opportunity cost of a super peak product is the foregone value of selling a peak product, noting the peak product will ordinarily cover a longer duration.

We acknowledge also the work being undertaken by the Energy Competition Task Force on PPAs.[89] It is our view that where agreeing to PPAs can be made easier for the market, this will be a positive outcome. In deciding on the level of intervention that is ultimately imposed to achieve this outcome, we recommend the Task Force remain cognisant of the fact that PPAs for unfirm output will be of limited benefit to the market.

6.5 Our recommendations

6.5.1 Priority access to New Co capacity will greatly enhance risk management

Our proposal for New Co to quarantine capacity for independent participants will provide the opportunity for independent retailers and generators to achieve the same risk management cost efficiencies as their vertically integrated competitors. The effect being that these independents will be able to offer the same firmed up energy deals as their gentailer competitors.

6.5.2 More detailed analysis of contracting positions is required

We recommend that the Electricity Authority undertake an annual assessment of the hedge contract market in New Zealand. Enabled by updated hedge disclosure obligations, this analysis should examine recent market dynamics such as trends in prices, volumes and product types. We recommend also that it seek views of the industry as to their experience in being able to efficiently hedge in the market. With this information the Electricity Authority will then have a much stronger evidence base to make conclusions about the effectiveness of risk management in the electricity market as well as identifying whether competition is likely to be effective or not, recognising the ability to be able to efficiently manage risk is a key factor for market entry and viability over the longer term.

The ability to perform this analysis effectively will be heavily impacted by other data that may or may not be available to the Electricity Authority. For instance, it would require generating unit level output data in order to determine the actual position of a gentailer in the market. Currently the Authorities generation output by plant series is noted to lack reliability and does not include all facilities in the market,[90] we understand that they intend to replace this data with a better series.[91] In addition, visibility of the position of generating units for each trading interval is required. We note that limitations to the Electricity Authority having this visibility include:

- Financial non-market participants may sell an OTC energy product they own to hedge their position elsewhere back to a market participant. There is no obligation for this to be disclosed. Where this occurs, the Electricity Authority would not have visibility of the true position of all market participants.
- There is a lack of historical information due to poor contract disclosure in the past, given the existence of long-term hedges it may be years until the Electricity Authority has full visibility of contracts under new disclosure obligations.
- We understand seasonal shape is not captured, only the MWh of the entire contract, its start and end dates, and the trading periods it is active. Therefore, there is no visibility on whether

[89] Further detail on the work of the Task Force on PPAs can be found here: https://www.ea.govt.nz/projects/all/energy-competition-task-force/consultation/entrant-generators-context-headwinds-and-options-for-power-purchase-agreements/

[90] For instance, a number of Manawa's facilities are not present in the dataset

[91] The Electricity Authorities generation by plant dataset foreword states their intention to improve this dataset. https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_MD

a contract has higher or lower volumes over winter versus summer. We are also aware that there are contracts where volumes decline over time, yet the Electricity Authority does not have specific information on how volumes change over time.

- Disclosure obligations do not always make it clear what plant generation following PPAs are assigned to.

We recommend that the Authority aim to resolve these gaps where possible, and obtain any other relevant information, in a form that would permit the necessary analysis to be undertaken.

In terms of data collection, we are aware the Electricity Authority has released a consultation paper seeking access to individual bids and offers in OTC markets with the objective of increasing transparency, improve market monitoring, and identify the need for level playing field measures.[92] It is unclear what benefit providing information of commercial negotiations will provide in addition to that obtained from information around settled transactions already captured under the existing HDO. Measures such as the proportion of requests which end in a trade or receive a conforming offer are impacted by a wide range of factors and drawing any causal links from this will be difficult.

[92] https://www.ea.govt.nz/projects/all/otc/consultation/improving-visibility-of-competition-in-the-otc-contract-market/

7 Gas market transparency

7.1 Introduction and summary of findings

The purpose of this chapter is to consider whether participants have sufficient gas information to make informed decisions.

Transparency on demand and supply conditions in the gas market is necessary to support efficient decisions about use of and investment in gas infrastructure.

In our view, information published on the New Zealand gas market is fragmented and incomplete. 'Point-in-time' supply and demand information is limited by data that is publicly available or voluntarily provided to the Gas Industry Co and is limited by the lack of real-time transmission information. This can limit the ability of the market to provide timely and accurate indications about how well it is functioning and, in doing so, hinder the ability of the market to plan efficiently to meet future gas demand and to respond to changing conditions.

To address this issue, we recommend:

- Centralising access to current gas market information in a single 'gas market dashboard' that is maintained by GIC.

  We also recommend that GIC be given formal powers to gather relevant historical information on gas reserves, production, storage, consumption and prices from gas market participants to publish on the dashboard.
- Codifying the requirement for GIC to produce annual studies to forecast and assess the adequacy of gas supply and infrastructure in the future.

7.2 What is the expected market outcome

Transparency in the gas market is required to:

- provide timely and accurate indications about how well the market is functioning, including signalling potential problems with the supply-demand balance for gas and storage services
- ensure that decisions about consumption, production, and longer-term investments are made based on complete and accurate information, and
- remove any potential information asymmetry and imbalance in bargaining power that users face when negotiating with producers.

7.3 Current market

7.3.1 Point in time gas market information is fragmented and incomplete

MBIE and GIC collect and publish current and historical information on gas reserves, production, storage, consumption and prices. This information varies in terms of completeness and frequency of publication. A summary of historical gas market data that is published on a regular basis is set out in the table below.

Table 8: Gas market data published in New Zealand

Category	What is published	Frequency of publication	Publisher
Reserves	1P, 2P and 3P reserves by gas field	Annual	MBIE
Production	Production volumes at Pokokura, McKee and Mangahewa, Maui, Kupe, Turangi and Kowhai	Daily	GIC
	Gross production and net production (gross production less gas flared, reinjected, and extracted as LPG), by gas field	Annual	MBIE
	Gas supply (net production less own use gas) in aggregate for all gas fields	Annual	MBIE
	Gross production, net production and gas supply in aggregate for all gas fields	Monthly and Quarterly	MBIE
Storage	Storage balance at Ahuroa storage facility	Daily	GIC
Consumption	Consumption volumes by category (i.e., energy, non-energy, agriculture, industrial, commercial, residential, transport)	Quarterly and Annual	MBIE
	Consumption by customer (individually for specific large industrial customers, and for electricity generators)	Daily	GIC
Prices	Average natural gas prices for wholesale, industrial, commercial and residential segments	Quarterly	MBIE + GIC

Source: MBIE, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/petroleum-reserves-data; GIC, https://www.gasindustry.co.nz/data/gas-production-and-consumption/; MBIE, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics; GIC, https://www.gasindustry.co.nz/data/gas-storage/

The daily gas market information published by the Gas Industry Co is based on publicly available data, or via voluntarily disclosures from gas market participants. The Gas Industry Co acknowledges that this data is likely to be incomplete as not all data is publicly available.[93] For instance, the Gas Industry Co does not publish daily production volumes for Kapuni as it is not confident that the publicly available information sufficiently captures the activity at this field. While the information published by MBIE is more comprehensive, it is published less frequently. For instance, MBIE publishes gas production volumes by gas field but only on an annual basis.[94]

[93] See: https://www.gasindustry.co.nz/data/gas-production-and-consumption/

[94] See: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics

There is limited up-to-date information published on production capacity, storage capacity, and storage injection and withdrawal rates. We are also not aware of publicly available sources for real time data on transmission capacity by pipeline, and gas transmission flows. Current information tends to come from ad hoc and voluntary updates, or estimates by third parties. Existing information disclosure arrangements do not provide this information to be collected and published on a systematic basis.

We note that certain companies are also subject to NZX disclosure obligations as publicly listed companies which may require reporting on gas production, storage and use.

7.3.2 The Gas Industry Co commissions annual studies on future gas supply and demand

Since 2012, the Gas Industry Co has voluntarily published annual supply and demand studies that investigate the current and forecast production and consumption of natural gas in New Zealand. These studies provide market participants with insights into the medium to long-term outlook for supply and demand in the gas sector. The 2024 study was completed by EY and analysed energy security, emissions and gas price outcomes across four scenarios developed in consultation with the Gas Industry Co.[95]

Apart from these studies, there is limited information published on forecast gas production, storage, consumption and prices, and the information that is available is incomplete and ad hoc.

In its 'Energy in New Zealand' publication, MBIE publishes high level forecasts for gas production in aggregate across all gas fields up to 2040. The *Gas (Facilities Outage Information Disclosure) Rules 2022* requires gas producers to inform the Gas Industry Co of planned (and unplanned) outages. The Gas Industry Co makes these disclosures available on its website. These Rules also require gas producers to provide the Gas Industry Co with forecast daily production volumes, and gas storage owners to provide it with forecast changes in withdrawal capacity. However, we understand that this information can only be used by the Gas Industry Co to monitor compliance with the Rules and is not published.

The Electricity Authority is consulting on its information gathering powers for electricity generation

The Electricity Authority is currently consulting on a proposal to increase the collection and publication of information on thermal fuel used for electricity generation through a clause 2.16 notice under the Code. As part of this proposal, the Authority is proposing to publish the following gas market information on a monthly basis:[96]

- **Gas storage volumes, per participant**: Amount of gas stored in a gas storage facility intended for electricity generation, reflecting the generator's best estimate at the time of reporting.
- **Contracted forward gas supply, minimum** (PJ/month, aggregated across participants): Estimate of minimum expected deliveries of gas, aggregated over all contracts, swaps or trades. Net of gas for non-electrical purposes. Reported as a minimum for a month, for the next 12 months.

[95] See: https://www.gasindustry.co.nz/our-work/work-programmes/supply-and-demand-2024/

[96] EA, *Improving access to thermal fuel information: clause 2.16 information notice – Consultation Paper*, 26 January 2025, p.20 (see: https://www.ea.govt.nz/projects/all/improving-access-to-thermal-fuel-information/consultation/improving-access-to-thermal-fuel-information/).

- **Contracted forward gas supply, maximum** (PJ/month, aggregated across participants) - Best estimate of maximum expected deliveries of gas, aggregated over all contracts, swaps or trades. Net of gas for non-electrical purposes. Reported as a maximum for a month, for the next 12 months.

7.4 Our assessment

The information published on the New Zealand gas market is fragmented and incomplete. 'Point-in-time' supply and demand information is limited by data that is publicly available or voluntarily provided to the Gas Industry Co, and is limited by the lack of real-time transmission information. The absence of sufficient information on demand and supply conditions limits any assessment of the adequacy of gas reserves, resources and infrastructure to meet domestic gas needs.

These issues can adversely affect the efficient operation of the gas market as they may:

- Limit the ability of the market to provide timely and accurate indications about how well it is functioning and, in doing so, hinder the ability of the market to plan efficiently to meet future gas demand and to respond to changing conditions, and
- Result in inefficient decisions about consumption, production, and the use of infrastructure services and longer-term investment decisions as these decisions are being made based on incomplete, inaccurate, or asymmetric information.

Incomplete information may also impede effective competition and the efficient trade of gas by imposing relatively high search and transaction costs on parties, hinder the price discovery process, and increasing asymmetry in bargaining power between users and producers.

In terms of the annual supply and demand studies procured by the Gas Industry Co, these studies are an important source of information for gas market participants on the future outlook of the gas sector. However, since they are prepared on a voluntary basis, there is a risk that the frequency, scale and scope of the reports may change over time. In addition, the reports that have been produced to-date appear to involve limited stakeholder consultation, particularly around development of suitable modelling scenarios, and do not appear to cover all relevant factors, noting they do not cover the adequacy of transmission and distribution pipeline capacity.

7.5 Our recommendations

7.5.1 Centralising historical gas market information

There are benefits in centralising access to relevant gas market information in a single 'gas market dashboard.' This would make it easier for gas market participants to locate the information they need and to have a common understanding of 'point-in-time' supply and demand conditions in the market. We recommend that the Gas Industry Co be tasked with developing and maintaining the gas market dashboard. As noted above, the Gas Industry Co already maintains a database of gas market information on its website that it draws from publicly available resources. The gas market dashboard would be an extension of this activity to cover additional information.

It is important that the gas market dashboard provide timely, comprehensive and accurate information on the supply-demand balance for gas. Complete and accurate information will improve the ability of the market to respond efficiently to changing market conditions, and result in more efficient decisions being made about consumption, production, and longer-term investment decisions. As such, the Gas Industry Co should be given formal powers to gather relevant historical information on gas reserves, production, storage, consumption and prices from gas market participants.

Our specific recommendations on the data that the Gas Industry Co should gather, and the frequency with which gas market participants should provide this data, are set out in the table below.

Table 9: Data to be collected and published by GIC

Category	What should be reported	Frequency of reporting	Difference versus status quo
Reserves	1P, 2P and 3P natural gas reserves, by gas field	Annual	Change in reporting entity from MBIE to GIC
Production capacity	Nameplate capacity, by gas field	Annual	New information that is not currently reported
	Available production capacity, by gas field	Daily	New information that is not currently reported
Production volumes	Production volumes (gross, net and supply), by gas field	Daily	Addition of daily production volumes for Kapuni, and other smaller gas fields not currently captured by GIC
	Planned and unplanned outage information	By event	No change to status quo
Storage	Nameplate capacity at Ahuroa storage facility	Annual	New information that is not currently reported
	Maximum injection and withdrawal rate at Ahuroa	Annual	New information that is not currently reported
	Storage balance at Ahuroa storage facility	Daily	No change to status quo
	Actual injection and withdraws at Ahuroa	Daily	No change to status quo
Transmission	Nameplate capacity, by pipeline	Annual	New information that is not currently reported
	Available capacity, by pipeline	Daily	New information that is not currently reported
	Gas flows, by pipeline	Daily	New information that is not currently reported
	Planned and unplanned outage information	By event	New information that is not currently reported

Category	What should be reported	Frequency of reporting	Difference versus status quo
Consumption	Gas consumption volumes, by qualifying customer (to include all gas electricity generators, and customers above a certain level of average daily demand)	Daily	Daily consumption volumes for a larger number of customers
Prices	Average natural gas prices for wholesale, industrial, commercial and residential segments	Quarterly	No change to status quo

7.5.2 Codify requirement to produce annual supply and demand study

There is benefit in codifying the requirement for the Gas Industry Co to produce annual studies to forecast and assess the adequacy of gas supply and infrastructure in the future. We recommend that these studies should minimally cover the following:

- medium to long-term demand forecasts for gas and pipeline services
- production capacity to meet existing and foreseeable demand for gas
- pipeline capacity to meet existing and foreseeable demand for pipeline services
- likely long-term production or transmission constraints
- forecast gas prices by market segment, and
- an assessment of likely medium to long-term shortfalls in gas supply.

We recommend that this assessment be undertaken across a range of potential future scenarios. The scenarios should be developed in consultation with gas market participants, MBIE and the Electricity Authority. The scenarios should be consistent with the EDGS produced by MBIE for the electricity sector. The analysis period should cover a minimum 20-year planning horizon. The Gas Industry Co should be required to publish a report setting out its modelling approach, key assumptions, findings, and the implications of its findings for the future gas market in New Zealand.

8 Distribution networks

8.1 Introduction and summary of findings

The purpose of this Chapter is to consider whether ownership, structure or design of markets are affecting the incentives for efficient investment in distribution networks.

There are currently 29 electricity distribution businesses (EDBs) in New Zealand. These EDBs are regulated by Part 4 of the *Commerce Act 1986* (the Act). The current regulatory arrangements came into force on 1 April 2009, following a legislative amendment to the Act in 2008.

Electricity distribution networks are essential to a well-functioning energy market. Electricity cannot reach end consumers such as households, businesses and industrial users without distribution networks. Appropriate investment in distribution networks is required to:

- Ensure security of electricity supply;
- Facilitate new sources of generation, including distributed generation;
- Allow users to consume electricity in new ways (e.g., to charge EVs); and
- Connect new sources of load that can spur economic development.

However, EDBs are natural monopolies. Such businesses need to be regulated properly to constrain their incentives to act in ways that may harm consumers (e.g., by pricing excessively, deterring upstream or downstream competition, or by becoming less efficient over time).

Our key finding in this chapter is that the current electricity distribution industry is too fragmented with too many small EDBs (relative to the size of the country), many of whom are exempt from price-quality regulation designed to promote the long-term interests of consumers. These EDBs are likely to be operating well below minimum efficient scale. This, in turn, is limiting the ability of most EDBs to:

- Operate and invest efficiently; and
- Innovate to deliver services more effectively to consumers.

Furthermore, the large number of EDBs operating in New Zealand, combined with lack of standardisation of policies, terms and conditions for connecting new customers, has created unnecessary complexity and transaction costs for new customers (i.e., generators and large loads) wishing to connect to the grid. This incentivises large new customers to make connection choices to minimise their transaction costs, rather than connecting efficiently to locations with spare grid capacity. This, in turn, would require inefficient network investments to expand capacity to avoid congestion, the costs of which are ultimately borne by all consumers.

To address these problems, our key recommendation is to amalgamate the existing 29 EDBs into five, similarly-sized 'Super EDBs', each of which would be headquartered in a major New Zealand city. This would:

- Allow EDBs to exploit scale economies and efficiencies from rationalisation (e.g., reducing duplicate workforces);
- Assist EDBs in attracting and retaining the skilled staff needed to plan, operate and manage the existing distribution networks effectively, and to build organisational capacity and capability;
- Potentially allow EDBs to access broader sources of external finance;

- Facilitate fundamental reforms to the regulatory framework that would improve outcomes for consumers; and
- Reducing the number of EDBs that potential new customers would have to deal with, thus reducing the complexity and transaction costs incurred by those customers when seeking to connect new load or sources of supply to a distribution network.

We also recommend the following changes, to improve outcomes to consumers from the regulatory arrangements governing EDBs:

- The removal of all existing exemptions to consumer-owned EDBs from price-quality regulation. Instead, all EDBs would be subject to individual price-quality path regulation, under which the Commission must take into account the particular circumstances of individual EDBs when setting regulatory allowances. This would allow EDBs to invest and innovate more effectively than under the current default price-quality framework.
- Require the Electricity Authority to specify the scope of the Input Methodologies (IM) that must be developed by the Commission. This would limit the scope for important methodology issues being excluded from the IM review process, and escaping the scrutiny of potential merits review, which provides an important discipline on the Commission's decision-making.
- Remove the current prohibition on the Commission using comparative efficiency benchmarking. This is an important tool that the Commission can use to drive better outcomes for consumers, which the Commission cannot use under the current provisions of the Act.
- Introduce a mandatory obligation for the Commission to undertake financeability tests when making price-quality determinations. This provides an essential reasonableness check on the Commission's decisions, and provides investors with greater certainty that committing to large (welfare-maximising) network investments will not result in a deterioration in an efficient EDB's credit rating.
- Retain the existing restrictions on EDBs owning and controlling generation assets in their own service areas. Current policy proposals to ease these restrictions are likely to have the unintended consequence of restricting, rather than encouraging, additional electricity supply. This would harm rather than help consumers.
- The Electricity Authority should expand its existing consultations to consider how the contractual terms for new connections can be harmonised and simplified. This would reduce the transactions costs faced by new customers wishing to connect new load or generation to the grid, thereby improving security of supply and promoting economic development.

8.2 What is the expected market outcome?

EDBs are natural monopolies because as their output increases, their per unit costs decrease. This means it is more efficient for only one EDB to serve customers in a particular geographic region. While this is the least cost market structure for distribution networks, the market power this confers means that, if left unchecked, EDBs would have an incentive, and ability, to degrade service performance, act inefficiently, and price substantially above their costs. Such conduct would harm consumers.

The ability to increase costs and prices and reduce service quality means that the EDBs are subject to economic regulation. The objective of regulation being to constrain the misuse of market power, while recognising that customers place high value on continued and reliable service provision. Meaning each of these outcomes need to be achieved simultaneously.

The tension between constraining market power while ensuring high service performance is universally addressed by regulators by ensuring prices are set with reference to efficient cost. This way, the business can expect to recover its operating costs and at least make a normal return on investment, while generating prices that are as low as compatible with continued and reliable service provision. In practice, this means emulating the outcomes that would occur in competitive markets, which include:

- Efficient investment in the assets required to deliver regulated services over the long-term;
- Efficient utilisation of those assets by consumers; and
- Pricing that reflects the efficient cost (including a reasonable, or 'normal' economic, return on capital invested) of supplying the regulated services.

The regulatory framework provides the Commission with two main, complementary 'tools' to deliver these outcomes:

- The ability to impose price-quality regulation on so-called "non-exempt" suppliers (explained in further detail below); and
- The ability to impose information disclosure requirements on all regulated suppliers.

Price-quality regulation aims achieve the Part 4 purpose by:

- Setting a ceiling on the prices or revenues that a regulated EDB may charge. This upper limit is determined by the Commerce Commission (the Commission) by estimating the efficient costs that an EDB would incur in delivering electricity services.[97] The regulatory framework incentivises EDBs to reduce their costs below the Commission's estimate (i.e., to become more efficient) because any such 'savings' are retained by the business for a period of time, and then shared with consumers.
- Setting a floor for service quality (e.g., network reliability), to avoid EDBs reducing their costs (to maximise their profits under the regulatory regime) by sacrificing service quality.
- The purpose of the information disclosure regime is to provide the Commission with the information it requires to monitor the performance of all regulated suppliers (to ensure that the Part 4 purpose is being achieved), as well as the information the Commission requires to apply price-quality regulation to non-exempt suppliers. These regulatory tools are discussed further in the next section.

8.3 Current market

The purpose of the existing regulatory framework for EDBs, as defined in section 52A of the Act, is to promote the long-term benefit of energy consumers in New Zealand by promoting outcomes that are consistent with those produced in competitive markets, such that regulated suppliers:[98]

- have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and
- have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and

[97] These costs include operating costs, capital costs (i.e., the required return on capital invested plus depreciation) and tax obligations.

[98] This is commonly referred to as "the Part 4 purpose."

- share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and
- are limited in their ability to extract excessive profits.

Price-quality regulation aims achieve the Part 4 purpose by:

- Setting a ceiling on the prices or revenues that a regulated EDB is able to charge. This upper limit is determined by the Commerce Commission (the Commission) by estimating the efficient costs that an EDB would incur in delivering electricity services.[99] The regulatory framework incentivises EDBs to reduce their costs below the Commission's estimate (i.e., to become more efficient) because any such 'savings' are retained by the business for a period of time, and then shared with consumers.
- Setting a floor for service quality (e.g., network reliability), to avoid EDBs reducing their costs (to maximise their profits under the regulatory regime) by sacrificing service quality.
- The purpose of the information disclosure regime is to provide the Commission with the information it requires to monitor the performance of all regulated suppliers (to ensure that the Part 4 purpose is being achieved), as well as the information the Commission requires to apply price-quality regulation to non-exempt suppliers. These regulatory tools are discussed further in the next section.

16 of the 29 EDBs are subject to a default/customised price-quality path regulation and are therefore referred to as "non-exempt EDBs"; the remaining 13 EDBs are exempt from price-quality regulation as they are deemed to be 'customer owned'. Price-quality regulation is implemented for EDBs in two forms:

- **Default price-quality path (DPP) regulation** – intended to be a relatively low-cost approach to setting revenue allowances for EDBs that does not involve the Commission undertaking detailed scrutiny of each EDB's expenditure proposals, and
- **Customised price-quality path (CPP) regulation** – an EDB may apply for a CPP if it considers that a DPP would be insufficient to meet its particular circumstances (e.g., to recoup its efficient costs, or to allow it to invest appropriately). The CPP process involves much more detailed scrutiny of the EDB's revenue proposal and costs and, therefore, imposes more regulatory burden on the EDB and the Commission.

The original intent of default/customised price-quality regulation was to balance the regulatory burden of having to regulate many EDBs against the desirability of accounting for firm-specific circumstances when setting regulated prices for individual EDBs. The expectation was that most EDBs would be able to manage sufficiently under DPPs in most circumstances; those EDBs that required a more bespoke treatment would always have the option of seeking a CPP.

Under the DPP framework, allowances for operating expenditure (opex) and capital expenditure (capex) are determined using relatively low-cost, top-down forecasting approaches that reflect industry-wide factors rather than detailed, firm-specific considerations. This obviates the need for the Commission to undertake detailed, bottom-up (i.e., engineering based) expenditure assessments (as happens in other jurisdictions overseas). However, the robustness of this approach is contingent on the Commission having access to appropriate historical and projected information on costs and performance.

A CPP determination has the same essential components as a DPP determination (e.g., the price path is determined via a building block approach). However, under a CPP process:

[99] These costs include operating costs, capital costs (i.e., the required return on capital invested plus depreciation) and tax obligations.

- the EDB in question must initiate the process by making an application to the Commission. By contrast, DPP reviews are initiated by the Commission; and
- the Commission may consider the specific circumstances of an EDB to set a path that better suits its needs. This may involve doing more detailed assessments of the supplier's cost requirements.

All EDBs are subject to information disclosure (i.e. regulatory reporting) requirements.

The Electricity Authority also has the following responsibilities in regulating EDBs:

- Development of the Electricity Industry Participation Code (the Code). The Code establishes the rules and obligations that must be met by EDBs,
- Development of industry guidelines—including, for example, distribution pricing, connection policies and connection pricing, calculation of distribution losses, and
- Monitoring of compliance against the Code and industry guidelines, and the granting of exemptions where deemed appropriate by the Electricity Authority.

Further detail on the approach to DPP regulation, CPP regulation and information disclosure is set out in Appendix C.

8.4 Are current frameworks delivering?

8.4.1 The two-tier DPP/CPP regime is no longer fit for purpose

We heard from a number of stakeholders that the DPP framework is too restrictive to facilitate the potential step-changes in investment and innovation required to support the energy transition. This is because the DPP framework adopts a 'one-size-fits-all' approach to set the expenditure (i.e., opex and capex) allowances for all non-exempt EDBs that have not requested a CPP decision. In other words, the Commission uses simple relationships between cost (i.e., opex or capex) and cost drivers, estimated using historical data, to set expenditure allowances for each EDB under a DPP decision. As these cost relationships reflect historical trends in the data, they are incapable of allowing properly for the potential step-changes in future expenditure that may be required to deliver New Zealand's energy transition.

The existing DPP/CPP framework was designed during a time when the electricity industry was largely in a 'steady state'. There was no significant impetus for growth of electricity networks, and no pressing need for innovation. However, the industry is no longer in steady state. Within the last six years, New Zealand has legislated a target of reaching net zero by 2050 and has, like many other industrialised countries, embarked on a major energy transition. The centrepiece of that transition is electrification of the economy, which can only be achieved with significant investment (e.g., to connect new sources of renewable generation, Consumer Energy Resources (CER) and to accommodate EV charging) and innovation in electricity networks and associated infrastructure.

Furthermore, the emergence of new technologies, such as Artificial Intelligence and cloud computing has created the potential for new types of energy-intensive industrial customers, such as data centres, which will want to connect large loads directly to the grid. Significant new network investment may be required in some regions to accommodate these customers.

Additionally, there is good reason to think that building network capacity ahead of actual demand may facilitate a more efficient energy transition by allowing EDBs to exploit scale economies and other savings when investing in large capacity upgrades, rather than in small,

sequential increments.[100] Again, the one-size-fits-all approach under the DPP framework does not provide the step-change in expenditure allowances required to fund significant, lumpy investment ahead of demand.

It is true that EDBs have the option of seeking a CPP that would better suit their circumstances. However, relying on this seems impractical under the current arrangements:

- Firstly, the energy transition is likely to require significant distribution network investment in almost all regions of New Zealand. Hence, the number of EDBs that may potentially require a CPP to facilitate the needed investment would likely overwhelm the Commission's resources.
- Secondly, as a number of stakeholders have told us, the perceived or actual cost/regulatory burden of a CPP process (particularly for small, less well-resourced EDBs) may deter some EDBs from pursuing a CPP that would otherwise allow them to undertake the prudent and efficient investment required to support New Zealand's energy transition. In other words, the existing regulatory arrangements may actually produce an underinvestment problem, which would ultimately harm energy consumers in New Zealand and deny development opportunities to remote and regional communities.
- Our conclusion is that now, when almost every EDB in New Zealand may require a more bespoke assessment of their investment needs, the existing DPP framework is inimical to New Zealand's energy transition, and the pressing need to improve energy security. An alternative regulatory framework that would require the Commission to undertake a close assessment of each EDB's individual expenditure requirements is needed. We discuss in section 8.5 below some options for such a framework.

We note that even in the absence of the energy transition, there would be case to move away from the existing DPP framework. Our analysis of the publicly available Information Disclosure data submitted by EDBs to the Commission indicates that:

- In general (i.e., across the industry as a whole), EDBs' networks assets are aging over time. That is, replacement of network assets is generally not keeping pace with the depreciation (i.e., wear and tear) of those assets; and
- There is a significant upward trend in the System Average Interruption Duration Index (SAIDI) associated with unplanned outages caused by defective equipment for several EDBs.[101] In other words, for those EDBs there appears to be a trend towards declining network reliability due to defective equipment.

The data on asset age and SAIDI are presented in Appendix C.3 of this report.

We cannot say definitively that the apparent decline over time in reliability for some EDBs is due exclusively (or even primarily) to the aging of assets. However, in the absence of firm evidence to the contrary, that is a reasonable conclusion to draw.

The exact reasons for the aging of EDB assets are not clear. However, the following statement by Firstlight Network (formerly Eastland Network) in an Asset Management Plan suggests that the regulated revenue that EDBs are permitted to earn under the DPP framework has been insufficient (too constraining) to allow asset renewal and replacement in line with the

[100] See, for example: Frontier Economics, *The IM review: Investing to enable decarbonisation and realise the benefits of electrification*, 18 November 2022. https://blob-static.vector.co.nz/blob/vector/media/vector-2023/frontier-economics-decarbonisation-and-electrification.pdf

[101] This data is focused on interruptions caused by defective equipment and so excludes interruptions caused by factors beyond the control of the business.

depreciation of those assets.[102] The EDBs are then investing only up to the level of their revenue allowance, rather than the revenue allowance being driven by EDBs' investment requirements:

> *Because of the low growth and surplus capacity in the network, Capital expenditure is dominated by renewals. The rate of renewal can therefore be used to manipulate the age of each asset category relative to its rate of depreciation. Most of the asset categories are being* ***renewed at a rate less than depreciation but commensurate with constrained revenue****, hence the overall asset is aging.*[103] [emphasis added]

If the current trend of aging assets continues, the industry could face a similar situation to the one currently being faced by the water sector in New Zealand. Decades of chronic underinvestment in the networks and infrastructure used by councils to deliver drinking water, wastewater and sewerage services has resulted in serious water quality problems, leakage, and safety issues for the community at large. While there is uncertainty about the actual quantum of expenditure required, early estimates undertaken for the Government identified an investment need of between $120 billion and $185 billion over the next 30 years to ensure water and wastewater services.[104] All this investment will need to be financed and delivered within a relatively short period of time (rather than gradually, as is normally the case for well-managed infrastructure). This may have serious financial viability implications for the owners of the water infrastructure, as well as potentially sharp cost increases for users of the assets.

It is essential that similar outcomes should not occur in the electricity industry, and the consumers that rely on that industry for economic prosperity, growth and development.

8.4.2 Many EDBs are too small to operate and invest effectively

New Zealand has 29 EDBs, which is a very large number, given the size of the country. By way of comparison, the State of Victoria in Australia, which has a similar land area to New Zealand but a population that is more than 30% larger than New Zealand's, has only five EDBs in total (see Table 10 below).

Table 10: New Zealand vs Victoria (Australia) – population, land area and no. EDBs

	New Zealand	Victoria
Population (June 2024)	5,332,800[1]	6,981,400[2]
Land area (sq km)	263,310[3]	227,600[4]
Number of EDBs	29	5

Source: [1] Stats NZ; [2] Australian Bureau of Statistics; [3] World Bank; [4] Land Use Victoria.

[102] Eastland/Firstlight Network has only ever been subject to DPP allowances; it has never received a CPP allowance.

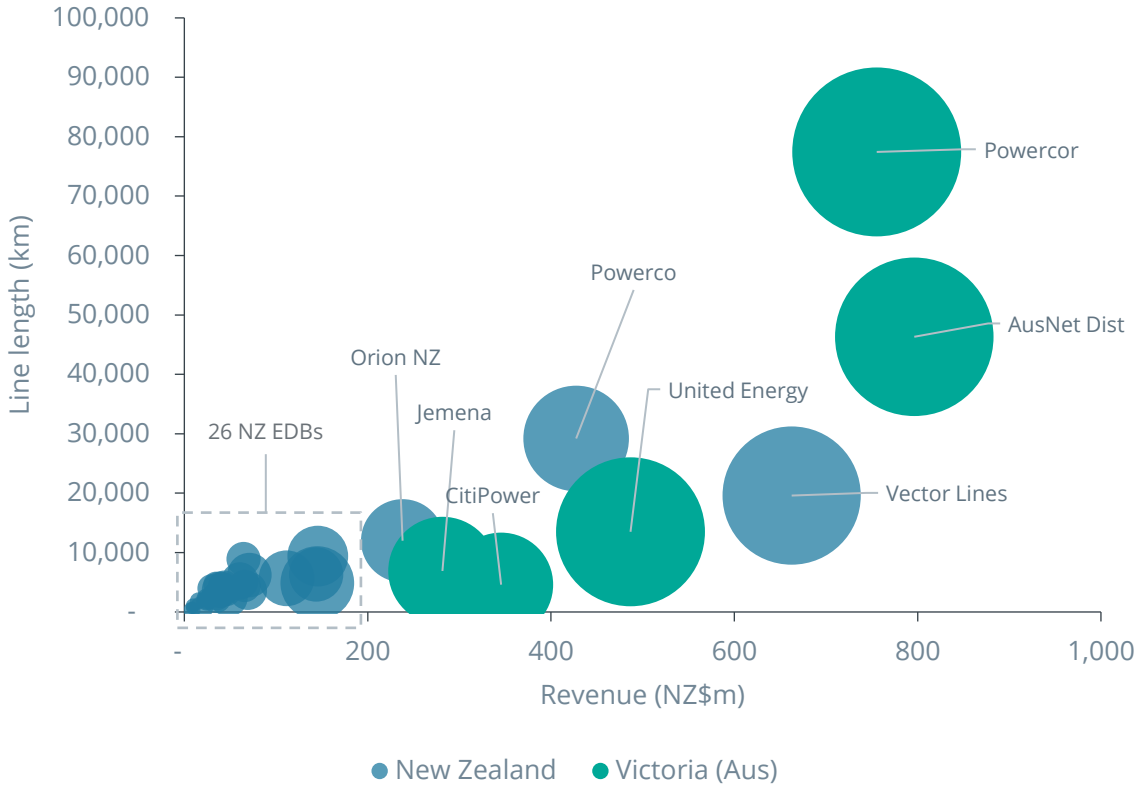
[103] Eastland Network, *Asset Management Plan 2019-2029*, 1 April 2019, p. 199.

[104] See: Reports prove case for urgent water infrastructure reform | Beehive.govt.nz and Water services reform national evidence base - dia.govt.nz

A consequence of having so many EDBs serving a relatively small population is that most of those EDBs are very small. This can be seen in Figure 50, which compares the size of EDBs in New Zealand and in Victoria, the smallest mainland State of Australia. The vertical axis of the chart plots the line length (kms) of each EDB, and the horizontal axis plots the revenue (NZ$ million) of each EDB. The size of the bubbles in the chart represents the number of connections served by each EDB; the larger the bubble, the more connections served.

The figure below shows that 26 of the 29 New Zealand EDBs are considerably smaller than all of the Victorian EDBs; only Orion, Powerco and Vector are somewhat similar in scale to the smallest of the Victorian EDBs. The smallest New Zealand EDB (Buller) serves just 4,889 connections. By contrast, the smallest Victorian EDB (CitiPower) serves 349,689 connections, which is comparable to Powerco's 359,857 connections. Powerco is the second largest EDB in New Zealand by number of connections.

Figure 50: Scale of New Zealand EDBs compared to EDBs in Victoria



Source: Frontier Economics analysis of Information Disclosure and Regulatory Information Notice data submitted by EDBs in New Zealand and Australia. Note: The size of the bubbles indicate the number of customer connections served by each EDB. All data are 2024 values.

In our view, the New Zealand EDB industry is too fragmented, with most EDBs operating well below minimum efficient scale. While we are aware that some other jurisdictions also have relatively small EDBs, this does not mean that this model is efficient, particularly for New Zealand.

A recurring theme we heard from a number of stakeholders is that some EDBs, particularly those that are not headquartered in the main cities in New Zealand, are too small and too remote to attract and retain skilled and experienced personnel. This limits their capacity to effectively:

- Undertake network planning and maintenance
- Manage corporate finance functions
- Engage with regulators, and
- Deliver complex investment programs.

The small size of the EDBs may also result in result in poorer governance and decision-making. There are, for instance, cases of small EDBs investing financial capital in ventures such as a clothing producer (i.e. Scanpower's investment in the now defunct Kiwi Sock Company) and a winery (i.e., Marlborough Lines' ongoing investment in Yealands Wine Group), rather than core electricity distribution services.[105]

It may also be more difficult for small EDBs to attract and raise the financial capital required to make network investments. By way of analogy, some council-owned water networks in Australia have historically preferred to finance investments using retained earnings, and have been reluctant to raise debt finance due to the risks and complexity involved in managing a debt portfolio. The aversion towards debt raising has, in some cases, capital-constrained those networks' ability to make network investments.

We also note that the largest EDB in New Zealand, Vector, is 75.1% owned by community trust. The remaining 24.9% of Vector's equity is listed and publicly traded on the NZX. Vector also holds a significant quantity of debt.[106] That is to say, the largest EDB in New Zealand has been able to access a much wider pool of financing (including publicly traded shares, equity from the community trust, retained earnings and debt) than most other EDBs. Its ability to access this range of finance is at least in part due to Vector's size.

Finally, we note that 13 of the smallest EDBs are exempt from price-quality regulation, primarily because they are considered too small to participate effectively even in the DPP framework.[107] In other words, the decision to exempt 13 EDBs — and to deny the consumers served by those EDBs the long-term benefits offered by effective regulation — was a pragmatic compromise reflecting the regulatory burden that would be imposed on EDBs and the Commission if price-quality regulation were to apply to all EDBs operating in New Zealand. In our view, it is inappropriate to simply assume away the harm (e.g., arising from very weak incentives for efficiency and innovation) that may potentially be imposed on some consumers, simply because those consumers happen to be served by small EDBs.

8.4.3 The Commission has too much discretion over the scope of the IMs

When the current regulatory framework for EDBs was designed in 2008, it was conceived as having three key elements:[108]

[105] The decision to invest in unrelated activities may also partly reflect the ownership structure of these EDBs. However, larger community trust and council-owned EDBs have not chosen to invest in such non-core activities.

[106] In 2024, Vector reported that it held over $2 billion in current and long-term borrowing.

[107] The oft-cited reason for this exemption is that these 13 EDBs are "consumer-owned", as though certain forms of ownership offer protection against the abuse of market power, or poor incentives for efficiency and innovation, by a natural monopoly. Of course, this reason does not withstand scrutiny because the largest, non-exempt EDBs in New Zealand are either wholly consumer-owned (e.g., Unison Networks, Orion) or are majority consumer-owned-owned (e.g., Vector).

[108] MBIE, Part 4 of the Commerce Act 1986: Merits Review Regime Evaluation, Summary Findings from Interviews with Stakeholders, April 2016, p. 5.

1. A dedicated Part 4 purpose statement to promote the long-term benefit of consumers in markets where there is little or no competition and little or no likelihood of a substantial increase in competition
2. A requirement for the Commission to specify key regulatory parameters, methodologies and processes in advance of their application in the economic regulation of goods or services (collectively termed input methodologies, or IMs). Section 52R of the Act provides that the purpose of the IMs is to "promote certainty for suppliers and consumers in relation to the rules, requirements, and processes applying to the regulation, or proposed regulation, of goods or services" under Part 4, and
3. Subjecting the IMs determined by the Commission to appeal to the High Court regarding the merits of any or all IMs (merits review). Note it is only the IMs that may be subject to merits review. The price-quality determinations the Commission makes by applying the IMs cannot be merits reviewed, but may be subject to judicial review by the Courts.

As MBIE has previously explained, the inclusion of the merits review mechanism within the regulatory regime had three purposes:[109]

4. To incentivise the Commission to make well-considered IM determinations. Note that it is not necessary for suppliers or consumers to actually pursue merits reviews in order to incentivise the Commission to make good determinations. Indeed, there have been very few such appeals since the first IMs were published in 2010. The mere threat of appeals can provide a powerful discipline on the Commission to make well-reasoned decisions
5. To provide an avenue for determinations to be reviewed for possible errors of substance or fact and, if necessary, rectified, and
6. To improve the quality of future determinations made by the Commission by establishing precedents which would increase the certainty (and therefore confidence) of stakeholders engaged in future regulatory processes.

It is important to understand that it was a deliberate design choice to separate the development of the IMs from the process of making price-quality determinations by the Commission. The intent was to maximise the predictability of the outcomes of the regulatory framework by:

- requiring the Commission to consult and develop in advance IMs that explain how it will make price-quality determination, and
- then permitting suppliers and consumers the option of seeking merits reviews of those IMs.

The process of the Commission then making price-quality determinations was then supposed to be a straightforward application of the settled IMs. The idea was that by the time the Commission begins the process of making a price-quality determination, all of the key approaches and methods that will be used to make that decision would have been set out clearly (and potentially tested through merits review) such that all stakeholders can anticipate with a reasonable degree of certainty the outcome of the Commission's decision. There should be no surprises, and the Commission should have very little discretion at all when making price-quality determinations because all major, contentious matters should have been addressed through the IMs review preceding the price-quality determination process.

However, it has transpired that many important issues have been relegated by the Commission to the price-quality determination process, rather than the IMs review process. A few examples include:

[109] MBIE, Part 4 of the Commerce Act 1986: Merits Review Regime Evaluation, Summary Findings from Interviews with Stakeholders, April 2016, p. 5.

- the precise methods that the Commission uses to set opex and capex allowances (for DPP and CPP decisions)
- the method the Commission uses to set regulatory depreciation allowances (which has become a particularly important and contentious issue for gas networks in particular)
- the method the Commission uses to assess the financeability of EDBs under a price-quality determination, (discussed further in section 8.4.5 below), and
- the method the Commission uses to set starting prices for each regulatory period.

No decision that the Commission makes in respect of any of these issues may be subject to merits review, because there is no IM in relation to any of these matters and, under the existing framework, only IM decisions may be merits reviewed. This undermines a key principle that the Commission should be held accountable, through the threat of merits review, for all material methodological decisions. The circumvention of the IMs also creates uncertainty for stakeholders about how the Commission will make its price-quality decisions. This also violates the important certainty principle, which was a deliberate feature of the regulatory framework when it was first designed.

8.4.4 The current prohibition on use of comparative efficiency benchmarking to set prices constrains the Commission excessively

Background to 2008 legislative reforms

The regulatory framework that applied prior to the introduction of the current regulatory regime in 2009 was a 'targeted control' regime, which had been introduced in 2001. Under that regime, the Commission was required to set price and quality 'thresholds' for EDBs periodically, and then assess their performance against those thresholds. If the Commission identified a breach of the thresholds, it was required to conduct a post-breach inquiry and determine whether it should impose more direct, formal controls on the network that had breached.

The Commission had no enforcement powers to sanction businesses that had been found to breach the thresholds. The notion underpinning this light-handed system of regulation was that the threat of more intrusive regulation would be sufficient to discipline and deter EDBs from breaching the thresholds. However, in practice a large number of breaches (many of which were relatively minor technical breaches) occurred. A substantial proportion of these remained unresolved by the time the thresholds regime was replaced. This left many stakeholders, including the Government of the day, feeling that the thresholds regime was not fit for purpose. The electricity networks were particularly concerned about uncertainty over what action the Commission would decide to take following a breach. These various concerns led the Government to pursue amendments to the Act that resulted in the present regulatory regime.

How past use of comparative benchmarking resulted in the existing prohibition against the use of such analysis by the Commission

Under the previous regulatory framework, the Commission used a CPI-X approach to set the price thresholds that applied to electricity networks. The X-factor was determined using benchmarking techniques that comprised:[110]

[110] The larger the X-factor set by the Commission, the more stringent were the price thresholds faced by the networks, all else remaining equal.

- An estimate of the industry-wide rate of productivity improvement (using Total Factor Productivity analysis), and
- Two factors that measured the relative performance of the networks (in terms of cost efficiency, using Multilateral Total Factor Productivity analysis) and profitability.

Over the two threshold resets that occurred between 2001 and 2009, significant industry dissatisfaction built up around, in particular, the way in which the Commission had implemented and used comparative benchmarking to determine the relative efficiency of the networks. Some suppliers considered that the comparative benchmarking work the Commission had undertaken had serious shortcomings but, notwithstanding those limitations, had been used in a mechanistic way to set the price thresholds with little allowance for those shortcomings.

Some suppliers considered that the Commission had set unreasonably stringent price thresholds that were susceptible to breach, and that comparative benchmarking was one of the key pieces of analysis that the Commission had relied on to set those thresholds. Even those suppliers that had performed relatively well in the Commission's comparative benchmarking analysis had misgivings because the results could be highly sensitive to the inputs and assumptions. This meant that a different set of assumptions and inputs could conceivably result in ostensibly high performing EDBs tumbling to the bottom of the Commission's league table, simply due to modelling choices and alternative assumptions, rather than true changes in efficiency.

These industry concerns about comparative benchmarking were seen as linked, inextricably, to what suppliers felt were problems with the thresholds regime. Specifically, if an EDB breached its price threshold (because it had been 'too low' a threshold using 'unreliable' comparative benchmarking), it faced a high degree of uncertainty about the Commission's response to the breach, which could range from no action to declaration of full control, and a range of other types of interventions in between these extremes. Policymakers were persuaded that this high degree of regulatory uncertainty could deter efficient investment.

Consequently, when the Government was considering reforms to the Act, the industry lobbied successfully to have a prohibition inserted into the amended legislation that would prevent the Commission from using comparative benchmarking to make price-quality determinations. Section 53P(10) of the Act now provides that:

> *The Commission may not, for the purposes of this section, use comparative benchmarking on efficiency in order to set starting prices, rates of change, quality standards, or incentives to improve quality of supply.*

For the sake of clarity, it is worth noting that:

- The prohibition on the use of comparative benchmarking in the Act only relates to the DPP regime. The sections of the Act that relate to the CPP and information disclosure regimes do not contain similar prohibitions.
- The Commission may (and has) used in its DPP decisions, benchmarking analysis that applies to the overall industry to estimate and inform its decision on the rate of productivity that applies to the overall industry. In other words, section 53P(10) relates specifically to benchmarking of the *relative efficiency* of *individual EDBs*, rather than measurement of changes in productivity of the industry as a whole over time.

- Finally, there is nothing in the Act that prevents the Commission from undertaking comparative efficiency analysis or productivity analysis as part of its Information Disclosure regime — for instance, to improve its (and stakeholders') understanding of how the efficiency and productivity performance of the industry, and individual EDBs, may be changing over time. However, the Commission has historically been reluctant to do this due to concern about how this may be viewed by the industry. Only very recently has the Commission begun to explore, tentatively, the possibility of undertaking comparative efficiency analysis to inform its general understanding of the industry as a whole, and the relative performance of individual EDBs.

Consequences of the current prohibition on comparative benchmarking

In 2014, the Australian Energy Regulator (AER) began using comparative benchmarking analysis in earnest to set the opex allowances for the 13 EDBs it regulates.[111] The AER's approach is to use historical data collected from EDBs (including data on actual expenditure) to estimate an 'efficient frontier' for the industry. An EDB on the efficient frontier can be considered as operating in a maximally efficient way. That is, the EDB could not produce more output, given the expenditure it incurs to deliver the regulated services. The AER then estimates the 'gap' between each EDB and the efficient frontier, and uses that estimate to adjust the opex allowances of individual EDB. For instance, if the AER finds that a particular EDB is very distant from the efficient frontier, then the AER will apply a large adjustment (commensurate with the estimated efficiency gap) to the EDB's actual opex as the starting point for forecasting a level of efficient opex for the next regulatory period.

When the AER first introduced comparative benchmarking, it felt that data on just 13 Australian EDBs was insufficient to reliably estimate the efficient frontier for the industry. It therefore included in its benchmarking analysis data on EDBs in New Zealand (collected and published by the Commission) and in Ontario (collected and published by the Ontario Energy Board).

In a recent report, the AER's adviser on comparative benchmarking analysis (a firm called Quantonomics) presented evidence (reproduced in Table 11) on the extent of efficiency and productivity changes that have occurred over time in Australia, New Zealand and Ontario.[112]

Table 11: Evidence on EDB efficiency and productivity changes from different sources

Jurisdiction	Empirical evidence[1]
Australia	• Between 2006 and 2023 efficiency/productivity **improved by between 0.3% and 0.4% p.a.** on average[1] • Between 2012 and 2023 efficiency/productivity **improved by between 2.5% and 2.8% p.a.** on average[1]

[111] The National Electricity Rules also require the AER to publish Annual Benchmarking Reports for electricity distribution and transmission networks. The Annual Benchmarking Reports present summary analysis of productivity and efficiency trends for each business and the industry as a whole, following detailed econometric and total/partial factor productivity analysis of data collected from the businesses. One objective of these reports is to inform all stakeholders about trends in productivity and efficiency performance. Another object is to incentivise the executives and Boards of the businesses to lift the performance of the businesses by 'naming and shaming' those networks that have lagged behind. There is general acceptance that Australian EDBs have responded strongly to the reputational incentives created by these Annual Benchmarking Reports by becoming more efficient over time in order to improve their ranking relative to their peers.

[112] Quantonomics, *Electricity Distribution Opex Cost Function: Potential Misspecification Issues*, 21 November 2024, section 2.1.1.

Jurisdiction	Empirical evidence[1]
New Zealand	• Between 2006 and 2023 efficiency/productivity **fell by 2.6% p.a.** on average[1] • Between 2012 and 2023 efficiency/productivity **fell by 2.8% p.a.** on average[1] • Between 2008 and 2023 efficiency/productivity **fell by between 1.2% p.a. and 2.2% p.a.** on average[2]
Ontario	• Between 2006 and 2023 efficiency/productivity **fell by 04% p.a.** on average[1] • Between 2012 and 2023 efficiency/productivity **improved by 0.3% p.a.** on average[1] • Between 2002 and 2011 there was **0% p.a. change** in efficiency/productivity on average[3]

Source: [1] Quantonomics analysis; [2] Cambridge Economic Policy Associates analysis; and [3] Pacific Economics Group analysis.

That evidence indicates that:

- Australian EDBs have become materially more efficient over time, particularly since the AER began using comparative benchmarking analysis to set EDB opex allowances. Consumers have benefited as a result because the Australian regulatory framework (like the New Zealand framework) shares efficiency improvements made by EDBs with consumers through lower prices
- By contrast, over the same period, EDBs in New Zealand have become less efficient. It seems very likely that the prohibition on the Commission using comparative benchmarking to set regulated prices is a key reason for this, and
- In Ontario, there has been very modest improvements in EDB productivity and efficiency over time. It is notable the Ontario Energy Board uses comparative benchmarking in a more limited way than the AER. In Ontario, comparative benchmarking analysis is used to set relatively modest 'stretch' targets for cohorts of EDBs; it has not been used to make the sorts of dramatic cuts to opex allowances that the AER has imposed on some Australian EDBs.

In summary, the current prohibition on the Commission using comparative benchmarking to set regulated prices for EDBs has likely limited the Commission's ability to drive efficiency improvements in the way the AER has done in Australia. This has ultimately been to the detriment of consumers in New Zealand.

8.4.5 The absence of a requirement for the Commission to conduct financeability assessments may deter the network investments needed to support the energy transition

Several regulators in the UK and Australia apply regulatory 'financeability tests' when making price-quality determinations for regulated utilities.[113] Some of these regulators undertake financeability tests because the primary legislation/statutory instruments governing the

[113] Examples of these regulators include Ofgem and Ofwat (the energy and water sector regulators, respectively, in the UK), the Australian Energy Regulator (AER), the NSW Independent Pricing and Regulatory Tribunal, the Essential Services Commission of Victoria, the Essential Services Commission of South Australia and the ACT's Independent Competition and Regulatory Commission. The Malaysian Aviation Commission has also recently applied a financeability test when setting regulated charges for the 30 airports in Malaysia.

regulatory framework explicitly require the regulator to have regard to, or to secure, the financeability or financial sustainability of the regulated businesses. Other regulators have voluntarily incorporated financeability tests into their regulatory frameworks because they recognise that such tests are good practice, as they provide a reasonableness check on the regulator's price-quality determinations.

The purpose of regulatory financeability tests is to check if the revenue that a regulated business is permitted to earn under a price-quality determination is sufficient to support at the credit rating and gearing levels assumed by the regulator when setting the revenue allowance. For example, under the current IMs, the Commission assumes that an efficient EDB would maintain a BBB+ credit rating and a leverage of 41%. The purpose of a regulatory financeability test in the New Zealand context would be to check if the allowed revenues under a price-quality determination would be sufficient for an efficient EDB to maintain those credit rating and gearing assumptions over the regulatory period.

An EDB could face a financeability problem if the regulator has set certain elements of the regulatory allowance (e.g., the allowed return on capital) too low, or if the EDB faces a temporary cash flow problem (e.g., because of a large capex program). Hence, a failure of the financeability test may be remedied by increasing the regulated business's revenue allowance (i.e., cash flows) over the regulatory period in which the financeability problem is identified.

During the 2023 IM review, a number of EDBs proposed to the Commission that it should develop an IM that sets out an explicit financeability test, similar to the tests used by regulators abroad. The EDBs argued that:

- EDBs would only make the network investments required to support the energy transition if the Commission's price-quality determinations provided revenue allowances that would allow those investments to be made without the EDBs' credit ratings deteriorating
- Equity investors should not be expected to 'top-up' the cash flows required to maintain a BBB+ credit rating, because the Commission's regulatory framework does not compensate equity investors for doing so. Equity investors should not be responsible for fixing a financeability problem if the problem was caused in the first instance by choices made by the regulator via its price-quality decision, and
- The inclusion of a financeability test within the IMs would provide all stakeholders (including investors) with certainty about how the test will be applied and interpreted by the Commission, and confidence that the regulatory framework would properly address any genuine financeability problems identified.

The Commission rejected this proposal stating that:[114]

- The Commission's preference was to retain the flexibility to decide whether and when to consider the financeability of EDBs
- EDBs that are concerned about financeability can apply for a CPP
- Financeability problems are primarily the responsibility of equity investors (rather than the Commission) to address, and
- Codifying a financeability test in the IMs would not necessarily promote certainty as to how the Commission would apply and use the information from such a test.

The Commission ultimately decided not to incorporate a financeability test in the IMs. However, the Commission decided to implement a financeability test to 'sense check' the outcomes of its

[114] Commerce Commission, *Financing and incentivising efficient expenditure during the energy transition topic paper - Part 4 Input Methodologies Review 2023 – Final decision*, 13 December 2023.

fourth DPP price-quality determinations (DPP4), which were finalised in 2024. In doing so, the Commission reiterated that:[115]

- There is no statutory duty on the Commission under Part 4 of the Act to consider financeability as part of its price-quality determinations; and
- By deciding not to codify a financeability test within the IM, the Commission preserved its discretion to consider financeability only when it considered it appropriate to do so.

The Commission concluded that there was no evidence of a serious financeability problem for any individual EDB over DPP4, so decided to make no adjustment to allowed revenues over the period.

The Commission's approach to financeability tests are problematic for several reasons:

- Firstly, the Commission's decision to not codify a financeability test within the IMs immunises any test that the Commission does subsequently decide to apply within a price-quality determination from merits review. In other words, no stakeholder can challenge the Commission's design or implementation of a financeability test on the grounds of errors in fact or reasoning. This means that material errors could go uncorrected and, more importantly, the Commission has weak incentives to design a test that can withstand the scrutiny of a merits review process.
- Secondly, by excluding financeability tests from the IMs, the Commission has effectively granted itself full discretion over whether and when to apply such a test. Allowing the regulator to 'pick and choose' in this way undermines certainty and predictability to stakeholders (a key objective of the regulatory framework). Furthermore, if the Commission can choose when to apply such a test, it could avoid doing so in periods when genuine financeability problems arise—because the remedy to such a problem would require the Commission to adjust its price-quality determinations. In other words, the Commission could decide when to circumvent or avoid an important check on its own decisions.
- Thirdly, the absence of a prescriptive test leaves the Commission with considerable discretion over how to interpret the results of any test that it does choose to apply. By way of example, most regulatory financeability tests assess outcomes using multiple financial metrics. It is common to see businesses perform well on some metrics and poorly on others. By not prescribing in advance how the various metrics are to be weighted, the Commission may conclude that there is no financeability problem because it has chosen implicitly to weight more heavily those metrics on which EDBs perform strongly, and down-weight those metrics on which EDBs perform poorly.

In 2024, the Australian Energy Market Commission (AEMC) considered a request by several electricity transmission networks in Australia to introduce a mandatory and prescriptive financeability test. The rationale for this request was that, when deciding whether to commit to major new transmission projects critical to Australia's energy transition, investors faced too much uncertainty about (a) whether price-quality decisions by the AER, in relation to those projects, would create financeability problems for the business; and (b) whether/how the AER would address any such problem, should they arise.

The AER opposed the request for a prescriptive and mandatory test for very similar reasons expressed by the Commission—namely, the AER preferred that it had maximum discretion about whether/when to have regard to financeability. The AER also considered that it should

[115] Commerce Commission, *DPP4 reset – Financeability of electricity distribution services in the default price-quality path – Issues paper*, 22 February 2024.

have full discretion over whether regulatory action should be taken in the face of an identified problem.

The AEMC ultimately concluded that it was important to limit the discretion of the AER, to provide the certainty that investors required in order to invest to support the energy transition. The AEMC's final rule:[116]

- Required the AER to undertake a financeability assessment (for qualifying transmission projects), if the business requested such an assessment at the time it submitted its regulatory proposal to the AER. The AER has no discretion to decline to undertake a financeability test, if one has been requested by the business,
- Required the AER to:
  - develop a binding guideline explaining exactly how the test would be applied (i.e., there would be no discretion for the AER to change the form of the test from one decision to the next, without updating the guideline);
  - ensure that the test presented in the guideline specifies in advance exactly what would constitute a pass or failure of the test (i.e., the AER would have no discretion to interpret the outcome of the test);
  - specify in the guideline what regulatory action would be taken if the test were failed (i.e., there would be no discretion for the AER to not act if the test were failed); and
  - ensure that that remedy for a failure of the test be implemented automatically (i.e., the AER would have no discretion over the extent to which regulatory allowances are adjusted in the event of a failure of the test).

The AER implemented the AEMC's rule and finalised the binding financeability guideline in November 2024.[117]

8.4.6 There are competition issues where EDBs own generation assets

Part 3 of the *Electricity Industry Act 2010* prohibits EDBs from owning electricity generation assets in certain circumstances. Part 6A of the *Electricity Industry Participation Code 2010* (the Code) requires corporate separation and arm's-length rules between EDBs and generators/retailers. The Electricity Authority summarises these existing restrictions as follows:

> *The provisions in the Act require full ownership separation if the distributor owns generation connected to the national grid. These rules only apply for generation over 250MW for grid connected generation (section 73 of the Act). The threshold for corporate separation and arm's-length rules is 50MW for distributor network connected generation (Part 6A of the Code). Part 6A also imposes rules for distribution agreements where distributors own more than 10MW of generation.*
>
> *The obligations in Part 6A were originally contained in Part 3 of the Act but were moved into the Code in 2022 by the Electricity Industry Amendment Act 2022 (Amendment Act). In moving the*

[116] AEMC, *National Electricity Amendment (Accommodating financeability in the regulatory framework) Rule 2024, Rule determination*, 21 March 2024.

[117] AER, *Financeability guideline, Final decision*, November 2024.

obligations into the Code, the intent was to provide for more flexible and responsive regulation in response to a rapidly evolving electricity system [118]

An EDB may apply to the Electricity Authority for a 'Part 6A dispensation', which would grant the EDB an exemption from the restrictions around corporate separation and arms-length operation rules. The Electricity Authority may only grant such a dispensation if it is satisfied that:

- it is not necessary, for the purpose of achieving the Electricity Authority's objectives under section 15 of the *Electricity Industry Act 2010* (which include the promotion of competition and protection of the interests of domestic consumers),[119] for the EDB to comply with Part 6A or the specific provisions of that Part, or
- granting a Part 6A dispensation in respect of the EDB would better achieve the Authority's objectives than requiring compliance.

The general policy statement that accompanied the Electricity Industry Reform Amendment Bill explained the purpose of these restrictions as follows:

The second main change is to narrow the scope of ownership separation requirements to focus on the geographic areas where there is potential for the exercise of market power and anti-competitive practices, namely, where lines and supply are co-located.

This is achieved by allowing owners of lines businesses to be involved in generation and retailing without limits outside of their lines area. Requirements for corporate separation and compliance with arm's-length rules are also repealed outside of their lines area.

At the same time, existing ownership separation rules are retained where lines and supply are co-located. This is because co-owned, co-located lines and supply businesses have both the incentive and ability to lessen competition in retailing and local generation. Ownership separation removes this incentive and ability.

[118] Electricity Authority, *Code amendment omnibus two: December 2023 – Consultation paper*, 15 December 2023, p. 6.

[119] Part 15 of the Electricity of the Electricity Industry Act 2010 defines the Objectives of the Electricity Authority as follows:

(1) The main objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

(2) The additional objective of the Authority is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers.

(3) The additional objective applies only to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers.

> *Where co-located cross-ownership of lines and supply is permitted in order to encourage investment in permitted generation, corporate separation and the requirement to act on an arm's-length basis is retained in order to reduce the risks of anti-competitive behaviour.*[120]

It is important to note that the existing restrictions do not prohibit EDB ownership and control of generation assets outside their service areas. They simply prohibit ownership and control of co-located distribution networks and generation assets, because it is this co-location that would enable EDBs to leverage their market power to harm competition upstream.

The Government has recently announced its intention to ease the existing restrictions on ownership and control of generation assets by EDBs.[121] In announcing this policy change, the Government stated that the current prohibitions impose undue costs on EDBs and duplicate protections offered by other regulations (e.g., the prohibitions against anticompetitive conduct in the Act).

The intention of this policy change appears to be to encourage investment in new sources of generation, to improve energy security and reduce the risk of inadequate power supply. However, this policy is likely to do more harm to consumers than good.

EDBs are regulated as natural monopolies because they have complete market power; they face no existing competition or threat of entry by new rivals. In the absence of the current restrictions, EDBs would have both the incentive and ability (by virtue of their market power) to act in a way that would make it difficult for any generators that compete upstream (e.g., by refusing or limiting network access, or by making successful operation of a competing generator more difficult). This would have the effect of reducing electricity supply which, in turn, would increase prices to consumers.

In other words, the recent Government policy announcement to ease restrictions on the ownership and control of generation assets by EDBs is likely to have precisely the opposite effect to the intended one — a reduction, rather than an expansion, of electricity supply.

The Government's announcement of this new policy suggests that existing regulations (such as competition law) would protect consumers against abuse of market power by EDBs. Enforcement action against anticompetitive conduct only occurs after consumers have already suffered harm. General competition law does not remove the incentive of EDBs to abuse their market power. Anticompetitive conduct of the kind that separation of ownership protects against may be difficult to detect and prove in Court. The Commission would need to gather sufficient evidence of the conduct to bring successful enforcement action. This is easier said than done. Hence, general competition law may not completely deter anticompetitive conduct by EDBs. By contrast, the existing restrictions on ownership and control of generation assets by EDBs remove the ability of EDBs to abuse their market power. This was explained by the Hon. Max Bradford (Energy Minister) during the second reading of the *Electricity Industry Reform Bill*, which introduced the rules separating ownership:

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120 Electricity Industry Reform Amendment Bill, Explanatory Note, General Policy Statement. https://www.legislation.govt.nz/bill/government/2007/0191/5.0/DLM1100197.html

121 Hon. Simon Watts, Hon. Shane Jones, *Rules to be eased to drive investment in electricity*, Ministerial Release, 26 February 2025. https://www.beehive.govt.nz/release/rules-be-eased-drive-investment-electricity#:~:text=Distribution%20businesses%20are%20currently%20prohibited,exemption%20from%20the%20Electricity%20Authority.

There has been much comment by some power companies and trusts on the provisions relating to separation of electricity distribution companies. I note, however, that only last week, the Director General of Electricity Supply in the United Kingdom - the industry regulator in that country - issued a consultation paper which concluded that "full separation of ownership of the supply and distribution businesses" in Britain "would be desirable". In essence, his conclusions are the same as ours. Only ownership separation breaks the incentives of line businesses to restrict competition to protect their own retailing [or generation] business. Similar changes are happening in the United States.

This conclusion needs to be thought about very carefully by those who consider some form of corporate separation and disclosure is sufficient. The UK has operated a heavy-duty regulatory regime for many years with a special purpose regulator with several hundred staff, a massive budget by our standards, tough licence conditions and price control. The end result has been frustration and a recognition that ownership separation is the only way to secure real competition, with the least intrusion of a regulatory regime.[122]

If the Government wishes to improve security of supply, it should adopt the recommendations presented in Chapter 4, which would address the issue directly, rather than pursuing policies that could result in a reduction in supply and a reduction in competition that would ultimately harm consumers.

8.4.7 EDBs' policies, terms and conditions for connecting new customers are unnecessarily varied and complex

Several stakeholders told us that there are significant price and non-price barriers that may be deterring efficient new customer connections (both electricity generation/supply and load) to distribution networks. The key themes in the feedback we received from stakeholders were the following:

- EDBs currently face no obligation to connect new customers (unlike in Australia, for example)
- EDBs currently have full discretion to develop their own connections policies, and terms and conditions for new connections. This has resulted in considerable and unnecessary variation and complexity in connections policies between EDBs. This complexity is exacerbated by the large number of EDBs (i.e., 29 in total) that customers may potentially interact with when deciding where to connect. Complexity and lack of standardisation of connections policies imposes significant transactions costs on customers dealing with multiple EDBs. The desire to minimise these transactions costs may result in customers connecting in sub-optimal locations (e.g., in parts of the network that already suffer from congestion, requiring more investment costs that are eventually passed on to consumers), and
- Because connections pricing is currently unregulated (i.e., EDBs can set their own connections price), and because EDBs may refuse connections, EDBs can currently charge new customers more than the incremental cost of connecting. This is likely to deter some efficient connections. We understand that one reason EDBs may charge more than the

[122] Hon. Max Bradford, *Electricity Industry Reform Bill – Second reading*, 22 May 1998. https://www.beehive.govt.nz/speech/electricity-industry-reform-bill

incremental cost of a new connection is because of a shortfall in cash flow required to finance the new connection. These sorts of 'financeability' problems may arise when the EDB is undertaking a large number of new connections, or several expensive connections, within a short period of time.

The Electricity Authority has already identified many of these issues and in 2024 commenced a consultation to address these concerns. The Electricity Authority has proposed a number of measures to improve the efficiency with which customers can connect to distribution networks, including:[123]

- amending the application processes for larger-capacity distributed generation (DG) applications
- adding application processes for larger-capacity load
- requiring EDBs to publish a 'network connections pipeline' for large capacity DG and load, and provide information on this pipeline to the Electricity Authority, and
- requiring EDBs to publish information on network capacity so that applicants can make more informed decisions on the optimal locations for connections.

The Electricity Authority has also proposed the following changes:[124]

- connection applicants will only pay for the 'minimum scheme' for their connection, unless they explicitly choose one or more enhancements
- EDBs who recover network capacity costs through connection charges will need to use published rates – charging for consuming capacity rather than adding capacity
- the introduction of a 'pioneer scheme', whereby, if certain criteria are met, later connection applicants are charged a contribution to the cost of the original connection, which is used to refund part of the costs contributed by earlier customers that connected to the same network. This is designed to encourage 'first mover' (or 'pioneer') customers to seek connections without fear of later customers free-riding on the contribution funded by the original customer
- introduction of dispute resolution provisions within the Code to encourage EDBs and applicants for new connections to negotiate in good faith
- the introduction of a pricing methodology that places limits on the share of share of connection and system growth investment that may be recovered upfront by EDBs through connection charges
- the introduction of a requirement for the Commission to reconsider price-quality path decisions (for non-exempt EDBs) that are potentially impacted by the application of the new connection pricing methodologies, and
- establishing a set of default contractual terms (rather than Code requirements), which would form the starting point for negotiations between EDBs and potential customers wishing to connect to the network.

123 Electricity Authority, *Network connections project: stage one amendments, Consultation paper*, 25 October 2024.

124 Electricity Authority, *Distribution connection pricing proposed Code amendment, Consultation paper*, 25 October 2024.

8.5 Our recommendations

8.5.1 Rationalise EDBs

Section 8.4.2 explained that New Zealand currently has too many EDBs, most of whom are too small to operate and invest efficiently. Section 8.4.7 also explained that the large number of EDBs contributes to the complexity faced by customers (generators and consumers of electricity) seeking new connections to distribution networks.

Our most important recommendation in respect of distribution networks, aimed at addressing these problems, is that the number of EDBs be rationalised. We have identified three options for implementing rationalisation:

7. The first-best option would be to amalgamate the existing 29 EDBs into a small number (say five) large regional EDBs
8. The second-best option would be to require amalgamation for only those EDBs that do not currently have any private ownership, and
9. The third-best option would be to maintain the existing 29 EDBs, but required EDBs within defined regions to coordinate together to, for example, undertake joint procurement and share resources to generate efficiencies.

Option 1: Mandate amalgamation of all 29 EDBs into a few large regional EDBs

Under this first option, the Government would direct, through legislation, the establishment of a small number large regional EDBs ('Super EDBs'). Ownership of the assets of the existing EDBs within each defined region would be transferred to the new Super EDB covering that region, and the existing owners of the current 29 EDBs would become shareholders in the new Super EDB. The ownership share of each shareholder would be determined according to the Regulatory Asset Base (RAB) value contributed by each current EDB to the new Super EDB, upon its formation.

Figure 51 below provides an illustrative example of how the existing 29 EDBs could be amalgamated to form five Super EDBs covering the following geographic regions:

- Auckland
- Waikato
- Wellington
- Canterbury, and
- Otago.

Each region in this example was selected to include at least one major city. This is critical to ensuring that each Super EDB can attract and retain the skilled staff, and to build the organisational capabilities, required to manage and operate the EDB effectively.

The individual EDBs identified for amalgamation in this example were chosen because of their geographic proximity to one another, rather than to preserve their existing ownership structure. For example:

- Powerco currently owns two geographically separated networks. In our example, its Eastern network would be amalgamated within the Waikato region (given its proximity to the other six EDBs within that region). Powerco's Western network would be amalgamated within the Wellington region for similar reasons, and, similarly

- Unison Networks currently owns two geographically separated networks. In our example, its Central network would be amalgamated within the Waikato region, and its Hawke's Bay network would be amalgamated within the Wellington region.

It would be important to ensure that EDBs are amalgamated into a single, contiguous region to ensure that network assets can be managed efficiently.

Indeed, we consider that taking into account practical realities such as those identified here are preferrable to attempting to undertake a scientific method for determining the new EDBs. For example, attempting to determine the minimum efficient scale of the networks would likely lead to false precision and ignore important local factors that are more likely to lead to successful businesses.

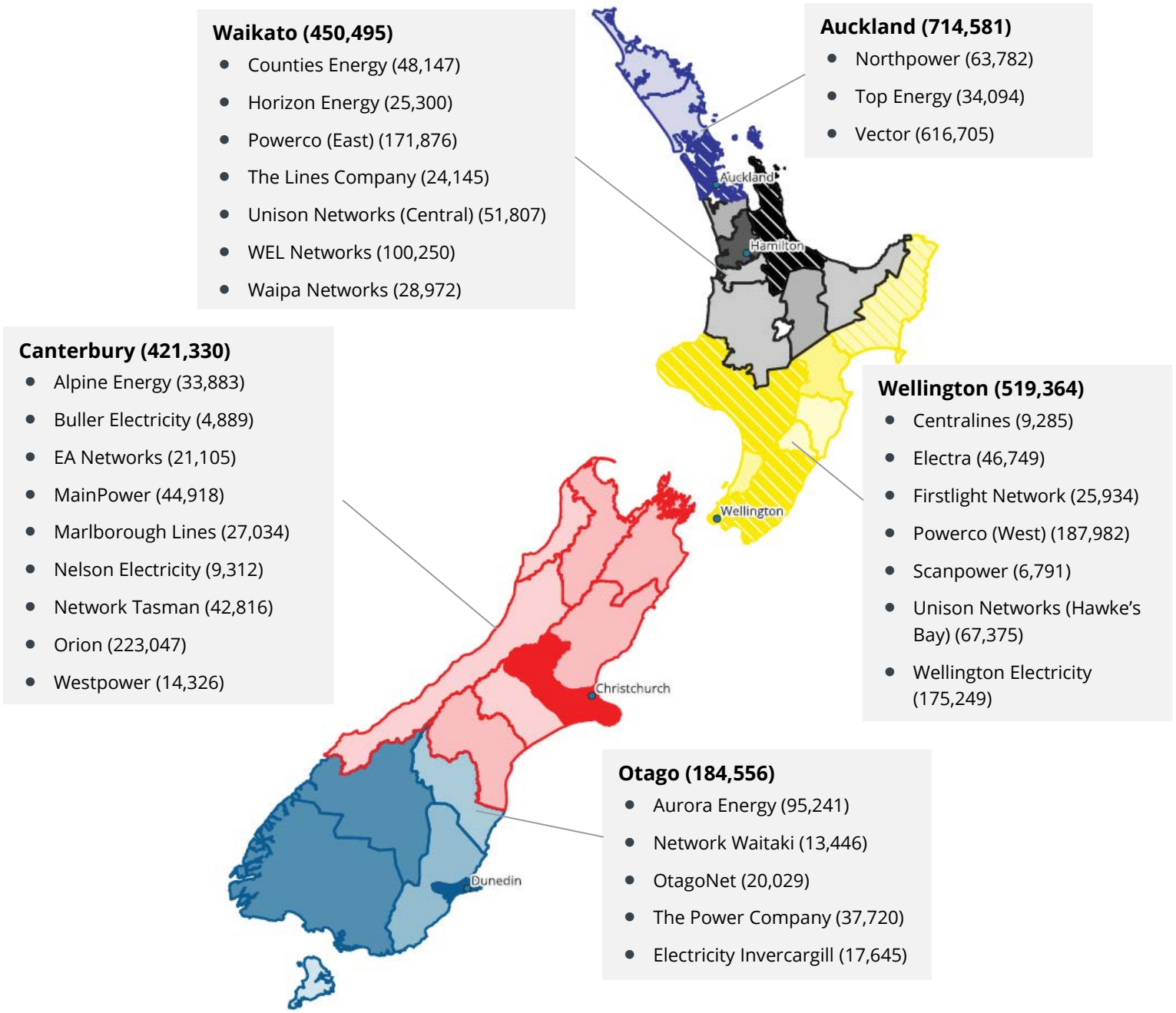
There are currently four EDBs (depicted in Figure 51 as hatched regions) that have some private ownership (with all other EDBs being owned by consumer trusts or local councils):

- Firstlight
- Powerco
- Vector, and
- Wellington Electricity.

The private shareholders in these networks invested without the expectation of structural reforms and amalgamations that could reduce the value of their investments (e.g., through dilution of control or expansion of ownership responsibilities for other, smaller networks). Therefore, we recommend that the Government make special provisions for private investors by giving them the option to:

- Become shareholders in the newly-formed Super EDBs
- Divest their ownership to other willing buyers before a certain date specified by the Government, or
- Sell their existing stake to the Government for a fair valuation of the assets to be determined through negotiation between the Government and the existing owner. This option would act as a 'backstop' for the existing private investors against a 'fire sale' scenario in which those investors wishing to divest are forced to do so at a deep discount. The Government would specify in advance a date by which the backstop offer to purchase shares from existing private owners expires, to ensure that investment decisions are made in a timely manner, without holding up the reform process.

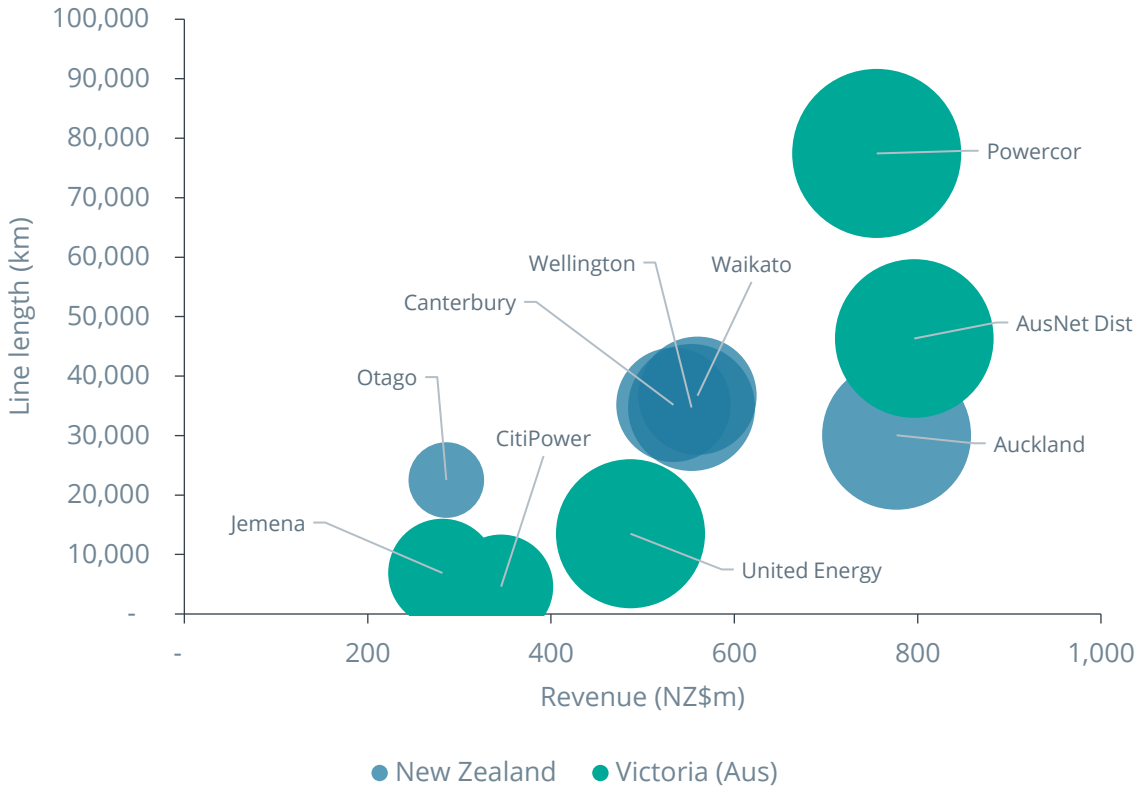
Figure 51: Potential model for aggregating existing 29 EDBs into five Super EDBs



Source: Frontier Economics. Notes: Total number of customers (as of 2024) reported in parentheses for each EDB and region. Individual EDBs with larger customers numbers are shown in darker colours, and EDBs with fewer customers are shown in lighter colours. Hatched regions denote EDBs with at least some private ownership.

Figure 52 shows that that following full amalgamation, the five Super EDBs in New Zealand would be of comparable scale to one another, and also to the five EDBs that operate in Victoria.

Figure 52: Scale of New Zealand EDBs compared to EDBs in Victoria following amalgamation



Source: Frontier Economics analysis of Information Disclosure and Regulatory Information Notice data submitted by EDBs in New Zealand and Australia. Note: The size of the bubbles indicate the number of customer connections served by each EDB. All data are 2024 values.

The key benefits of full amalgamation of the existing EDBs would be the following:

- Ensuring that each Super EDB would have sufficient scale to attract and retain skilled personnel to plan, operate and manage existing distribution networks effectively. This would enhance the asset and financial management capabilities of the EDBs.
- Ensuring that each Super EDB would have the scale to access wider sources of financial capital (at lower cost), which is essential to be able to finance the network investments needed to support the energy transition and to enhance security of power supply throughout New Zealand.
- The opportunity to generate efficiencies – for example, through rationalisation of workforces (i.e., eliminating duplication of back office roles), and economies in procurement and logistics.
- The ability to reform the price-quality regulation framework by applying individual price-quality path (IPP) regulation to all the Super EDBs (see section 8.5.2), without dramatically increasing the Commission's resourcing requirements. This would improve the likelihood that each EDB receives a MAR that is tailored properly to its particular circumstances, thus facilitating better, more targeted investment by EDBs.
- Reducing the number of EDBs that potential new customers/access seekers would have to deal with. This, in turn, would reduce the complexity and transaction costs incurred by new customers when seeking to connect new load or sources of supply to a distribution network.

Option 2: Exempt privately-owned EDBs from amalgamation but mandate amalgamation of all other EDBs

If the Government considers that it would be too difficult or impractical to require privately-owned EDBs to amalgamate with publicly-owned EDBs, a second-best alternative would be to exempt privately-owned EDBs from amalgamation; all other EDBs would be required to amalgamate.

As shown below in Figure 53, using the illustrative example presented above, this would result in nine EDBs in total comprising:

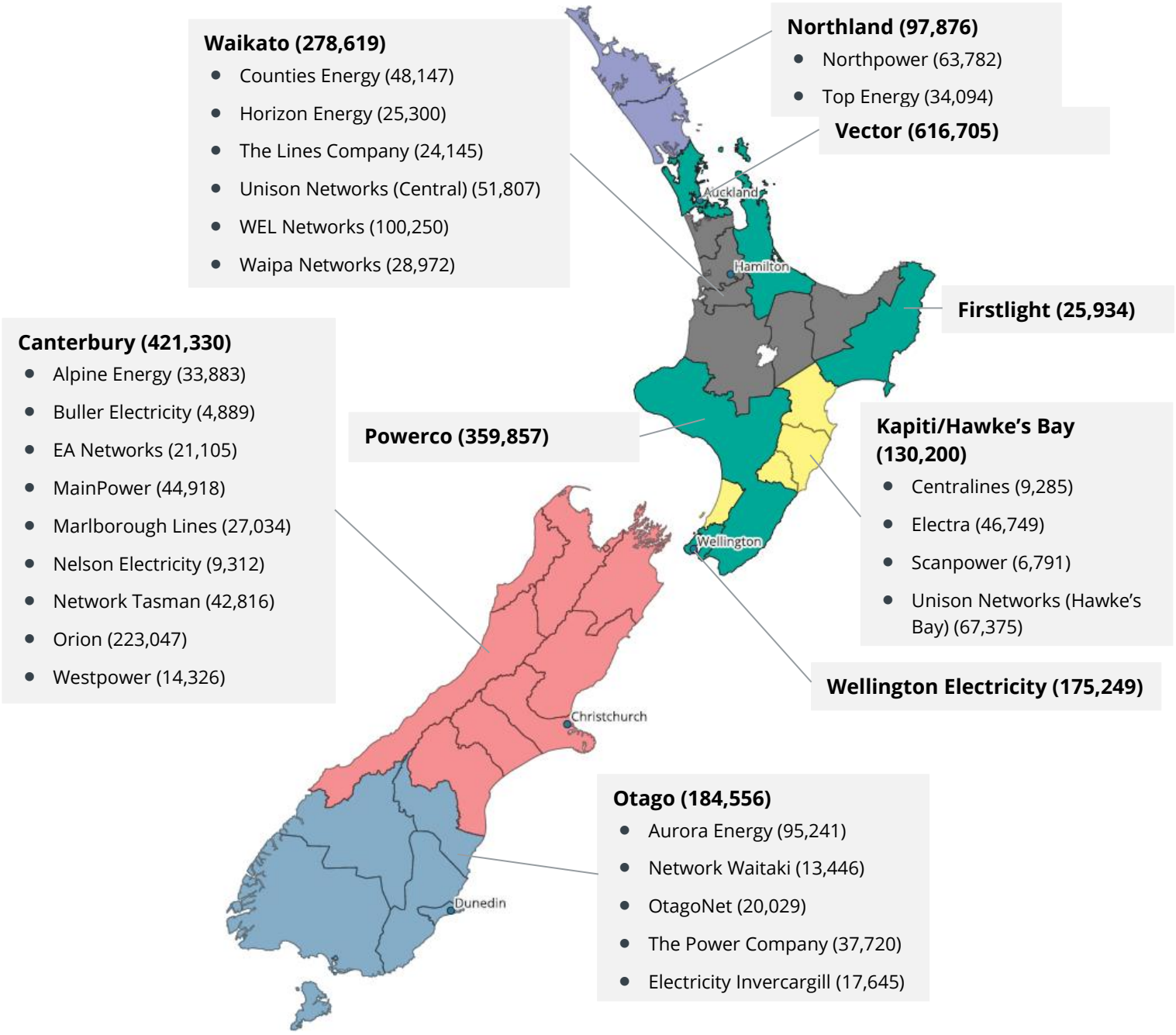
- Five regional EDBs (Northland, Waikato, Kapiti/Hawke's Bay, Canterbury and Otago), and
- Four privately-owned EDBs (Firstlight, Powerco, Vector and Wellington Electricity).

This model would result in materially less benefit than Option 1 described above because:

- Most of the nine EDBs would be considerably smaller (in terms of the number of connections served) than the five Super EDBs under Option 1. As Figure 54 shows, there would also be considerable variation in the size of the New Zealand EDBs (whereas, under Option 1 each of the Super EDBs would be of more comparable scale), and some of the EDBs (i.e., Firstlight, Northland, Kapiti/Hawke's Bay, Wellington Electricity) would remain very small. Hence, the scale economies from amalgamation would likely be much smaller than under Option 1.
- A key benefit under Option 1 would be the enhancement of organisational capacity/capability of each EDB, most of which would derive from combining very small EDBs with much larger EDBs that already have significant capacity/capability. This would not be possible under Option 2 since some of the largest EDBs (such as Powerco, Vector and Wellington Electricity) are privately owned and, therefore, would be exempt from amalgamation.
- Furthermore, some of the EDBs (e.g., Northland and Kapiti/Hawke's Bay) would not operate in regions with major cities. That would limit those EDBs' ability to attract and retain highly skilled and experienced personnel that would contribute to organisational capacity/capability.
- Two of the nine EDBs (Powerco and Kapiti/Hawke's Bay) would be responsible for operating geographically non-contiguous networks. This would result in less efficient asset management.
- In order to apply IPP regulation to all nine EDBs (see section 8.5.2 below), the Commission may need to be provided with additional resourcing. Furthermore, the very smallest EDBs are unlikely to have the capacity and resourcing to participate effectively under an IPP framework.

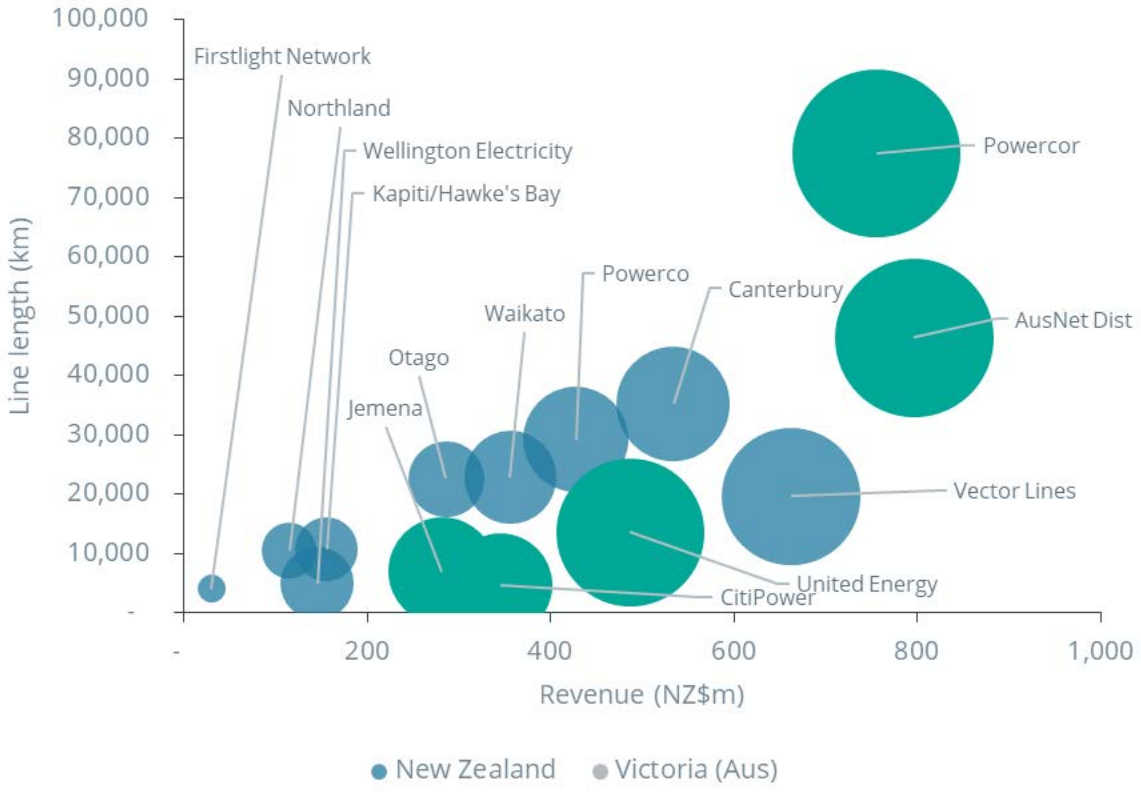
For these reasons, Option 2 would be a less optimal model of amalgamation than Option 1.

Figure 53: Potential model for aggregation under Option 2 (exempting privately-owned EDBs from amalgamation)



Source: Frontier Economics. Notes: Total number of customers (as of 2024) reported in parentheses for each EDB and region. EDBs with at least some private ownership are denoted in green.

Figure 54: Scale of New Zealand EDBs under Option 2 (exempting privately-owned EDBs from amalgamation)



Source: Frontier Economics analysis of Information Disclosure and Regulatory Information Notice data submitted by EDBs in New Zealand and Australia. Note: The size of the bubbles indicate the number of customer connections served by each EDB. All data are 2024 values.

Option 3: No amalgamation but require EDBs in defined regions to coordinate operations

If the Government determines that any amalgamation would be impractical, then the third (and least-best) option would be to retain the existing 29 EDBs as they are, but require them to coordinate with other EDBs within defined regions to generate better efficiency and operational outcomes. This coordination could involve, for example:

- Joint procurement of assets and services, and
- Sharing of personnel (e.g., maintenance crews).

It would be very difficult to prescribe precisely how the EDBs must coordinate with one another. Hence, EDBs would need to come to voluntary agreements on the areas in which they wish to coordinate with one another. Given that this would provide EDBs with considerable discretion, it is likely that many, through inertia, would default to the status quo arrangements. For instance, there would likely be a strong preference amongst most EDBs to not reduce their own workforce and then share personnel between networks. This would limit the extent to which cost efficiencies could be realised.

Furthermore, larger and more well-resourced EDBs are likely to be reluctant to share those resources with smaller EDBs.

Finally, given that coordination generally occurs more effectively under common ownership, management and governance structures, it is unlikely that EDBs will coordinate effectively with one another unless they are brought together through amalgamation.

Option 3 is likely to be the least effective model for rationalisation because:

- Separate ownership is unlikely to create the right incentives and conditions for effective coordination
- There would likely continue to be significant duplication, rather than rationalisation, of roles and personnel
- Maintaining separate ownership is unlikely to build significant organisational capability
- The smallest EDBs would continue to be headquartered outside major cities. Thus, attracting and retaining skilled and effective staff is likely to remain a persistent challenge for those EDBs
- It would be impossible to apply full IPP regulation to all 29 EDBs without a considerable increase in resourcing to the Commission. Even if the Commission's resourcing were enhanced substantially, the smallest EDBs (of which there would be many) would not have the resources and capability to engage effectively with an IPP framework, and
- The maintenance of 29 separate EDBs would continue to impose significant complexity and large transaction costs on new customers seeking to connect to the grid.

We note that a variation to Option 3 would be to allow EDBs to voluntarily agree to establish umbrella organisations that are owned and governed by the member EDBs to provide joint procurement and sharing of personnel. However, this has been an option to date and has only occurred in a limited instance. Furthermore, the likelihood would be that the strong EDBs would be willing to join with each other but would be reluctant to take on weaker EDBs. The implication being that those networks most in need of help may be left stranded on their own. Requiring the joint coordination avoids this potential problem.

8.5.2 Reform the price-quality regulation framework

As explained in section 8.4.1 the DPP/CPP framework is no longer fit for purpose, given New Zealand's commitment to the energy transition, and the energy security challenges the country currently faces. The existing framework does not sufficiently incentivise the efficient investment and innovation that is required to meet these challenges.

We therefore recommend that the regulatory framework be reformed fundamentally by making the following changes:

- Remove all exemptions from price-quality regulation. There is no sound case for exempting any EDBs from price-quality regulation, given that all EDBs (regardless of size or ownership structure) are natural monopolies that have both the incentive and ability to exploit their market power to harm consumers, and have very weak incentives to become more efficient over time. Concerns about the regulatory burden (on EDBs and the Commission) of subjecting all EDBs to price-quality regulation would be addressed by rationalising the number of EDBs in the industry, as recommended in section 8.5.1.
- Abolish DPP regulation. DPP regulation applies a one-size-fits-all approach to all non-exempt EDBs, and was introduced as a pragmatic compromise to the resourcing constraints that the Commission would face when regulating a large number (16) of EDBs. The 'blunt' nature of DPP determinations, which do not have regard to the particular circumstances of individual EDBs (which can vary significantly), results in regulatory allowances that may not allow EDBs to invest optimally or to innovate in order to meet the challenges of the energy transition or to improve energy security outcomes. The justification for a DPP framework falls away if the number of EDBs in the industry is rationalised. The implementation of this recommendation

would require a repeal of all relevant sections of Part 4 of the Act that deal with DPP (and CPP) regulation.

- Apply IPP regulation to all EDBs. The Commission would be required to make price-quality determinations for each EDB, taking into account its particular circumstances. This would mirror the approach the Commission is currently required to follow for Transpower. Each EDB would be required to make a price-quality proposal to the Commission (using the IMs), and the Commission would respond to that proposal with draft and final decisions (also made using the IMs). The key benefit of this approach is that the revenue allowances for each period would be set to reflect what each EDB would likely need to spend efficiently and prudently to promote the Part 4 purpose. This is more likely to allow EDBs what they require to invest and innovate.

These changes, among other things, will mean that EDBs will get a revenue allowance based on their individual needs. The effect being giving permission to the EDB to invest in the things it needs to, rather than investing to remain with the revenue requirement for a default price path. The result being that network infrastructure is better capable of managing the transition to a low carbon economy and the risk of network failure is reduced.

8.5.3 Require the Electricity Authority to specify scope of IMs

As explained in 8.4.3, contrary to the original intent and design of the regulatory framework, the Commission has exercised significant discretion over the scope of the IMs. The Commission has increasingly relegated the process of determining the methodologies it will use to make important aspects of price-quality decisions to the price review process, rather than developing those methodologies as part of periodic IM reviews. As a consequence:

- Those matters (which are often very contentious) have become immune from the threat of merits review. This reduces the Commission's accountability for decisions on those matters, contrary to the original intent of the regulatory framework, and
- EDBs, consumers and other stakeholders have no certainty over how the Commission will approach important aspects of the price-quality determinations before they are made. This too is contrary to the original intent of the regulatory framework.

The fundamental problem is that the Commission has broad discretion over the scope of the IMs. It may therefore intentionally or unintentionally exclude from the IMs matters that ought properly to be within their scope.

The remedy to this problem is for the scope of the IMs to be determined independently of the Commission. In our view it would be inappropriate to specify the scope of the IMs in the Act as this would result in a regulatory framework that is too inflexible. It is important that the regulatory framework is sufficiently adaptable to respond to new developments and changing circumstances. It would be impractical to pursue legislative change each time a new IM is required, or an existing IM becomes redundant.

As an alternative, we propose that responsibility for determining the scope of the IMs be transferred from the Commission to the Electricity Authority. This would likely require an amendment to the Act.

In practice:

- Immediately prior to the commencement of a periodic review of the IMs, the Electricity Authority would:

- Conduct a public consultation on the scope of the IMs. All stakeholders, including the Commission, may make submissions to the Electricity Authority setting out their views on the scope of the IMs, and
- The Electricity Authority would publish draft and final determinations (with reasons) on the scope of the IMs.

- The Commission would then conduct the IMs review according to the scope defined by the Electricity Authority. The Commission would have discretion (as it currently does) to decide whether/how individual IMs should varied. However, the Commission would not have discretion to exclude certain matters from the review altogether.

Under the current arrangements, section 52X of the Act allows the Commission to amend an IM at any time. The Commission would continue to have this power. However, an amendment should be made to section 52X to clarify that the Commission would not have the power to remove or exclude IMs that the Electricity Authority has determined that it must develop. That is, section 52X would only grant the Commission authority to vary an IM (with that decision to vary subject to merits review), not the power to delete IMs altogether.

This change would make the Commission more accountable for its decisions and provide all stakeholders with greater certainty over the regulatory framework.

The arrangements we suggest mirror loosely the institutional arrangements in Australia that separate the competencies of rule-making (which is the responsibility of the AEMC) and regulatory decision-making (which is the responsibility of the AER). By and large, this separation of powers has resulted in good regulatory outcomes by circumscribing the discretion available to the regulator.

8.5.4 Remove the prohibition on the Commission using comparative efficiency benchmarking to set prices

The current prohibition on the Commission's use of comparative efficiency benchmarking when making pricing decisions has tied the Commission's hands too much, has probably led to EDBs in New Zealand becoming less efficient over time. By contrast, in Australia, where the AER has used comparative efficiency benchmarking directly to make price-quality decisions, some EDBs have delivered significant efficiency improvements, which have been shared with consumers through lower prices.

We recommend that the current prohibition on the Commission's use of comparative efficiency benchmarking be removed.

That prohibition is currently set out in section 53P(10) of the Act. That section is contained only in the part of the Act that deals with the operation of the DPP framework; there is no analogous prohibition in the provisions of the Act that deal with the operation of the IPP or CPP frameworks. If all provisions that relate to the DPP framework are repealed (as we recommend in section 8.5.2 above), then this prohibition would fall away. In these circumstances, no similar prohibition should be added to the provisions that deal with the operation of the IPP framework, which we recommend should apply to the EDBs going forward.

Permitting comparative benchmarking to set prices does not mean that prices are actually determined using a benchmark value, instead, the intention is that benchmarking is used to inform the regulator when setting prices. For instance, by having regard to the relative efficiency between businesses in terms of operating expenditure, or replacement expenditure.

We expect that benchmarking will also become more useful where the EDBs are amalgamated. This is because they will then be of a similar size to distribution networks in their region, namely those in Australia.

8.5.5 Embed mandatory financeability tests within the regulatory framework

As explained in section 8.4.5, the Commission has to date resisted requests from EDBs to include a financeability test within the IMs. This is because the Commission has preferred the discretion to decide whether/when a test is required as part of a price-quality determination. The Commission has also felt that codifying a financeability test within the IM would make the test too prescriptive. However, the prescription that the Commission has sought to avoid is precisely what will give investors the certainty and confidence to commit funds to network investments, knowing that the regulatory framework will address any financeability issues (arising from the Commission's decisions), if they emerge. A consequence of the Commission's decisions to exclude financeability tests from the IMs is that any test the Commission does subsequently design and apply (as part of a price review) cannot be subject to merits review.

We recommend that a mandatory financeability test be embedded within the regulatory framework that applies to all lines companies, including EDBs. To implement this, we recommend:

- The inclusion in section 52A(1), which defines the Part 4 purpose, a new requirement to ensure that regulated suppliers can remain financeable. An example of possible new drafting is included below in Box 4. The reason for such an inclusion to the Part 4 purpose is because, when rejecting past requests by EDBs for it to develop a financeability IM, the Commission has repeatedly stated that "the Part 4 regime does not set any express statutory duty or direction requiring us to consider financeability in our decision making."[125] The proposed inclusion in the Part 4 purpose would make clear to the Commission that consideration of financeability is mandatory rather than discretionary
- The issuance of guidance to the Electricity Authority that when it publishes the scope of the IMs for the next IM review (see section 8.5.3), it should include a requirement for the Commission to develop a financeability IM, and
- The issuance of guidance to the Commission that any financeability IM it develops must be prescriptive rather than principles-based. This is essential to ensure that the outcomes of the test are predictable to (and replicable by) any stakeholder. By way of example, the financeability guideline recently published by the AER demonstrates that such a test can be designed.[126] Of course, the test applied by the Commission must be designed to reflect circumstances in New Zealand, rather than simply mimicking the test that has been developed in Australia.

Box 4: Proposed amendment to the Part 4 purpose

52APurpose of Part

(1) The purpose of this Part is to promote the long-term benefit of consumers in markets referred to in section 52 by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services—

[125] For example: Commerce Commission, DPP4 reset – Financeability of electricity distribution services in the default price-quality path, Issues paper, 22 February 2024, para. X6.

[126] AER, *Financeability guideline*, Final, November 2024.

(a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and

(b) can remain financeable in each regulatory period; and

(c) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and

(d) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and

(e) are limited in their ability to extract excessive profits.

(3) In this Part, the purpose set out in subsection (1) applies in place of the purpose set out in section 1A.

Source: Frontier Economics.

8.5.6 Retain existing restrictions on EDBs owning and controlling generation assets in their own service areas

Section 8.4.6 explained that the Government's intention to easing restrictions on EDBs owning and controlling generation assets in their own service areas would give EDBs the ability to exercise their market power in a way that would harm consumers.

To avoid such outcomes, we recommend that the Government retain the existing restrictions. The Government's motivation seems to be increase investment in generation assets, to address energy security concerns. We agree that this is an important objective. Chapter 4 recommends better ways to ensure security of supply, without harming the interests of consumers.

We note that this recommendation is not intended to prevent EDBs from owning assets such as batteries where these provide network support services. It is important for promoting efficient outcomes that EDBs have access to the full suite of build or buy options when it comes to network support. However, where these assets participate in the wholesale market or sell energy to customers, this arrangement should be done at arms-length to the EDB so that it is not able to financially benefit from the sale of that electricity.

8.5.7 Electricity Authority to expand existing consultation to consider how the contractual terms for new connections can be harmonised and simplified

Section 8.4.7 explained that there is currently considerable and unnecessary variation and complexity in connections policies between EDBs, because each EDB has full discretion to develop its own connections policies.

The Electricity Authority has already identified a number of barriers to efficient new connections and has proposed several amendments to the Code to overcome or reduce those barriers. The Electricity Authority's consultation on those proposed amendments is ongoing.

One proposal that the Electricity Authority has proposed is the establishment of a set of default contractual terms (rather than Code requirements), which would form the starting point for negotiations between EDBs and potential customers wishing to connect to the network. In our view this would help streamline the connections process.

We recommend that the Electricity Authority expand its current consultation to consider:

- in more detail how contractual terms and conditions for new connections can be standardised
- standardising the technical requirements for new connections. Stakeholders told us that EDBs currently have a highly varied technical requirements for no apparent reason other than each EDB's requirements were developed independently. This creates unnecessary complexity for customers wishing to deal with multiple EDBs. The harmonisation of technical standards may require the establishment of an industry working group to ensure appropriate coordination and representation of views, and
- whether it would be appropriate to introduce a mandatory requirement for EDBs to connect new customers that have made firm new applications (i.e., that have complied with the specified technical requirements).

9 Transmission and system operation

9.1 Introduction and summary of findings

Transpower undertakes two roles in New Zealand's electricity market. It owns and operates the high-voltage electricity transmission grid, and it is the system operator for the wholesale market.

Its dual role creates potential conflicts of interest, particularly the risk of overinvestment in transmission capacity to minimise outages or supply constraints. However, we expect that the level of regulatory oversight provided by the Commerce Commission and the Electricity Authority will limit the extent to which any actual or potential conflicts of interest that may distort market outcomes. Given this, we recommend that the system operator role stay within Transpower.

As grid owner, Transpower is subject to regulation by both the Commerce Commission, which is responsible for setting the maximum revenue that Transpower may recover from consumers, and the Electricity Authority, which is responsible for determine how that revenue is recovered.

Transmission planning and investment is governed by the Capex IM developed by the Commerce Commission. The Capex IMs include many of the features that we would expect to see as part of an effective transmission planning framework. The Capex IMs require Transpower to apply an Investment Test to major capex projects (MCPs), which are reliability projects, or augmentation projects above $30m. We recommend introducing a streamlined version of the Investment Test that applies to augmentation projects that fall below $30 million but above a nominal threshold of, say, $8 million. This recommendation ensures that the market can have confidence that Transpower investment is efficient and having proper regard to non-network solutions.

Transpower has recently argued that Renewable Energy Zones (REZs) should be introduced in New Zealand to address first mover disadvantages and high connection costs. The Electricity Authority has addressed first mover disadvantage through changes to the transmission pricing methodology (TPM). High connection costs is principally due to the lack of locational investment signals for generation. While a REZ will provide signals for generation to collocate, it is an intrusive and expensive answer to the problem. As an alternative, we recommend that Transpower produce an annual Electricity Opportunities Statement (EOS) that highlights the opportunities for invest in new electricity assets, include opportunities to collocate and reduce costs.

The Electricity Authority is responsible for developing a TPM which specifies how Transpower must set its transmission charges. The new TPM made significant changes to the transmission charging framework, including by introducing benefit-based charges. We have some concerns that the new TPM will not improve efficiency. However, we note that the new TPM has undergone an extensive stakeholder consultation exercise. As such, we recommend a 'wait and see' approach to observe whether the outcomes that the Electricity Authority envisage will arise in practice.

In its system operator role, Transpower monitors and coordinates security of supply for the industry against the following standards which are set by the Electricity Authority in the Code. The North Island Winter Capacity Margin (NI-WCM) reflects the adequacy of peaking generation and south-to-north transmission capacity to meet expected peak winter demand and is set at 630 MW to 780 MW. A disadvantage of applying a fixed MW range is that the NI-WCM is unable to respond to market changes, including factors that may affect the frequency, duration and magnitude of loss of load events, until the standard is reset. To address this, we recommend that

the NI-WCM be amended to provide greater flexibility to respond to factors that change the frequency, duration and magnitude of loss of load events.

9.2 What is the expected market outcome?

9.2.1 Transmission planning and investment

Transmission planning should deliver the right network investments at the right time and at lowest cost that maximise benefit for users. A transmission planning framework will better meet these efficiency objectives by incorporating the following:

- Investment plans should be based on **realistic projections** of the anticipated generation mix, load profiles and public policy mandates over the lifespan of transmission investments.
- Network planning should be undertaken on a **holistic basis** over a sufficiently **long period** of time. Looking at a portfolio of investments rather than only individual projects will help to focus on total cost of investment and account for the interdependencies between different parts of the energy network. Given the long life of network assets, network planning must consider how the energy landscape might evolve over multiple decades to ensure that investments made today remain relevant and efficient far into the future.
- Identification of major investments should be based on a **comprehensive cost benefit analysis** that clearly explains the investment need, identifies the credible options that may address that need (including both network and non-network options), assesses the costs and benefits of each credible option against an appropriate counterfactual in which the option is not implemented, and selects the option that maximises net market benefits.
- Uncertainties should be addressed through **scenario-based planning** and **sensitivity analysis**. In particular, any cost benefit assessment should examine net market benefits across a range of plausible future scenarios, with the number and choice of scenarios dependent on the credible options under consideration. The analysis should also test the robustness of the results to changes in key parameters, such as cost estimates, load forecasts and the discount rate that has been applied.
- Significant investment decisions, particularly around network augmentation, should be subject to **stakeholder consultation**. Engagement with different groups, including generators, non-network proponents, distribution network operators, energy consumers and other industry groups help to test underlying inputs, identify and address stakeholder concerns and contribute to improved decision-making.

9.2.2 Transmission pricing

Principles of efficient transmission pricing

Electricity customers are better off when transmission prices:

- allow network operators to recover the efficient costs of providing network services
- provide signals to customers to use the network efficiently, which means using the network only at those times when the value from that consumption exceeds the costs of providing it
- maintain both of the above outcomes over time given changing productivity, technology and consumer preferences.

The costs of electricity networks are primarily based on the costs of investment to meet expected peak demand. This means that prices that encourage efficient use will signal to customers the impact their consumption has on the need to invest more in the network to meet

peak demand. Where customers value consumption more than that investment cost, that consumption is efficient.

Prices for new connections are a particular element of network pricing. Again, the price signal should encourage customers or new supply to connect to the network, and at a particular location, when they expect to derive more benefit from that connection than the cost of connection and providing ongoing supply. There is a question about what contribution customers should make to the costs they impose deeper in the network, with an expectation that connecting parties face the full cost of any assets that are dedicated to the user. In transmission networks the debate centres on whether the 'causer' or the 'beneficiary', or some mixture of this, pays.

9.2.3 System operation

Efficient system operation involves balancing least-cost, secure electricity supply with demand now and into the future.

Broadly, the system operator's role is to manage electricity generation and transmission to balance supply and demand, and to meet stipulated reliability and security of supply standards. This role typically involves operating and administering energy markets, procuring ancillary services, and monitoring system performance and managing contingency events.

Actions of a system operator that promote efficiency include:

- Dispatching generation and load in a least-cost fashion to meet energy and operator-determined ancillary service requirements.
- Providing efficient systems for interfacing with the market, for example submitting market bids and offers, settlement, retail transfers, and outage planning and coordination.
- Providing high-quality and timely market information including demand and market forecasts, market notices relating to contingency or lack of reserve events, and longer-term assessments of security of supply.
- Providing information and analysis to related bodies, for example transmission planners, regulators and rule-makers.

9.3 Current market

9.3.1 Transpower's dual role in the electricity market

Transpower undertakes two roles in New Zealand's electricity market:

- As **grid owner**, Transpower owns and operates the high-voltage electricity transmission grid. Its role is to ensure electricity is transported from generators to some large electricity users and distribution businesses that deliver it to homes and businesses. Transpower is responsible for building, maintaining and operating the transmission network.
- As **system operator**, Transpower operates the wholesale electricity market through which generators sell electricity to retailers who then supply consumers. Its role is to ensure that electricity supply and demand are in balance at all times and to manage voltage and frequency on the grid to ensure it remains stable at all times. It also tracks and reports on whether there is sufficient generation and transmission capacity in the country.

Transpower's dual role as both the transmission network owner and system operator creates potential conflicts of interest, particularly the risk of overinvestment in transmission capacity to minimise outages or supply constraints. Additionally, the system operator role may have

incentives to resist market designs that reduce the need for transmission assets, as a larger asset base enhances Transpower's commercial returns. Several structural and regulatory safeguards that have been implemented to address these concerns. These include:

- **Separation of roles**: Transpower's system operator function is legally and operationally distinct from its role as the grid owner. This separation is mandated by the Electricity Industry Participation Code to ensure impartiality and independent in decision making.
- **Governance measures**: Transpower has implemented governance structures, including a dedicated sub-committee of its Board, to monitor and manage independence risks in its system operator role. Annual assurance programs and other conflict of interest procedures are intended to further address potential conflicts.
- **Regulatory oversight**: The Commerce Commission reviews Transpower's proposed investments to ensure they are prudent and efficient. Large investments are subject to additional scrutiny through the need to undertake a cost-benefit analysis and a requirement on Transpower to engage with industry stakeholders. Transpower also faces explicit incentives to pursue cost efficiencies and spend less than its capex allowances. Additionally, the Electricity Authority oversees the system operator's performance, ensuring alignment with market efficiency and reliability goals.

9.3.2 Transmission planning and investment

Transmission revenues are subject to regulation by the Commerce Commission

Transpower's transmission business is subject to individual price-quality path (IPP) regulation and information disclosure requirements. Under the IPP framework, the Commerce Commission is responsible for setting the maximum revenue that Transpower may recover from consumers to run the transmission network efficiently, and the minimum quality standards it must meet. The Commerce Commission will typically make a determination for a five-year regulatory period, with the most recent IPP covering the period from 1 April 2025 to 31 March 2030.

The rules which govern how the IPP framework is applied are set out in two input methodologies (IMs) that are developed and published by the Commerce Commission. These are:

- the **Transpower IM**, which covers matters such as how assets are valued and depreciated, how the cost of capital is estimated, how tax should be treated, and the allocation of common costs between Transpower's grid operator and system operator services; and
- the **Capex IM**, which sets out the rules for Transpower proposing, and the Commission assessing, Transpower's capital expenditure proposals, including the circumstances in which investment is subject to a net benefit test, and how that test should be applied.

Categorisation of Transpower's transmission capex under the IMs

The Capex IM categorises Transpower's capital expenditure into three groups:

- **Base capex** – Covers asset replacement, refurbishment, business support, and IT, as well as network augmentation projects below $30 million. The Commerce Commission sets a total base capex allowance, but Transpower decides how to allocate it.
- **Listed projects** – Projects expected to exceed the base capex threshold but with uncertain timing, scope, or cost. These are not included in the initial base capex allowance. Transpower can seek approval during the regulatory period, with approved funding added to its annual revenue updates.

- **Major capex projects** (MCPs) – Large projects for grid reliability and major network upgrades exceeding the base capex threshold. They also include expenditure for non-transmission solutions and consequential opex. MCPs require separate approval and cannot be funded from the base capex allowance or other MCPs. Transpower can submit MCP proposals at any time.

Transpower is required to undertake a CBA for significant investments

MCPs are subject to an Investment Test. This is an economic cost-benefit analysis to assess and rank different investment options. The aim is to identify the investment option that delivers the largest net benefit to the electricity market over the assessment period, typically 20-years. It must only consider costs and benefits that apply to electricity consumers.

The assessment of net market benefits is undertaken using multiple scenarios, with the default scenarios being the Electricity Demand and Generation Scenarios (EDGS) published by MBIE. Transpower may propose feasible and reasonable alternative scenarios, provided that it has considered the views of stakeholders.

For projects that are not classified as MCPs, Transpower does not need to apply the Investment Test and therefore does not have an explicit requirement to consider alternative options, including alternative non-network options, when undertaking the cost benefit analysis for these projects. However, these projects are still expected to be net beneficial, and Transpower is still required to estimate the net electricity market benefit for base case projects that are expected to cost more than $30 million and listed projects.[127]

Transpower's proposed capex projects are subject to stakeholder consultation

The Capex IMs require stakeholder consultation for Transpower's base capex proposals, listed project applications, and major capex proposals. For MCPs, this includes an explicit requirement on Transpower to consult on potential non-network solutions that may be used to address the identified need.

Transpower is exploring the concept of a Renewable Energy Zone

In early 2022, Transpower published consultation papers exploring the concept of introducing renewable energy zones (REZs) in New Zealand with the aim of delivering renewable generation connection more efficiently. In its consultation paper, Transpower identified two main challenges would be addressed by a REZ.

- **First mover disadvantage**: when future connections in an area are expected, the first connector would be reluctant to bear the cost of efficiently sizing the assets for anticipated connections. A REZ would aim to develop a commercial framework that reduces the need for a single customer or network owner to fund an efficiently sized connection.
- **High connection costs**: this arises from the high cost of building network assets to connect renewable generators to the grid. Transpower argued that a REZ will help to overcome high connection costs because the costs are able to be shared between several connecting customers. Also, the incremental cost of making a connection capacity larger is generally low, such that it is possible for larger connections to be lower cost on a per unit basis (i.e. $/MW).

Transpower proposed a process for developing REZs in New Zealand. In broad terms, the process involved:

- Adopt assessment criteria to identify and prioritise REZ regions. These criteria may include: whether renewable developers were already seeking to build in the area, the estimated cost

[127] Capex IM, clauses 3.2.1(a) and 3.2.3(f).

of network investment, network capacity in the region, whether the region has high levels of renewable resources in areas where lower cost land is available, whether additional generation and storage will improve network resilience or enable network deferrals, and other socioeconomic impacts.

- Use a coordinated tender process to attract and commit generation. This process starts with an Expression of Interest to assess interest in developing renewable generation in the area. Shortlisted developers will then enter a formal tender to select projects for the REZ and coordinate funding for necessary transmission or distribution upgrades. Prospective developers would be scored against selection criteria, which may include: land security, financing stage, design progress, stakeholder engagement, consenting status, and network connection concept assessment.
- A requirement to contractually commit to partaking in the REZ. Each developer would be required to fund a proportion of the network upgrade required for the REZ; pro-rated based on generation capacity. The aim being to minimise the risk of the asset owner having under-used network infrastructure and the need for the network owner to socialise the unused portion across other customers.

Transpower received 129 responses on its consultation paper across a wide range of individuals, energy sector participants, businesses, iwi and hapū, local and central government, advocacy groups, and industry bodies. Of these, 54 submissions were for the Renewable Energy Zones National Consultation and 75 were for the Renewable Energy Zones Northland Pilot Concept Consultation.

The responses to the consultation were mixed. While many stakeholders supported the concept of REZs, a number of stakeholders raised concerns that the 'market failure' underpinning the need for REZs had not been sufficiently identified and justified.

One underlying concern was the need for further analysis to define the problem and issues that REZs were seeking to address. Several respondents expressed concern that the benefits or drawbacks of the concept were not clear and had not been properly assessed, and stated that analysis was required on whether the proposed REZ concept was better than other alternative options. This includes the new Transmission Pricing Methodology (TPM), which was under development at the time, and includes measures to address first mover disadvantages. Similarly, some felt that the existing connection queue backlog was the real issue. Respondents also suggested that work be undertaken to identify impacts on the wider energy system to ensure that it does not create a barrier itself or disadvantage non-REZ activity by participants occurring in the energy market.

Following the consultation, Transpower indicated it will further consider the points raised before proceeding with REZs.

9.3.3 Transmission pricing

Transmission pricing methodology is determined by the Electricity Authority

Allowed revenue is recovered through charges paid by customers connected directly to the transmission network, including generators, distributors and large customers. The Electricity Authority is responsible for developing a transmission pricing methodology which specifies how Transpower must set its transmission charges.

A new transmission pricing methodology

The current TPM commenced on 1 April 2023, following an extensive consultation process conducted by the EA over the period 2019 to 2022. The current TPM seeks to address certain shortcomings that had been identified with the previous TPM.

The Electricity Authority argued that the previous TPM had several flaws. In particular, it argued that the charge to signal use at peak times distorted locational signals by spreading the costs of regional grid investments across all New Zealand, and distorted use of the grid by inefficiently discouraging use at times consumers most value it. The belief being it encouraged customers to unnecessarily invest to avoid paying transmission charges. The Electricity Authority also argued that a HVDC charge – which recovered the costs of the HVDC line between the North and South Island - operated as a 'tax' on South Island generation (as it was only paid by South Island generators) and inefficiently encouraged investment in more expensive North Island generation.

At the heart of the new TPM is the desire to ensure that transmission prices (together with wholesale electricity prices): (a) signal the economic (incremental) costs of transmission services (b) allocate the cost of transmission investments to customers that benefit from them (c) recover costs in ways that do not distort consumption and investment decisions.

The latest TPM includes three types of transmission charges:

- **Connection charges**, which recover the cost of assets that connect individual customers to the transmission network, and are paid by the connecting customer (generator or load). This is largely similar to the connection charges that applied under the previous TPM, with some changes to address first mover disadvantages.
- **Benefit-based charges** (BBCs), which recovers the 'covered cost' for new and certain historic interconnection investments (benefit-based investments, or BBIs), and are paid by the customers who are expected to benefit from them based on their share of the expective positive net private benefit from the BBI. Covered cost includes the return on and of capital on the BBI, and an allocation of Transpower's total operating costs.
- **Residual charges**, which recover residual revenue (i.e., maximum allowable revenue less the revenue recovered through other transmission charges), and are paid by electricity users only and allocated according to each customer's gross load.

Additional detail on the changes made to transmission charges is provided in Appendix D.

9.3.4 System operation

Transpower's role as system operator

In its system operator role, Transpower fulfills various functions including:

- **Operating the electricity wholesale market** – which requires determining the optimal combination of generation and reserve providers for each trading period. This is done in real-time to maintain a balance between supply and demand and ensure system security. It also manages supply emergencies and contingent events that disrupt the balance between supply and demand.
- **Reporting on security of supply** – which involves reporting on generation capacity, demand and fuel availability over different time horizons. The aim being to identify if there will be enough supply and network to meet demand in the future.
- **Outage planning and ancillary services** – which is the coordination of generation and transmission outages, facilitating commissioning of new plants, and procuring ancillary services to support system stability.

Part 7 of the Code requires Transpower, as the system operator, to publish the Security of Supply Forecasting and Information Policy (SOSFIP) and the Emergency Management Policy (EMP). The SOSFIP outlines how the system operator prepares and publishes information to assist market participants in managing security of supply risks. The EMP sets out the steps that the system operator will take during an extended emergency.

Part 9 of the Code requires Transpower to publish the System Operator Rolling Outage Plan (SOROP). The SOROP provides guidelines for managing electricity supply shortages. Additionally, Part 9 allows Transpower to request specified participants to develop their own participant rolling outage plans (PROPs). Furthermore, Part 9 of the Code establishes the circumstances under which Transpower must initiate an official conservation campaign (OCC). If a conservation campaign is called, retailers will compensate consumers each week for reducing electricity use (with funding provided by the EA).

These policies collectively form a framework for managing extended emergencies where the power system's ability to meet demand over a prolonged period is at risk.

Transpower has some discretion over access to contingent water storages

According to the SOSFIP, Transpower must determine electricity risk curves that represent the different risks of future shortage. The electricity risk curves are determined in a modelling exercise using assumptions provided in Cl 6.1 of the SOSFIP[128], which include for example using a medium demand forecast, accounting for uncertainty in future inflows, and assuming full availability of generation and transmission assets unless better information exists. These risk curves are used to inform various contingent storage release boundaries which, when triggered, provide operators of hydro generation access to various levels of contingent water storage.

The electricity risk curves are based on a particular risk of future shortage plus a 50 GWh buffer, which may be adjusted from time to time by Transpower. This buffer was added following consultation in 2018-19 to address circumstances where storages were low, but shortage risk was very low or zero (based on anticipation of imminent inflows).[129]

The risk curves are based on the level of water storages in aggregate, but individual storages (controlled by different operators) may reach low levels at different times. One storage at high levels and one storage at low levels may not trigger a release boundary, but it may pose a problem for the operator of the storage at low levels, which requires access to contingent storage to continue generating.

In the dry year of 2024, Transpower adjusted the buffer to the 'Alert' contingent storage release boundary which is based on a future shortage risk level of 4%. The buffer was temporarily increased from 50 GWh to 420 GWh during September 2024 and then 200 GWh during October

[128] https://www.ea.govt.nz/documents/2711/SOSFIP.pdf

[129] See Section 3.3 of the SOSFIP Review 2018 Decision Paper (p12), available https://static.transpower.co.nz/public/bulk-upload/documents/SOSFIP%20Decision%20incl%20Cover_May2019.pdf?VersionId=jmwhszfjkNtGYScuwK0_hjodwrV7_dVK

2024, enabling earlier access to contingent storages.[130] In submissions, Meridian[131] and ERANZ[132] argued that practical operation restrictions mean the 50 GWh buffer is systemically too low. ERANZ submitted:

> *Furthermore, Transpower could do more to overcome practical operating restrictions. For example, there are 151 GWh of storage in the low ranges of Manapōuri and Te Anau lakes, and it is extremely hard for the operator to use that storage given their draw-down limits and timeframes within which lake levels must increase. The proposed buffer includes an allowance for only 50 GWh of that storage, meaning there remains a high likelihood that, under the current proposal, all reservoirs except Manapōuri and Te Anau could be at, or close to, the bottom of their controlled storage and the Alert would still not be triggered. That would result in significant security of supply risks.*

Security of supply standards are codified

Transpower monitors and coordinates security of supply for the industry against the following standards which are set by the Electricity Authority in the Code:[133]

- **National Winter Energy Margin** (NZ-WEM) reflects the adequacy of generation to meet expected national electricity demand under extended dry periods across the winter months. It is currently set at 14 per cent to 16 per cent.
- **South Island Winter Energy Margin** (SI-WEM) reflects the adequacy of generation and north-to-south transmission capacity to meet expected South Island electricity demand under extended dry periods across the winter months. It is currently set at 25.5 per cent to 30% per cent.
- **North Island Winter Capacity Margin** (NI-WCM) reflects the adequacy of peaking generation and south-to-north transmission capacity to meet expected peak winter demand. It is currently set at 630 MW to 780 MW

The standards are intended to represent an efficient level of reliability – that is, where the expected cost of shortage is equal to the expected cost of new generation. A positive margin is required to cover unexpected events such as generation plant outages, transmission outages, or unusually high demand. With a higher margin the risk of shortages during peak periods will be lowered, but there will be a higher cost from having additional generating plant available. With a lower margin, there will be reduced generating plant costs, but a higher risk of shortages.

130 See Section 3.1, p6: https://static.transpower.co.nz/public/uncontrolled_docs/ERC_buffer_decision_22Aug2024.pdf?VersionId=dNsbgsS78Pc25HaXBNRgBi9Hgtj1FK6i

131 https://static.transpower.co.nz/public/uncontrolled_docs/Meridian%20submission%20-%202024%20Adjustment%20to%20Alert%20Contingent%20Storage%20Release%20Boundary.pdf?VersionId=YVxXDt9pKyunjKXzceXNwR13M7Xtjo1T

132 https://static.transpower.co.nz/public/uncontrolled_docs/ERANZ%20Submission%20-%202024%20Adjustment%20to%20Alert%20Contingent%20Storage%20Release%20Boundary.pdf?VersionId=OXuQ8NL70Ov.Wf0IxtLJ.w5i3s7ycDlt

133 Cl 7.3.2 Electricity Industry Participation Code, available https://www.ea.govt.nz/documents/6713/Electricity_Industry_Participation_Code_2010_JAqL2SN.pdf

Access to information is governed by the Code

Clause 9.18 of the Code allows Transpower to gather information from market participants to meet certain security of supply obligations. This clause was recently amended by the Electricity Authority to allow Transpower to gather information that is needed for it to implement and comply with the SOSFIP and EMP[134].

9.4 Our assessment

9.4.1 Transmission planning and investment

The Capex IM is fit for purpose but recommend extending application of investment test

In our view, the Capex IMs include many of the features that we would expect to see as part of an effective transmission planning framework. This includes a requirement to undertake a cost benefit analysis of proposed investment options, and to engage with industry stakeholders.

The Investment Test in the Capex IMs that applies to MCPs is similar in many respects to the Regulatory Investment Test for Transmission (RIT-T) that the Australian Energy Regulator applies to significant transmission network investments in the Australian NEM.

One key point of difference between the Investment Test and the RIT-T is the capital cost threshold that triggers when the tests need to be applied, which in turn determines the type of projects to which the tests apply. In Australia, the RIT-T applies to any capital project that exceeds $8 million in estimated capital costs. Projects that fall between $8 million and $54 million, which typically includes asset replacement programs and smaller augmentation projects, are assessed under a streamlined version of the RIT-T. In contrast, as indicated above, the Investment Test only applies to MCPs, which cover reliability investments, and augmentation projects that exceed $30 million. This means that the Investment Test applies to a smaller subset of projects than the AER's RIT-T, since the Investment Test does not apply to replacement projects nor to augmentation projects that are not classified as MCPs.

Another key difference between the Investment Test and the RIT-T is that the Investment Test considers a narrower range of benefits compared to the RIT-T. Specifically, electricity market benefit is defined in the Capex IM as being benefits that are received or incurred by consumers. The implication is that the Investment Test will select options that maximise consumer surplus only. In contrast, the RIT-T allows consideration of market benefits to those who consume, produce and/or transport electricity. This means that the test will select options that maximise consumer and producer surplus.

Expanding the investment test to consider a broader range of benefits would be consistent with the principles of allocative efficiency. However, in the context of network augmentation, most of the benefits that arise are likely to be allocated to consumers. This contrasts with replacement expenditure, which may result in demonstrable benefits for network operators by, for example, improving safety outcomes. Therefore, we do not consider that this change would have very much practical effect.

The case for administered REZ is unclear

Transpower argues that a REZ will address two key problems – the first mover disadvantage, and high connection costs. We acknowledge that a first mover disadvantage can arise and there can be efficiencies through coordination. Therefore, we agree that encouraging new generators to co-locate at strategic parts of the network will help to address these issues, which will benefit

[134] https://www.ea.govt.nz/documents/6707/Provision_of_information_to_system_operator_-_Gazette_notice.pdf

customers. However, it is not clear to us that an *administered* REZ as proposed by Transpower is required to achieve this outcome. Specifically, we consider that other, less intrusive, options are available to address this issue that have either yet to be fully implemented, or have not been fully explored.

The challenges with introducing an administered REZ have been identified by stakeholders as part of Transpower's consultation exercise. Chief among these concerns is that implementation of a REZ would be administratively difficult and expensive, and may inadvertently preference generators within the REZ to the exclusion of potentially more efficient generators outside the REZ. The establishment of REZs also requires substantial upfront costs to be incurred, with the likelihood that much of this cost could be imposed onto customers for an uncertain benefit.

As discussed above, the Electricity Authority has explicitly changed the connection charging framework within the TPM to address first mover disadvantages. Specifically, the Authority has introduced a pioneer scheme to collect a financial contribution from second and later connecting parties towards the capital cost of the connection investment that was funded by a first mover customer. In addition, the Authority has introduced a mechanism that would recover from the first mover only costs relating to the capacity the first mover actually needs, with the costs of additional anticipatory capacity allocated to other customers. We consider that these changes will help to address first mover disadvantages.

The issue of high connection costs is partly attributable to first mover disadvantages (which have been addressed in the TPM). However, in terms of locational signals, a primary purpose of the nodal market that exists in New Zealand is to ensure that there are strong locational signals for generation. This is not something that exists in Australia where a REZ scheme operates. A centrally coordinated REZ could strengthen locational signals for generation to collocate and allowing the sharing of infrastructure costs. However, this is a fairly intrusive answer to the problem, and we believe that there are other options – such as publication of a new Electricity Opportunities Statement – for New Zealand to be clearer about what type of generation investment is required, and where this investment could be located to maximise benefit for market participants.

9.4.2 Transmission pricing

At the outset, we note that the new TPM has undergone an extensive consultation process, including a judicial appeal that was dismissed by the High Court. The issues set out below have been considered during this consultation exercise.

Minimise the administrative burden of the pioneer scheme to better allow it to address Type 1 FMD

We agree with the Authority that a pioneer scheme can address Type 1 FMDs that may distort investment and impede development of the electricity network. A pioneer scheme ensures that the first connecting party is not left exposed to the full cost of its connection where subsequent connections are anticipated. It ensures that all customers connecting to a new area contribute equitably to the costs of extending the electricity network, which in turn encourages timely and efficient network connections.

Additionally, the scheme prevents subsequent connections from free-riding on infrastructure funded by the initial connecting party. This ensures that all connecting parties face appropriate cost signals, including subsequent connecting parties, thereby promoting efficient decisions about the timing and location of connections.

The disadvantages of a pioneer scheme are that it will impose additional administrative costs on Transpower. The costs involved in the pioneer scheme would be to maintain a database of

connection assets, check a new customer's connection against the information held in the database to determine whether the scheme is applicable, determine the size of the rebate if the scheme applies, and facilitate the transfer from the new customer to the pioneer.

We recommend that the Authority consider measures to minimise the administrative burden on Transpower, who will play a key role in facilitating these refunds. A well-defined and mechanistic approach to the scheme would reduce complexity and ensure smooth implementation. We also recommend allowing Transpower to deduct a reasonable administrative fee from the refund to cover the costs of administering the process. Precedent for such fees exists, including in the Pioneer Scheme implemented in Australia.[135]

Too early to tell whether Electricity Authority's approach will address Type 2 FMD

We agree that it may be efficient for Transpower to oversize connection assets. The key question becomes how to allocate the costs until subsequent movers connect to the network.

During the consultation exercise, some stakeholders preferred the benefit based approach (which was initially proposed by the Authority itself), while others preferred the pool and share approach (which was initially proposed by Transpower). The decision to adopt a hybrid of these two approaches is an attempt by the Authority to take a 'middle path.' In our view, it is too early to assess whether the hybrid approach will effectively manage the risk of Type 2 FMD.

The Electricity Authority's intention for including a benefit based approach is to ensure that there is a level of scrutiny on the proposed connection investments. It states: "By not socialising the entire capital cost of anticipatory capacity, there will be an incentive on identified beneficiaries to critically evaluate the merits of anticipatory capacity, and therefore submit information into Transpower and the Commerce Commission processes, contributing to the correct decision to "right-size" the grid."

We have concerns about whether this outcome will result in practice. It seems unlikely that expected beneficiaries will have any more information than Transpower as to the level of future electricity demand, and hence the investment required to meet this demand. Indeed, Transpower, as system operator, is likely to have access to more comprehensive data regarding future electricity demand. Predicting future electricity demand and optimal grid investments is inherently complex and uncertain, making it challenging for beneficiaries to critically evaluate anticipatory capacity. Beneficiaries may also lack the technical expertise to effectively assess and challenge Transpower's investment proposals.

An alternative approach to that adopted by the Electricity Authority is that the costs of building early are met by Transpower and accumulated, and then charged to parties when they connect. This would mean the parties receiving the benefit of the efficiencies of building early receive the additional timing costs of doing so as well, avoiding socialising the costs and privatising the benefits as would be achieved under the second option. This would put a heavier onus on Transpower to right size the assets, since it would bear the risk that customers do not connect.

Concerns over whether benefit based changes will promote efficiency

BBCs aim to allocate the costs of certain grid investments to customers in proportion to the benefits they receive. The overarching principle is that customers pay for the assets that they use, and do not pay for the assets they do not use. This is intended to promote efficient investment by encouraging grid users to take account of the impact of their own use on the cost of new grid investment. It encourages grid users to seek new investment in the grid when the benefit they expect to receive from that investment is greater than their anticipated share of

[135] See, for example, Essential Energy, 'Company Procedure: Pioneer Scheme CEOP8020', 18 May 2023, p.4.

cost. A beneficiaries pays approach may also be justified on equity grounds, meaning that those who do not benefit from a service are not required to subsidise it for others.

In order to be efficient, BBCs should support the right investments being made at the right time and in the right places and help ensure the best use of existing and future infrastructure. Under the BBC framework, it is envisaged that efficient pricing signals would be provided through two main mechanisms.

First, it is envisaged that customers would seek to understand the expected BBC they would face from a future investment. This is explained by the Electricity Authority below.

> *Benefit-based charges are intended to promote more efficient investment by transmission customers and increase scrutiny of proposed transmission investments. Consumers who would benefit and end up paying for a grid investment would have a greater interest in having a say on that investment, to make sure it is fit for purpose and better than alternative solutions. This should result in better information for Transpower and the Commerce Commission on grid investment proposals, and solutions to capacity issues that best meet the needs, at the lowest cost, of the affected transmission customers. It should also discourage customers from proposing or supporting projects that benefit them but are inefficient and supported only because they would largely be paid for by other customers.*[136]

We are not convinced that this outcome will arise.

The outcome expected by the Electricity Authority is predicated on users discerning how their usage decisions affect the prospects of a grid upgrade, users understanding how their benefits will be assessed in distributing the costs of an investment, users understanding how changes to their actions will affect the cost and allocation of investments, and users anticipating the actions of other users and taking these into account in determining their own actions. In our view, this is very challenging for users to undertake given the high level of uncertainty regarding future use of the network, and the complexity involved in quantifying the benefits of certain investments.

The simple method put forward in the TPM involves applying certain simplifying assumptions to reduce the administrative burden on Transpower. Most notably, initial allocations are made based on historic grid usage, and then scaled to a weight of 62.5:37.5 for load to generation. The application of these assumptions means that allocations of BBCs calculated under the simple method will only reflect a customer groups private benefits by chance. For larger investments captured under the price-quantity method, the complexity and uncertainty associated with the development of BBCs will make it difficult for network users to know what the transmission charges will in different circumstances.

Second, it is envisaged that BBCs, being levied as fixed charges, would not affect the pricing signals that are provided by wholesale electricity market nodal prices. That is, nodal prices would signal the immediate cost of using the grid. However, in our view, this too faces challenges. Nodal prices are more likely to reflect SRMC rather than LRMC, and so are unlikely to provide adequate signals for the cost of upgrading the network to meet demand. In practice, very few customers are exposed to nodal prices. This is because most customers choose to remain insulated from their effects by seeking products that are hedged and provide stable fixed rates.

[136] Electricity Authority, *Proposed Transmission Pricing Methodology – Consultation Paper*, 8 October 2021, p.24.

In addition, retailers bundle charges and so dull network signals that could be made available to end users if they were required to pass-through actual rates.

The adoption of BBCs is a means of moving away from more traditional forward based pricing based on LRMC concepts. In contrast to LRMC charges, BBCs apply only to beneficiaries of the investments, they are paid only once the actual investment is made, and are fixed-like charges. The Electricity Authority has generally been critical of LRMC pricing, noting as follows:

> *The LRMC charge provides a variable price signal ahead of an investment, which is an incentive for customers to adjust their consumption and generation. To the extent that transmission charges for a new investment are to be shared among all customers (via a tilted 'postage stamp' charge, see below) rather than beneficiaries, the LRMC signal would be inefficient. Further, the role of nodal prices in efficiently restricting grid use to capacity would be undermined and grid use would be suppressed inefficiently by such a charge.*[137]

In our view, BBCs are less likely to promote efficient use of, and investment in, the grid than LRMC pricing. Given the challenges identified above, we consider that BBCs (or, at least, the potential for future BBCs to be incurred) are unlikely to provide effective signals for the cost of using the grid. We also consider that the Authority's view that LRMC would apply on a postage stamp basis is an unnecessarily narrow application of the pricing approach. It is possible, for instance, that different LRMCs are calculated for different parts of the network so as to signal where changes in network demand might give rise to the need for future network investment.

Recovery of residual costs seems appropriate

As explained above, residual costs should be recovered from charges that minimise changes in the use of the network. There are two broad ways this can be achieved:

- charging a fixed network supply charge per customer, which does not vary according to a customer's use of the network; and/or
- marking up consumption or capacity based charges to those customers or parameters that are likely to be less responsive to changes in price - commonly known as 'Ramsey charges'.

The TPM adopts the former approach. The initial allocations are made in accordance with customers lagged four-year rolling average of gross energy usage, with this four-year period commencing the financial year eight years prior. We consider that recovery of residual costs via fixed charges is appropriate. While there are many ways that costs can be allocated to different customer groups, the approach adopted by the EA has undergone extensive consultation with stakeholders and should therefore be retained.

9.4.3 System operation

Dual role for Transpower does not appear to distort outcomes

There is extensive regulatory oversight over Transpower's dual roles. This oversight is provided by the Commerce Commission in relation to the prudency and efficiency of investment in and operation of the transmission network, and the Electricity Authority in relation to Transpower's performance in meeting its system operator obligations. In our view, we expect that the level of

[137] Electricity Authority, p.134.

oversight provided by these organisations would limit the extent to which any actual or potential conflicts of interest that may distort market outcomes.

Apart from regulatory oversight, there are also structural and governance measures that have been implemented to ensure Transpower's independence. While we have not assessed the adequacy of these measures, we expect they will further strengthen our finding and help to mitigate Transpower's ability or incentive to overdevelop the electricity transmission network.

Given this finding, we recommend that the system operator role stay within Transpower.

Security of supply standards are inflexible

The NI-WCM is New Zealand's sole resource adequacy standard for capacity, given that the South Island generally has ample generation capacity to meet demand. The NI-WCM is a winter peak demand-oriented standard, as this is when demand is typically highest and when generation and transmission capacity is under the most stress.

The NI-WCM is applied as a fixed MW range. An advantage of this approach is that it is easily measurable, monitored and communicated to industry. However, a disadvantage of this approach is that the NI-WCM is unable to respond to market changes, including factors that may affect the frequency, duration and magnitude of loss of load events, until the standard is reset. Market changes, such as greater reliance on electricity, and greater penetration of intermittent generation, would be expected to affect reliability assessments but may not be addressed under the NI-WCM (at least, unless and until the standard is reset). This may result in over or under investment in capacity to achieve reliability targets.

In contrast, in other countries such as Australia and the United Kingdom, equivalent security of supply standards are often expressed in terms of a lost load metric. For instance, in Australia, reliability standard is currently expressed as: in Australia is a maximum expected unserved energy (USE) in a region of 0.002 per cent of the total. The advantage of this approach is that investment in capacity will reflect changing expectations on the frequency, duration and magnitude of loss of load events. The disadvantage of this approach is that it is relatively more complex (and hence costly) to implement, requiring more regular analysis of factors affecting lost load on the network.

The contingent storage release buffer is under review

Transpower is currently reviewing its electricity risk forecasting framework, including a full review of the contingent storage release buffer.[138] Transpower has indicated it will also consider shorter-term temporary measures to deal with a potentially dry 2025.

Information challenges are being addressed by the Electricity Authority

The Electricity Authority has recently amended clause 9.18 of the Code to allow Transpower to gather information that is needed for it to implement and comply with the SISFIP and EMP. We understand that this will help to address concerns that Transpower was unable to access the information it required to meet its security of supply obligations under the Code.

[138] https://www.transpower.co.nz/news/system-operator-launches-review-electricity-risk-forecasting-framework

9.5 Our recommendations

9.5.1 Transmission planning and investment

Delivering economically efficient investments

A new streamlined version of the Investment Test should be introduced that would apply to augmentation projects that fall below the $30 million base capex threshold but above a nominal threshold of, say, $8 million. Below the $8 million threshold is where it is unlikely to be cost-effective to undertake detailed cost benefit analysis.

Our recommendation would not prevent Transpower from reprioritising its expenditure during a regulatory period. However, this recommendation ensures that the market can have confidence that Transpower investment is efficient and having proper regard to non-network solutions. We consider this is particularly important given Transpower's role as system operator. This recommendation will provide added confidence that Transpower is not making its role as system operator easier, through increased network, at the expense of customer bills.

The key outcome will be additional public consultation on proposed augmentations. This may involve the following steps:

- Transpower should be required to publish a project specification consultation report for proposed augmentation projects that fall within the range of $8 million and $30 million. The information that Transpower should be required to include in this report should be detailed in the Capex IM, but minimally should include:
    - an overview of the investment need, and the assumptions used in identifying the investment need
    - the technical characteristics that a non-transmission option would be required to deliver in order to address investment need
    - a detailed description of all credible options that Transpower considers addresses the investment need, and
    - application of the Investment Test to identify the preferred option.
- Stakeholders should be invited to make submissions on the project specification consultation report. A consultation period of around two months may be appropriate.
- Following completion of the consultation period, Transpower should be required to publish a project assessment conclusions report. The information that Transpower should be required to include in this report should be detailed in the Capex IM, but should minimally include:
    - an overview of the investment need, and the assumptions used in identifying the investment need (including any updates from the first report)
    - a detailed description of all credible options that Transpower considers addresses the investment need (including any updates from the first report)
    - a summary of and response to the stakeholder feedback received on the project specification consultation report, and
    - application of the Investment Test to identify the preferred option (including any updates from the first report).

A key difference between the process that would apply to augmentation projects that fall within the range of $8 million and $30 million, and major capex proposals, is that the former would not require an explicit determination by the Commerce Commission. This is because these projects

are captured by the base capex allowance approved by the Commission. However, in the event of a dispute around whether Transpower has followed the requirements for the streamlined Investment Test, it should be open for stakeholders to appeal to the Commerce Commission and for the Commission to arbitrate the dispute and make a binding decision on Transpower, including potentially requiring Transpower to revisit its analysis.

We have also considered whether the Investment Test should be expanded to include large asset replacement programmes. This is the case in Australia. However, in our view, this change is unlikely to be warranted at this time. In our experience, most asset replacement programmes are relatively uncontroversial, noting that existing assets are typically replaced when they reach the end of useful or serviceable life, and the replacement asset is usually governed by the latest available technology. The current requirement in the Capex IMs to ensure that large replacement projects in excess of the base capex threshold are net beneficial is likely to be sufficient.

Coordination of new generation capacity

An administrated REZ, in the manner proposed by Transpower, should not be introduced at this stage. Instead, Transpower should be required to produce an Electricity Opportunities Statement (EOS) on an annual basis that highlights the opportunities for market participants, investors, governments and other bodies to invest in new electricity assets and systems to maintain a reliable and secure supply of electricity and minimum cost.

The benefits of an EOS for New Zealand has been recognised by the Electricity Authority:

> *There is an opportunity for New Zealand to be clearer about what it wants in terms of renewable generation investment. While relevant information exists on locations with grid capacity, grid expansion plans, projected demand, electricity market settings, and relevant government policies, it is dispersed and not presented with (international) developers in mind…*
>
> *The Authority proposes it would be useful for an Annual Electricity Generation Investment Opportunities report to be published, targeting international developers in particular. The Authority suggests this function sits best with MBIE – it complements the type of information already produced by MBIE (eg, generation stack updates, electricity demand and generation scenarios (EDGS)) and Transpower (eg, Transmission Planning Report). NZTE, Transpower, the Overseas Investment Office, and the Electricity Authority would provide input as needed. The Authority is interested in stakeholders' views on where the responsibility for such a report best sits.*[139]

We consider that an EOS can be used to provide effective locational signals for generation investment to minimise network costs and benefit customers. We expect that this will be simpler and less costly to undertake compared to introducing a REZ, and will not crowd our efficient generation investment in areas outside of designated REZs.

[139] Electricity Authority, *Promoting competition in the wholesale electricity market in the transition toward 100% renewable electricity – Issues Paper,* 2022, p.48.

9.5.2 Transmission pricing

Recommend a 'wait and see' approach for the new TPM

Notwithstanding the concerns raised in the preceding section, the new TPM has undergone an extensive stakeholder consultation exercise. The issues raised above were considered during that consultation. Given this, and given that the TPM is still relatively new, we recommend a 'wait and see' approach to observe whether the outcomes that the Electricity Authority envisage will arise in practice.

9.5.3 System operation

Security of supply standards should be updated

We recommend that the NI-WCM standard be amended to provide greater flexibility to respond to factors that change the frequency, duration and magnitude of loss of load events. This can be achieved in several ways, including:

- retaining the NI-WCM as a fixed MW range, but undertaking more frequent (e.g., annual) reviews of the appropriate range, or
- adopting a security of standard expressed in terms of expected lost load, similar to the reliability standard that applies in places such as the United States[140] and Australia[141].

The former approach would provide more flexibility than under the status quo but would still be limited by the frequency and duration of reviews conducted. The latter approach would better address security of supply concerns in the future, at the expense of being harder to conceptualise compared to the status quo.

Given the factors above, we recommend that the NI-WCM be amended to reflect a reliability standard expressed in terms of the maximum expected unserved energy during winter peaks on the North Island.

[140] See for example MISO, ERCOT and NERC documents: https://ftp.puc.texas.gov/public/puct-info/agency/resources/pubs/news/2024/PUCT_Adopts_Reliability_Standard_for_the_ERCOT_Market.pdf , https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf , https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.1.pdf.

[141] https://www.aemc.gov.au/energy-system/electricity/electricity-system/reliability

10 Market institutions

10.1 Introduction and summary

The purpose of this chapter is to consider if the regulators have the right roles and responsibilities to promote security of supply and affordable prices.

We have considered the delineation of roles between the Electricity Authority and the Commerce Commission and also the Electricity Authority and the Gas Industry Company (GIC). In terms of the delineation of roles between the Electricity Authority and the Commerce Commission, our view is that the roles between each is broadly appropriate and no material change is required. However, we consider that the current delineation between the electricity and gas regulator is outdated and not fit-for-purpose given the current environment, in particular, the need for heightened visibility of the gas sector for the efficient operation of the electricity market. Therefore, we propose that a new Energy Authority be formed that undertakes combined electricity and gas regulation.

Our discussions with the electricity sector in New Zealand did reveal a level of dissatisfaction with the performance of the Electricity Authority. These concerns centred on its decision-making processes and also how it prioritises issues. Our view is that more formal arrangements for considering code changes proposed by the sector may address concerns about how the Authority decides on its work program and its process for making decision.

10.2 What is the desirable market outcome?

Market institutions play a crucial role in delivering governance by setting rules, enforcing contracts, and fostering transparency, which supports efficient and competitive markets. Governance refers to how decisions are made and implemented within the market.

The governance arrangements in a market should ensure that institutions behave in a manner consistent with the overarching objectives of the market. Well-designed governance arrangements should lead to market participants behaving consistently with the market objective without the need for direct regulation.

For many markets, governance is little more than the provision of a legal framework for the protection of common law rights, such as for private property and the enforcement of contractual obligations. However, for an electricity market more comprehensive governance structures are required for two reasons:

- **Government objectives** – the electricity market was set up by the Government to achieve a number of key objectives. Governments, therefore, have an ongoing interest in ensuring that the market continues to advance these underlying goals, and
- **Electricity market characteristics** – the characteristics of electricity supply make it prone to market failure. It is a commodity that is mostly provided instantaneously rather than being stored, the transport infrastructure exhibits strong natural monopoly and public good characteristics, and it is subject to public policy requirements for system security and reliability. It therefore requires a detailed code of conduct and set of market rules, appropriately developed, administered and enforced by institutions set up for those purposes.

Market institutions are required primarily to address a principal-agent problem. Customers are the ultimate principals with Government's and market institutions serving as agents of customers. Customers are primarily concerned with lower prices and security of supply. Market

institutions can deliver on these concerns either through incentives to encourage good behaviours or obligations that parties act in a certain way.

In terms of allocating functions to specific institutions, the key principles are:

- **Avoiding conflicts of interest** – strong institutional performance requires that the incentives of the institution are aligned with those of consumers, which in turn are set by Governments. Multiple conflicting interests within a single institution can cloud the decision making of that institution and prevent it from performing any of its functions in an optimal manner.
- **Clear definition of responsibilities** – A lack of clarity in the boundaries of an institutions functions blurs incentive structures and undermines the effective performance of these functions.
- **Appropriate independence from government** – Certain functions are better allocated to entities closely associated and responsive to government, while others are better allocated with some distance to government. For instance, key strategic policy-making functions should reside close to governments as they are responsible to voters for the success or failure of public policy.

10.3 Current market

10.3.1 Institutional arrangements

The starting point for the institutional arrangement for the electricity market in New Zealand is the statutory basis for the regime. The electricity industry in New Zealand is governed by a series of statutes. Key statutes include:

- **The Electricity Act 1992** – which sets out the regulatory framework for the supply of electricity, including for electrical workers. It covers matters such as codes of practice, licensing and the power and duties of electricity operators.
- **Electricity Industry Act 2010** – which provides the framework for regulation of the electricity industry, including establishing the Electricity Authority as the electricity regulator.
- **The Commerce Act 1996** – which provides for a specific regime to regulate electricity lines businesses and also provides for consideration of market power and competition issues.

Below the statutes are regulations and the code. The Electricity Industry Participation Code 2010 sets out the duties and responsibilities for all industry participants and the Electricity Authority. There are five regulations, namely:

- Electricity (Exemptions from Registration)
- Electricity Industry (Levy of Industry Participants) Regulations 2010
- Electricity Industry (Participants and Roles) Regulations 2012
- Electricity Industry (Enforcement) Regulations 2010
- The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004

The regulatory agencies that exist in New Zealand and their roles are described in Table 12 below.

Table 12: Electricity market institutions

Agency	Function	Objective
Electricity Authority	Established under the Electricity Industry Act 2010 and independent from the Government, the Authority regulates the electricity market. It has responsibility for developing, administering, monitoring and enforcing the Electricity Industry Participation Code 2010, which are the rules that govern nearly every aspect of the electricity industry.	"...promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers" And, for dealings with domestic and small business customers "...protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers."
Commerce Commission	The primary competition, fair trading, consumer credit and economic regulatory agency. Therefore, it is not an electricity specific regulator. It regulates electricity lines companies under Part 4 and Part 4A of the Commerce Act 1986. It also assesses market power, mergers and competitive behaviour under Parts 2 and 3 and 3A of the Act. It is independent from Government.	"...promote the long-term benefit of consumers in markets referred to in section 52 by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services— (a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and (b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and (c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and (d) are limited in their ability to extract excessive profits."
MBIE	Government department that leads government policy and strategy. MBIE publishes extensive statistics and data on energy markets, including the Electricity Demand and Generation Scenarios that explore potential future electricity demand and the generation capacity required to meet that demand.	

Gas Industry Company

While not specifically an electricity market institution, given gas is an important fuel for electricity generation the operation of the gas industry regulator is also relevant to the effective operation of the electricity market.

The governance arrangement of the downstream gas activities is set out in Part 4A of the Gas Act (1992).[142] More specifically, downstream gas activities have, since 2004, been 'co-governed' under the Gas Act (1992) administered jointly by the government and by the Gas Industry Company (GIC).

The GIC is a body approved by the Minister for Energy and is charged with the responsibility implementing an array of legislative, regulatory and other statutory instruments that governs how the downstream gas industry functions.

The GIC is a Limited Liability company that is managed by a Board. The Board nominates a candidate director who must be duly elected at an annual general meeting.[143] The directors elect the Chair.[144] The Board is to consist of seven directors of which four are to be independent of any interest in the gas industry, although currently there are an even number of industry and independent Board members.[145]

In a March 2005 speech to the Gas Industry Forum the then Minister for Energy, the Hon Trevor Mallard highlighted that the legislated co-regulatory model for governance of the gas industry was part of a suite of initiatives to "… facilitate the New Zealand gas sector's transition to the post Maui era".[146] The suite of policy initiatives were directed at encouraging the development of the gas sector and the government developed arrangements that aimed to encourage greater involvement and ownership of the gas sector's development. The Minister said in his speech that the "… government does not directly operate in the gas market".[147] The Minister went on to say that it was important the gas sector "… not to lose sight of the need to produce sensible solutions for matters which run to the heart of public concerns …".

The GIC's powers cover a wide range of activities[148], namely to:

- recommend gas governance regulations and gas governance rules under Part 4A of the Gas Act;
- administer, monitor compliance with, investigate, enforce, and apply penalties or other remedies for contraventions of, any or all of the gas governance regulations and gas governance rules;
- establish, operate, and facilitate the operation of, markets for industry participants;

142 New Zealand Gas Act (1992) Weblink: http://www.legislation.govt.nz/act/public/1992/0124/latest/DLM285412.html

143 Gas Industry Company Constitution (amended 2008), Clauses 20.9 and 20.10, Weblink: https://www.gasindustry.co.nz/assets/CoverDocument/Constitution-of-Gas-Industry-Company-Limited.pdf

144 Gas Industry Company Constitution (amended 2008), Clauses 21, Weblink: https://www.gasindustry.co.nz/assets/CoverDocument/Constitution-of-Gas-Industry-Company-Limited.pdf

145 Gas Industry Company Constitution (amended 2008), Clauses 17.1 and 17.2, Weblink: https://www.beehive.govt.nz/speech/gas-key-govts-sustainable-energy-development https://www.gasindustry.co.nz/assets/CoverDocument/Constitution-of-Gas-Industry-Company-Limited.pdf

146 Beehive.govt.nz (2005), "gas a key to govt's sustainable energy development", 3 March, Weblink: https://www.beehive.govt.nz/speech/gas-key-govts-sustainable-energy-development

147 *Op cit* Beehive.govt.nz (2005)

148 Gas Industry Company Constitution (amended 2008) Section 4.1, Weblink: https://www.gasindustry.co.nz/assets/CoverDocument/Constitution-of-Gas-Industry-Company-Limited.pdf

- establish or implement one or more complaints resolution systems required by gas governance regulations or gas governance rules;
- recommend regulations under the Gas Act that require industry participants to pay a levy to the Company, and collect any such levy;
- advise and report to the Minister in relation to the New Zealand gas industry.

In discharging its responsibilities under the Gas Act, the GIC must have regard to the objectives in the Government Policy Statement of Gas Governance (2008)[149] which has an overarching requirement that the GIC recommends rules and regulations that "... ensure that gas delivered to existing and new customers in a safe, efficient, reliable and environmentally sustainable manner". The Policy Statement sets out the things that they are to regularly report to the Minister to allow the government to monitor the GIC is fulfilling its role.

10.4 Our assessment

10.4.1 Allocation of responsibilities between the Electricity Authority and the Commerce Commission

We have identified certain matters where there is some overlap of responsibilities between the Electricity Authority and the Commerce Commission, namely:

- The approach to economic regulation of network companies, and
- Addressing issues for competitive markets.

Regarding the second of these issues, we were told that when competition issues have been raised in the market that these have been handballed between the Commerce Commission and the Electricity Authority. We do not think this is a failure in the delineation of obligations between the institutions. It is more likely that the Commerce Commission was aiming for a pragmatic approach to the issues before more serious steps are taken. Indeed, the establishment of the Energy Competition Task Force appears to be part of aiming to identify pragmatic solutions to issues market participants had identified.

Furthermore, we do not support a model whereby a sector specific regulator is responsible for competition regulation. While there are pros and cons associated with sector specific regulation versus a general competition regulator, the benefits of general competition regulation likely outweigh any benefits from sector specific regulation, including for the following reasons:

- A separate competition regulator is more likely to have a broader perspective on competition and industry economics.
- Separating regulatory and policy roles from competition regulation roles is more likely to deliver welfare enhancing policy choices. This is because, a sector specific regulator may choose to deny structural changes in the sector when a more efficient solution would be more effective regulation or other policy changes. Even if this was not the case, industry may be suspicious that an inappropriate instrument is used and so erode investor confidence.
- From a broader economy perspective, it is important that competition issues are dealt with in a consistent manner across sectors. The value of this consistency is it provides more certainty for investors.

[149] Government Policy Statement (2008), Weblink: https://www.gasindustry.co.nz/assets/DMSDocumentsOld/rules-and-regulations/4791GPS-2008.pdf

- There is increasing convergence across sectors, for instance between gas and electricity but also across digital based industries. A general competition regulator that is dealing with multiple sectors is better placed to understand how these forces are likely to shape the industry.
- There is a limited supply of people with the skills necessary to undertake detailed analysis of competition issues. If there are multiple, industry specific, competition agencies these skills will be spread more thinly and the quality of analysis is likely to suffer.

In terms of the issue for the economic regulation of network companies, this relates to the responsibility for considering pricing structure. Having the Electricity Authority with more control over pricing structure may limit the Commerce Commission's ability to integrate its approach to revenue setting with pricing for customers. Electricity networks are built with sufficient capacity to ensure peak demand is met. Price structures can influence the incentive for consumers to use electricity at peak times. So, for example, if customers are provided with a correct signal for the use of the network at peak time, a regulator can reasonably assume that any demand driven augmentation costs are reasonably efficient. This is because customers have signalled, through their consumption in response to the price signal, that they value consumption at peak times more than the cost of augmenting the network to meet that demand.

When faced with a proposal for additional expenditure to meet peak demand the Commerce Commission may prefer that the network business better signal to customers the cost of meeting peak demand than approving the expenditure allowance. However, the separation of responsibilities between revenue and price regulation may limit its ability to do this.

Despite the potential for this constraint on how economic regulation is applied, we have not heard that this current arrangement is creating difficulties in the market or overly constraining the Commerce Commission's approach to economic regulation. Therefore, this is likely a matter to keep an eye on rather than impose change at this point in time.

10.4.2 Role of the GIC

The co-regulatory model for the gas sector appeared to align with the Government's dual objectives at the time: encouraging investment in the sector through direct involvement in policy and regulatory development, while also ensuring appropriate checks and balances. These were achieved through a majority of independent directors on the GIC board and significant Ministerial oversight and control via the governance instruments outlined above. In the 20 years since this arrangement was established there have been some important changes in the energy market that justify revisiting the continued appropriateness of this model.

Chief among the changes that have occurred in the past 20 years is that the gas sector is in rapid decline, and this decline imperils the reliability and security of electricity supply. This is because it reduces the ability for gas generation to meet dry year risks and to support firming beyond short term requirements. It is important that New Zealand consciously and urgently consider the competing options of facilitating the investment in the development of local sources of gas (onshore and offshore) or the development of an import terminal. However, given the urgency of this task, and the challenges that the gas sector now faces, it is unclear whether the current gas regulatory model will be adequate in responding to the key needs for the electricity sector.

Other factors that are warrant revisiting the current gas and electricity regulation model include:

- **Industry convergence and interdependence:** Beyond the fuel security issues identified earlier, the past two decades have seen significant convergence between the gas and electricity sectors. Policies that impact electricity – such as those relating to pricing and hedging – also influence the financial performance of the gas sector, and vice versa. This interdependence highlights the need for coordinated development and management of both

sectors to support a smooth energy transition and deliver the best outcomes for consumers. The existence of separate governance arrangements for gas and electricity may no longer be well-suited to achieving these objectives.

- **Potential for institutional efficiencies:** Since the establishment of the GIC, New Zealand has developed the Electricity Authority which has almost equivalent roles and responsibilities for electricity as the GIC has for gas. Bringing both roles under a single governance framework could generate operational efficiencies and reduce duplication.
- **Opportunities for harmonisation:** There is scope for greater alignment of regulatory and policy settings across the gas and electricity sectors in areas such as consumer protection, information disclosure, and the development of consistent frameworks for policy and regulatory assessment.
- **Governance and public confidence:** While the GIC operates under strong oversight from MBIE and the Minister for Energy, it is not a Crown entity like the Electricity Authority, and instead functions under a co-regulation model. This structural distinction may erode public confidence if it gives rise to perceptions that the GIC's interests are not fully aligned with those of consumers or government policy.

10.4.3 Electricity Authority work program and decision making

During our engagement with the sector, there was a general level of dissatisfaction with the Electricity Authority and its decision-making processes. There are several possible reasons for this dissatisfaction. Firstly, it is expected that a body that has oversight and control over an industry will usually be met with the dissatisfaction of the industry subject to controls, so the presence of dissatisfaction does not necessarily indicate a problem with the agency.

Having said this, there are concerns that need to be addressed. For example, stakeholders have told us that issues can be raised with the Electricity Authority but how they are dealt with, and if they are dealt with at all, is entirely at the discretion of the Authority. This leads to some stakeholders feeling they are ignored, or lower priority. Indeed, we have identified matters where the Authority has not fully delivered on certain responsibilities that have been assigned to it.[150] As part of the Electricity Price Review the Authority was assigned tasks including addressing data access issues, which do not appear to have been actioned. We are also aware of participants communicating concerns to the Electricity Authority with apparently little formal action in response.

In addition, we have found instances where required market data has not been published. For example, the Electricity Market Information website indicates that it would provide retail entity brand, trader and parent company information annually from 2011.[151] However, we were unable to locate this information and had to request it directly from the Electricity Authority. This type of data is crucial to assessing market performance.

We are also aware of concerns about the Electricity Authority's decisions lacking a firm evidentiary basis. While our review of the Authority's decisions suggests that market concepts are well understood, it is not clear that the Authority has then undertaken the necessary analysis to reach the conclusions it reaches. For example, despite having extensive data on hedging contracts, it does not appear that the Electricity Authority has used this data in the way we would expect it to for analysis of competition in the market. Where the Electricity Authority has done

[150] Examples include multiple recommendations that emerged from the 2019 Electricity Price Review, including the aforementioned recommendations relating to consumer data access and also bill standardisation.

[151] Electricity Authority - EMI (market statistics and tools)

this analysis, it could do a better job of communicating this to stakeholders, including how it fits within the economic principles that underpin its objective.

While resource constraints are often cited as a challenge for regulatory bodies, our review suggest this may not be the primary issue in this case. The Electricity Authority's funding is determined through its levy-funded appropriations, with its 2024 funding amounting to nearly 98 per cent of its proposal.[152] This suggests that the Authority is largely receiving the revenue requirement it has sought, in this case an increase of over $11 million compared to previous annual funding.[153] The Authority also has a workforce of 124 permanent and nine fixed-term employees.[154] By comparison, the AEMC, which oversees rule-making for both electricity and gas markets in Australia with oversight over millions more customers, has 122 employees.[155] While the AEMC does not have an enforcement function, the Electricity Authority does not have responsibilities for the gas market.

10.5 Our recommendations

10.5.1 Combined energy regulator

We recommend that a new entity be created that combines the functions of the Electricity Authority and the GIC. We consider the circumstances that justified the development of a separate and different governance model for gas and electricity have changed sufficiently to reconsider the existing gas governance arrangements. We believe that the importance of consistent and urgent action to manage the energy transition, and the prospects of cost saving opportunities that can be gained from streamlining and harmonising the current regulatory arrangements by combining the electricity and gas policy and regulatory functions, justify the amalgamation of gas and electricity functions under an expanded Electricity Authority to be renamed the Energy Authority.

A new Energy Authority should take over the functions currently managed by the GIC and create parallel arrangements for gas within the Authority as they apply to electricity, where appropriate, and bespoke arrangements for gas, where appropriate. It is important that the unique characteristics of the gas sector are taken into account when deciding how to amalgamate the sectors into a single regulator given certain regulations and policies that are applied to electricity are unlikely to be suitable for the gas sector.

The Energy Authority should be required to take advantage of the economies that exist from already undertaking many of the same policy and regulatory functions for the electricity sector. That is, it is our expectation that an expanded Energy Authority should cost significantly less to operate than the combined total cost of operating the GIC and Electricity Authority separately.

We note that combined energy regulator is a common feature throughout the world, for example:

- **The United Kingdom** - Office of Gas and Electricity Markets
- **Australia** - Australian Energy Market Commission and Australian Energy Regulator
- **Singapore** - Energy Market Authority

[152] https://www.ea.govt.nz/news/general-news/authority-receives-uplift-in-budget-2024/, and Electricity Authority, Relieving pressure to deliver regulatory reform at pace: Proposed levy-funded appropriations 2024/25 Consultation paper, 19 December 2023, p.5.

[153] Authority receives uplift in Budget 2024 | Electricity Authority

[154] Electricity Authority, Annual Report 2023/24, p.68.

[155] AEMC, Annual Report 2023-34, p.37.

- **Malaysia** - Energy Commission
- **Italy** - Italian Regulatory Authority for Energy, Networks and Environment (ARERA), and
- **Canada** – Canada Energy Regulator.

We recommend that regard to these international models be taken into account when forming the new Energy Authority.

10.5.2 Formal code change process

We recommend that a formal code change process should be implemented that obliges the Electricity Authority to assess code changes that have been proposed by the sector under a legislated procedural framework. This should be modelled on the approach taken by the Australian Energy Market Commission (AEMC) in Australia.[156] Our direct experience with the Australian model is that it has worked well and is widely supported by the sector. We believe that formalising a code change process will address stakeholder concerns that the Electricity Authority does not take enhancements proposed by the sector seriously or that it may give preferential attention to matters raised by certain stakeholders over others. Requiring that this activity be conducted under a prescribed process will ensure that matters are addressed in a timely manner.

In terms of the quality of the Authority's decision making and its ability to deliver on tasks assigned to it or that it initiates. We recommend that the Electricity Authority is subjected to a targeted review of how it performs its functions. The purpose being to identify if it is allocating resources to the right areas of its functions, whether the resources it does have are well aligned with the delivery of its functions, and if its process for internal decision-making has sufficient checks and balances to deliver robust outcomes.

[156] See Appendix E for a description of the AEMC's rule making framework.

11 Market monitoring

11.1 Introduction and summary

The purpose of this chapter is to consider how market monitoring and compliance enforcement is undertaken in New Zealand, and specifically, if it is consistent with, in our opinion, international best practice. Our particular focus for this analysis is the approach to monitoring for the presence and exercise of market power.

In considering the approach to market monitoring we have focused on the framework adopted for the Electricity Authority for this task rather than its actual decisions made.

A reality of market monitoring is that it is hard, and reviewing simple indicators is not sufficient to understand competitive market dynamics. It is our view, therefore, that the biggest improvements can be made to market monitoring by developing a more sophisticated approach to assessing market power and identifying and measuring barriers to entry so the Electricity Authority can determine where to direct pro-competitive changes to the market. Specifically, it is our view that the Electricity Authority has either not collected sufficient data to perform this task effectively, or has not used the data that it has to support a robust assessment of market outcomes. We are recommending that the Electricity Authority leverage Transpower's specialised expertise as System Operator, and its access to real-time operational data to further improve its market monitoring capabilities. In terms of the analysis that the Electricity Authority undertakes, moving beyond reliance on competition metrics requires that it make better use of contracting data so that it has a better understanding of the incentives of market participants in each trading interval and over time.

11.2 What is the desirable market outcome

11.2.1 Role of market monitoring

From a market regulator's perspective, market monitoring involves oversight of the market to, in general:

- Provide an early warning on emerging issues regarding participant conduct and the economic performance of the market
- Identify any sources of enduring economic inefficiency – productive (using too many resources), input allocative (using an inefficient mix of resources), output allocative (producing the wrong outputs and selling outputs at economically inefficient prices) and dynamic efficiency (investment not occurring efficiently, that is at the right time, place and kind)
- Identify whether participants are complying with the market rules, and
- Identify whether changes in policies, market rules or regulations designed to address previously identified issues have had the expected effects on participant conduct and market performance.

11.2.2 Monitoring starting point

The starting point for monitoring any market is being clear about how the market is designed to operate and what outcomes the design is expected to produce. This is important so those who are responsible for monitoring a market have a basis for deciding whether the market is performing within reasonable bounds, or otherwise.

In the context of this review, a particular concern is whether firms are exercising market power in the wholesale market in ways that harm customers and the economy. Therefore, in this section, we have focused on monitoring the competitiveness of the market.[157]

11.2.3 Monitoring challenges

Several features of energy-only electricity markets, such as that which operates in New Zealand, make monitoring for participant market power particularly challenging:

- **Scarcity pricing is a design feature not a flaw:** As previously indicated, high prices during periods of scarcity are not necessarily a sign of market failure, even when they are caused by transitory market power. This is because these prices at times of scarcity are necessary to signal investment and/or incentivise demand response. Therefore, it can be difficult to identify if prices are merely reflecting the scarcity of capacity relative to demand at that time, and so the value of that energy in the market, or if it is due to substantial market power. It is certainly the case that it is not appropriate to judge the competitiveness of an energy-only market design, such as that operating in New Zealand, based on short to medium term market outcomes. Scarcity prices are designed to send signals to investors for new supply options and/or demand response (short to long-term). The most efficient response to scarcity prices may take some time. As was explained well by the Australian Energy Market Commission when it was reviewing whether there was market power in Australia's National Electricity Market, which is also an energy-only market:[158]

  > *In electricity generation, which is characterised by relatively high fixed costs and 'lumpy' investments, a competitive response to price signals will not occur in very short timeframes. It is therefore important to recognise prices must be sustained above estimates of LRMC for a sufficient period of time, reflecting a time frame in which new entry may reasonably be expected to occur. This also recognises it is not likely that generators recover their costs in a steady way over time. At times, generators' operating margins may be relatively high, while at other times, the margin will be quite low or even negative.*
  >
  > *The existence of material barriers to entry may prevent a normal market response under conditions of workable competition from occurring, namely new entry into the market in response to price signals.*
  >
  > *As a result of these considerations, the Commission defined substantial market power in the context of the NEM as the ability of a generator or group of generators to increase annual average wholesale prices to a level that exceeds LRMC, and sustain prices at that level due to the presence of significant barriers to entry.*

  The above does not necessarily mean that high scarcity prices ought to be tolerated in the long term. If there is no investment response emerging to address enduringly high scarcity prices this would tend to indicate that there are substantial barriers to entry. Market monitoring should also consider the factors that are important for determining market competitiveness, notably the presence and extent of barriers to entry.

- **Volatility is a necessary and intentional feature**: Because supply and demand must be matched instantaneously, when capacity is scarce it is possible for even the smallest generator to be pivotal (i.e. necessary to operate to meet demand) and so drive very high prices. Again, such volatility supports desirable market outcomes like signals for new investment or demand response, as well as creating incentives for welfare enhancing hedging practices. However, the presence of this volatility means it can be difficult to

[157] In section 5.2 of this report we identify the key features that are expected in competitive markets.

[158] AEMC 2013, Potential Generator Market Power in the NEM, Final Rule Determination, 26 April 2013, p.iii.

differentiate between price manipulation that drives price spikes versus those that arise due to the specific conditions in a trading interval. In terms of market monitoring, what is important is understanding the circumstances that give rise to price volatility. If this volatility occurs at times and in a way that is consistent with the market design, then these types of volatility events may not be of concern. However, if price volatility occurs in circumstances that are unexpected vis-à-vis the design, market monitoring would assist in identifying whether such an outcome is episodic or likely to become more common.

- **Need to recover costs**: In an energy-only market the main source of revenue for most generators is currently from the sales in the spot electricity market. Obviously, generators also sell hedging contracts to smooth out these revenues over time and they earn a premium on these contract sales for managing this risk, but this source of revenue is secondary to earnings in the spot market. Unless generators expect to recover their avoidable costs, they will shut their capacity and, in doing so, prices will rise, all other things being equal. This exit will improve the financial viability of the remaining generators. Market monitoring can assist in understanding the extent to which generators are recovering their costs and, thus, help inform an assessment of whether generators would be expected to exit or enter the market.
- **Complexity of electricity markets:** Electricity markets rely on a complex system of rules to determine a dispatch solution and clearing price that must have regard to the physics of a complex interconnected power system involving thousands of different types of electrical equipment operating in unison in real time. This complex combined economic and technical system produces a vast amount of data that is used in real time to maintain a secure and reliable power system. Much of this data can also be used to monitor the operation and performance of the market. For example:
    - participant bidding information can be used to analyse the presence and extent of auto-bidding and whether this is leading to tacitly collusive outcomes
    - dispatch data can be used to determine whether generators are operating in a manner consistent with least cost operation and the circumstances in which generators do not offer their capacity to generate electricity
    - dispatch data and demand data can be used to assess the reliability of the system through the assessment of reserve plant margins
    - dispatch data can also be used to identify instances and extent of disorderly dispatch due to network congestion, which could indicate the requirement for more transmission capacity, and
    - price data can be used determine the margins being earned by each generator and whether certain generators are earning more or less than expected.

Given the complexity of the market and the extent of interaction between a wide range of factors affecting market/system outcomes, most of which are outside the control of participants and are often beyond participants' knowledge at the time decisions are made, there is an inherent risk that the data produced by a market is misunderstood and is therefore subject to misrepresentation. To avoid this risk it is essential that market monitors have a detailed understanding of the operation of the power system as well as the market. It is also crucial that market monitors understand how participants operate in practice in the market and appreciate the complex and seemingly conflicting commercial objectives traders seek to optimise. To support their analysis market monitors need access to resources, tools and training to meet the challenges of appropriately analysing market and system data.

11.2.4 Competitive indicators

In economics, there is an important linkage between market structure – that is, how many competitors there are and their relative market shares - and market competitiveness.

In general, this linkage suggests that if there is a fewer number of larger market participants there will be less competition and greater economic inefficiency. This framework is generally applicable to any market, and in this context, electricity wholesaling and retailing.

One of the foundational models economists use to explain the relationship between market structure and competition is known as the Cournot model. The Cournot model, expressed in detail in Box 5 below, is built on a few key assumptions:

- Firms compete by deciding how much of a product to produce, rather than by setting prices.
- Each firm assumes that its competitors' production levels are fixed and that the market price adjusts based on total supply.
- In the short run, the number of firms in the market is fixed — no new firms can enter.

When each firm maximises its profit, the relationship between the market price, the firm's marginal cost (the cost of producing one more unit), and its market share can be expressed in a way that shows how competition affects pricing.

In simple terms:

- The mark-up of price over marginal cost is influenced by the firm's market share and how responsive customers are to changes in price (price elasticity of demand).
- The larger the firm's market share, the more it can act like a monopolist by charging a price further above its marginal cost.
- Across the industry, the overall mark-up reflects the distribution of market power among all firms.

This model allows us to quantify how market concentration affects pricing and can be used to assess whether a market is behaving competitively or whether some firms may have the power to restrict output and raise prices, at least in the short run.

Box 5: Cournot model

The main features of the Cournot model are:

- Firms compete by setting quantities, taking price as given, and taking the quantities of other firms as given; and
- In the short-run, the number of firms is fixed, and there is no entry.

In this model, any one firm will face a residual demand curve given by total demand less the sum of the output of other firms. Any one firms' share (s) of total production (q) can be given by $s_i = q_i/q$

At profit maximisation, the following expression relating price to marginal cost must hold true for each in the industry:

(1) $$P(q)[1-1/(e/s_i)] = MC(q_i)$$

where p denotes price, (q) denotes aggregate industry demand, (e) denotes the absolute value of elasticity, $MC(q_i)$ denotes marginal cost for the individual firm.

The expression is simply the traditional expression for the mark-up of price over marginal cost associated with a monopolist, mitigated by the expressions denoting market share. The larger the firm's share is, the closer the price mark up is to that expected under monopoly.

The expression can be rewritten as:

(2) $(p-MC_i)q_i/pq = -(1/e)s_i^2$

In equilibrium, this is true for all firms, so the expression for the industry as an aggregate is given by:

(3) $[\sum_i(p-MC_i)q_i)]/\sum_i pq_i = (-1/e)\sum_i s^2$

The measure of market power is the mark-up of price over marginal cost, as given by the left hand term of the expression. The mark up is greater the lower the price elasticity of demand (e); and the greater the sum of the squares of the market shares of each firm in the industry ($\sum_i s^2$).

The remainder of this section describes the main features, advantages, and drawbacks of the principal methods used to assess the competitiveness of a market. While these measures are typically used to identify the potential effects of mergers, they are equally useful for assessing competitiveness, and that is the focus of their use in this section of the report.

The methods discussed are:

- Structural approaches – Lerner index and concentration ratios, and
- Residual demand analysis.

Structural approaches and analysis

The Lerner Index

A useful way to understand how much influence a company has over the prices it charges is through a concept known as the Lerner Index.[159] This index is a measure of market power. It tells us how far a company is able to push its prices above its costs. In a perfectly competitive market producers will charge their (short run) marginal costs. This means the Lerner Index result equals zero. As a company gains more control over the market, the Lerner Index moves closer to 1, signalling stronger market power.

The main advantage of the Lerner Index is that it provides the most direct and accurate measure of market power by estimating Lerner Index values across a number of scenarios in order to identify differences with and without mergers.

There are, however, two key drawbacks associated with the Lerner Index:

- **Informational scarcity** – particularly:
  - It is not possible for regulators to perfectly observe and verify costs
  - Price series for a number of different counterfactual scenarios are required. However, by definition, these prices cannot be observed and so must be simulated, or generated, by some process.
- **Applicability to the New Zealand electricity market** – in an energy-only market it can be difficult to interpret the outcomes of a Lerner Index as all costs are meant to be recovered by

[159] The Lerner Index is: L = (Price-Marginal Cost)/Price, where the value of L lies between 0 and 1

the spot price, including fixed costs. For the last generator required to meet demand, the marginal generator, to make a contribution to fixed costs it is necessary in an energy-only market for prices to rise above the operating costs of that generator. Indeed, in a perfectively competitive energy-only market the expected outcome is that at times of scarcity the price will rise up to the value of unserved energy. This is the point where supplying another customer would require the reduction in use by another customer. Furthermore, prices need to be above costs to also compensate for times when they are below costs. The implication being that the Lerner Index could show prices above costs while the market is still functioning efficiently. In New Zealand, Lerner index estimates will be heavily influenced by estimates of the opportunity cost of water. As hydro generators can cover their costs in a market with a far lower price than observed, but their opportunity cost, which is their true short run marginal cost, is derived from the presence of other generation in the market.

A reasonable substitute to the Lerner Index

A more reasonable way to apply a Lerner Index to an energy-only market, given the issues raised above, is to compare spot prices against long run marginal costs rather than operating costs (which are short-run marginal costs). In this case, long run costs should also be compared against long term prices, such as average prices.

The Long Term Lerner Index is relatively easy to formulate from the outputs of cost modelling typically used to analyse market prices and costs. Two broad methods that have been used to estimate long run marginal costs of electricity generation include:

- **The first method** focuses on the cost of building the next likely power station. This "new entrant" cost sets a benchmark. If prices stay above this level, it would attract new investment, increasing supply and pushing prices down. So, in a competitive market, prices tend to gravitate toward this cost.
- **The second method** takes a system-wide view. It considers the most efficient mix of generation type, like base load, mid-merit, and peaking plants, to meet demand at the lowest overall cost. This reflects how electricity is actually supplied across the day and year.

Both methods offer useful insights, with one focusing on investment signals and the other on real-world system efficiency. The second method is likely to be best suited to the New Zealand market, given the risks and inefficiencies associated with selecting a single candidate plant to provide a reference price for all electricity market.

Measures of concentration

The high informational requirements of the Lerner Index approach has encouraged regulators to adopt more indirect approaches to inferring the existence of market power. The approach traditionally used has been to measure the degree of firm concentration, on the basis that greater levels of concentration are associated with a greater scope for the exercise of market power. The reasoning stems from the Cournot model discussed above. Two measures of concentration typically used by regulators are:

- **Concentration Ratios (CR)**. For example, the combined market share accounted for by the largest *x* firms (CR*x*).
- **The Herfindahl-Hirschmann Index (HHI)**. As has been previously explained, the HHI for a market is calculated by summing the squares of the market share of each firm in the relevant market.

The application of the CR and HHI measures to instances of horizontal integration usually takes place in the context of a wider investigation that comprises a number of other steps. For

example, pursuant to the 1996 Merger Guidelines adopted by the US Department of Justice and the Federal Trade Commission, the United States Federal Economic Regulation Commission (FERC) uses the HHI index in order to ascertain the impact of a merger on market power.

The Commerce Commission state in their Merger and Acquisition Guidelines that they use market share and concentration measures to assess mergers but are clear that these measures are "*… insufficient in themselves to establish whether a merger is likely to have the effect of substantially lessening competition*". They go on to state that a full analysis of the range of factors outlined in their Guidelines need to be considered.[160] This is a position that we strongly endorse because of the shortcomings of each of the traditional competition measures, as we discuss further below.

An advantage of concentration measures is that they are straight-forward to apply and compute in the context of the Cournot model described above. They also provide a clear-cut benchmark against which to assess competitiveness of the market.

However, for many years several criticisms have been advanced regarding the use of concentration measures, and more generally, the structural analysis which supports their application.[161] Particularly:

- They do not convey any information how prices change in response to decisions taken by firms on output (price elasticity of demand). This particularly significant for electricity generation given the short-run inelasticity of demand for electricity.
- They require a pre-defined geographic market without explicitly modelling the incentives that a generator may have, or not have, to serve a particular market. That is, it is assumed that if a generator can serve a particular market, it will serve it if it feasibly can.
- They do not tend to provide modelling of the strategic interactions between market participants, or changes in the fundamental parameters affecting the operation of the market. This omission is particularly constraining in electricity market analysis given the interplay of transmission and generation constraints, the need to constantly match supply and demand, and varying levels of available capacity, are central to determining if, and at what times, generators have the incentive and ability to exercise market power.
    - More specifically, it is argued that the manner in which electricity markets operate create specific, albeit generally time-limited, opportunities for the exercise of market power. For example, in a situation in which demand is high, transmission constraints are binding, and competing generators are operating at maximum capacity, a particular generator is likely to have the incentive to withhold capacity from the market. This raises the price received on all infra-marginal plant, and consequently allows it to appropriate extra profits, which (in the short to medium term) cannot be competed away since as other generators are capacity constrained. A generator may exercise market power even if overall concentration, or individual market share, is relatively low. Some simulations of interaction in which generators strategically withhold capacity when others are capacity constrained yield results that simultaneously show an increase in the Lerner Index (i.e.

[160] New Zealand Commerce Commission (2022), *Mergers and acquisitions Guidelines*, Para 3.49 and 3.50, page 23. Weblink: https://comcom.govt.nz/__data/assets/pdf_file/0020/91019/Mergers-and-acquisitions-Guidelines-May-2022.pdf

[161] See Roach, (2002) op.cit. see also Borenstein, S., J. Bushnell, and C. Knittel, (1999) "Market power in electricity markets: Beyond concentration measures", *The Energy Journal*, Vol. 20. 4; Hieronymous, W. H., J. Henderson, C. A. Berry (2002), "Market power analysis of the electricity generation sector", *Energy Law Journal,* Vol. 21. 1; Deb, R., R. Matacangay, and S. Deb (2002), "An analysis of generation market power in the Midwest Interconnect", *The Electricity Journal*, April.

increasing market power) and decreasing HHI values (precisely because capacity is withheld from the market).

The criticisms of concentration measures need to be qualified by a reminder, however, that the purpose of the tests for market power is not to detect the temporary exercise of market power by generators. Instead, market power should be viewed as the ability to raise prices sustainably in the long run. The key issue of concern in a longer run analysis is the possibility of substitution. Measures of market concentration may be relevant insofar as higher levels of concentration could provide a greater scope for entry deterrence activities.

In respect of the choice of between the different concentration measures for the electricity sector, there is almost no reason to use only a CR*x* measure over a HHI as there is almost always the required data to determine the market share of every market participant.

Residual demand analysis

Residual demand analysis is essentially a special case of the basic Cournot model described above. In this analysis, all firms but one in the market are assumed to act competitively. Meaning they sell electricity at cost and take the market price as a given. These price taking firms constitute the 'competitive fringe' of the industry. The supply curve for this competitive is the sum of their marginal cost curves. The remaining firm faces a residual demand curve, which is the demand that is left after the 'competitive fringe' has supplied its share. As it is the only firm available to supply this remaining demand, it is the only firm that exercises market power.[162]

The approach helps to identify whether one firm in a competitive market may still be in a position to influence prices. The core idea is that when demand is relatively inelastic, a generator can benefit from withholding supply to push up spot prices. The less responsive demand is, the more attractive the trade-off becomes between higher prices and reduced dispatch volumes. In this context, market power refers to a generator's ability to unilaterally raise prices.

The extent to which a generator has the incentive to exercise this power is constrained by the extent to which its output is covered through hedging contracts, among other things. As has been previously discussed, financially firm hedging contracts create strong incentives for generators selling these contracts to bid competitively (this is because the contract reduces the payoff from raising spot prices to the strike price of the contract). This means that even if the market is structurally concentrated, fully hedged generators are likely to bid competitively and the resulting spot price would reflect this competitive bidding.

It may be argued that the generator with latent market power will not hedge away their influence over the spot price. However, this ignores the risks to a generator attempting to improve their position by limiting their contracted position to give themselves the opportunity benefit from higher spot prices. These risks include the possibility that the generator's uncontracted position alone is insufficient to, at an acceptable risk, raise spot prices. Even if the uncontracted generator was able to raise spot prices, this increase may not be sustainable, and if it is not, then the benefit is unlikely to filter through to future hedge prices. In addition, the returns of that generator are exposed to the uncertainties and risks of the spot market and their returns will be more volatile. It is doubtful that the generator will remain so exposed to the spot market, with the implication being they will increase their contract position to stabilise their returns. The

[162] The approach thus places restrictions on the basic Cournot model, by imposing price-taking behaviour on N -1 firms. The Nth firm, in order to maximise profits, bids spot prices that satisfy, for each half-hour of the day, the equation:

$$(P-MCj)/P = -1/ej(p)$$

where MCj denotes the marginal cost of generator j, and –1/ej(p) measures the inverse elasticity of residual demand facing generator j. (This is simply a reformulation of equation 1 above for an individual firm).

resulting increase in contract position will then erode the generator's ability to raise the spot and, hence, the contract price.

While higher and more volatile spot market returns might initially encourage other generators to reduce their contract cover and mimic the uncontracted strategy, this collective shift lowers the risks for each by aligning their market exposure. With multiple uncontracted generators, similar bidding behaviour becomes more likely. However, there will be powerful incentives for the uncontracted generators to defect and restore their contracted position because contract buyers will place a higher value on the (lower) remaining supply of contracts. The appeal of more stable returns and higher contract premiums is likely to prompt a return to greater contract coverage, ultimately restoring market equilibrium.

Key drawbacks of this approach include:

- Requiring all but one firm to be treated as price takers is a severe restriction to the underlying Cournot model. No guide is provided as to why any particular set of firms should be treated as the competitive fringe, and why only one particular firm should be a monopolist pricing on a residual demand curve. Therefore, the restriction risks being arbitrary.[163]
- It relies on historical data and the estimation of participant's response to historic constraints in pre-defined geographic markets. Therefore, while it may provide insights into the incentives and ability an individual generator may have had to bid up the spot price in specific time periods, it does not necessarily provide an understanding of whether market power can be exercised in the long run.
- It has significant computational demands. An alternative approach, therefore, is to use a Supply Margin Approach (SMA) or Pivotal Generator Analysis. A pivotal generator is one that is required to operate to meet demand. If a generator is required to meet demand, and in light of the price inelasticity of demand for electricity, that generator is no longer a price taker and it can offer its capacity at a mark-up knowing it will be dispatched at the inflated price (hence the relationship to the Lerner Index). SMA style measures can take account of contracted positions (which reduces the incentive to withdraw capacity).

11.2.5 Barriers to entry

The competitiveness of a market is fundamentally related to the extent of barriers to entry – that is, the obstacles that make it technically difficult and/or uneconomic for a new participant to enter a market to take advantage high prices, and is entering the market they make it more competitive. If there are barriers to entry the market will be competitive and vice versa.

There are four main categories of entry barriers that could be considered:

- **Legal/regulatory barriers** – these are things like laws and regulations that stifle entry into a market and can include the time and costs or obtaining the necessary licenses and approvals to operate in a market, difficulty in obtaining access to intellectual property necessary to operate in a market. These barriers also include regulatory compliance costs and bureaucratic inertia that can frustrate entry.

[163] Indeed, in the context of electricity generation, the assumption that all but one firm are pure price takers seems inconsistent with observed experience. It is safer to assume that at least some rival generators are liable to change their output in response to output decisions by other generators (i.e. at least some generators have a reaction function), and are likely to have incentives to compete away the extra gains a generator may try and appropriate by reducing its output.

- **Economic barriers** – these barriers include the high costs of entry, whether existing participants have the benefit of sunk costs and economies of scale which makes it difficult for a new entrant to be cost competitive.
- **Technological barriers** – these barriers include having monopoly access to important factor markets (e.g. specialised labour and capital) and exclusive or priority access to critical technology and business systems necessary to compete.
- **Strategic barriers** – these barriers include things like market presence (brand awareness), established advertising and promotion channels and a customer base that allows producers to price discriminate to frustrate a new entrants' marketing campaign.

These barriers exist for electricity generation and retailing.

11.3 Current market

Market monitoring as undertaken by the Electricity Authority involves:

- Determining if the observed market performance is consistent with a well-functioning and disciplined market, and is to the long-term benefit of consumers
- Review previous initiatives to assess if they're working as planned
- Checking if long term opportunities and incentives for efficient entry, exit and investment and innovation in the market are occurring
- Checking if industry participants are developing and operating the electricity system in an efficient manner to manage both security and reliability of our electricity supply, and
- Checking whether industry participants are complying with the Code.

Data and analytical tools that the Electricity Authority relies on to monitor the market includes:

- Developing weekly trading conduct reports and quarterly market performance reviews
- Conducting in-depth reviews and studies of particular topics
- Tracking and reporting on final prices, retail market share and consumer switching[164]
- Maintaining databases and making analytical tools available
- Assessing offers and prices to check participants' compliance with the trading conduct rule (Box 6)

Box 6: NZ's new trading conduct rule (clause 13.5A of the Code)

In June 2021, the EA implemented a new rule for participants in the electricity market to clarify expected behaviours in the wholesale electricity market (spot market only) and prevent suppliers from taking advantage of situations where the system relies heavily on one or a small number of suppliers. The new rule requires participants to ensure that their offers reflect the offers that would be made in a competitive market. This new rule replaced the previous High Standard of Trading Conduct (HSOTC) provisions that were criticised for being too vague and unworkable in nature.[165] [166]

[164] https://www.emi.ea.govt.nz/

[165] https://www.tonybaldwin.co.nz/publications/February%202020%20Initial%20Proposal.pdf

[166] https://www.meridianenergy.co.nz/public/Investors/Reports-and-presentations/Submissions/MDAG-HSOTC-submission.pdf?

EA's market monitoring team's step-by-step approach to monitoring the new trading conduct rule involves:

- Step 1: Identify trading period where the spot price looks inconsistent with underlying conditions by leveraging one or more of these analyses:

(a) an interactive indicator dashboard;

(b) a model of final price to see when actual prices deviate from expected prices (based on supply and demand conditions) and;

(c) a model of costs (including opportunity costs, scarcity pricing) to produce values that EA can use to compare to spot prices.

- Step 2: Once the relevant trading periods have been identified, EA will study the offers in that period to further understand the reasons behind the offers. The approach will likely include comparing offer prices to economic costs. To deal with the uncertainty associated with estimates of economic cost, EA will use sensitivity analysis by producing a range of estimates.

- Step 3: Once the steps above have been carried out, the EA may seek an explanation from the parties involved and/or allege (formally report) a breach of Code

Source: https://www.ea.govt.nz/documents/2160/Market_monitoring_new_trading_conduct_rule.pdf

More broadly, the Electricity Authority monitors compliance in the market by adopting a risk framework (reviewed every 2 years) that prioritises monitoring of high-risk provisions in the Code, Act and regulations. The Authority developed a compliance monitoring framework that informs its annual monitoring program. Policies and procedures sit under the Compliance Strategy for specific compliance activities, such as participant registration, participant auditing, education, monitoring, investigation, domestic and small business consumer protection and enforcement. Figure 55 sets out the relationship between different elements of the Electricity Authority's compliance approach.

Figure 55: Relationship between the Compliance Strategy, Compliance Monitoring Framework, and Compliance Monitoring Procedure

Source: https://www.ea.govt.nz/documents/890/Compliance_monitoring_framework.pdf

The Electricity Authority has also undertaken targeted reviews on conduct and performance in the wholesale electricity market. One such review was undertaken in 2021 to investigate

outcomes in the wholesale market since the Pohokura outage in 2018.[167] The trigger being a sustained increase in average spot prices since that time. The approach the Authority took to this review was to apply the 'structure, conduct, and performance' approach to competition analysis that we introduced in Section 5.3 of this report. The finding from the Electricity Authority in this review was that it could not make a firm conclusion on the driver of price increases, but observed some evidence of an increased incentive for generators to exercise market power. It also noted there are factors that have delayed investment in recent years, including uncertainty about the Tiwai Point Smelter.[168] Importantly, the Electricity Authority identified a lack of available data as a constraint on its ability to reach firm conclusions, stating:[169]

> *It is not possible to definitively conclude whether all of the increase in prices is due to underlying conditions, including uncertainty about future gas supply from existing fields, or if some of the increase is due to prices not being determined in a competitive environment. This is because, given the data available to the Authority, it is difficult to account perfectly for all underlying conditions.*

11.4 Our assessment

11.4.1 Framework for market monitoring

Without auditing the actual analysis undertaken by the Electricity Authority with respect to the framework adopted for market monitoring, we have to rely on considering if the process it takes and analysis it does appears appropriate. While this does not tell us if the quality of the analysis is sufficiently robust, we have found that the Electricity Authority's overarching framework to market monitoring is broadly consistent with international best practice. However, it could improve its collaboration with other market institutions.

Specifically, the Authority:

- Adopts a **risk-based framework** to monitor compliance with the Code, Act and regulations by prioritising high-risk provisions. The objective being to more effectively allocate limited resources. This is consistent with the approach taken by other regulators, such as the ERA in Western Australia, which also relies on a risk-based approach. ERA prioritises WEM monitoring into three categories:[170]
  - Mandatory: Areas the WEM Rules mandate that the ERA must monitor.
  - Risk-based: Areas the ERA has identified as requiring monitoring from the risk assessment process.
  - Trend-based: Areas the ERA has decided to prioritise for monitoring based on its observations of the market.
- Aims to employs a **data-driven approach** to create performance metrics and analytical tools for assessing market performance. Regulators in Australia, the UK and the US also adopt a highly data driven approach. We note, however, in Texas US the ERCOT outsources the task of overseeing the Texas WEM to independent economic consultants to form an Independent

[167] Electricity Authority, 'Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market Since the Pohokura Outage in 2018, 15 November 2021.

[168] Electricity Authority, 'Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market Since the Pohokura Outage in 2018, 15 November 2021, p.iv.

[169] Electricity Authority, 'Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market Since the Pohokura Outage in 2018, 15 November 2021, p.ii.

[170] https://www.erawa.com.au/cproot/24375/2/GB-SUB-77-2025-Attachment-2-Monitoring-Protocol-v7-0-WEM-Procedure-clean-version.PDF cl 3.2.1

Market Monitor (IMM) team. We do not think this approach is necessary, and undertaking this activity in-house with external support where needed ensures the regulator has strong market knowledge.

- Implements **regular market review reporting**, including on a weekly and quarterly basis. This exercise is typically regarded as best practice to ensure transparency and accountability. For example, Germany's Bundesnetzagentur agency similarly conducts annual surveys and publishes reports to ensure transparency in the electricity market. The Bundesnetzagentur is required to publish a report annually on the results of its monitoring activities, conducted in the performance of its regulatory tasks in the electricity and gas sectors, most notably to create transparency in the markets.[171]

While we think broadly the Authority adopts a robust approach to market monitoring, we think New Zealand could benefit from **enhanced collaboration** with other agencies and market participants, such as the System Operator. For instance, in Australia, the Australian Energy Market Operator has obligations to support the Economic Regulation Authority in Western Australia in carrying out market monitoring functions by providing and undertaking analysis of the Market Surveillance Data Catalogue[172] and assisting in monitoring market behaviour, such as during market behaviour investigations.[173]

Ofgem in Great Britain explicitly incorporates collaboration with customer advocate groups (Citizens Advice) into its market monitoring efforts, by working closely with customers to assess electricity supplier's adherence to customer service principles and gain insights into consumer experiences with suppliers and on broader energy issues. While the Electricity Authority similarly conducts annual surveys of residential households to gauge customer perceptions of the Authority's performance in achieving its statutory objectives, the results do not explicitly contribute to the Authority's market monitoring efforts. Nevertheless, conducting annual customer surveys which have also expanded to include questions about customers' awareness of Electricity Authority's Customer Care Guidelines, [174] reflects Electricity Authority's growing focus on customer-centric oversight. We note that the Energy Competition Task Force is a joint process between the Commerce Commission and Electricity Authority, and this sort of collaboration should be commended.

11.4.2 Application of market indicators

The basic electricity market monitoring that currently exists is sufficient to ensure compliance but much more needs to be done by the Electricity Authority to develop and apply approaches to understand and monitor market competitiveness at both the wholesale and retail level. Indeed, requiring the Authority to adopt certain market power tests because they are used in other jurisdictions is not sufficient to truly understand competitive dynamics. Instead, we believe much more sophistication is required for market monitoring in New Zealand, this is particularly the case given the material changes that are being proposed in response to perceived market power issues.

Structural approaches have been used as a screen for market competitiveness. They have the advantages of being relatively clear cut, with set threshold values, and having relatively low computational requirements. However, they suffer from the fact that they are indirect tests of

[171] https://www.bundesnetzagentur.de/EN/Areas/Energy/DataCollection_Monitoring/start.html

[172] The Market Surveillance Data Catalogue identifies data to be compiled concerning the market and is provided to the ERA.

[173] https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/monitoring-the-effectiveness-of-the-market

[174] https://www.consumer.org.nz/articles/electricity-authority-s-consumer-care-obligations-what-you-need-to-know

market power, as they do not provide information on price and output changes, nor do they model the strategic interaction between market participants. They may therefore fail to detect the opportunities generators may have to exercise market power, which may occur over specific, and usually limited, time-periods.

Residual demand analysis is based on extreme restrictions to the underlying Cournot model. To the extent that these restrictions are not validated, they are liable to lead to biased and/ or spurious measures of market power. Setting aside these problems, the approach may help, on the basis of historic data, to identify when the exercise of market power is made more likely owing to lower levels of price-elasticity of demand. However, this analysis is based on historic data within pre-determined geographic markets, and does not provide a guide to whether or not market power can be manifested through sustainable manipulation of price levels, as opposed to a transient ability to manipulate the spot price. Moreover, residual demand analysis involves a higher computational load. An alternative that overcomes some of the drawbacks of residual demand analysis is pivotal analysis. This involves lower computational load, can be used on a forward-looking basis and can account for the impact of hedging contracts on behaviour. However, again, this is only sufficient as a screen and more detailed and sophisticated analysis is needed.

In terms of assessing long-term measures of market power, the Authority should be systematically identifying barriers to entry for each level of the market. Monitoring should be oriented towards identifying the presence and extent of these barriers and tracking over time whether entry is becoming easier with changes in the market rules, or harder, due to the changing nature of the entry barriers.

While the Electricity Authority has been collecting contract data for a number of years, they do not have all the data they need to make an appropriate assessment of the contract position of the generators and they have not been routinely analysing the contract data they have been collecting. It is also unclear to us whether the Electricity Authority has an adequate knowledge of how to consider the risks of hedging and how this affects the analysis of market competitiveness. Indeed, it is our view that if there was a more sophisticated understanding of how the wholesale and retail market interacts through hedging, the Competition Taskforce, which included the Electricity Authority, would not have supported the so-called level playing field proposal.[175] While the name of this proposal may leave the public with the impression that the proposed changes will represent an improvement over the existing arrangements, it is our strong view (as explained in 5.4.2) that the proposal will result in price rises for most customers. We accept that the champions of this level playing field proposal, which includes the independent retailers and gentailers, will enjoy an improvement to their margins, which is why they promote this proposal, but this change will be at the expense of all electricity customers.

11.5 Our recommendations

11.5.1 Transpower should provide more support for market monitoring

While we believe that the Electricity Authority's current approaches to market monitoring and compliance broadly align with regulatory best practices, we recommend that Transpower, the system operator, play a more significant role in supporting the Authority's market monitoring

[175] Competition Taskforce (2025) "Energy Competition Task Force looks to level the playing field between the gentailers and independent generators and retailers", 27 February, Weblink: https://comcom.govt.nz/news-and-media/media-releases/2025/energy-competition-task-force-looks-to-level-the-playing-field-between-the-gentailers-and-independent-generators-and-retailers#:~:text=The%20Energy%20Competition%20Task%20Force,participants%20in%20the%20electricity%20market.

functions. At present, the Electricity Industry Participation Code 2010 (Code) does not explicitly outline Transpower's role in supporting the Authority in this capacity, unlike the arrangement between the ERA and AEMO. In the Western Australian electricity market, AEMO is explicitly tasked with compiling and analysing data for the Market Surveillance Data Catalogue, which AEMO provides to the ERA to facilitate effective market monitoring.[176]

In contrast, the Electricity Authority is tasked with undertaking its market monitoring, without formal obligations in the Code on Transpower to assist (noting that Transpower does provide some level of support to the Authority).[177] Although the Authority already currently relies heavily on data analytics tools (e.g., Electricity Market Information website to track prices and other market performance indicators) and is transparent through the regular publishing of reports on market performance, we propose to leverage Transpower's specialised expertise as a system operator and access to real-time operational data to further improve the Authority's market monitoring capabilities. By leveraging Transpower's position as the system operator, the Authority could gain more unique insights into market participants' compliance with market rules, which might otherwise be unavailable.

As such, we recommend amending the Code to include a provision requiring the system operator (Transpower) to maintain a data catalogue similar to AEMO's Market Surveillance Data Catalogue,[178] updating it as necessary, to ensure that the Authority has access to the to market data and analysis needed to more effectively monitor the market.

We note, however, that it remains important that the Electricity Authority retains as much independent capability as it can. The sharing of data should not mean that the Electricity Authority becomes overly dependent on Transpower for market monitoring purposes.

11.5.2 The Electricity Authority needs to adopt a more sophisticated approach to competition analysis

While the Electricity Authority could pay more attention to developing and analysing a range of competition metrics as described above, it is our view that the biggest improvements can be made by developing a more sophisticated approach to assessing market power and identifying and measuring barriers to entry so the Authority can determine where to direct pro-competitive changes to the market.

We have emphasised throughout this section of the report about the importance of paying particular attention to the contracted positions of generators when considering the competitiveness of the market. In considering this contracted position, it is also important to have regard to the virtual contracts that exist between the generation and retailing arms of the gentailers. When a gentailer serves customers under a fixed price retail contract the cashflows and cashflow risks are equivalent to when an explicit hedging contract exists between a separate generator and retailer. This means that the customer load served under fixed price retail contracts should be treated as an equivalent hedging contract. The Authority therefore also has to have a good data on customer load at a granular level and the nature of the retail contracts that are used by the retailers (i.e. are they fixed or floating prices).

To support this initiative, it is essential that the Electricity Authority improve their collection of contract data and capability for analysing this contract data so that they can make an appropriate assessment of the contracted position of participants. This contract information can

[176] https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/monitoring-the-effectiveness-of-the-market

[177] Transpower System Operator Strategic Plan, June 2024 p13

[178] WEM Rules, cl.2.16 Monitoring the Effectiveness of the Market

then be incorporated, together with data about the technical network and generator constraints, into the competition measures discussed above to help the Authority monitor the competitiveness of the market.

A Dry year risk appendix

A.1 Introduction

This appendix:

- expands on the international approaches to managing security of supply set out in section 4.6, and
- provides further information on the current state of gas supply in New Zealand.

A.2 International approaches to capacity

Capacity planning for system reliability is a critical function in power systems worldwide, ensuring that electricity supply meets demand under varying conditions. Different jurisdictions adopt diverse approaches, ranging from centralized, government-led planning to market-based mechanisms that rely on price signals and competitive auctions. We have reviewed several markets with similar features to New Zealand. Specifically, Brazil, Columbia, California and Texas.

A.3 Brazil

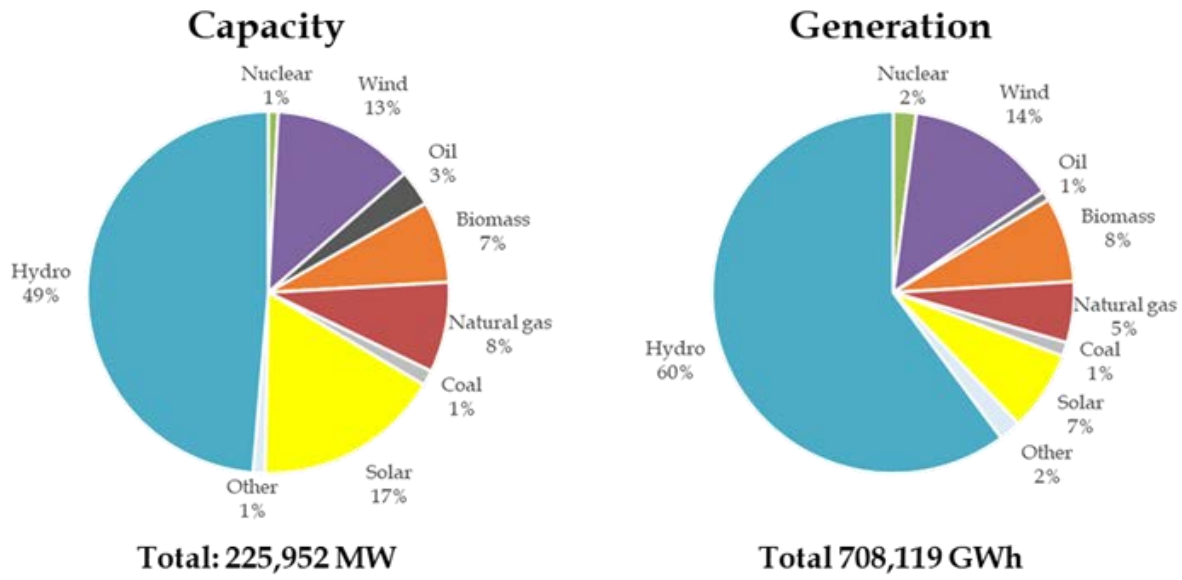
Market overview

The initial restructuring of the power sector in Brazil started in 1995, with the privatization of distribution companies, where investors in the distribution companies were granted public service concessions with tariffs set through price cap regulation. Within a three-year span (1995-1998), the main regulatory and market institutions were founded, and an initial round of privatization of generating companies was carried out. This was followed in 1999 by new transmission facilities and new hydro concessions auctions.

Despite these changes, generation capacity expansion lagged far behind demand and this imbalance, combined by a severe drought, led to an electricity crisis in 2001–2002. The crisis prompted a sweeping sector overhaul: in 2004 the government implemented a new model centred on competitive auctions for long-term power contracts (Law 10,848/2004), with the first such auction held in December 2004. Today, Brazil's capacity planning revolves around this auction-based system, underpinned by a strengthened institutional framework: a dedicated planning agency (Empresa de Pesquisa Energética, "EPE") and active oversight by the Ministry of Mines and Energy ("MME") and the regulator (Agência Nacional de Energia Elétrica, "ANEEL").

Brazil has one of the world's largest power sectors, characterized by a predominantly renewable generation mix and a fully interconnected national grid (Sistema Interligado Nacional, "SIN") operated by the ONS (Operador Nacional do Sistema Elétrico). In 2023, Brazil had over 225 GW of installed generating capacity, dominated by hydro (49%), followed by solar (17%) and wind (13%) (see Figure 56).

Figure 56: Installed capacity and generation by fuel type, 2023



Source: EPE

Brazil's electricity market is divided between a regulated segment (Ambiente de Contratação Regulado, "ACR"), where distribution companies procure power for captive consumers through auctions, and an unregulated market (Ambiente de Contratação Livre, "ACL"), where large consumers and traders can sign bilateral contracts directly. The unregulated market (ACL) is expanding and currently accounts for 39% of the market.[179]

How it identifies resource needs

Brazil determines its future resource requirements through integrated long-term planning and rigorous reliability assessments led by government agencies. The cornerstone of this process is the Energy Expansion Plan (Plano Decenal de Expansão de Energia, PDE) prepared annually by EPE under guidelines from the MME.[180] The PDE provides a detailed outlook of demand growth projections, generation expansion options, and system adequacy assessments over a 10-year horizon.[181]

The PDE modelling explicitly considers the hydrological variability by simulating the hydro system over many inflow scenarios to ensure that the expansion plan meets energy needs in dry sequences. Each potential new project (whether a thermal plant, wind farm, etc.) is evaluated for its contribution to firm energy and firm capacity at peak.[182] In essence, the "resource need" is defined in terms of ensuring enough firm energy and firm capacity to keep the loss-of-load risk under 5%. If a shortfall is projected – for example, if demand growth outstrips supply under adverse conditions – the plan will flag the need for additional capacity by a certain date.

Once the ten-year plan identifies resource needs, it serves as a guide for investment decisions and policy actions.

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179 CCEE. Mercado Livre. Accessed on March 5, 2025. https://www.ccee.org.br/mercado-livre-acl

180 EPE. PDE 2034. September 2024. www.epe.gov.br/sites-pt/publicacoes-dados-abertos/publicacoes/PublicacoesArquivos/publicacao-804/topico-737/Relat_rio_PDE_2034_e_Anexo_II___Proposi__o_de_Diretrizes_para_elabora__o_do_PDE_2035.pdf

181 MME. Supply Reliability Criteria (Critérios de Garantia de Suprimento). November 2019. www.gov.br/mme/pt-br/arquivos/criterio-de-suprimento-v2.pdf

182 Ibid.

Tools and interventions to address shortfalls

Brazil ensures resource adequacy through long-term energy auctions, firm capacity mechanisms, and shorter-term contracts, primarily managed by ANEEL (Regulator) and MME. By design, 100% of the load must be contracted, whether a consumer is in the regulated or unregulated market. Distribution companies serving captive consumers must contract 100% of peak load via centralized auctions which may be of new or existing energy. Unregulated customers must secure their energy needs through bilateral agreements.

New energy auctions are held typically with 3 to 6 year lead times (A-3 to A-6), securing long-term Power Purchase Agreements ("PPAs") lasting 15-30 years, depending on technology.[183] Recent auctions awarded 30-year contracts for hydro, 20-year for wind and biomass, and around 15-20 years for thermal plants. Existing energy auctions are meant to address shorter-term supply gaps or delays (A-1, A-2 lead times), contracting plants typically for 1-5 years; these auctions provide flexible, higher-priced interim solutions.

A critical recent development is Brazil's introduction of Capacity Reserve contracts in 2021, explicitly procuring dispatchable capacity separate from energy, initially limited to thermal plants.[184] The inaugural December 2021 auction secured several gigawatts through 15-year contracts starting in 2026. Upcoming auctions are evolving towards technology-neutral approaches, considering storage, demand response, and firm renewables, and incorporating shorter-term contracts to address specific reliability gaps identified by planners (such as a 5.5 GW deficit noted by PDE 2034). Brazil is thus progressively unbundling capacity from energy.

Brazil's regulatory framework imposes strict penalties on auction winners who fail to fulfill their obligations. Energy auction winners must complete project construction and start commercial operation by the agreed deadline, maintaining compliance with ANEEL and ONS regulations. They must deliver contracted energy volumes or ensure availability (for dispatchable plants), with penalties for delays, underperformance, or failure to supply, including fines (calibrated by severity of non-compliance), contract termination, forfeiture of financial guarantees, and potential exclusion from future auctions.[185] Capacity auction winners must ensure their plants are available and dispatchable when requested by ONS. Compliance is monitored through performance audits, and failures to meet dispatch requirements or availability obligations lead to financial penalties, revenue reductions, or contract termination.[186] Frequent non-compliance can result in exclusion from the market and regulatory sanctions imposed by ANEEL.

A.4 Columbia

Market overview

Colombia undertook a restructuring of its energy market following the severe energy shortage and rolling blackouts caused by the 1991 El Niño-related drought. In December 1992, the national government reorganized the Ministry of Mines and Energy, dissolving the National Commission of Energy (the regulator) and establishing two specialized administrative units: the Commission of Energy and Gas Regulation ("CREG") and the Commission of Energy-Mining

183 The International Energy Agency (IEA). Brazil Renewable Energy Auctions. August 26, 2015. https://www.iea.org/policies/5750-brazil-renewable-energy-auctions

184 IEMA. According to an IEMA bulletin, the first reserve capacity auction restricts hiring only to thermal power plants. December 2021. https://energiaeambiente.org.br/according-to-an-iema-bulletin-the-first-reserve-capacity-auction-restricts-hiring-only-to-thermal-power-plants-20211217

185 ANEEL. Criteria for Imposing Penalties on Agents in the Electricity Sector. June, 11 2019. https://www2.aneel.gov.br/cedoc/ren2019846.html

186 MME. https://www.gov.br/mme/pt-br/assuntos/secretarias/sntep/reidi/portarias/2022/08-agosto/portaria-gm-674-2022-reidi.pdf

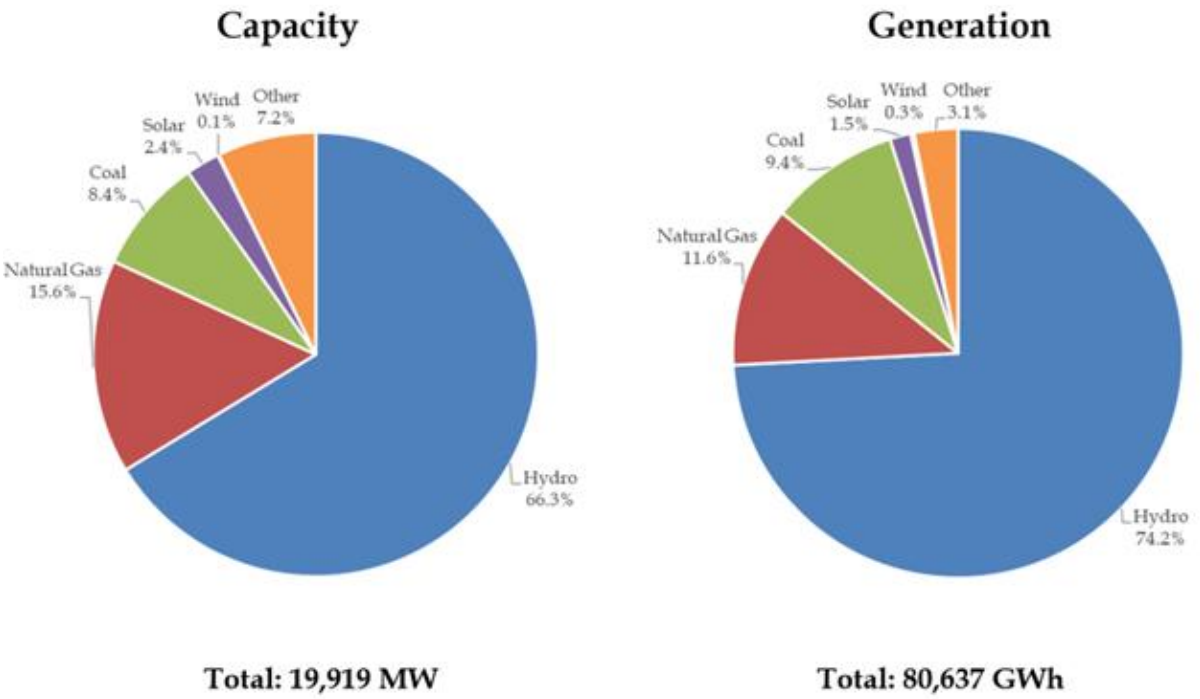
Planning ("UPME"). This restructuring continued in 1994 with the enactment of the Law of Public Utilities and the Law of Electricity, which laid the foundation for the current regulatory framework governing public utilities, including the electricity sector.[187]

All resources connected to the Colombian grid must participate in the wholesale market, as physical bilateral energy contracts are not permitted. Instead, like in most Latin American countries, bilateral contracts function as financial contracts for differences ("CfDs"). The market is regulated by an independent regulatory commission, while the Ministry of Energy is responsible for formulating energy policy. The state-owned company Interconexión Eléctrica S.A. ("ISA") acts as system operator through its subsidiary XM. There are minimal restrictions on thermal or hydro plant bids, and vertical integration is allowed.[188]

XM operates the national transmission grid and administers the wholesale electricity market in Colombia. The XM-controlled area covers 47% of the country's total area and 93% of the population,[189] and contains 99.996% of the country's generation. Areas of the country not covered by the transmission grid are mainly dependent on diesel generators.[190]

Most of Colombia's power generation is comprised of hydroelectric resources, with natural gas and coal as a backstop when dam levels decrease due to droughts.[191].

Figure 57: Installed capacity and generation by fuel type, 2023



Source: XM Colombia. Reporte Integral de Sostenibilidad, Operación y Mercado 2023, May 2024.

187 Ley 142 de 1994 and Ley 143 de 1994.

188 XM. Estructura del mercado eléctrico colombiano. 2025. https://www.xm.com.co/transacciones/registros/registro-agentes-y-contactos/estructura-del-mercado

189 IPSE. Caracterización Energética de las ZNI. 2024. https://ipse.gov.co/cnm/caracterizacion-de-las-zni/

190 Ibid.

191 Reporte Integral de Sostenibilidad, Operación y mercado 2023. May 2024. https://www.xm.com.co/sites/default/files/documents/Reporte%20Integral%20de%20Sostenibilidad%2C%20Operaci%C3%B3n%20y%20Mercado%202023_XM.pdf

How it identifies resource needs

The UPME prepares semi-annual reports on electricity demand projections with a 15-year horizon. The latest projection, published in July 2024, covers the period 2024-2038 and considers multiple key factors, such as economic growth, changes in consumption patterns, and climatic conditions. Among these, the El Niño phenomenon plays a crucial role, as Colombia relies heavily on hydroelectric generation. The country's history of blackouts prior to the restructuring of the electricity sector highlights the importance of anticipating variations in energy supply due to climatic factors.[192] These reports are designed to support decision-making by multiple government entities.[193]

CREG uses the UPME's reports and projections to conduct an analysis of the firm energy balance to determine the need for new auctions. Their assessment focuses on the availability of energía firme (firm energy), which refers to generation that can be reliably produced 24/7, as well as demand forecasts. However, they do not target a specific reliability margin when making these decisions. Instead, both CREG and the Ministry of Energy and Mines provide broad justifications, stating only that they have analysed firm energy supply and demand before reaching a conclusion on whether to proceed with an auction.[194]

This commission assesses medium-term energy supply and demand, considering both the current availability and the projected generation capacity.[195] Additionally, CREG's analysis includes monitoring the evolution of energy demand in relation to the projections made by UPME. The comparison between expected demand and available generation capacity helps identify potential deficits and determine whether new auctions are necessary. Likewise, the transmission capacity assigned to generation projects is considered to assess whether the existing infrastructure is sufficient to meet the system's future requirements.[196]

Tools and interventions to address shortfalls

Reliability charge

The reliability charge (cargo por confiabilidad) is one of Colombia's key regulatory and financial instruments designed to enhance long-term energy security. This regulatory mechanism was established in 2006 by CREG to ensure the continuous supply of electricity during periods of scarcity, particularly during the El Niño phenomenon, which significantly reduces hydroelectric generation.[197] The system is based on Firm Energy Obligations (Obligaciones de Energía Firme, "OEFs") which are commitments made by power generators to guarantee the availability of electricity when needed.

These OEFs are allocated through an auction process managed by the Administrator of the Commercial Exchange System (Administrador Sistema de Intercambios Comerciales, "ASIC"), ensuring a competitive and transparent selection of energy providers who can contribute system reliability. For these purposes, the required OEFs are auctioned among generators to cover the

192 UPME. Proyección de la demanda de Energía eléctrica y Potencia máxima. 2024-2038. July 2024. https://www1.upme.gov.co/DemandayEficiencia/Documents/Proyeccion_demanda_energia_electrica_y_potencia_maxima_rev_jul2024.pdf

193 UPME. Ficha Metodológica. April 30, 2020. https://www1.upme.gov.co/DemandayEficiencia/Documents/Ficha_Metodologica_PDE.pdf

194 CREG. La CREG está revisando el balance de energía firme para determinar si es necesario realizar nuevas subastas. July 2024. https://creg.gov.co/publicaciones/15749/la-creg-esta-revisando-el-balance-de-energia-firme-para-determinar-si-es-necesario-realizar-nuevas-subastas/

195 Ibid.

196 La República. La CREG estudia balance para determinar si se necesitan nuevas subastas de energía. July 25, 2024. https://www.larepublica.co/economia/la-creg-estudia-la-posibilidad-de-realizar-nuevas-subastas-3915292

197 XM. Cargo por confiabilidad. n/d. https://www.xm.com.co/transacciones/cargo-por-confiabilidad/descripcion

system demand. The remuneration for generators is settled and collected by ASIC and paid by ratepayers through the tariffs charged by retailers. Given Colombia's heavy reliance on hydropower, this mechanism plays a crucial role in maintaining grid stability and preventing energy shortages. The number of OEFs is calculated based on a parameter CREG calls target demand, which represents the total domestic energy demand projected by the UPME for each month of the planning period. This demand is adjusted by a percentage determined by CREG and reduced by the energy already covered through previous OEF allocations and the firm energy from non-centrally dispatched plants.[198]

Generators that are awarded OEFs are paid a fixed amount in USD per kilowatt-hour, paid monthly for the duration of their obligation period, regardless of whether the energy is physically delivered to the system. This approach ensures that power plants maintain sufficient generation capacity and remain operational during times of crisis, encouraging investment in both thermal and renewable energy generation. Failure to comply with Firm Energy Obligations (OEF) in Colombia results in various penalties. Non-delivery of OEFs can result in multiple penalties. If non-compliance leads to energy rationing, the resulting financial balances are distributed among affected retailers, who must return these amounts to end users as lower restriction costs. Additionally, generators that fail to commission their plants on time may lose their assigned OEF and associated remuneration.[199]

In summary, the reliability charge serves as an instrument to enhance both short- and long-term energy security. In the short-term, it encourages thermal generators to be able to generate capacity immediately in case of hydrological deficiencies. In the long-term, this mechanism acts as a safeguard against market volatility and extreme weather events that could otherwise threaten the country's electricity supply.[200]

Energy expansion and renewable energy auctions

In Colombia, energy expansion auctions (subastas de expansión de energía) are a mechanism regulated by CREG to ensure the reliability of the country's electricity supply. In these auctions, generation companies, investors, and ongoing projects are invited to increase their generation capacity and guarantee energy availability during critical periods.[201] Under this system, registered power marketers purchase generation capacity offered by generation companies. Only market agents certified by the UMPE can participate, as this allows them to connect to the National Interconnected System (“SIN”) and ensure electricity delivery on the specified dates. The firm energy mechanism in these auctions means that awarded bidders have a contractual obligation to supply the committed energy within the designated period. There are clauses that outline penalties in case of non-compliance.[202] Similar to the OEF mechanism, the procured quantity is determined based on the target demand parameter, which corresponds to the UPME's projected national energy demand for each month.[203]

198 CREG. Documento CREG-085. December 8, 2007. < https://gestornormativo.creg.gov.co/gestor/entorno/docs/resolucion_creg_0085_2007.htm

199 CREG. Resolución 71 de 2006. October 6, 2006. < https://gestornormativo.creg.gov.co/gestor/entorno/docs/resolucion_creg_0071_2006.htm

200 Clifford Chance. Colombia: Cargo Por Confiabilidad. February 2019. https://www.cliffordchance.com/briefings/2019/02/colombia_cargo_porconfiabilidad2019auctio.html

201 Holland and Knight. Nueva subasta para asignación de OEF en Colombia. https://www.hklaw.com/en/insights/publications/2023/02/nueva-subasta-para-asignacion-de-oef-en-colombia

202 Ibid.

203 XM. Resultados subasta CLPE 03-2021. < https://www.xm.com.co/sites/default/files/documents/Informe_Resultados_Nueva_Subasta_2021.pdf

Colombia held its first renewable energy auctions in 2019 to address the challenges of diversifying its electricity generation mix and increasing non-hydro renewable energy participation. The first auction in February 2019 assigned bids between buyers and sellers but failed to award contracts due to unmet competition criteria. However, the second auction in October 2019 successfully awarded around 1.3 GW of wind and solar photovoltaic capacity, marking a significant step toward increasing renewable energy deployment. The auction mechanism allowed for long-term PPAs, ensuring price stability for sellers and reducing exposure to market volatility for buyers.[204] The most recent renewable energy auction, held on February 16, 2024, for the 2027-28 period, successfully awarded 4.4 GW of solar energy and 4.1 MW to a new biomass plant.

CREG incentives for early entry

Starting in 2021, CREG introduced financial incentives to encourage early project operation by compensating projects that begin generating electricity before their full operation date. To this end, payments are provided from the start of partial operation until the project reaches full capacity, with amounts determined based on the investment value ("IAE Inversión") and the costs of operations, maintenance, and administration ("IAE AOM"), weighted according to the capacity in operation.

Additionally, in some cases, an additional percentage is recognized as an incentive, subject to an assessment of its feasibility and authorization by CREG. This percentage is defined based on an analysis of the cost-benefit ratio of advancing the project, considering factors such as cost savings for users compared to more expensive alternatives or potential supply constraints. Projects that meet the established criteria may request a feasibility assessment from UPME.[205]

A.5 California Independent System Operator ("CASIO")

Market overview

CAISO operates the power grid and wholesale electricity market across approximately 80% of California. The remainder of California is operated by local balancing authorities and utilities, such as Imperial Irrigation District, Los Angeles Department of Water and Power, Sacramento Municipal Utility District, Valley Electric Association, Balancing Authority of Northern California, Turlock Irrigation District, PacifiCorp West, Bonneville Power Administration, and Sierra Pacific Power.[206]

An Energy Imbalance Market ("EIM"), launched in October 2014, currently allows CAISO to effectively dispatch generation from sources located in balancing authority areas outside of its footprint. The WEIM has enhanced grid reliability and generated cost savings for its participants. Besides its economic advantages, the WEIM improves the integration of renewable energy, which leads to a cleaner, greener grid.

The Resource Adequacy ("RA") policy framework, launched in 2004, governs the reliability of electric service in California, which effectively creates a bilateral spot market for capacity. Load Serving Entities ("LSE") must procure sufficient capacity to meet their peak load with a reserve margin requirement defined by the California Public Utilities Commission ("CPUC").

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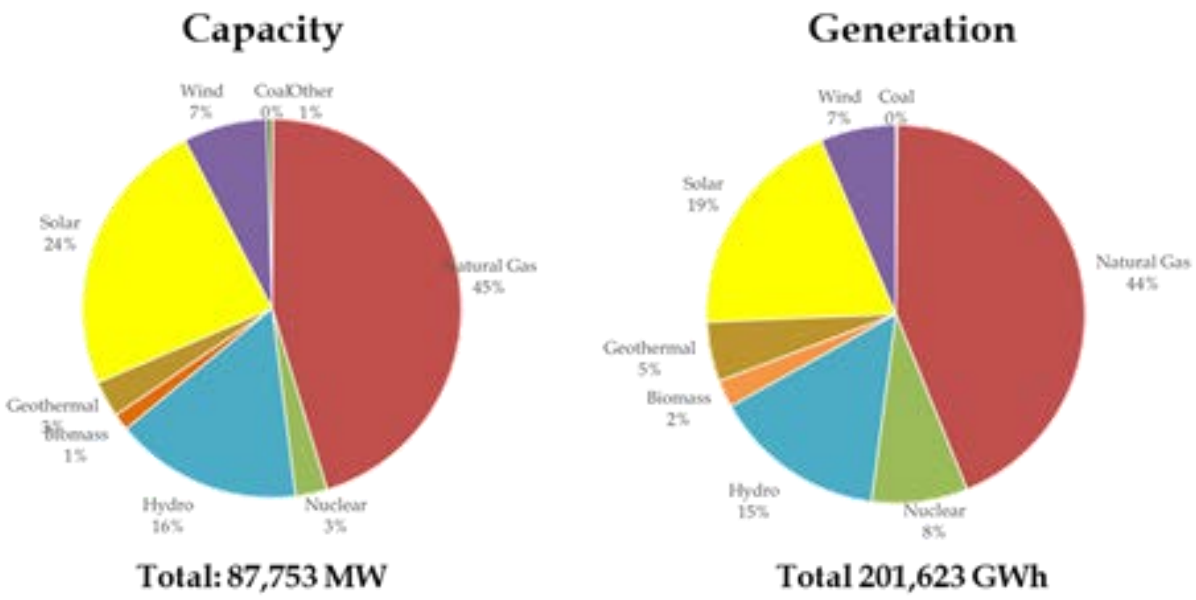
[204] IRENA. Renewable energy auctions in Colombia: Context, design and results. 2021. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/March/IRENA_auctions_in_Colombia_2021.pdf

[205] CREG. Resolución 127 de 2021. January 27, 2021. < https://normas.cra.gov.co/gestor/docs/resolucion_creg_0127_2021.htm

[206] California Energy Commission. Map of Balancing Authority Areas in California. February 26, 2015. http://www.energy.ca.gov/maps/serviceareas/balancing_authority.html

CAISO operates day-ahead and real-time energy markets, as well as various ancillary services markets. As shown in Figure 4 (which excludes out-of-state capacity), California is dominated by natural gas fired facilities, representing 45% of installed capacity. Hydroelectric generation capacity represents 16%, nuclear represents 3%, and renewables (including wind, geothermal, solar, and biomass) represent around 35% of capacity. However, it should be noted that this installed capacity does not include distributed generation, such as residential solar photovoltaic installations, which has developed significantly in recent years. Generation performance follows the same trend but hydroelectric generation fluctuates based on hydrology conditions.

Figure 58: Installed capacity and generation by technology type, 2003



Source: California Energy Commission

How it identifies resource needs

California has an ambitious target to achieve carbon neutrality across its entire economy by 2045.[207] As a result, entities working in the energy sector have incorporated policy and market developments into resource planning, most specifically into demand forecasts and transmission planning.[208] To ensure that these forecasts and plans are successful, the CPUC, the California Energy Commission ("CEC"), and CAISO have agreed, via a memorandum of understanding, to align resource planning, transmission planning and procurement processes.[209] The CEC develops energy demand forecasts. These demand forecasts are then used by the large Investor Owned Utilities ("IOUs") as the basis for their load forecasts and by CPUC for the development of the integrated resource plan, which is then used by CAISO to develop transmission plans.[210] This context provides a useful framework to understand the multiple drivers and entities in play for a power system as large as California's.

While legislative and policy goals are incorporated into the demand forecasts that then lead to resource identification processes for the major electricity stakeholders in the region, reliability also plays an important role in identifying resources for the market. The Business Practice

[207] California Energy Commission 2023 Integrated Energy Policy Report. p. 15.

[208] Ibid, p.2

[209] Ibid, p.3.

[210] Ibid, p.21.

Manual for Reliability Requirements details the general objectives for resource adequacy for CAISO, as well as the general factors used to assess needed resource levels to satisfy reliability. To ensure that the system is reliable, CAISO aims to keep generating capacity exceeding customer demand by an amount that accounts for variables such as planned maintenance, forced outages, variations in weather or demand.[211]

Tools and interventions to address generating shortfalls

In 2004, the CPUC adopted a Resource Adequacy ("RA") policy framework to ensure system reliability and incentivize new resources to come online.[212] The CPUC RA program requires LSEs to procure capacity (RA obligation) to meet the following three requirements:

- System RA: Each LSE provides a load forecast that is then adjusted by the CEC forecast to meet a reserve margin of 17%;
- Local Resource Adequacy: An annual CAISO study is developed that uses the 1-in-10 weather year and the N-1-1 contingency
- Flexible Resource Adequacy: An annual CAISO study that reviews the largest three-hour ramp for each month that is needed to maintain system reliability

LSEs use bilateral contracting for forward capacity procurement.[213] To guarantee that these requirements are met, annual and monthly filings are evaluated by the CPUC.[214] Additionally, CAISO designates Reliability-Must-Run ("RMR") units to generate power to maintain system reliability.[215] CAISO has the right to designate a generating unit as an RMR resource, subject to technical analysis.[216] When it comes to dispatch, RMR resources are required to meet Day-Ahead and Real-Time Availability standards.[217] RMR contracts are paid for by transmission customers.[218]

California also has an incentive program for individual customers to install their own generation, called Self-Generation Incentive Program ("SGIP").[219] The CPUC's SGIP provides incentives to support existing, new, and emerging distributed energy resources. Qualifying technologies include: wind turbines; waste heat to power; pressure reduction turbines; internal combustion engines; microturbines; gas turbines; fuel cells; and advanced energy storage systems.

211 Ibid, p.21.

212 California Public Utilities Commission. *Resource Adequacy Homepage*.

213 California Public Utilities Commission. *2022 Resource Adequacy Report*. May 2024. P. 4.

214 Ibid.

215 California Independent System Operator Corporation. *Fifth Replacement Electronic Tariff*. April 1, 2024. P. 1145.

216 Ibid.

217 Ibid.

218 California Public Utilities Commission. *2022 Resource Adequacy Report*. May 2024. P. 33.

219 California Public Utilities Commission. Self-Generation Incentive Program (SGIP). https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program

A.6 Electric Reliability Council of Texas ("ERCOT")

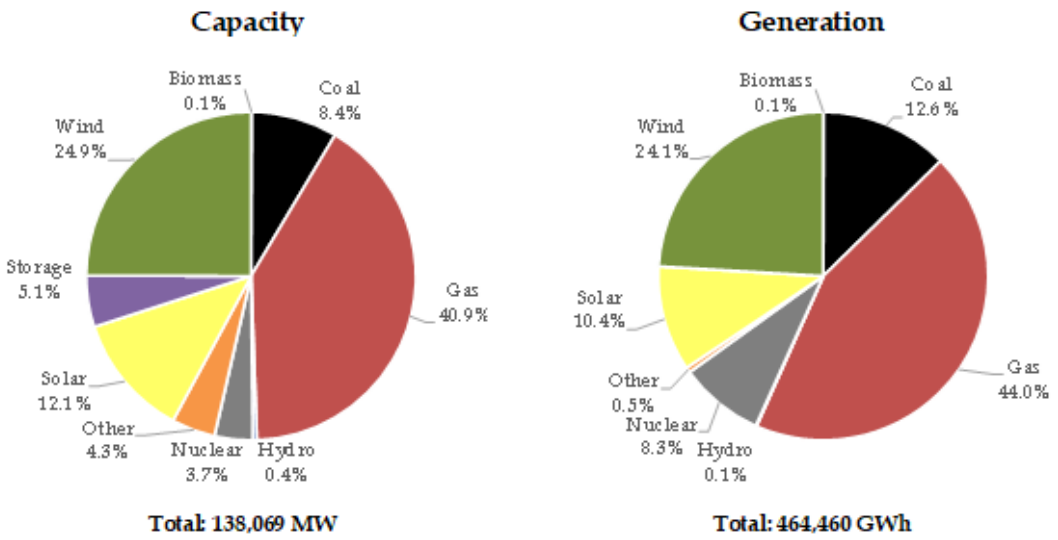
Market overview

ERCOT operates the transmission grid and administers the wholesale electricity market in most of Texas. The ERCOT controlled area covers 75% of the state's total area220 and provides energy to 90% of the state's total load.[221]

Unlike other independent system operators in the United States that are subject to Federal Energy Regulatory Commission ("FERC") oversight, ERCOT operates under the regulation of the Public Utility Commission of Texas ("PUCT"). ERCOT is not synchronously connected with the two major US interstate grid systems, the Eastern and the Western Interconnections, and is thus deemed not to be engaged in interstate commerce. ERCOT operates a nodal real-time energy market and a co-optimized day-ahead energy and ancillary services market, designed to efficiently allocate resources and maintain grid reliability, which is supplemented with hourly reliability unit commitment ("RUC").[222]

As of December 2024, ERCOT has installed generating capacity of over 138 GW – which is dominated by gas-fired capacity with 40.9% (see Figure 59). The next largest component of capacity (in maximum seasonal ratings) is wind (24.9%), followed by solar (12.1%), then coal (8.4%), storage (5.1%), and lastly nuclear (3.7%). Hydro and the remaining fuels constitute a relatively small part of installed capacity currently (4.8%).

Figure 59: Installed capacity and generation by fuel type, December 2024[223]



Source: ERCOT. Report on the Capacity, Demand and Reserves ("CDR") and Fuel Mix Reports, December 2024

220 Other parts of Texas area are served by utilities belonging to the Southwest Power Pool, the Midcontinent Independent System Operator, and the Western Electricity Coordinating Council.

221 ERCOT website. *Quick Facts*. Accessed on February 2025. <https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf>

222 In 2026, this framework will be enhanced by the introduction of Real-Time Co-Optimization ("RTC"). See ERCOT, *RTC+B Task Force Update*. September 13, 2024.

223 Capacity by fuel type has been calculated based on maximum summer and winter ratings. "Other" includes DC Ties, demand response and interruptible load. Synchronized capacity is not considered.

How ERCOT identifies resource needs

ERCOT does not impose a mandatory reserve margin or reliability standard. Instead, the dynamics of the ERCOT market are governed by investment signals generated through market prices, which are influenced by market fundamentals and an administratively established price scarcity mechanism known as Operating Reserve Demand Curve ("ORDC").

However, this does not imply that ERCOT lacks reference values for these metrics. At the request of PUCT, ERCOT has been estimating the Market Equilibrium Reserve Margin ("MERM") approximately every four years since 2014, which reflects the reserve margin that the market is likely to maintain in equilibrium based on projected market conditions. Furthermore, in August 2024, the PUCT also ordered the adoption of a targeted reliability standard, aiming to balance system reliability with cost management amid rising demand.[224][225] These frameworks provide a benchmark for measuring and projecting grid reliability in the ERCOT region, allowing for informed decision-making regarding necessary improvements to meet growing power demands.

ERCOT also issues semi-annual and monthly reports that are used to monitor short and long-term resource adequacy.[226] The Capacity, Demand and Reserves ("CDR") report, which is released in May and December, offers a comprehensive assessment of potential supply resource availability and demand over the next five years. The CDR is also supported by a more detailed risk analysis report called Monthly Outlook for Resource Adequacy ("MORA"). This report functions as an early indicator of the hourly risk that ERCOT may need to issue an Energy Emergency Alert ("EEA") or implement controlled outages to ensure grid reliability during the upcoming two months.

Therefore, to complement the inherent dynamics of an energy-only market, ERCOT has implemented several mechanisms to monitor grid performance, assess potential resource requirements, and recommend market enhancements to mitigate the risk of undesirable events.

Tools and interventions to address shortfalls

ERCOT implements various mechanisms to manage resource adequacy and grid reliability. In the short-term, ERCOT is responsible to engage non-market resources through its RUC process to safeguard the functioning of the power grid. This process, which is carried out on both a day-ahead and real-time hourly basis, is designed to maintain the reliability of the ERCOT system by securing sufficient resource capacity, including ancillary service capacity, at key locations to consistently meet projected system demand. Resources fulfilling RUC obligations are eligible to receive make-whole payments but may also be subject to a claw-back provision.

Additionally, RMR procedures are fundamental in identifying and managing the need for generation units that would otherwise be retired to support grid reliability also in the short-term. An RMR unit is a generation resource that operates under a contractual agreement with ERCOT and would otherwise not be in service, except when required to provide voltage support, ensure system stability, or address local transmission constraints under credible single contingency

[224] PUCT. Public Utility Commission of Texas Adopts Reliability Standard for the ERCOT Market. August 29, 2024. https://ftp.puc.texas.gov/public/puct-info/agency/resources/pubs/news/2024/PUCT_Adopts_Reliability_Standard_for_the_ERCOT_Market.pdf

[225] Going forward, ERCOT is required to conduct reliability assessments every three years, beginning in January 2026, to evaluate whether the system meets the established thresholds and is likely to continue meeting them over the subsequent three years. These assessments will be based on probabilistic simulations, with assumptions and modelling inputs open to stakeholder review and commission oversight. Should the system fail to meet the reliability standard, ERCOT will recommend market design changes to address any deficiencies. These recommendations will be subject to independent review by the market monitor to ensure cost-effectiveness and alignment with the region's long-term reliability goals

[226] ERCOT website. Resource Adequacy. Accessed on March 2025. < https://www.ercot.com/gridinfo/resource>

scenarios. If ERCOT determines that a resource is essential to maintaining system reliability, it may enter into an RMR agreement to provide "out-of-market" compensation to sustain the unit's operation.[227] ERCOT also utilizes a process to evaluate alternative solutions, known as Must-Run Alternatives ("MRA"). Rather than compensating an uneconomic resource to remain online, ERCOT may issue a Request for Proposals to identify and procure alternative resources capable of resolving the identified reliability issues.

Furthermore, ERCOT will implement the new Dispatchable Reliability Reserve Service ("DRRS") in response to House Bill 1500.[228] This ancillary service has been designed to address the increasing uncertainty in ERCOT's real-time market while maintaining flexibility in the design to accommodate future market developments aimed at ensuring resource adequacy. Despite not being implemented yet, this service is expected to significantly reduce the need for out-of-market interventions, such as RUCs, by providing more market-based mechanisms to ensure grid stability during periods of high demand or renewable output variability.

According to ERCOT, there are other short-term solutions to improve resource adequacy. For example, enhancing demand response programs, particularly for residential customers, expanding the Firm Fuel Supply Service ("FFSS") program,[229] and supporting the interconnection of Texas Energy Fund ("TEF") generation projects. Additionally, there are opportunities to improve battery optimization and collaborate with large energy consumers, such as data centers, to strengthen operational flexibility.[230]

In light of the growing demand for dispatchable resources, ERCOT has also started implementing long-term solutions to address future reliability challenges in ERCOT. Established by the Texas Legislature in 2023, the TEF was designed to provide low-interest loans and grants to support the development of new power generation facilities that would enhance the grid's reliability. The PUCT has advanced seventeen of these applications, accounting for nearly 9.8 GW of new generation, to the loan negotiation phase.[231] These projects primarily focus on dispatchable resources, which are critical for ensuring grid reliability, particularly during periods of extreme weather and high demand. However, not all applications were successful. Indeed, one application was rejected as it failed to meet the due diligence requirements, while three winning projects were withdrawn due to equipment procurement constraints, among other matters.[232] In total, the TEF is expected to allocate more than $10 billion in loans and grants over the next decade, with a focus on projects that can come online by 2026.[233] The selection criteria for TEF loans include the ability of the project to improve reliability, reduce the frequency of RUCs, and provide ancillary services, particularly in areas of the grid that are prone to congestion.

ERCOT's comprehensive approach to maintaining grid reliability involves a combination of established processes and forward-looking innovations. The RUC process and RMR agreements

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227 In accordance with the RMR Agreement, ERCOT shall assess a penalty of $10,000 per operating day against the RMR unit for each unexcused misconduct event. See ERCOT. Nodal Protocols, Section 6: Adjustment Period and Real-Time Operations, February 1, 2025.

228 Texas Legislature (88th), House Bill 1500, Section 22. Effective on September 1, 2023.

229 This service aims to ensure resource availability during natural gas curtailments or other fuel supply disruptions. It will be acquired through an RFP process, issued by August 1st of the year the service obligation period begins. Source: ERCOT Website. Firm Fuel Supply Service, Accessed on March 2025. https://www.ercot.com/services/programs/firmfuelsupply

230 ERCOT. ERCOT Releases Capacity, Demand and Reserves (CDR) Report; Planning Reserves Pressured as Texas Economy Grows. February 13, 2025. https://www.ercot.com/news/release/02132025-ercot-releases-capacity

231 S&P Commodity Insights. Texas regulators authorize state to negotiate energy fund loans for 9.8 GW. August 30, 2024.

232 As a result, PUCT has decided to advance other applications to the due diligence phase that were not considered initially.

233 S&P Commodity Insights. Texas staff evaluating 72 applications for new power generation funding. August 19, 2024.

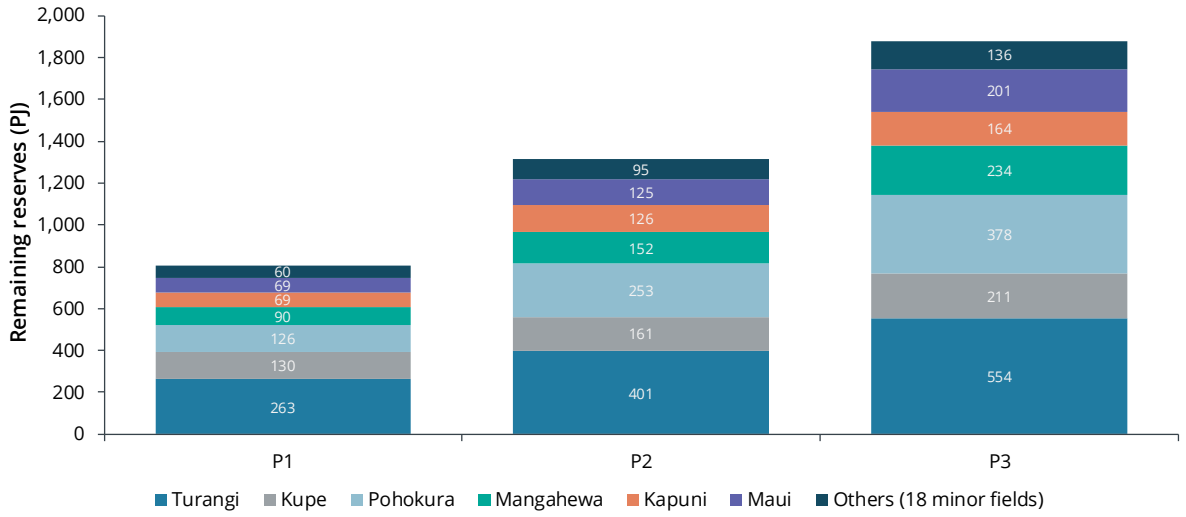
play a vital role in securing non-market resources, while new initiatives like DRRS aim to reduce reliance on out-of-market interventions. Long-term solutions, such as the TEF, are poised to further bolster grid stability by facilitating the development of dispatchable resources. As ERCOT continues to navigate evolving energy demands, these measures collectively ensure a resilient and reliable power grid for the future.

A.7 The state of the gas market in New Zealand

Gas supply

There are 18 natural gas fields in New Zealand. As at January 2024, total P1 reserves are around 800PJ, which is around 9% of total recoverable P1 supplies. More than 90% of remaining gas reserves are based in 6 main fields. There are three main offshore fields (Pokohura, Maui and Kupe) and three main onshore fields (Mangahewa, Turangi and Kapuni).

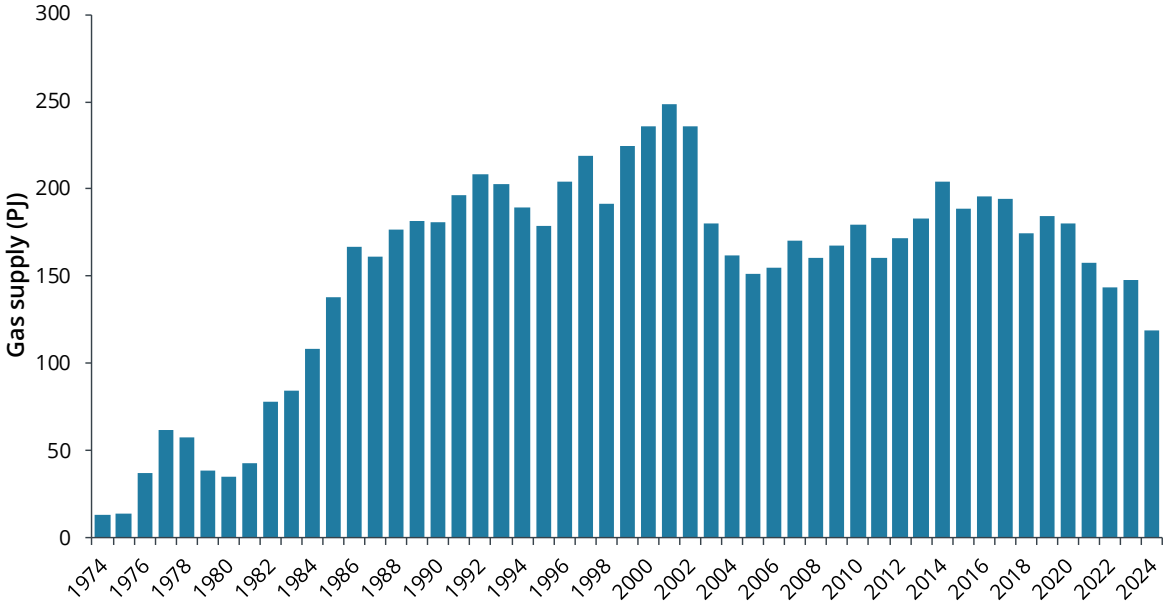
Figure 60: Remaining gas reserves, by gas field (PJ)



Source: MBIE, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/petroleum-reserves-data

Annual net gas production has steadily fallen over the past decade, from around 204PJ in 2014 to 119PJ in 2024. A key contributor to this decline is reduced net production at Pohokura gas field, which has fallen from 72PJ to 16PJ per year over the same period. This has been compounded by the lack of new gas field discoveries.

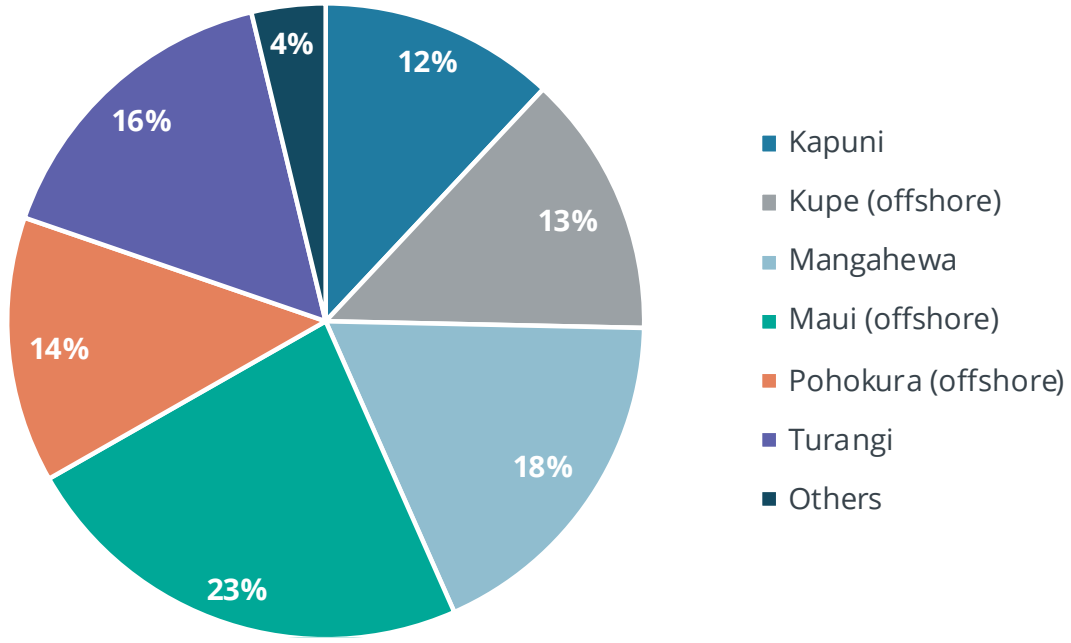
Figure 61: Annual net gas production (PJ)



Source: MBIE, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics. Note: Gas supply is gross production, less gas flared, reinjected, and extracted as LPG.

Offshore gas fields are a key contributor to gas supply. In 2024, around 60% of gas production was from offshore fields and 40% was from onshore fields.

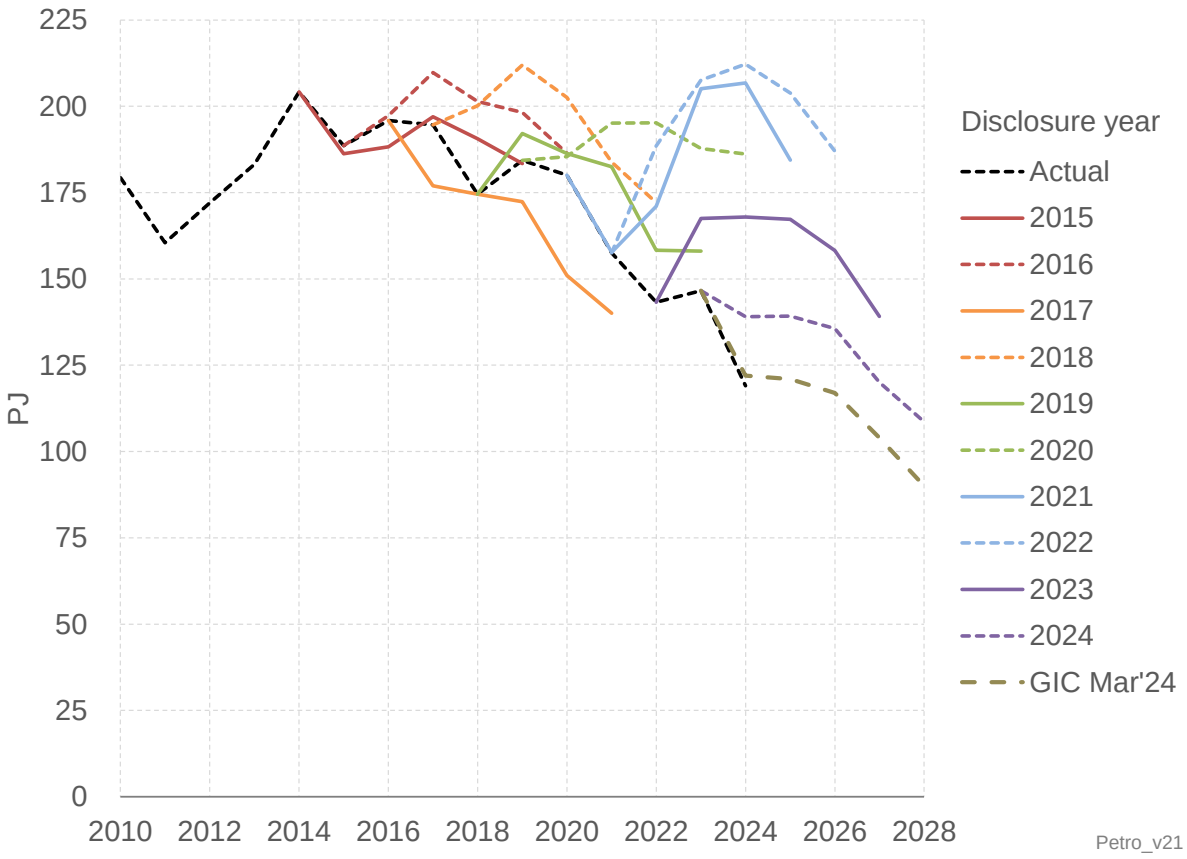
Figure 62: Net gas production in 2024, by gas field



Source: Source: MBIE, https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/gas-statistics. Note: Net gas production is gross production, less gas flared, reinjected, and extracted as LPG.

Supply difficulties were not anticipated by the market. Actual gas production has generally been lower than projected gas production, and this gap has grown since 2021. Most recent forecasts predict that gas production is expected to continue to decline in the near term.

Figure 63: Actual versus projected gas production by disclosure year



Source: Concept Consulting.

In order to conduct exploration activities, companies must be issued an exploration permit. The Government allocates exploration permits by inviting applicants to tender in a process called a 'Block Offer.' The Government selects the areas to be tendered under Block Offers based on its prospectivity and commercial interest from industry nominations. In 2018, the Government introduced a ban on exploration permits outside onshore Taranaki. Since the ban, there have been four onshore exploration permits issued (one each to Todd Energy and Riverside Energy, and two to Greymouth).

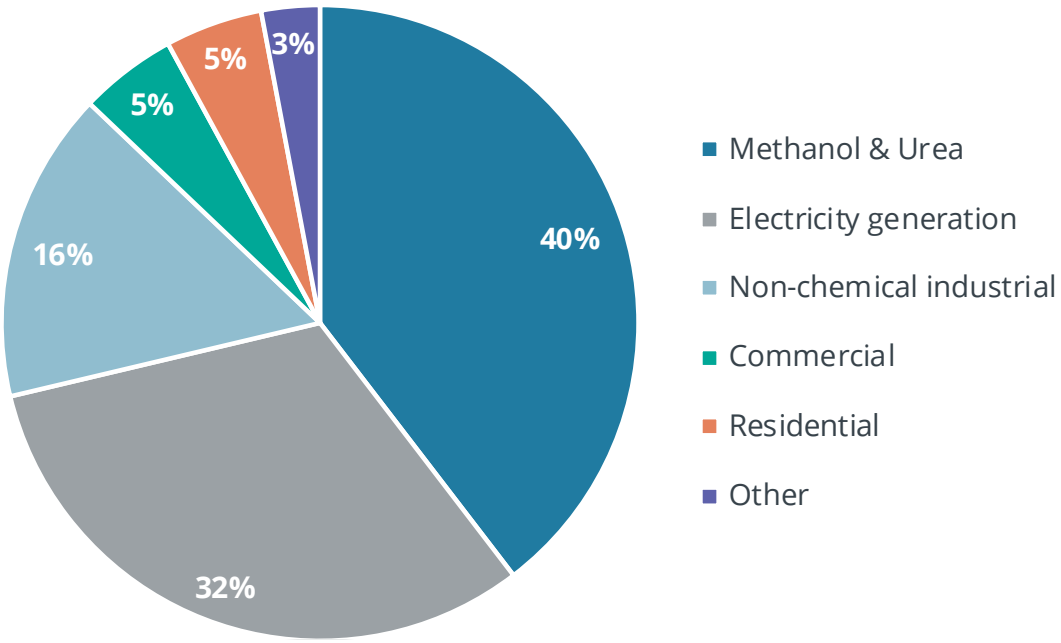
In recent years, major IOCs such as Anadarko, Chevron, Equinor, Shell and Woodside have decided to exit the New Zealand market. The ban on offshore exploration is likely a contributing factor to these companies leaving as it significantly reduced opportunities for future exploration and development of gas fields, and created uncertainty for the future of oil and gas in New Zealand. Other factors that may have contributed to the exit of these firms include declining production in existing fields, low global oil prices, and distance from potential markets, which affect the economic viability of projects.

While the current Government intends to reverse the ban on offshore exploration, this has yet to take effect. Even if the ban is removed, and new offshore gas fields are discovered, development of the field from discovery to first production would be expected to take 5 to 10 years. This would not help to alleviate any near term concerns regarding gas supply shortages.

Gas demand

The majority of gas demand is attributable to a small number of large industrial customers and electricity generators. Methanex is the largest gas consumer in New Zealand, accounting for around 40% of annual gas consumption. Methanex turns gas into methanol for export to Asia Pacific markets for use in plastics, chemicals and industrial processes. Electricity generators are the second largest users of gas, accounting for around 25 per cent to 30 per cent of annual gas consumption.

Figure 64: Gas consumption past 5 years



Source: GIC, https://www.gasindustry.co.nz/assets/CoverDocument/Briefing-to-Incoming-Minister-for-Energy-January-2025-website.pdf.

Methanex plays a critical role in the gas sector through:

- **Underwriting gas development**: Gas producers are less willing to invest in development new gas supply without an offtake agreement. Methanex has played a key role in underwriting the development of gas fields given its requirement for long-term and constant supply of significant volumes of gas.
- **Providing flexibility to respond to generation requirements**: Gas producers cannot easily vary production in response to changes in electricity demand or prices. When more gas is required for electricity generation, particularly for peaking and dry year demand, another gas user has to reduce consumption. Methanex has historically been prepared to flex its gas usage to provide demand response For example, in 2024, Methanex entered into short-term commercial arrangements to provide its contracted natural gas into the New Zealand electricity market. As a result, Methanex temporarily idled its manufacturing operations in New Zealand in 2024.

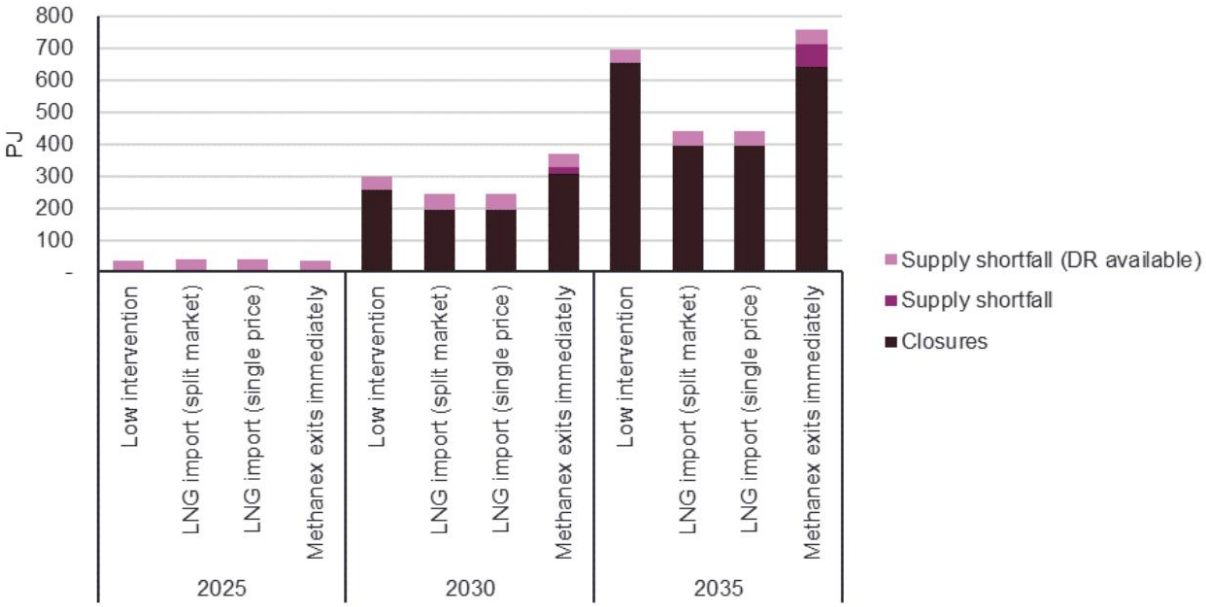
Future supply and demand balance

The GIC commissioned a study into the gas supply and demand balance in the future. The study looked at several scenarios, including:

- **Low intervention**: little intervention to develop further supply or incentivise fuel switching.
- **LNG import**: LNG is imported to help resolve supply constraints. Two options considered:
  - Split market: Ringfencing LNG supply to shield customers who use domestic gas.
  - Single price: Gas price is set by the marginal supplier.
- **Methanex exists immediately**: Methanex ceases production by the end of 2025.

The results of the study are summarised in the figure below.

Figure 65: Modelling of future gas shortfalls



Source: EY, https://www.gasindustry.co.nz/assets/CoverDocument/GasSupplyAndDemand_2024_11_28.pdf.

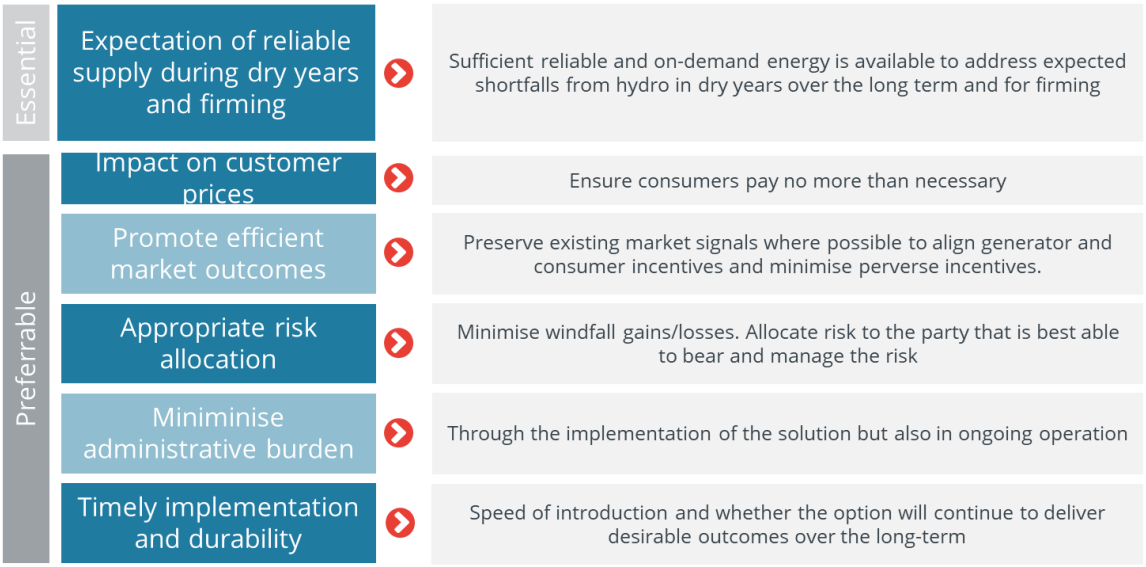
The study shows shortfalls in demand and supply in all scenarios for the future. Some of this shortfall can be met through demand response, principally from Methanex and other industrial players. In all cases, ongoing unavailability of gas is forecast to lead to industrial and/or commercial consumers reducing or shutting down their operations. In the 'Methanex exists immediately' scenario, the availability of demand response is substantially reduced, resulting in increased challenges to security of supply in the electricity sector, particularly in a dry year.

B Assessment of options to address dry year risk and for firming

B.1 Introduction

The purpose of this appendix is to set out our assessment of the alternative options for addressing dry year risk and for firming that were identified in Section 4.5. It adopts the assessment criteria that was presented in that section. For ease of reference, those criteria are set out again in Figure 66 below.

Figure 66: Assessment criteria for models to address dry year risk and for firming



Source: Frontier Economics

The options considered are as follows:

- Implementing the status quo,
- The proposed New Co
- A strategic reserve, similar to the former Whirinaki solution
- Obliging Genesis to be a regulated default provider of firm capacity
- A capacity market
- Mandatory contracting, and
- Tradeable certificates.

For each of the options we describe their key design features, namely:

- How capacity is procured
- How capacity is funded
- What constraints exist to limit market power
- How the option interacts with the existing market design

- What governance or regulatory arrangements are required, and
- How risks are allocated with respect to policy uncertainty risk and cost or price risk.

This is then followed by our analysis of each of the options against the assessment criteria identified above.

B.2 Implementing the status quo

Table 13: Design Features: Implementing the status quo

Design element	Option description
How capacity is procured	The four gentailers enter into a firm energy guild through a Heads of Agreement for a 10-year period to toll fuel through the Huntly generator. The gentailers would fund and own their allocation of fuel for the generator with Genesis operating the generator. TCC is set to be retired. Market signals in the energy-only market provide signals for new firm generation capable of addressing dry year risks and firming, as they have been for a number of years now. That is, the four gentailer offtakers would reflect the high scarcity value of the capacity and these costs would flow into higher electricity prices.
Funding	Costs for the Heads of Agreement option would be recovered through spot and contract market revenues (including the Huntly Firming Option), with Genesis receiving a fee from the other gentailers operating the Huntly unit on their behalf. Any future capacity that enters the market would earn revenue in the same way all existing generators in New Zealand earn revenue.
Constraints on market power	Existing constraints on market power would persist, in addition to the non-discrimination provision as proposed by the Energy Competition Taskforce. Aside from non-discrimination provision, the gentailers would have discretion about how any excess capacity is sold to independent parties. Virtual disaggregation of gentailers would be implemented at a future date.
Interaction with existing market design	Huntly units would be traded in the same way as existing generation in New Zealand. Future investment is subject to existing pricing and investment signals.
Governance / regulatory requirements	• Approval is given from the Commerce Commission for gentailers to collaborate on the Heads of Agreement. • Detailed design of the non-discrimination contracting arrangement building on proposal put forward by the Energy Competition Taskforce • Implementation of the virtual disaggregation model
Risk Allocation: Policy and cost uncertainty	Existing generators would bear all of the policy and cost uncertainty risks

Table 14: Assessment: Implementing the status quo

Criterion	Assessment
Expectation of reliable supply during dry years and firming	This model fails to provide lasting confidence in dry year and firming reliability beyond the Heads of Agreement, as it does not resolve policy uncertainty. Virtual vertical disaggregation of gentailers would prevent them from using their own generation as a natural hedge against their load, the inability to back new capacity with a firm customer load would undermine its bankability, thereby reducing incentives to invest in new firm generation. In short, it does not fix the long-term issues and so increases the likelihood that there is insufficient capacity to address dry year and firming risk.
Impact on customer prices	• The Heads of Agreement creates a regulator approved consortium across the dominant players in the market that would ultimately see customer prices rise as the gentailers are collectively able to foreclose on independent participants. • Because the model fails to address long-term issues, we expect higher scarcity pricing and significantly elevated average prices during winter. This is likely to prompt policymakers and regulators to intervene with reactive measures, which is more likely than not to lead to inefficient and potentially counterproductive outcomes. • If the gentailers actually have market power, the non-discrimination provisions will provide gentailers with the incentive to increase the price of internal contracts (i.e. they will charge themselves and competitors the same uniform high price), and so raise the price of contracts they offer to the broader market, with these costs ultimately passed onto customers. Virtual separation as a way of overcoming market power does nothing to reduce market power, it just shifts where and how it is applied. Unfortunately, if the gentailers did have market power that they used via their transfer prices, the gentailer reaction to virtual separation will, for the reasons explained above, cause prices to rise for their customers, which are the vast majority of customers. If the gentailers don't have market power, or don't exercise their market power through their transfer prices, virtual separation will simply weaken these businesses' ability to fund new investments, and this will make matters worse for consumers longer term. Therefore, virtual separation creates problems with or without market power. Virtual separation only enhances the ability of the independent retailers to charge more as they and the gentailers will face the same (high) wholesale costs and they will attempt to use their lower retailing costs to gain market share. • The virtual disaggregation proposal will mean that the efficiency benefits associated with vertical integration are lost. This will see the gentailers incurring additional costs that will be passed onto customers. These efficiency costs arise through the risk premiums that are reflected in explicit financial hedges, which are largely avoided as a cost in a vertically integrated model, which is why businesses vertically integrate – to become more cost efficient. Loss of cost efficiency will be directly translated into higher prices.

Promote efficient market outcomes	◔	This model can be adopted within the current market and maintains existing investment signals. However, market failures, policy uncertainty, and investor concerns mean those signals will not lead to new firm capacity that is able to effectively address dry year and firming risk and improve competition. For instance, if market signals were sufficient to address the problem, we would expect Genesis would preserve Huntly for its own use, TCC would be refurbished, and firms would invest in new dispatchable capacity capable of operating for extended periods of time (rather than only peaking capacity). However, this is not occurring.
Appropriate allocation of risk	○	Gentailers would carry policy uncertainty risk that is impossible for them to manage on their own. The Heads of Agreement merely spreads this risk beyond Genesis to the other gentailers.
Minimise administrative burden	◑	• The administrative costs of establishing the Heads of Agreement will be borne by the gentailers and so is low cost for the market. • There will be administrative costs associated with establishing and monitoring the non-discrimination provisions. Monitoring the non-discrimination provisions will be extremely challenging and so potentially costly. The hidden cost is that participants contract at different times, over different time horizons, for different shapes using different products. Further, the price paid today can change tomorrow as more information becomes available. Therefore, it will be difficult to identify discrimination. • There will be high administrative costs from establishing virtual vertical disaggregation through the design of the framework as well as for the businesses to implement the arrangement.
Timely implementation and durability	◑	The Heads of Agreement can be implemented relatively quickly, however, it does not solve the long-term investment issue.

B.3 New Co model

Table 15: Design Features: New Co model

Design element	Option description
How capacity is procured	Initially, firm capacity would be procured via contract with Huntly and potentially TCC. New Co would then identify the most cost-efficient means of meeting projected dry year and firming shortfalls having regard to available fuel and supply options as well as demand response options. New Co may choose to procure supply through PPAs, tolling, or asset ownership.

Funding	Costs are recovered through wholesale market revenues like all other generators in New Zealand (spot prices and contracts). However, because Huntly and TCC may demand a price that is above the costs to operate, New Co would be permitted to recover any shortfalls through a levy.
Constraints on market power	Generation is bid into the market at a regulated price that reflects a competitive market price. Initial negotiations with Huntly for its capacity would be subject to a negotiate / arbitrate framework as a means of constraining its market power. Independent generators would receive a priority allocation of generation capacity, ensuring they are not reliant on the gentailers for firm capacity.
Interaction with existing market design	New Co would bid into the market like all other generators, except its offer price would be capped at its variable cost of supply (which is what it would offer in a highly competitive market).[234] It will also contract like all other generators, except a portion of contracts will be reserved for independent operators to have first right of refusal. It will then generate to protect its contracts like all other generators in NZ - this generally means that it will guard against unfunded difference payment risks by offering its capacity into the market at its avoidable (variable) costs of production. This also provides an incentive for participants to contract with New Co given, absent a contract to defend, it has no incentive to generate. This is a key point of difference with the reserve energy model that was implemented using the Whirinaki plant. Because Whirinaki's operation was governed by regulatory obligations rather than contractual incentives, its operation created moral hazard within the market by undermining incentives for participants to invest or manage their own risks.
Governance / regulatory requirements	• Clear objectives on New Co to ensure it only procures capacity sufficient to address dry year and firming shortfalls. The Government, as the residual risk holder, should be responsible for determining this parameter and presumably would do so on advice from the Department and other market agencies including the System Operator and Electricity Authority. • Regulations to ensure that the generator is bid at cost (this can be a light-handed obligation with monitoring of compliance). This is likely the outcome anyway if New Co is required to sell financially firm contracts equivalent to its firm capacity (which should be an obligation). • Provisions regarding how contract access priority for independent generators works. • Design of the negotiate / arbitrate framework for the initial negotiation with Genesis Energy.
Risk Allocation: Policy and cost uncertainty	The Crown would bear all of the risk associated with government policy uncertainty, which is a risk created by the Government itself. To the extent there is any remaining cost risk, this would be socialised through an industry levy where it is required.

[234] More precisely, the competitive market price is the short-run marginal cost of supply. However, electricity generators incur other variable costs, such as start-up costs, that need to be amortised over the expected duration of operation and would imply cost recovery occurs above short-run marginal cost.

Table 16: Assessment: New Co model

Criterion	Assessment	
Expectation of reliable supply during dry years and firming	●	The primary objective for New Co is to ensure reliable supply during dry years and to meet firming shortfalls. While it can use a variety of options to secure capacity, including PPAs and contracting, the option to own assets (rather than rely on contracting alone) ensures that necessary investment will proceed where the private sector is unwilling. Furthermore, Crown backing will provide confidence to upstream fuel developers to source fuel resources for thermal generation.
Impact on customer prices	●	• New Co would be bid into the market at the competitive market price (which would be based on its variable costs) – which it would anyway if they sold financially firm contracts equivalent to their physically firm capacity, it would only impact on wholesale prices where it was the marginal generator • Crown funding means a low cost of capital for any borrowing required. This is particularly relevant where perceived risks mean contracted/private sector options are too high cost • By providing independents with a form of vertical integration through contracting, it can improve the competitiveness of the retail market and further drive down prices for customers
Promote efficient market outcomes	◕	• By bidding into the market at the competitive price New Co will not cause inefficient distortions price to signals in the market, noting other technologies/generators can set the marginal price at times of scarcity – in particular, batteries and gas peaking plants can be expected to signal market scarcity through offer prices. • Clear objectives and oversight will ensure that New Co does not procure more firm capacity than is needed and so crowd out other firm investment or procure inefficient assets.
Appropriate allocation of risk	●	Policy uncertainty risk is managed by party the that creates the risk, i.e., the Crown.
Minimise administrative burden	◑	A meaningful amount of administrative obligations are required to establish the model – the most important being to ensure strong governance arrangements over New Co, but also to establish how energy is bid in the market and to provide for the negotiate / arbitrate framework
Timely implementation and durability	●	This model can be implemented as soon as agreement can be reached with Genesis over Huntly (i.e. replacement of HoA). Binding the Government to investment decisions means the solution is enduring over time.

B.4 Strategic reserve – akin to former Whirinaki approach

Table 17: **Design Features: Strategic reserve**

Design element	Option description
How capacity is procured	The System Operator would hold periodic tenders for capacity/energy that is held in reserve to be used in specific emergency situations when hydro capacity is very low. It would be feasible also for demand to tender to provide strategic reserve services. Similar to the former arrangements for the Whirinaki plant, these resources are held outside the market and only dispatched in defined conditions.
Funding	Costs are socialised to all market participants via a levy is charged either through retailers or distributors.
Constraints on market power	This option would not protect against the possibility of owners of firm capacity having market power, noting a price signal is needed to motivate the supply of the service.
Interaction with existing market design	This is a non-market intervention. Similar to the intended design of the Whirinaki plant model, the generation would not participate in the market unless called upon to address a supply shortages. Consequently, retailers and industrial participants would not be able to contract separately with the strategic reserve generation as it would not be available to supply energy during normal times. While excluding the reserve from the market is intended to protect the functioning of the energy-only market, these are resources that will be used at times of scarcity, with the implication being that participants and developers will be aware that the use of the strategic reserve will dampen scarcity price signals. This option would be focussed on managing dry year risk rather than assisting in the provision firming capacity to the broader market.
Governance / regulatory requirements	• Framework for identifying potential shortfall in a forthcoming winter(s) • Framework for identifying eligibility criteria for strategic reserve • Criteria for trigger for use of reserve resources • Oversight to ensure compliance with strategic reserve conditions (e.g. sufficiently maintained to operate when called upon) • Arrangements for how the generator is bid into the market and compensated for generating when called upon
Risk Allocation: Policy and cost uncertainty	The central buyer would bear the policy risk for the duration of scarcity reserve agreements, and generators beyond this time. Cost risk is borne by consumers given the socialised cost recovery.

Table 18: Assessment: Strategic reserve

Criterion		Assessment
Expectation of reliable supply during dry years and firming	◑	Strategic reserve mechanisms have traditionally been used so that retiring plant stays available longer, rather than to motivate investment in new plant. Therefore, it is uncertain whether the mechanism would be capable of motivating investment in new capacity, although in principle it could. We note, the former reserve energy scheme in New Zealand did trigger investment in the Whirinaki power plant. Strategic reserve agreements that are fixed for the remaining economic life of an asset, or if it is a new generator, for its full economic life, are more likely to result in the provision of additional generation capacity. Notably, for Huntly to be used as the strategic reserve plant, it would need to 'exit' the energy-only market. The removal of this generator from the generally available supply of generation capacity would worsen existing reliability, competition and pricing issues.
Impact on customer prices	◔	• Paying for new capacity that is held out of the market until it is needed to address dry year and firming risk is likely to increase the costs of electricity to customers by driving increases in spot and contract prices because the withdrawn plant will increase scarcity in the market. • Given the reluctance of the private sector to invest in (or retain) assets capable of addressing dry year and firming risk, the cost of procuring future strategic reserve assets could be substantial.
Promote efficient market outcomes	○	The assets would be held out of the market with the intention that they do not impact on existing market signals. However, similar to the case for the Whirinaki plant, if participants have certainty about the circumstances about when reserved capacity will be offered to the system, it will undermine any incentive for participants to invest or manage their own risks. These distortions will be evident in investment, spot pricing and contracting. This is a key difference to the New Co model, whereby participants would have an incentive to contract with it to ensure it was motivated to operate during times of firm supply shortages. If Huntly was used as the strategic reserve its removal from the market would likely see spot prices, and so contract prices, increase as it would see supply and demand tighten further.
Appropriate allocation of risk	◕	Whether the model appropriately allocated risk would depend on the duration of contracts for strategic reserve. It would require binding contracts for the economic life of assets in order to mitigate policy risk. Noting that this may not be sufficient to address policy risk that can hamper investment in upstream fuel resources.

Minimise administrative burden	◕	Given this option is similar to the Whirinaki reserve energy scheme, it is possible to model it on that scheme and so implement it relatively quickly. However, we note that there were many issues about the way in which Whirinaki was implemented and we would not recommend following the previous approach.
Timely implementation and durability	◑	Whether this option could be implemented quickly depends on whether there are resources available to provide the service, noting that any resources used could not be used for other purposes and so could not participate more generally in the energy-only market. The result from the Whirinaki reserve energy scheme suggests the model is not durable over time. Indeed, its use in places like Germany has been as a means of managing short-term transition to renewables rather than to address enduring reliability issues.

B.5 Obliging Genesis to be a regulated default provider of firm capacity

Table 19: Design Features: Genesis as default firm capacity provider

Design element	Option description
How capacity is procured	Genesis Energy would be formally designated to provide a pre-determined amount of firm capacity to the market under a regulatory scheme. The capacity commitment would be set by the System Operator based on forecast dry-year and firming shortfalls. Genesis may use its own assets and/or contract with third parties (e.g. Contact's TCC).
Funding	Costs are recovered through wholesale market revenues like all other generators in New Zealand (spot prices and contracts). An availability payment may be required to ensure that Genesis is able to fully recover the costs of its assets. This cost would be socialised by recovering it from customers via a levy through distribution charges.

Constraints on market power	• Because Genesis would have market power in the provision of firm capacity for dry years and firming it would be required to bid its capacity in at a regulated price. The method for regulating prices would likely need to be more intrusive than for New Co because of the commercial objectives of Genesis, and because Genesis has other assets and so an ability to shift costs between them and use regulated assets to maximise profits on unregulated assets. • Requirement to offer a priority allocation of capacity to independent operators before it is made available to gentailers • Bolstered market monitoring to identify if Genesis is operating its assets in a way that is favourable to its other generating assets or customer load • Ring-fencing arrangements to prevent cross-subsidisation between its other assets and the firming service
Interaction with existing market design	Genesis would need to be obliged to ensure its capacity is available for certain times of need given it may otherwise have an incentive to not operate the generator at levels that are desirable for the market (noting withdrawal may favour outcomes for its other generators). This incentive might be moderated by its contracting behaviour. This structure represents a significant intervention because a large commercial trading entity would now not be trading in a commercially predictable manner.
Governance / regulatory requirements	• Rules about how much capacity Genesis needs to make available to address dry year and firming short-falls, this would be determined by an independent party (such as the SO) • Regulations to ensure that the generator is bid at cost, this will need to be more intrusive than for New Co given the other assets owned by Genesis, the extent of market power it would have, and the risk of cross-subsidy/cost shifting • Provisions regarding how contract access priority for independent generators works • Ring-fencing arrangements to ensure the firm capacity obligation is separate from the rest of Genesis • Bolstered market monitoring provisions to ensure Genesis does not operate the firm capacity in a way that is favourable to its remaining portfolio.
Risk Allocation: Policy and cost uncertainty	Genesis would bear policy uncertainty risk as well as some cost recovery risk, the availability payment would address some of the short-term cost recovery risk.

Table 20: **Assessment: Genesis as default firm capacity provider**

Criterion	Assessment

Expectation of reliable supply during dry years and firming	◕	This option will be effective if the Government is able to force Genesis to procure new firm and dispatchable capacity.
Impact on customer prices	◑	• Customers would likely to be required to pay an availability charge to Genesis to ensure it recovers its costs. Genesis apparently does not consider it is able to make sufficient revenue from Huntly to justify operating it without a tolling arrangement with other gentailers. Therefore, when subject to a regulated price is likely that an additional availability charge will be needed. • The offer price in the spot market for generation from Genesis owned thermal generation would need to be regulated • By providing independent operators with a form of vertical integration through contracting, it can improve the competitiveness of the retail market and further drive down prices for customers • Stringent ring-fencing and market monitoring will be needed to ensure that Genesis is not able to behave in ways that would increase costs to customers, such as cost shifting towards regulated assets or operate its thermal assets in a way that is favourable to its remaining portfolio. Controls would also need to be developed, implemented and monitored to ensure that Genesis provided fair access to the firming capacity.
Promote efficient market outcomes	◑	• Regulated bidding of firm energy at a competitive market price will preserve existing market price signals • Contracting with participants should ensure that Genesis makes capacity available when it is most valued by the market, however, additional obligations may be required • It will be necessary to ensure that Genesis does not over-procure firm dispatchable capacity and so crowd out the market • Preventing Genesis from bidding above its own cost up the scarcity value in the market, and forcing it to invest in new thermal assets, is expected to have a detrimental impact on its market value. Indeed, Genesis may prefer to divest itself of its thermal assets.
Appropriate allocation of risk	○	Under a regulatory solution Genesis would bear the risk of policy uncertainty, which it is unable to manage itself. Therefore, it may be left with stranded assets and it will certainly face more business uncertainty
Minimise administrative burden	◔	Extensive regulatory arrangements would need to be imposed to implement this solution and these would need to be enforced over time
Timely implementation and durability	◕	This option can be implemented relatively quickly and could be durable so long as the Government is able to force Genesis to procure new firm capacity

B.6 Capacity market

Table 21: Design Features: Capacity Market

Design element	Option description
How capacity is procured	In a capacity market, capacity is procured centrally via regulation and separately from energy. This is typically done through centralised auctions based on the view from the System Operator about the reliability standard that is required for the market and forecasting the capacity required considering dry year risks. Auctions need to be run several years in advance of delivery to allow time for new entrants and investments. They would also need to provide for various time horizons. For instance, longer term agreements for new capacity. A key challenge for the design of the scheme will be addressing the uncertainty associated with output from renewable and hydro generation. That is, the extent that capacity can receive a capacity payment would need to be linked to its expected contribution to firm capacity.
Funding	An obligation is placed on retailers to pay a levy based on the amount of electricity they supply. The cost of this would then be passed onto customers.
Constraints on market power	The capacity auction requires that participants indicate the lowest price at which they are willing to provide capacity. If there is limited firm capacity in the market certain participants may have market power and so demand a high minimum. However, high prices may be needed at times in order to encourage new entry.
Interaction with existing market design	A capacity market is a fundamental change to the market and so cannot interact with the existing market design

Governance / regulatory requirements	• Develop new and detailed market rules and procedures establishing the design of the capacity market, including: ○ Resource adequacy standards ○ Eligibility requirements ○ Procurement mechanisms, including auction design ○ Funding mechanisms ○ Performance and compliance monitoring ○ Balancing market design for ensuring energy matches demand in real time
Risk Allocation: Policy and cost uncertainty	Capacity providers would bear the risk of policy uncertainty beyond the duration of the capacity obligation.

Table 22: Assessment: Capacity Market

Criterion	Assessment
Expectation of reliable supply during dry years and firming	This option does not resolve policy uncertainty and shareholder concerns and so will not fix the long-term reliability issue. This is because there is no mechanism that obliges investment in assets needed to address dry year risk and firming requirements. The implication is that capacity credits will be assigned to technologies that are less firm than thermal generation. This means that either substantial capacity resources are drawn on to achieve capacity targets, and / or the risk of unserved energy is higher than is preferred given the prospect that capacity paid under the scheme is unable to deliver when needed.
Impact on customer prices	• Capacity markets have a tendency to over-procure capacity given their primary function is to attempt to deliver sufficient capacity to meet demand. This means a reasonable safety margin on the reliability target is likely, combined with the challenges of ascertaining the firmness of renewable technologies, the solution can be expected to increase costs to customers through an over-procurement of capacity. • Because it does not resolve the policy uncertainty and shareholder concerns it is likely that remaining providers of firm capacity will possess market power, which will drive up the price of procuring firm capacity.

Promote efficient market outcomes	◔	• Given the capacity obligation will need to be fulfilled, but this will likely by technology that is less suited to this task (due to the risks of investment in thermal capacity), it is likely that this solution will mean that the cost of achieving reliable supply will be far higher than compared to options such as New Co.
Appropriate allocation of risk	○	Policy uncertainty risk would remain with generators who are unable to adequately manage these risks that arise because of government policy uncertainty.
Minimise administrative burden	○	Extremely significant administrative arrangements will be needed to design and operate the capacity market
Timely implementation and durability	○	Designing a capacity market will take many years. Once designed, auctions will need to be undertake years in advance of delivery. Therefore, this option cannot be implemented for many years. It will not be durable over time given it does not fix the barriers to investment, at least not in an efficient way.

B.7 Mandatory contracting

Table 23: Design Features: Mandatory contracting

Design element	Option description
How capacity is procured	Liable entities (e.g. retailers) are required to contract bilaterally for a defined quantity of firm generation capacity or demand response based on their forecast share of system peak demand. Eligible contracts must meet regulatory criteria for firmness, duration, and dispatchability. Contracts would be for a period of 2-4 years to balance the need for revenue certainty with minimising barriers to retailer entry. Forced contracting models generally don't involve a requirement to have these backed by physical plant. The aim is that the risks associated with forced financially firm contracts will drive the seller to invest in generating plant to manage the unfunded difference payments, but unless this is an obligation the seller may manage the contracting risks in a way that does not increase the supply of dispatchable generation capacity.
Funding	Funded by liable entities (retailers) contracting with eligible capacity or demand response.

Constraints on market power	No specific measures available to address market power in the market for firm capacity contracts recognising that the intent is that price signals provide a signal for new investment in capacity. Some regulations may be imposed to limited contract volumes that can be purchased to avoid dominance by a few firms.
Interaction with existing market design	Mandatory contracting would be an overlay on the existing market – it is a significant intervention.
Governance / regulatory requirements	• Identify liable entities and their specific contracting obligations • Make arrangements regarding eligible providers of contracts and the requirements for those contracts • Identify the information and data that liable entities are required to provide the regulator • Provide for compliance auditing and enforcement arrangements • Provide for regulatory oversight of contracting auctions
Risk Allocation: Policy and cost uncertainty	Policy uncertainty risk would remain with the providers of firm capacity used for contracting and there is no way that this can be managed. Price risk would be borne by retailers and ultimately customers.

Table 24: Assessment: Mandatory contracting

Criterion	Assessment
Expectation of reliable supply during dry years and firming ○	This option does not resolve policy uncertainty or shareholder concerns and so will not fix the long-term reliability issue. This is because there is no mechanism that translates forced contracting into investment in generation capacity that produces most, or any, social benefit – that is, investment in dispatchable capacity.

Impact on customer prices	○	• This option increases the market power of providers of firm dispatchable capacity because participants who are forced to contract for a particular type and quantity of contract will compete for the existing supply of this capacity and unless there is an obligation on a participant or agency to invest in additional capacity, all this will do is drive up prices. • Requiring a particular form of hedging be used (i.e., contracting) can impose prudential obligations participants may have otherwise been able to avoid (e.g. through demand management), or only incur closer to the time of contract delivery. These additional costs would need to be passed on to customers. • Because the solution will be unlikely to motivate socially optimal investment (for reasons explained in our report) in new firm dispatchable generation capacity, wholesale costs will increase substantially as supply and demand tightens or the investment that occurs will be privately optimal but socially sub-optimal. This is likely to prompt policymakers and regulators to intervene with reactive measures, which is more likely than not lead to inefficient and potentially counterproductive outcomes.
Promote efficient market outcomes	◔	• Given the solution is unlikely to fix the long-term reliability issues, it will likely lead to substantial increases in spot prices in an energy only market and lower reliability. • Contractual obligations at times of tight supply should motivate generators that do have contracted capacity to produce output when it is privately most rewarding to do so. • Mandatory contracting would impose additional costs, or at least requirements, onto independent generators that would not need to be faced by generators that own generation assets and so reduce competition in the retail electricity market.
Appropriate allocation of risk	○	Policy uncertainty risk would remain with generators who are unable to adequately manage these risks that arise because of government policy uncertainty.
Minimise administrative burden	◔	Reasonably significant administrative arrangements would be needed to design and monitor the arrangements
Timely implementation and durability	○	The model could not be implemented until the scheme was designed and tested, it would not prove durable over time because it does not fix the barriers to investment.

B.8 Tradeable certificates

Table 25: **Design Features: Tradeable certificates**

Design element	Option description
How capacity is procured	Firm generators or demand response resources are issued capacity certificates for verified firm capacity. Certificates are tradable. Retailers must procure and surrender certificates proportional to their contribution to system peak demand. The Electricity Authority would verify firm capacity eligibility and issues certificates. The certificate seller bears the obligations attached to these certificates. If the certificate obliges the seller to develop generation capacity of a certain type then the seller bears the financial, physical and reputational risks associated with those investments. For example, if the tradeable certificate obliges the seller to develop a thermal generator the seller would be forced to bear the investment and operational risks, noting that the likely candidate sellers have already demonstrated through their inaction on developing necessary dispatchable generators that investing in these plants would not be what they would do by choice. This option actually involves forcing firms to invest in the very generators that previous New Zealand governments have condemned and they fear future governments will strand. These investments will therefore involve very significant investment risk.
Funding	Funding is via retailers who procure certificates, with the cost reflecting the cost of securing capacity, including the significant financial risks.
Constraints on market power	This option would not protect against the possibility of owners of firm capacity having market power, noting the value of certificates needs to rise to the level needed to drive new investment in eligible capacity.
Interaction with existing market design	Tradeable certificates would be an overlay on the existing market – it is a significant intervention. It will be necessary to develop arrangements that ensure providers of certificates are able to provide energy at the times it needed. However, certificates may influence the incentives to contract and bid capacity into the spot market.
Governance / regulatory requirements	• Creation of the certificates regime and eligibility framework • Rule setting for how certificates are sold and traded • Compliance and enforcement arrangements
Risk Allocation: Policy and cost uncertainty	Policy uncertainty risk would remain with the providers of certificates, retailers, and ultimately customers, would bear the price risk through the purchase of the certificates

Table 26: Assessment: Tradeable certificates

Criterion		Assessment
Expectation of reliable supply during dry years and firming	○	This option forces market participants to invest in plant that previous New Zealand governments have condemned and it is likely that future government will condemn again and likely strand by policy change. This option introduces an unmanageable risk to every market participant and represents a significant intervention. Also, it is unclear how this scheme results in socially optimal investment in dispatchable plant. For example, it is likely that it is more cost efficient (from a scale perspective) to invest in a few large scale projects rather than sellers individually investing in smaller scale projects. To overcome these cost inefficiencies there would need to be a co-ordination of the investment response. This then risks the problem associated with the current Huntly proposal (see above).
Impact on customer prices	○	Given the solution is unlikely to fix the long-term reliability issues, or fix it economically, it will lead to substantial increases in electricity prices, certificate costs, and lower reliability.
Promote efficient market outcomes	○	• This option increases the market power of providers of firm dispatchable capacity by forcing liable participants to purchase certificates. • Given the option does not address policy uncertainty risks, scarcity pricing will increase without a corresponding investment response. • Monitoring and penalty arrangements will be needed to ensure capacity is available when it is needed.
Appropriate allocation of risk	○	Policy uncertainty risk would remain with generators who are unable to adequately manage that risk. The costs of this will be passed on to consumers and/or will adversely affect the value of these businesses.
Minimise administrative burden	◔	Substantial regulatory arrangements would be needed to design, implement and monitor a certificates scheme
Timely implementation and durability	○	Designing a certificates scheme could not be done quickly. The option is not durable over the long term because forces participants to invest in projects it does not want to invest in.

C Distribution networks appendix

C.1 Introduction

Section C.2 provides an overview of the economic regulation framework that applies to EDBs in New Zealand under Part 4 of the Act. Section C.3 presents evidence that, in general, the network assets of EDBs are aging over time, as well as the resulting impact on network reliability outcomes. Section C.4 provides one detailed example of a material methodological issue that the Commission has excluded from the scope of the IMs, and discusses the consequences of that decision.

C.2 Approaches to economic regulation in New Zealand

Default price-quality path (DPP) regime

The key features of the DPP regime are the following:

- DPPs are determined using a building block framework. In essence, this is the same framework that is used by regulators in Australia, the UK, in many parts of Europe and Singapore.
- Many of the steps associated with determining the building blocks (i.e., asset valuation, cost allocation, regulatory tax treatment, estimation of the cost of capital, regulatory rules and processes) are specified in advance through development and application of 'Input Methodologies' (IMs). The IMs are detailed and prescriptive guidebooks that set out the approach the Commission will follow on each of these key elements. They may each be subject to a single merits review, and must be revised at least every seven years.
- Allowances for operating expenditure (opex) and capital expenditure (capex) are determined using relatively low-cost, top-down forecasting approaches that reflect industry-wide factors rather than detailed, firm-specific considerations. This obviates the need for the Commission to undertake detailed, bottom-up (i.e., engineering based) expenditure assessments (as happens in other jurisdictions overseas). However, robustness of this approach is contingent on the Commission having access to appropriate historical and projected information on costs and performance.

Customised price-quality path (CPP) regime

An EDB may apply for a CPP if it considers that its requirements would not be met adequately under a DPP.

A CPP has the same essential components as a DPP (e.g., the price path is determined via a building block approach). However, under a CPP process, the Commission may consider the specific circumstances of an EDB to set a path that better suits its needs. This may involve doing more detailed assessments of the supplier's cost requirements.

The rules and processes for CPP proposals, including the requirements for a proposal and the criteria the Commission must follow when evaluating a proposal, are set out in IMs. Once a CPP expires, an EDB will transition back onto the DPP, although it still retains the option of making another CPP proposal later.

The Commission has made four CPP decisions to date:

- Orion Networks sought a CPP following the 2011 Canterbury earthquake. The Commission set a CPP for Orion Networks, which is expired in March 2019;
- Powerco applied for a CPP in June 2017, seeking an increase in allowed revenues to fund a major upgrade to its network. The Commission set a CPP for Powerco, which expired in March 2023;
- Wellington Electricity applied for a CPP in December 2017, seeking an increase in allowed revenues to undertake significant reinforcement of its network to improve its resilience against the risk of future earthquake damage. The Commission set a three-year CPP that expired in March 2021; and
- Aurora Energy applied for a CPP in June 2020, seeking an increase in allowed revenues to address significant safety and reliability concerns with its network. The Commission set a five-year CPP that is due to expire in March 2026.

Information disclosure regime

Under Part 4 of the Act, all 29 electricity distribution networks, gas pipelines and Transpower are subject to an information disclosure regime.[235] Under this regime, the Commission publishes requirements for these businesses to submit appropriate information—including data on prices, measures of quality, financial information, and forecasts of future expenditures (including planned investment in the network). These requirements are reviewed and amended periodically. The Commission uses these data to assess and report publicly the performance of these suppliers over time.

The primary objectives of the information disclosure regime are to enhance transparency over the performance of these regulated businesses, and to allow the Commission to assess whether regulation is working well. The assessment role played by the information disclosure regime was considered a necessary part of the regulatory framework, when it was introduced, since several businesses (i.e., 13 community and trust-owned distribution businesses, and airports) are not price-quality regulated formally, and because the DPP regime necessarily means the Commission does not undertake detailed scrutiny of individual EDBs' costs when setting default price-quality paths.

The information collected by the Commission over several years through the disclosure regime provides a rich and detailed dataset that could potentially be used to assess efficiency performance. Further, the detailed reporting guidance published by the Commission in its information disclosure decisions, and the Commission's periodic review and refinement of this guidance, and correction of data, means that the quality and consistency of the information collected by the Commission has improved over time.

Under Part 4 of the Act, the Commission is required to publish a summary and analysis of the data submitted by the businesses subject to the information disclosure regime. The Commission has also developed an interactive Performance Accessibility Tool to allow stakeholders to view and understand, in a user-friendly way, the information gathered through information disclosures.

C.3 Distribution network age and reliability

To investigate the aging of EDB networks, we use the information disclosure data submitted by EDBs to the Commission to create indices of the average ages of networks.

[235] An information disclosure regime also applies under Part 4 of the Act to major airports in New Zealand.

We first take the data on asset ages reported in EDBs' information disclosure responses.[236] This data contains information on the age of assets, by network, asset sub-category, and disclosure year, providing asset counts by year of installation.

For each network and sub-category we first correct the data to ensure consistency across years.[237] We then seek to find the assets that comprise the extent of the network as at 2013. For each year from 2014 to 2024, we consider that some new assets may have been used to expand the network, relative to the assets that were in place in 2013. Any additional assets, beyond that which would maintain the number of assets of the previous year, are assigned as expansion assets with the remainder of the new assets assigned to the notional existing network.

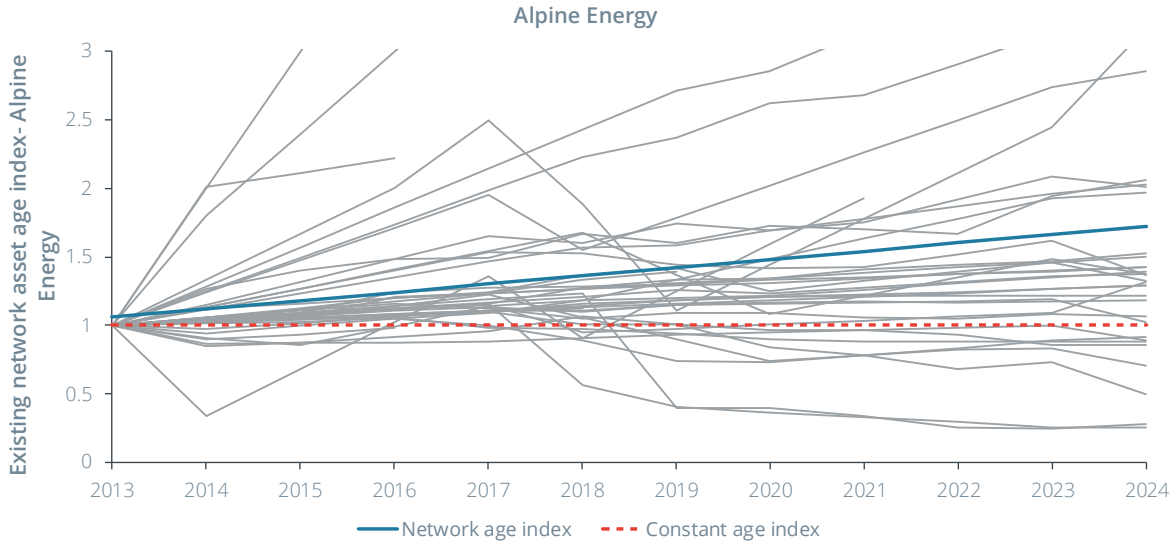
We then find the ages of assets allocated to the existing network, by comparing the installation year to the disclosure year. We note that for some older assets the installation year is provided as a range, for example 1940-1949. For these assets we take the midpoint of the range (i.e., 1945) as the installation. We then take the weighted average ages to obtain the average age for each EDB, sub-category and disclosure year.

We note that there are 50 sub-categories of asset types, with some having considerably longer asset lives and average ages. To account for this we present average age indices, normalising average ages to the average age as at 2013.

Finally, we construct the network age index by averaging the age index of each of the sub-categories.[238] For simplicity (and in the absence of any other measure, such as asset value, that could be used to weight sub-categories), we weight each sub-category equally.

Figure 67 below presents the age indices for each of the 29 EDBs. As can be seen, after excluding expansion assets, the networks have aged materially from 2013 to 2024.

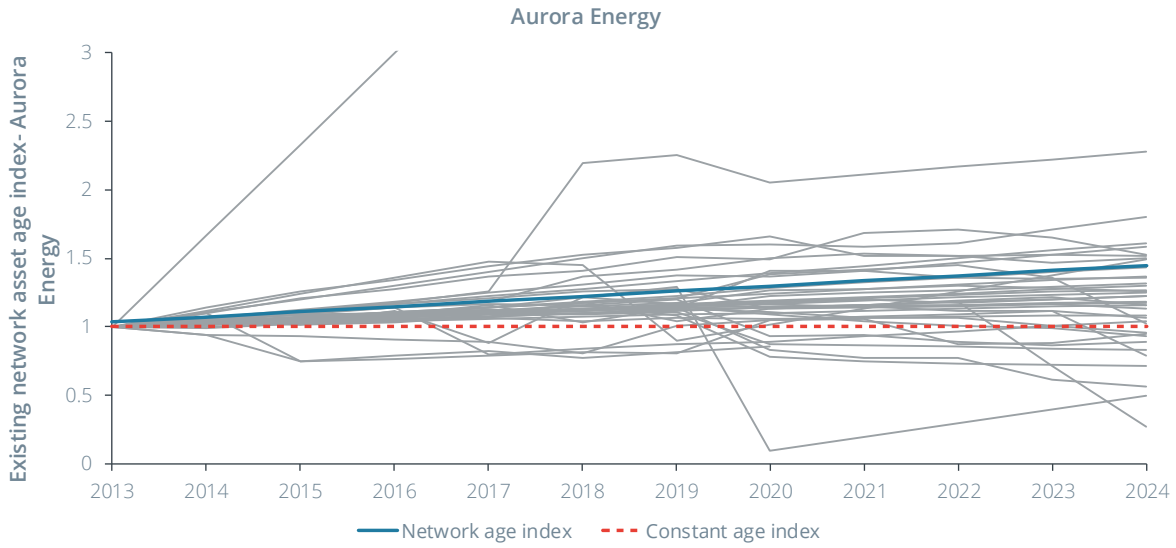
Figure 67: Network age indices of EDBs



236 Section 9b: Asset Age Profile.

237 Specifically, we adjust historical asset counts by installation year to ensure that the asset counts by installation year are weakly decreasing over time. For example, if the disclosures state that 100 assets installed in 2000 were present as at 2010 but 110 assets installed in 2000 were present as at 2011 we would adjust the data so that 110 assets installed in 2000 were present as at 2010.

238 Not all asset subcategories yield valid age indices for all EDBs, for example by having no assets in the subcategory in 2013.


Aurora Energy
Existing network asset age index- Aurora Energy
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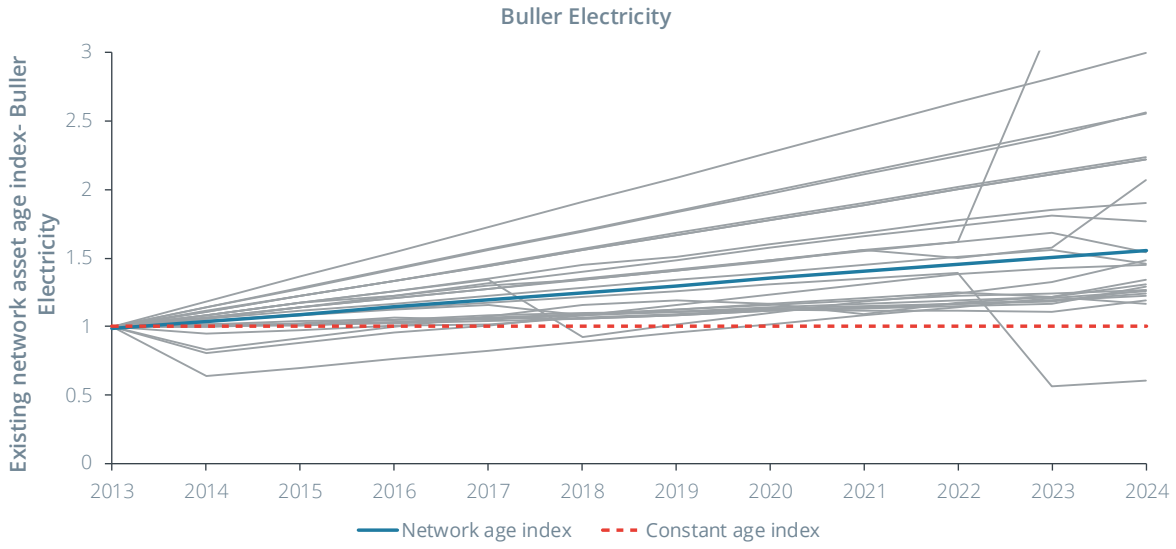
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Existing network asset age index- Buller Electricity
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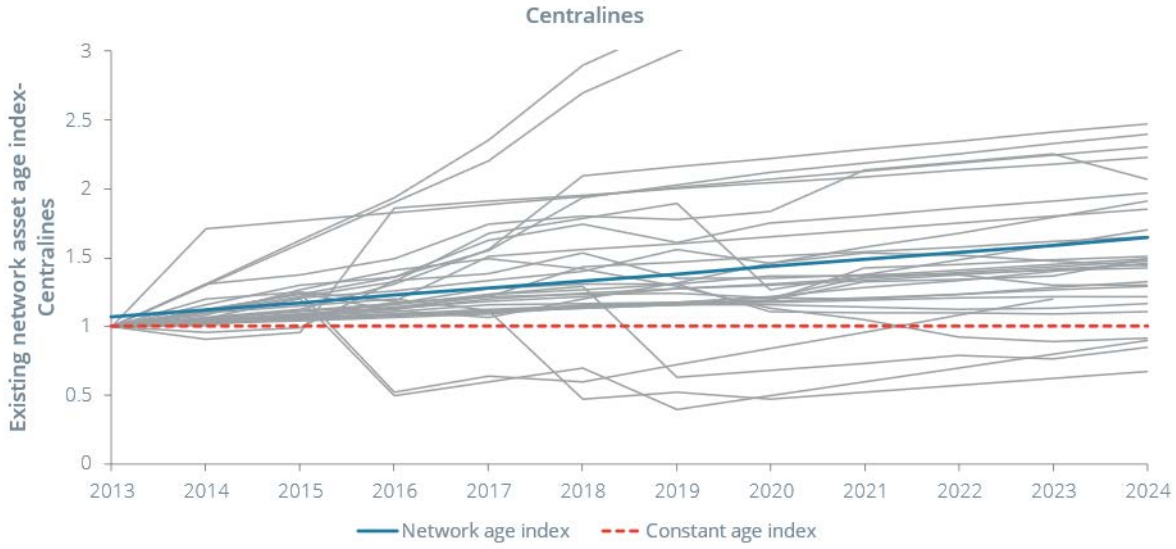
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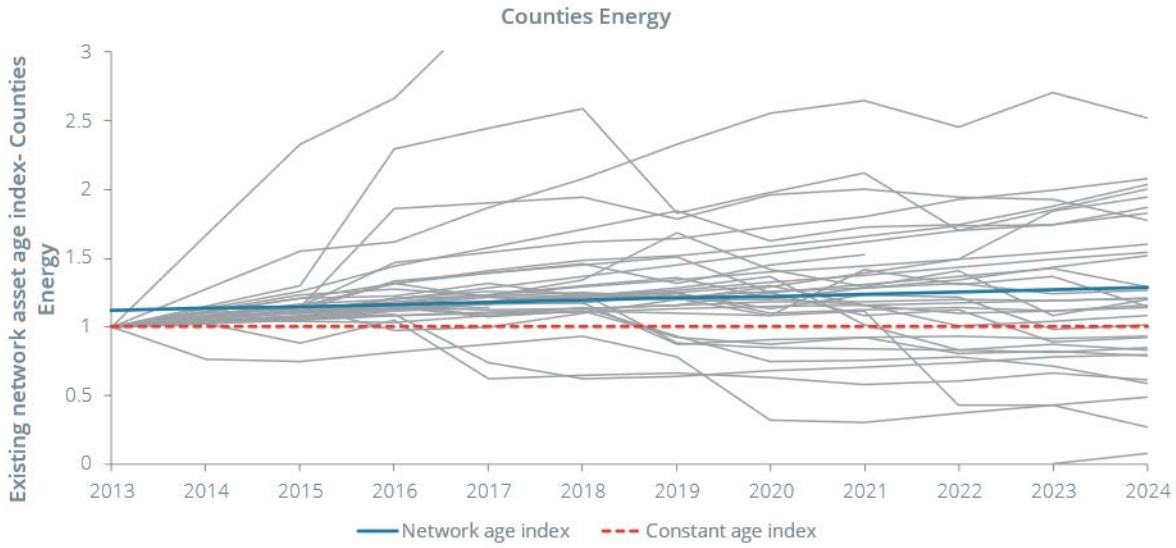
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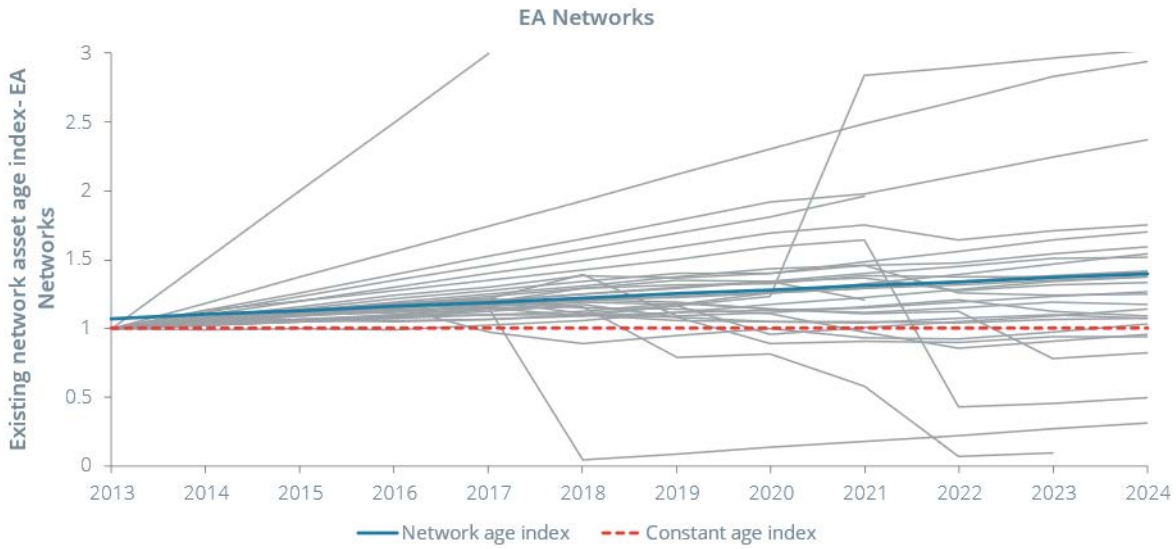
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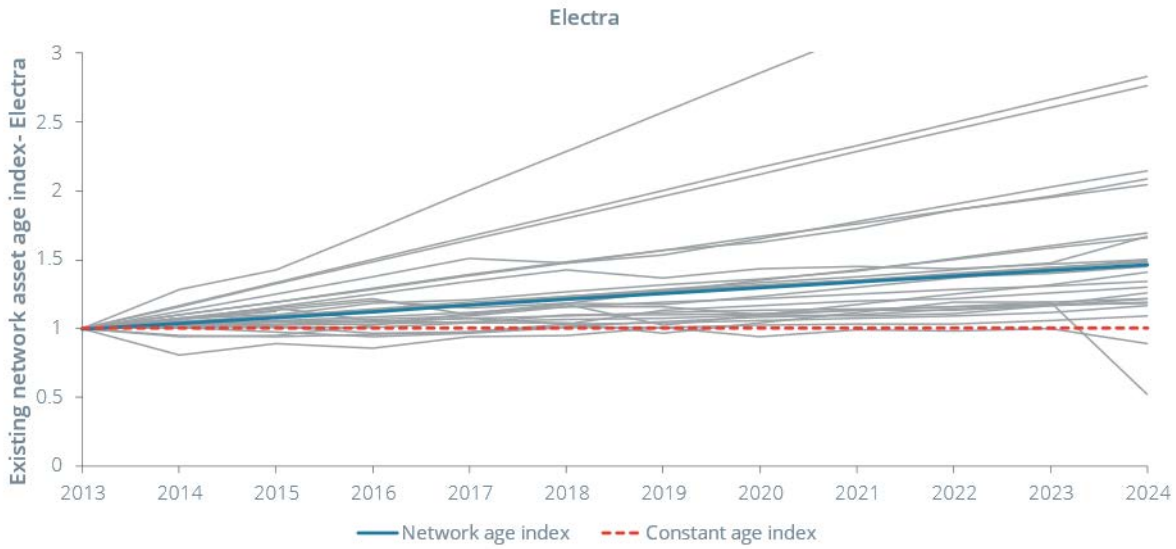
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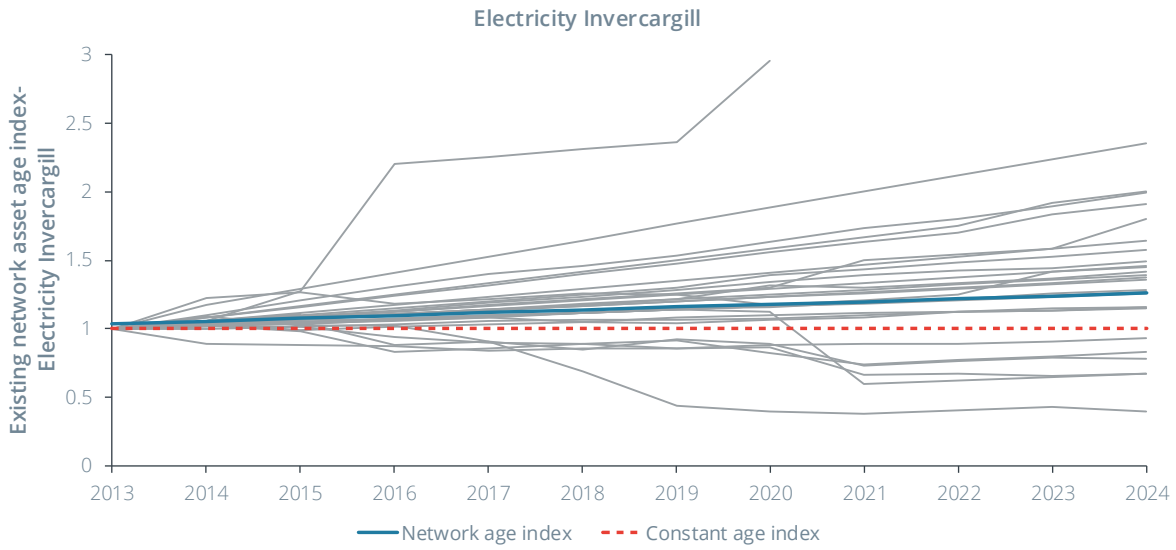
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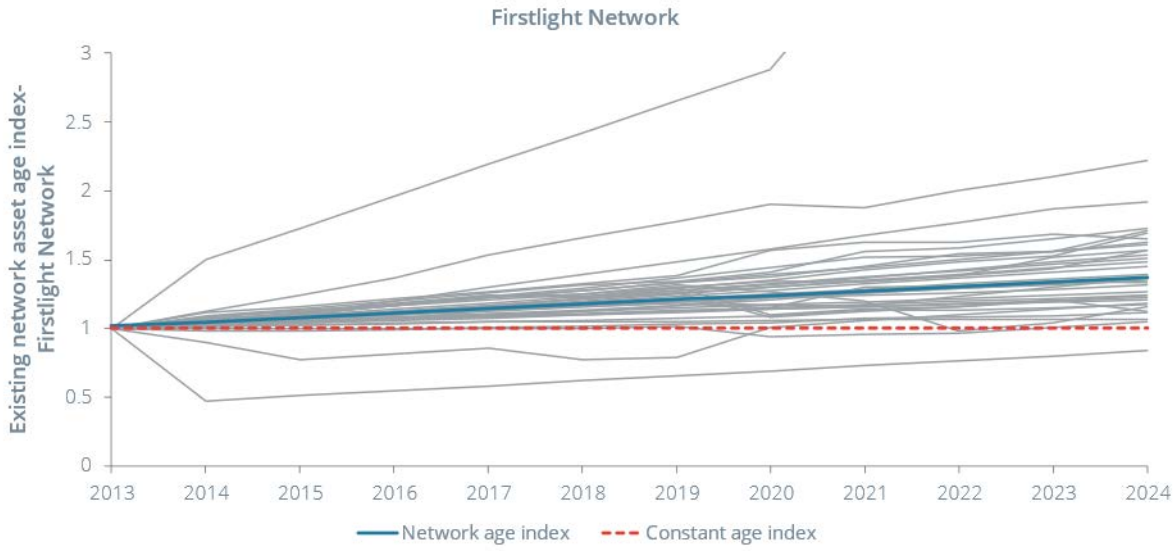
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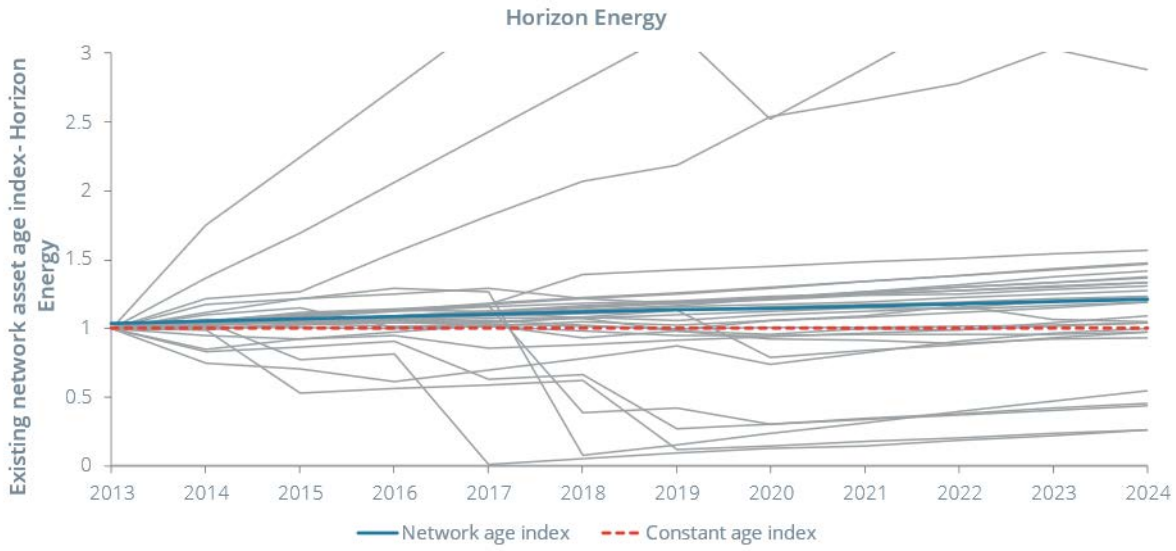
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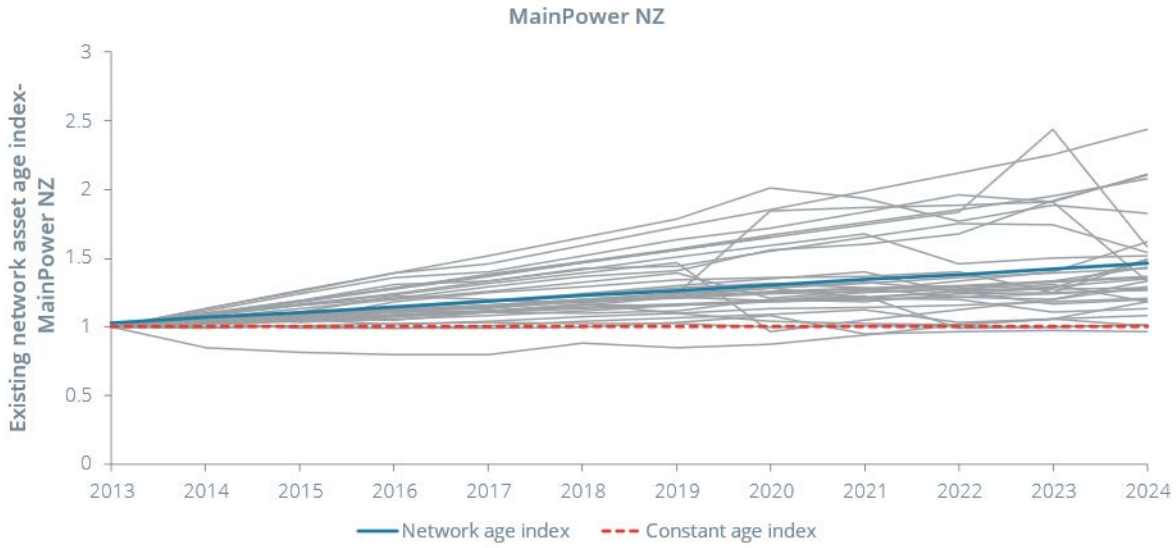
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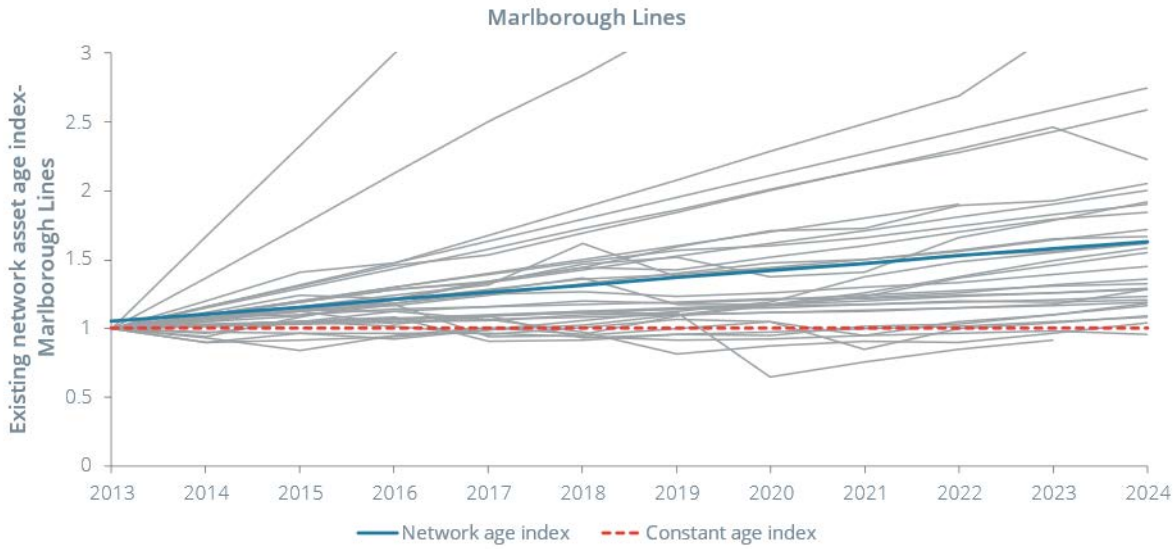
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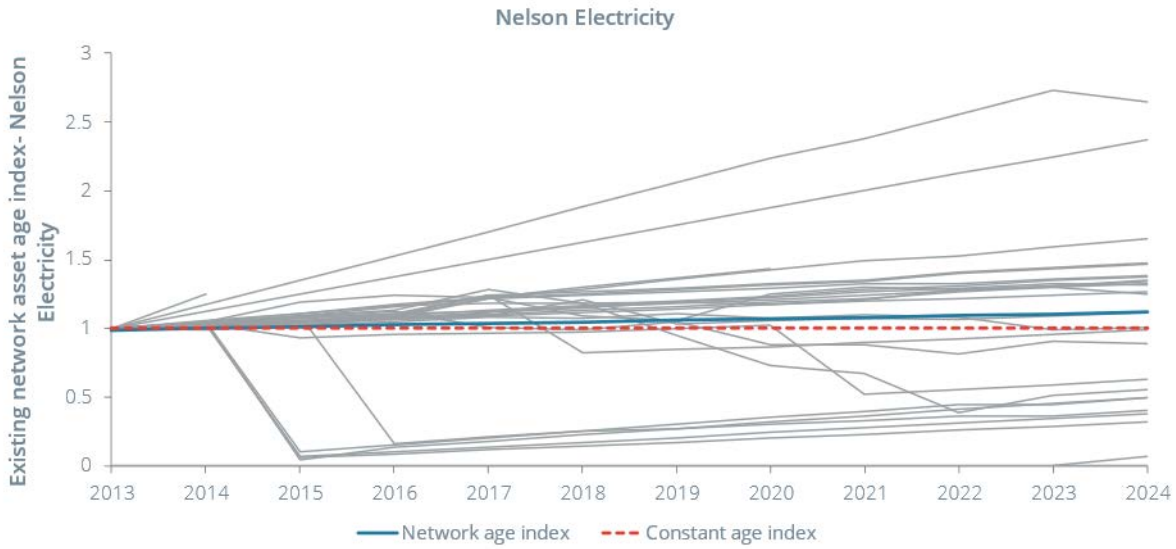
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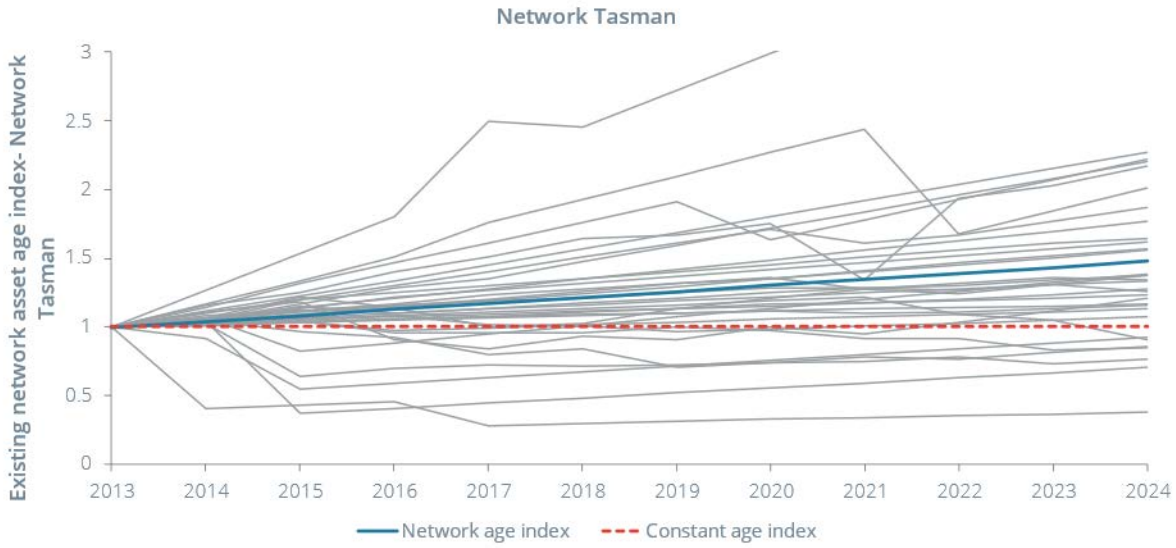
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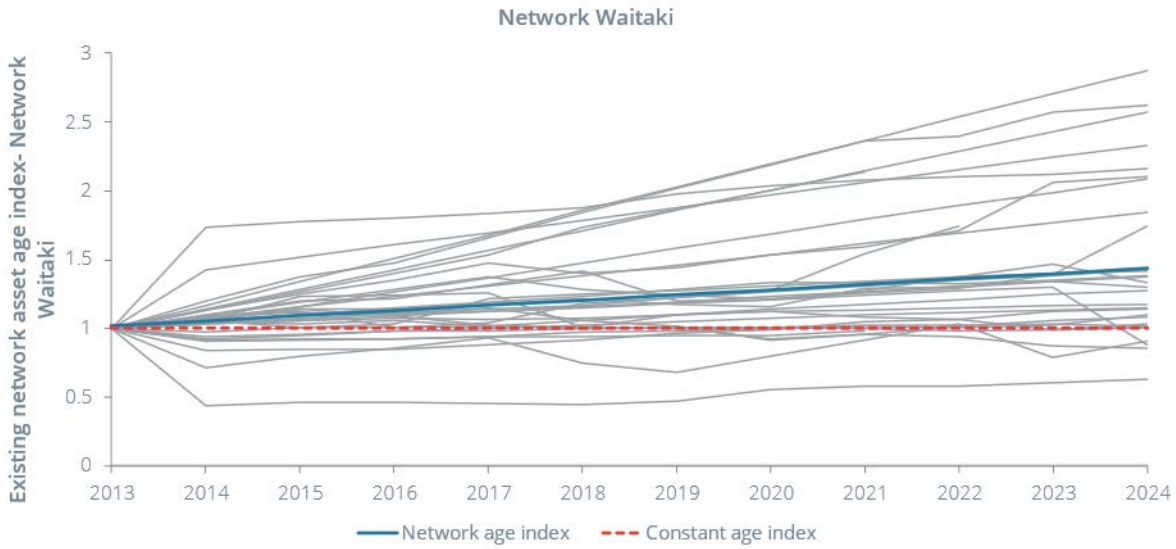
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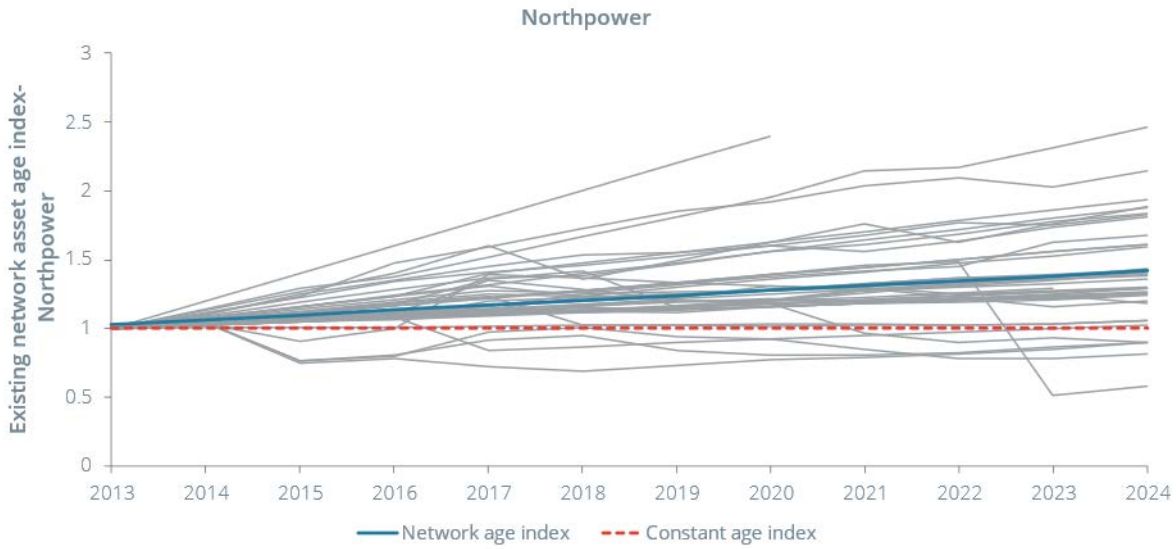
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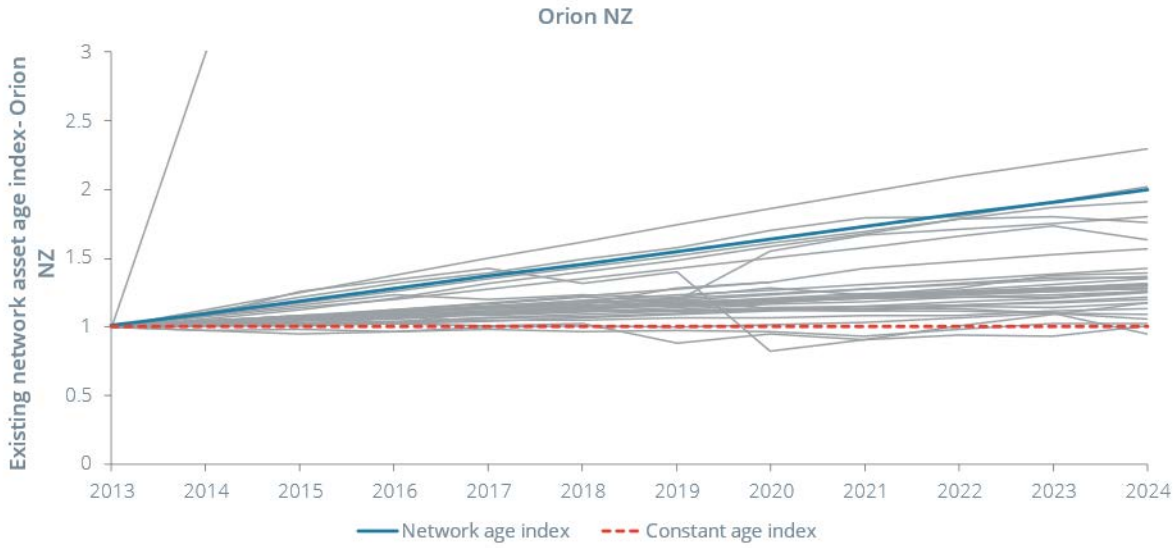
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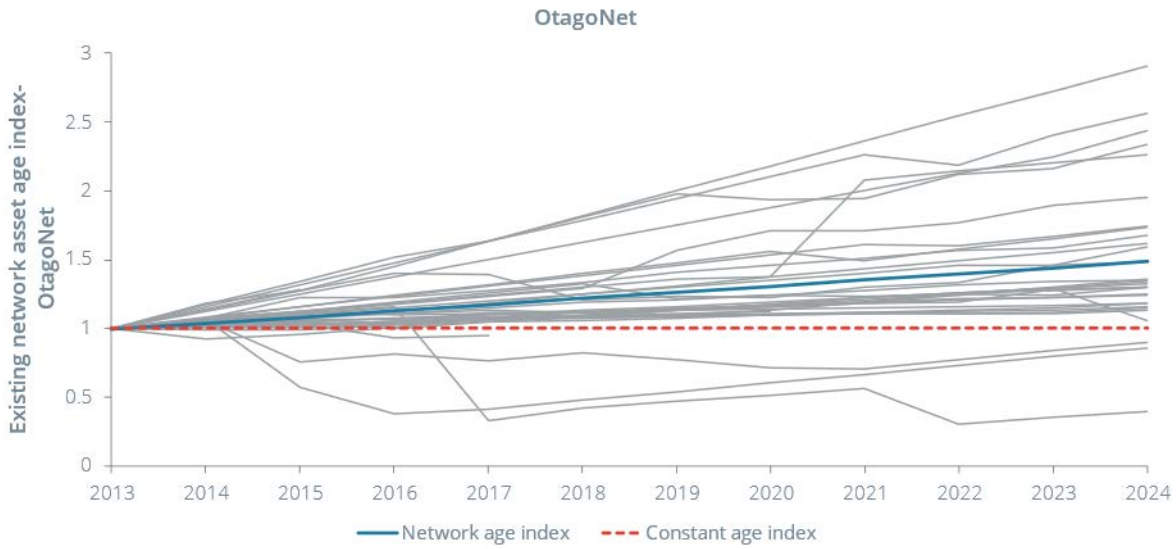
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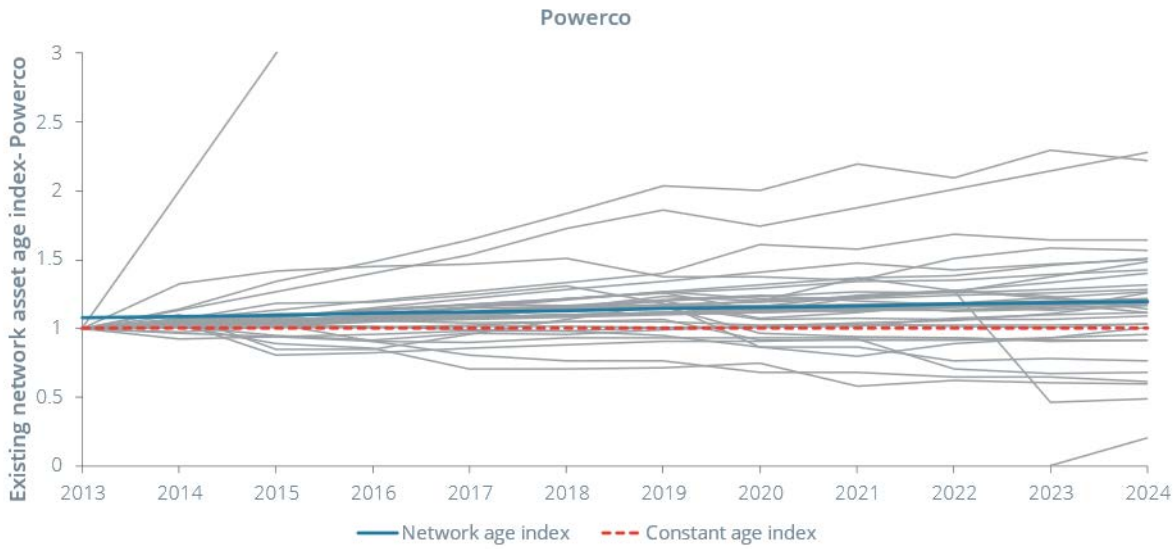
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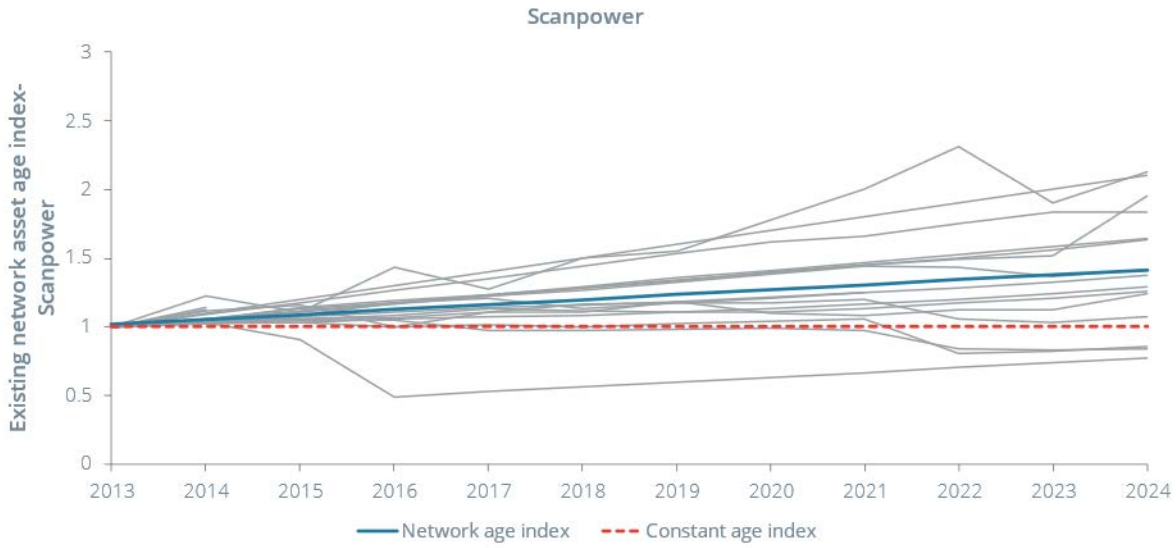
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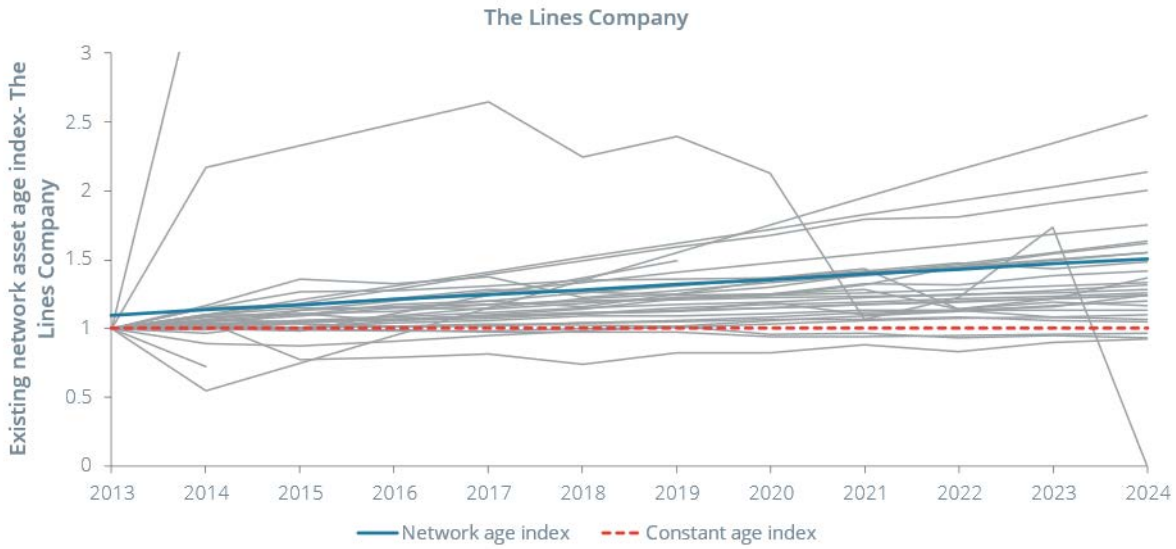
The Lines Company
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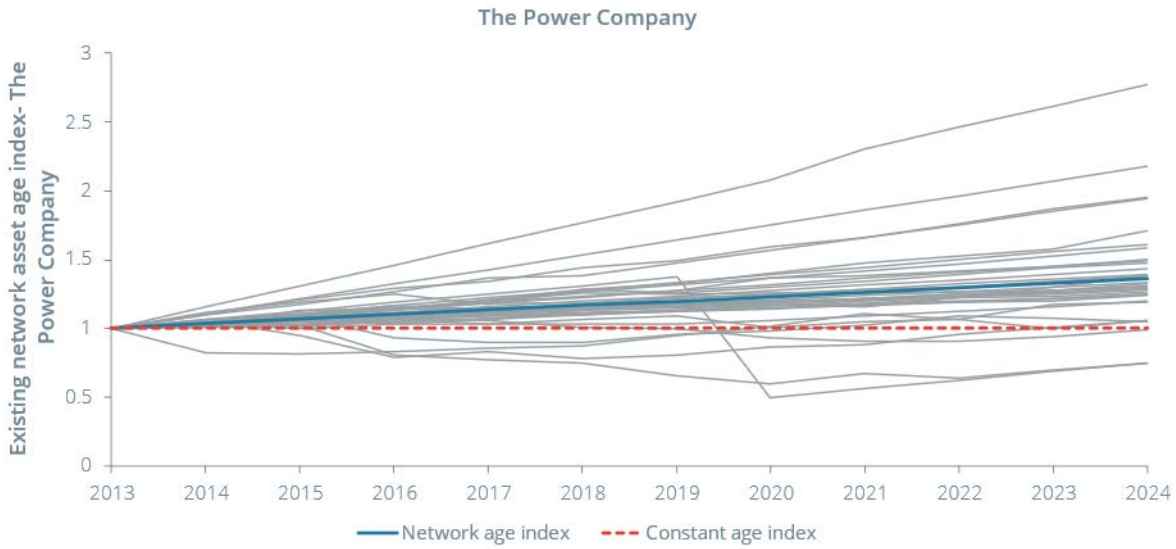
The Power Company
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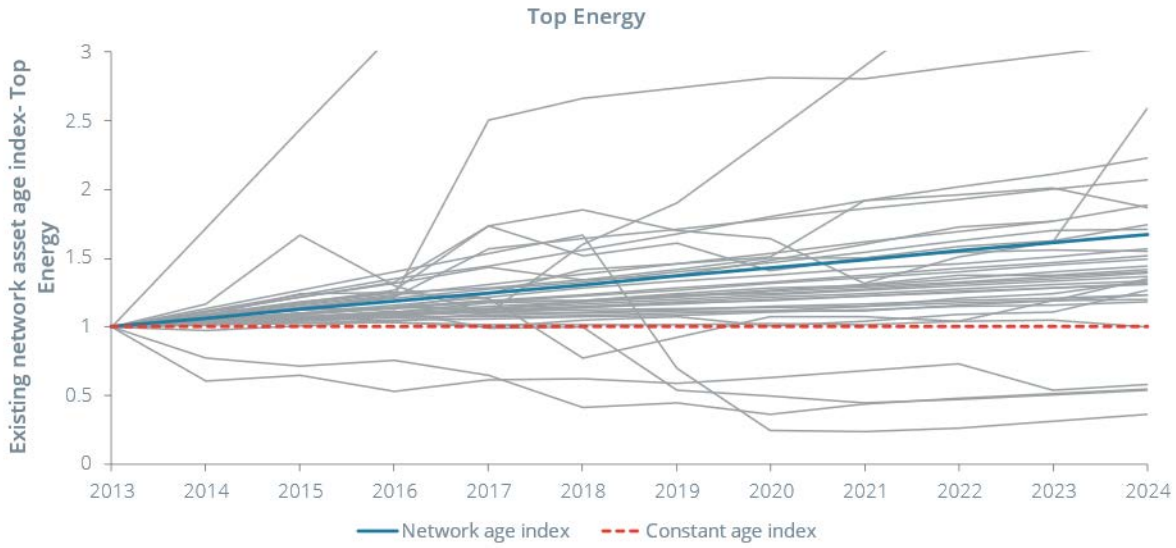
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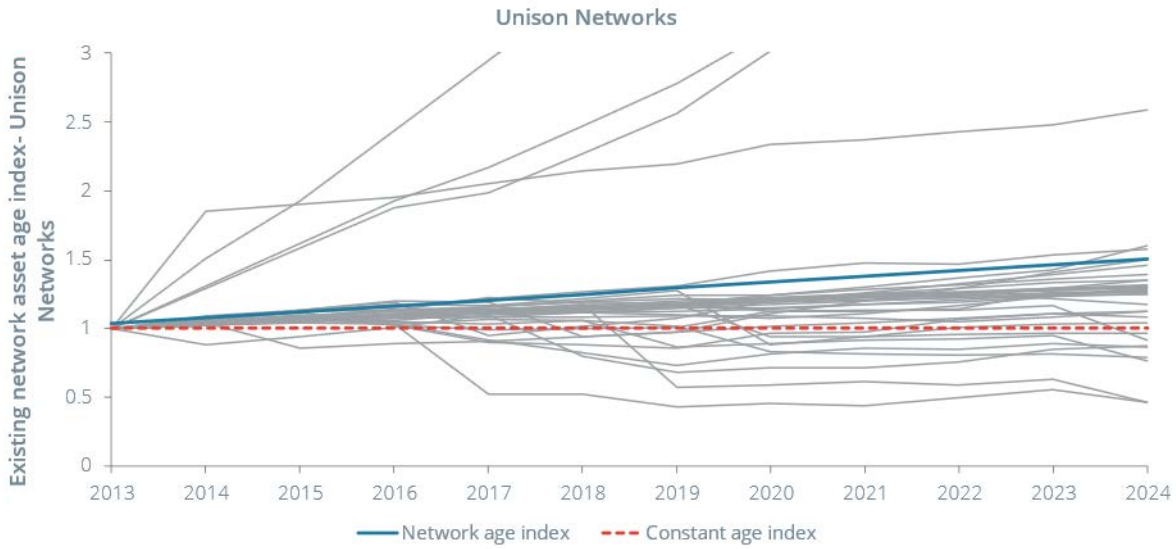
Unison Networks
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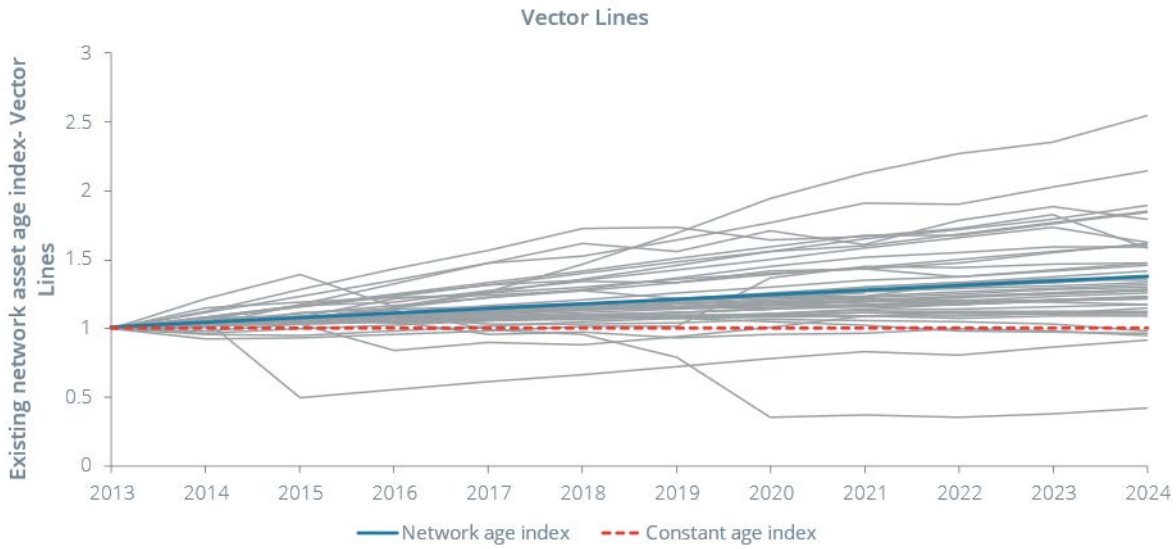
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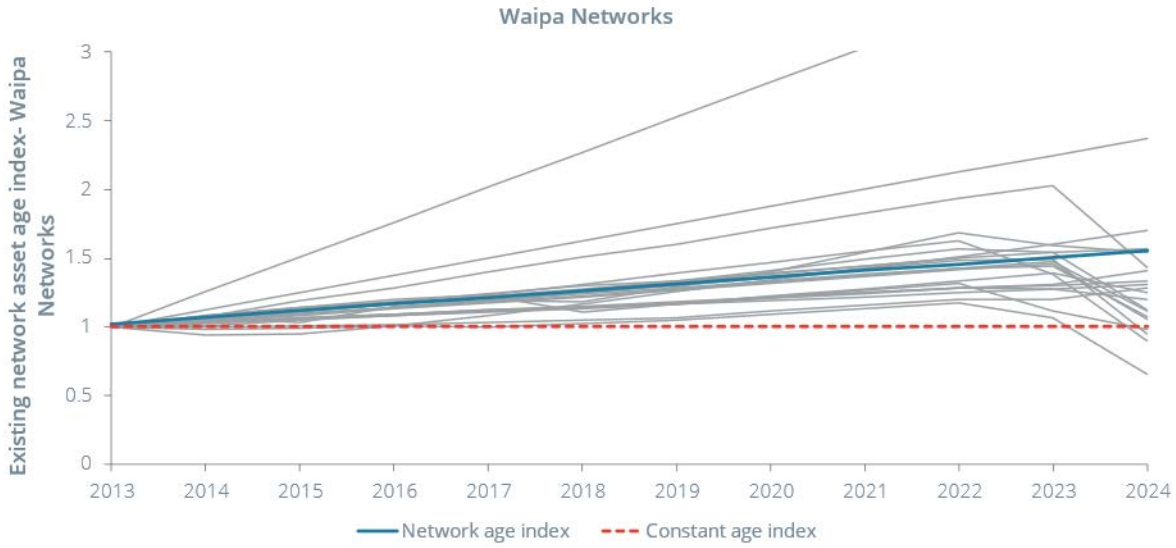
Waipa Networks
Existing network asset age index- Waipa Networks
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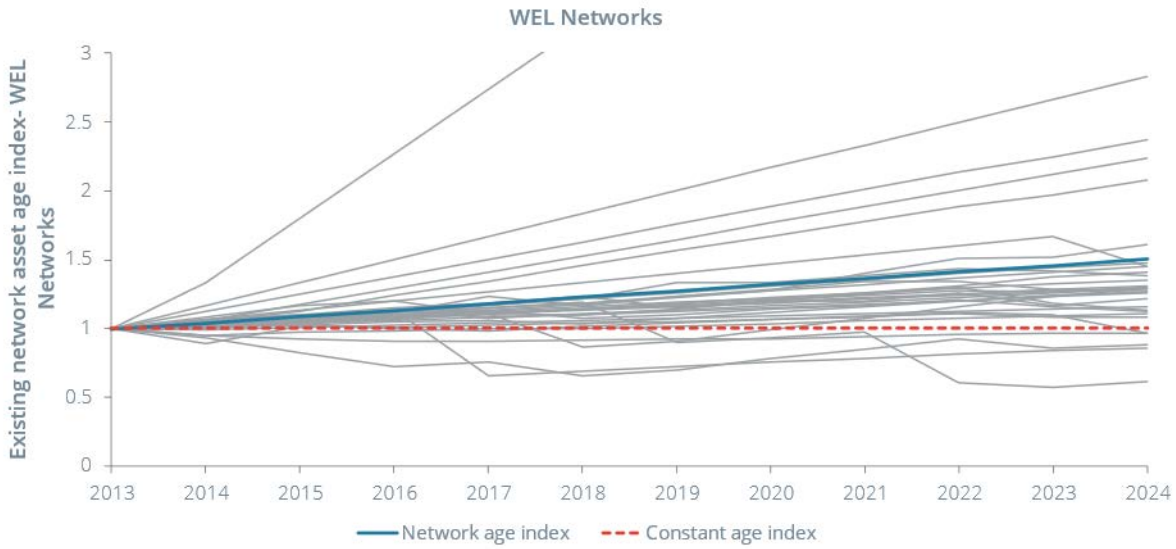
WEL Networks
Existing network asset age index- WEL Networks
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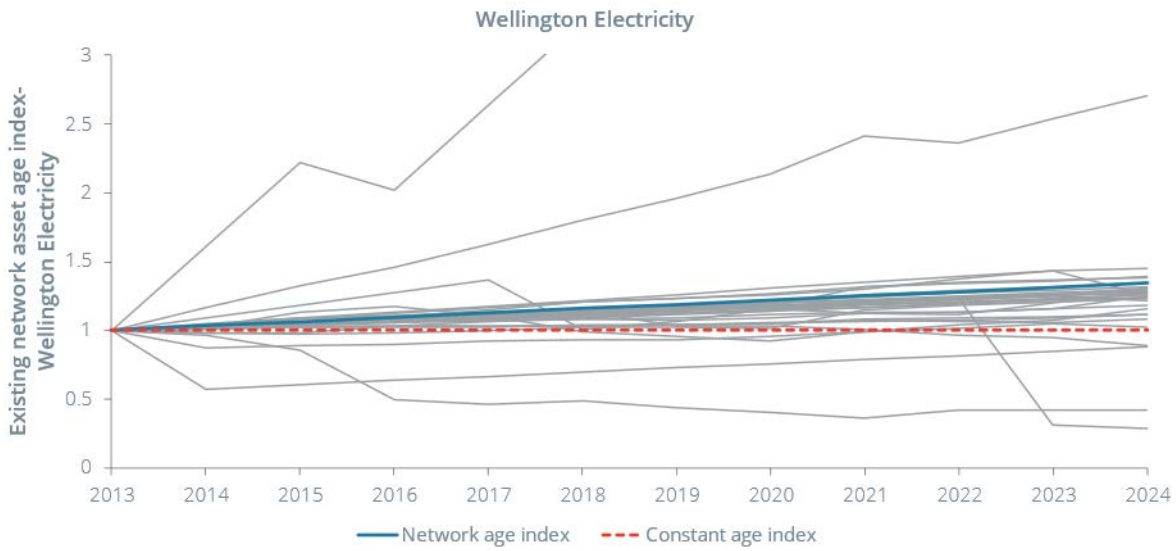
Wellington Electricity
Existing network asset age index- Wellington Electricity
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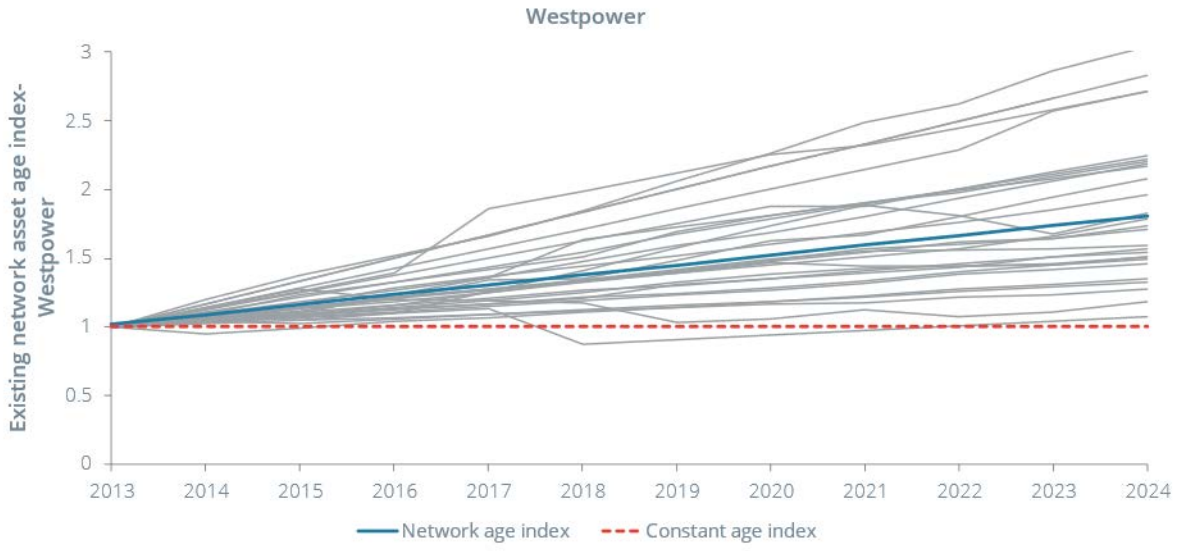
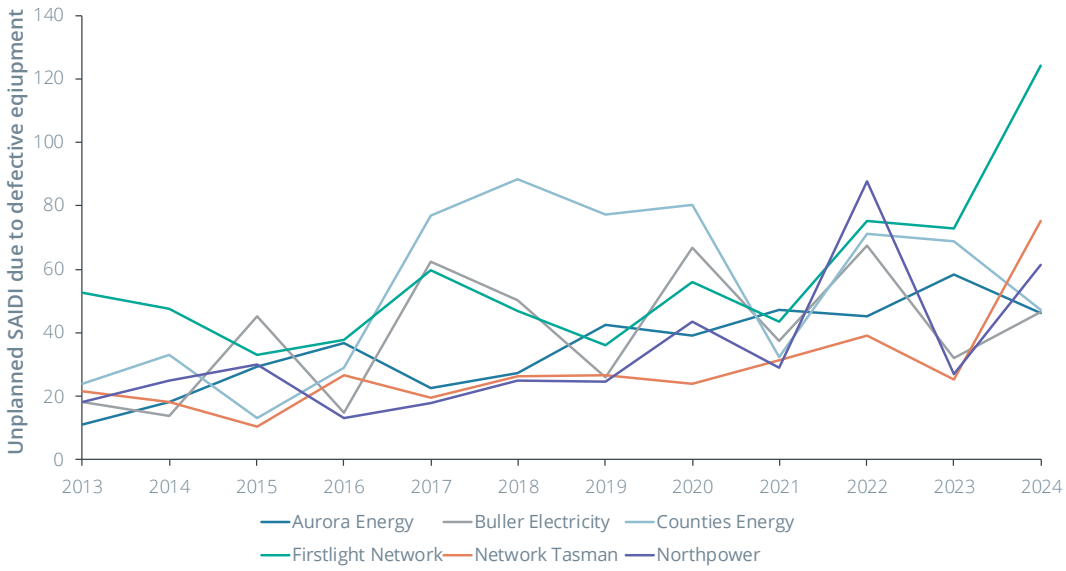


Source: Frontier Economics analysis of EDB information disclosure data

The impact of an increase in the age of assets may be a reduction in reliability, as aging assets become more susceptible to failure, leading to outages experienced by customers. We consider the data on reliability available in the information disclosures.[239] The information disclosure data allows us to observe unplanned outages that are due to defective equipment. These outages can be quantified by the SAIDI[240] measure, a commonly used reliability index which provides the average cumulative outage duration experienced by customers on a network.

Figure 68 below shows that SAIDI, relating to outages caused by defective equipment, has increased over time for a for a number of EDBs. In other words, reliability outcomes associated with defective equipment have deteriorated over time for some EDBs. This is consistent with what might be expected for EDBs with aging assets.

Figure 68: Unplanned SAIDI due to defective equipment



Source: Frontier Economics analysis of EDB information disclosure data.

239 Section 10(ii): Class C Interruptions and Duration by Cause.

240 System average interruption duration index.

C.4 Example of a material issue that has been excluded from the scope of the IMs

Section 8.4.3 explained that the Commission has chosen to exclude a number of important issues from the scope of the IMs. This Appendix provides, for illustrative purposes, details about one of these issues to demonstrate the poor outcomes that can arise from the Commission's discretion to choose the scope of the IMs.

Section 53P(3) of the Act requires that the starting prices for each regulatory period set by the Commission must be either:

- the prices that applied at the end of the preceding regulatory period, or
- prices, determined by the Commission, that are based on the current and projected profitability of each supplier.

To date, the Commission has set starting prices for EDBs that are based on the current and projected profitability of each supplier using a 'building blocks' approach to determine the Maximum Allowable Revenue (MAR) that each EDB may earn in the first year of each regulatory period.[241,242]

However, the Commission has not established an IM that specifies *how* it will set starting prices and, in particular, how it would determine any limit on the extent to which the MAR may increase from the final year of one regulatory period to the first year of the next (sometimes referred to as the 'P0 adjustment' or the 'starting price adjustment').

This was a matter of contention when the Commission established the first IMs in 2010. Following the publication of the 2010 IMs, Vector sought a judicial review of the Commission's decision to not publish an IM detailing how it would reset starting prices for each regulatory period. Vector argued that:

- The absence of such an IM left too much unresolved uncertainty about how the Commission would reset starting prices for each regulatory period. A key purpose of the IMs regime was to provide suppliers and consumers with as much upfront certainty as possible about how each regulatory determination would be made. The absence of an IM explaining how the Commission would approach a task as fundamental as resetting starting prices for each regulatory period fails to provide the level of regulatory certainty that was intended when the Act was amended to create the current regulatory framework.
- The regulatory framework only allows merits reviews to be sought in relation to IM decisions made by the Commission. The absence of this IM means that no party (suppliers, consumers or anyone else) can seek a merits review of the method the Commission ultimately uses to reset starting prices.

241 Commerce Commission, *Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision, Reasons Paper*, 27 November 2019, para. 5.22.

242 The Commission now applies a revenue cap to EDBs. Hence, while the Act refers to "starting prices" the Commission generally refers to "allowable revenues" that EDBs may earn. Commerce Commission, *Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision, Reasons Paper*, 27 November 2019, para. 5.5.

The High Court ruled in favour of Vector.[243] However, the High Court's judgment was subsequently overturned by the Court of Appeal,[244] and the Court of Appeal's judgment was upheld by the Supreme Court.[245]

The question of how the Commission sets starting prices has become important (and is likely to remain important in coming years) because in its most recent regulatory decision for gas pipeline businesses (GPBs) the Commission decided to impose a 10% limit on the starting price adjustment.[246]

This had knock-on implications for the rate of change in regulated prices over the regulatory period:

- In circumstances where the required increase in real prices between the final year of DPP2 and the first year of DPP3 was less than 10%, then starting prices for DPP3 were set to allow full recovery of the MAR for the first year, with no increase in real prices allowed in any subsequent year. This was the situation that applied to Vector. The Commission found that allowing Vector to recover its full MAR in the first year of DPP3 would require a starting price adjustment of 7.7%. Since this represented a real price increase of less than 10%, Vector's starting prices were set in line with its full MAR. Vector's prices were only allowed to increase in line with CPI over the subsequent years of DPP3.
- Where the required increase in real prices between the final year of DPP2 and the first year of DPP3 exceeded 10%, then the starting price adjustment was capped at 10%. However, in these cases the Commission set an "alternative rate of change", whereby the prices of GPBs whose adjustment to starting prices was capped at 10% were allowed real increases in prices over the regulatory period. This was the situation faced by GasNet, Powerco, First Gas Distribution and First Gas Transmission.

Importantly, the Commission capped the annual real increase in the MAR for all GPBs at 10% per annum.

Hence, there is an important relationship between the starting prices set by the Commission and the extent to which the price limit in subsequent years may bind.

- If the full starting price adjustment was allowed by the Commission, then there would be no need for any real increases in prices over the remaining years of the regulatory period. In turn, this would mean that any limit on the increase in prices in subsequent years would be less likely to bind.
- However, if the starting price adjustment was capped by the Commission, then any price limit imposed by the Commission for subsequent years would be more likely to bind, because some increase in the supplier's real prices in those years would be necessary to recover the MAR over the period.

That is to say, in situations where the Commission decides to cap the adjustment to starting prices, there may be a need for prices in subsequent years of the regulatory period to increase by more than CPI in order for the supplier to be made whole over the regulatory period.

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243 *Vector Ltd v Commerce Commission*, [2011] NZHC 976.

244 *Commerce Commission v Vector Ltd* [2012] NZCA 220, [2012] 2 NZLR 525.

245 *Vector Ltd v Commerce Commission*, [2012] NZSC 99.

246 It is worth noting that the Commission only decided to cap the starting price adjustment for GPBs at DPP3, when the MAR increased from DPP2 levels. The Commission did not limit the starting price adjustment for GPBs (or EDBs) in prior regulatory periods when the MAR was reduced from one period to the next. In other words, the Commission has applied limits on the starting price adjustment in an asymmetric way.

However, a limit on annual price increases in subsequent years of the regulatory period could result in the supplier recovering less than its MAR over the period.

It is not at all clear that any of these outcomes were (or could have been) anticipated by the Court of Appeal or the Supreme Court that upheld the Commission's decision to not develop an IM that specified how starting prices would be reset. At the time those judgments were handed down, the Commission had not yet made any regulatory determinations under the Part 4 regime. It certainly had not foreshadowed that it might impose a limit on the starting price adjustment. Indeed, this is a relatively new development that, for the reasons explained above, could have important implications for investment incentives.

In response to the Commission's draft DPP3 decision for GPBs, Vector raised concerns that the 10% cap on the starting price adjustment applied by the Commission appeared to be arbitrary and noted that the Commission had not presented any analysis as to how it had arrived at that number.[247] In other words, Vector was concerned that the Commission had not presented any reasoning at all to justify its 10% limit on the starting price adjustment.

The Commission's response to Vector's concerns was that the choice of the 10% figure was a "judgement call" (i.e., it was not underpinned by any testable evidence or analysis). The only justification that the Commission offered for the figure was that it had been used in previous decisions:

> *The 10% cap was a judgement call and reflected a balance between ensuring prices reflect the costs of providing the service, including the impact of shorter economic lives of assets, and minimising price shocks to consumers. The value of 10% has been used in a number of previous resets, for example in the 2010 to 2015 reset for Alpine Energy Limited, Centralines, The Lines Company, and Top Energy Limited where a 10% cap on price increases was applied.*[248]

It is highly unlikely that such an explanation would have withstood a merits review challenge, had it been provided by the Commission as part of an IM decision. However, the Commission was immune to any such appeal because its decision to impose a limit on the starting price was made as part of the price-quality determination.

In summary, the Commission has recently introduced a cap on starting price adjustments for some suppliers (i.e., GPBs) that:

- Was not foreshadowed at the time the Court of Appeal and the Supreme Court handed down judgments in relation to Vector's application for judicial review of the Commissions' decision not to publish an IM that specified how starting prices would be reset.
- Was not supported using any testable evidence or analysis. Rather, the Commission has simply noted that the cap is a matter of judgement.
- May result in suppliers being unable to recover their efficient costs over a regulatory period because the imposition of the cap may require prices in subsequent years to increase in real terms, but those price increases may also be limited by the Commission.

[247] Vector, *Default Price-Quality Paths for Gas Pipeline Businesses from 2022 Submission on the Commerce Commission's Draft Decision*, 14 March 2022, p. 27.

[248] Commerce Commission, *Default price-quality paths for gas pipeline businesses from 1 October 2022, Final Reasons Paper*, 31 May 2022, para. 4.41.

- Cannot be subjected to merits review by suppliers, consumers or any other party because the Commission has not developed an IM that specifies how it will reset starting prices, and only IMs may be subjected to merits review under the current regulatory framework.
- It may or may not decide to extend to other suppliers (e.g., EDBs) in future. Given that the limit on starting price adjustments imposed by the Commission on GPBs was based only on its judgment, there is no way to anticipate what circumstances the Commission may deem it appropriate to extend the cap to other suppliers. It was precisely this kind of uncertainty that the regulatory framework sought to avoid.

D Transmission and system operation appendix

D.1 Introduction

This appendix provides a further exploration of the approach to transmission pricing in New Zealand.

D.2 Transmission pricing

Changes to connection charges to address first mover disadvantage

The Electricity Authority identified two types of first mover disadvantage (FMD).

The **Type 1 FMD** issue arises if the initial transmission customer that is charged for a connection investment (the first mover) continues to bear the full cost of the connection even if other customers later connect to the asset. This may cause customers to delay their connection to avoid becoming the first mover, potentially slowing investment in new generation or in the electrification of load. To address this, the proposed TPM contains a mechanism to collect a financial contribution from second and later connecting parties towards the capital cost of the connection investment that was funded by a first mover customer. This is commonly referred to as a pioneer scheme.

The **Type 2 FMD** issue arises if an initial connecting customer must carry the full cost of connection capacity in excess of its own requirements, until subsequent movers connect. The anticipatory capacity is being built for future, uncertain, customers. This creates uncertainty and cost for the first mover that may discourage it from agreeing to anticipatory capacity, even if building this now would be efficient (because building one bigger asset now is usually cheaper than building two smaller assets – one now and another later – that add up to the same capacity). These effects could lead to inefficiently undersized connection investments or deter connection by first movers.

To address Type 2 FMD, the Electricity Authority has adopted a hybrid approach. This involves allocating 50% of the capital cost of anticipatory capacity to identified regional beneficiaries under a benefit-based approach (using the simple method regional allocation tables), and allocating the remaining 50% of the capital cost of anticipatory capacity to all transmission customers under a "pool-and-share" approach, through an addition to the asset component of the connection charge.

Allocation of benefits for benefit based charges

The TPM sets out three methods for determining the allocation of the costs of a BBI, and which approach applies depends on the type and size of the project.

The **simple method** applies to BBIs that, at the time of the investment decision, are expected to cost $20 million or less. It is designed to be a relatively simple approach to allocate the covered cost of low-value BBIs. It does this by using standardised regions and customer groups that are determined for a fixed (typically 5-year) period. Allocations are based on a customer group's historic grid use (mean historic offtake or mean historic injection).

The TPM requires that 67.5% of the covered cost of any low-value BBI be allocated to load and 32.5% to generation. In its Final Decision, the EA decided that a load to generation weighting of 62.5%:37.5% would likely promote its statutory objective. In reaching this view, the EA relied on:

- the underlying logic that outages have a higher impact on consumers than generators (as reflected in the value of lost load relative to wholesale market prices as a broad indicator of relative value); and
- the harm to consumers of over-allocating costs to generators being likely worse than over-allocating costs to load, given that unnecessarily loading costs on generators inefficiently delays entry of new generation.

The **price-quantity method** applies to BBIs that exceed $20 million, and which are not covered by the resiliency method. This involves estimating the regional net private benefit of a BBI for each modelled region and customer group, and allocating these to customers within each customer group based on historic grid usage. A customer's starting allocation for the BBI is its individual net private benefit divided by the sum of all customer's individual net private benefit.

The price-quantity method requires consideration of four types of benefits:

- market benefits, which are material impacts on prices or quantities in wholesale market
- ancillary service benefits, which are material reductions in allocable cost of ancillary services
- reliability benefits, which are material reductions in unserved or unsupplied energy, and
- other benefits, which are subject to limits but may include, for instance, safety improvements

The **resiliency method** applies to the subset of BBIs for which the primary purpose is to mitigate a risk of cascade failure or another high impact, low probability (HILP) event resulting in unserved or unsupplied energy. Unlike the price-quantity method, the resiliency method only uses one modelled region (the region that would be affected by the HILP event or cascade failure risk) and one customer group (all the offtake customers located in the modelled region, except grid connected batteries).

Allocations are based on customer's mean annual offtake over the five years preceding the final investment decision date for the BBI. The EA has noted that allocation solely to load would achieve allocations that are broadly in proportion to expected positive net private benefits, "because of the large difference between the value of lost load (~20k/MWh) and the per MWh operating profit of generation….".

E Market institutions and market monitoring appendix

E.1 Introduction

This appendix sets out the approach to rule making in Australia, noting the recommendation contained in section for New Zealand to adopt a similar approach. It also provides further detail on our review of international approaches to market monitoring.

E.2 Australian rule making framework

AEMC's role

The Australian Energy Market Commission (AEMC) is responsible for making and amending the National Energy Rules under the National Energy Laws:

- National Electricity Law (NEL)
- National Gas Law (NGL)
- National Energy Retail Law (NERL)

Under the National Energy Laws, AEMC's work is guided by three legislated national energy objectives:

- National electricity objective (NEO)
- National gas objective (NGO)
- National energy retail objective (NERO)

Rule change process

However, a unique aspect of AEMC's role is that any party, except for the AEMC, can propose changes to the rules. There are four types of rule changes processes which operate to different timeframes that the AEMC can undertake: standard rule changes; expedited rule changes; fast-tracked rule changes; and trial rule changes.

There are a number of formal stages in a rule change process (Figure 69):

1. Proponent submits rule change request
2. The AEMC commences rule change process and seeks submissions on rule change request (e.g., AEMC will typically publish a consultation paper at the start of the rule change process)
3. Stakeholders (including the proponent, if they wish) lodge submission on rule change proposal
4. AEMC publishes draft rule determination and seeks submissions on the draft determination
5. Stakeholders (including the proponent, if they wish) lodge submission on draft rule determination, and
6. AEMC publishes final rule determination

Figure 69: AEMC's standard rule change process

Source: AEMC - A guide to the rule change process

Further details on the other three types of rule change processes are available in AEMC's Guide to the rule change process.[249]

Key information to include in a rule change request submission[250]

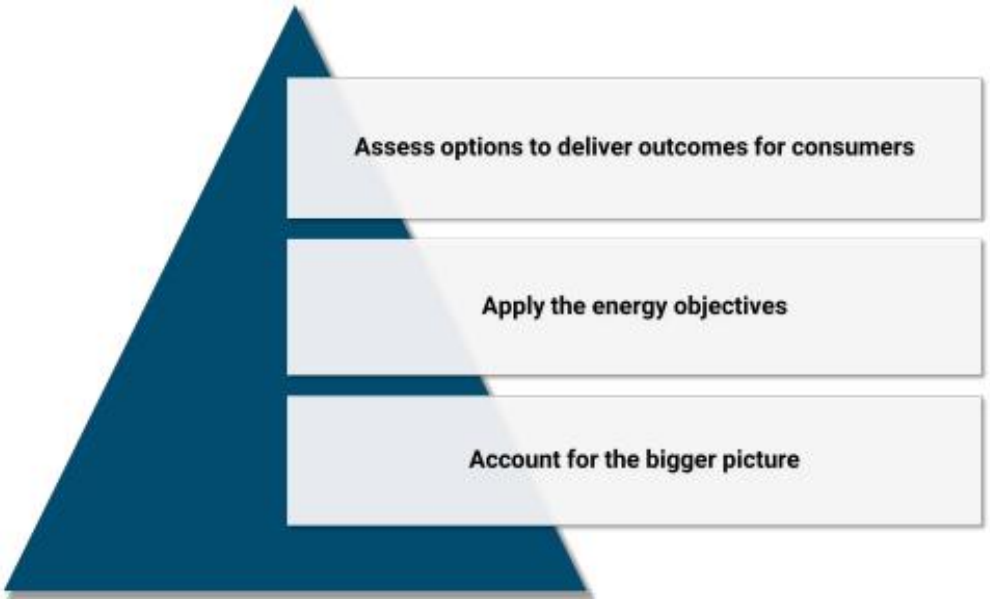
The rule change request must be submitted in the form of a written submission to AEMC and must contain certain information including:

- a statement of the nature and scope of the issue(s) concerning the existing rules that is to be addressed by the proposed rule change request and an explanation of how the proposed rule change request would address the issue(s). The AEMC may only make a rule change if it is satisfied that the rule change will or is likely to better contribute to the achievement of the energy objectives - focusing on the long-term interest of consumers. (Figure 70) If the rule change request is under the National Energy Retail Rules, it is also important to consider if it is likely to meet the consumer protection test.

249 https://www.aemc.gov.au/sites/default/files/2020-12/A%20guide%20to%20the%20rule%20change%20process_20201208.pdf, p5-6

250 https://www.aemc.gov.au/sites/default/files/2020-12/A%20guide%20to%20the%20rule%20change%20process_20201208.pdf, p6

Figure 70: AEMC's high-level decision-making framework



Source: AEMC

- an explanation of how the proposed rule change request will or is likely to contribute to the achievement of the relevant energy objective. The AEMC determines whether to make or amend rules by applying the relevant energy market objectives.[251] The AEMC may only make a Rule if it is satisfied that the Rule will, or is likely to, contribute to the achievement of the relevant energy objective. [252] The national energy laws also set out various other rule making tests for the AEMC to apply in certain cases, for example the NEL outlines the following rule making tests that the AEMC must take into account in certain cases:[253]
- form of regulation factors (Box 7)
- revenue and pricing principles (Box 7)
- innovative trial principles in certain cases
- certain matters in relation to the making of jurisdictional derogations, and
- an explanation of the expected potential impacts of the proposed change to the rules on those likely to be affected.

Box 7: Form of regulation factors and the revenue and pricing principles

The national energy laws also set out various other rule making tests for the AEMC to apply in certain cases. In addition, AEMC may give such weight to any aspect of the national energy objectives as it considers appropriate in all the circumstances and the AEMC must have regard to any relevant MCE statement of policy principles.[254]

[251] in the case of the NER, the National Electricity Objective in section 7 of the National Electricity Law (NEL). In the case of the NGR, the National Gas Objective in section 23 of the National Gas Law (NGL). In the case of the NERR, the National Energy Retail Objective in section 13 of the National Energy Retail Law (NERL).

[252] AEMC, How the national energy objectives shape our decisions, March 2024

[253] Part 7, Division 1, Subdivision 2 of the NEL

[254] https://www.aemc.gov.au/regulation/energy-rules/mce-statements-policy-principles

In the NEL and NGL, an example of other rule making tests that the AEMC must take into account include: the form of regulation factors; and the revenue and pricing principles in making a rule.

Source: Part 7, Division 1, Subdivision 2 of the NEL, Chapter 9, Part 1, Division 2 of the NGL

Note that in the case of a rule change request from an energy regulatory body that could be a "fast tracked" rule, a summary of the consultation conducted by the energy regulatory body is required.

AEMC's considerations when deciding whether to initiate a rule change process

Following receipt of the rule change, the AEMC decides whether to formally initiate the rule change process after considering whether:[255]

- the rule change request adequately addresses the issues raised in the initial submission
- the rule change request appears not to be misconceived or lacking in substance
- the subject matter of the rule change request appears to be within the scope of the AEMC's powers to make a rule
- the subject matter of the rule change request appears not to relate to a rule made (or not proceeded with), in the previous 12 months or if the AEMC are already taking action in relation to the subject matter. In this case, the AEMC may decide to consolidate a rule change request with another rule change request if it considers it necessary or desirable that they should be dealt with together.

To do this AEMC firstly assesses whether a new or amended rule is necessary. To determine this, AEMC relies on the COAG principles as a guide to best practice regulation (Box 8).

Box 8: COAG principles

[255] https://www.aemc.gov.au/sites/default/files/2020-12/A%20guide%20to%20the%20rule%20change%20process_20201208.pdf, p7

The COAG guide to best practice regulation sets out the principles for regulatory processes that are to be applied by governments, ministerial councils and national standard setting bodies, which reflect a commitment to establish and maintain effective arrangements to maximise the efficiency of new and amended regulation and avoid unnecessary compliance costs and restrictions on competition:

- establishing a case for action before addressing a problem
- a range of feasible policy options must be considered, including self-regulatory, co-regulatory and non-regulatory approaches, and their benefits and costs assessed
- adopting the option that generates the greatest net benefit for the community in accordance with the Competition Principles Agreement,[256] legislation should not restrict competition unless it can be demonstrated that:
  - the benefits of the restrictions to the community as a whole outweigh the costs, and
  - the objectives of the regulation can only be achieved by restricting competition
- providing effective guidance to relevant regulators and regulated parties in order to ensure that the policy intent and expected compliance requirements of the regulation are clear
- ensuring that regulation remains relevant and effective over time
- consulting effectively with affected key stakeholders at all stages of the regulatory cycle
- government action should be effective and proportional to the issue being addressed

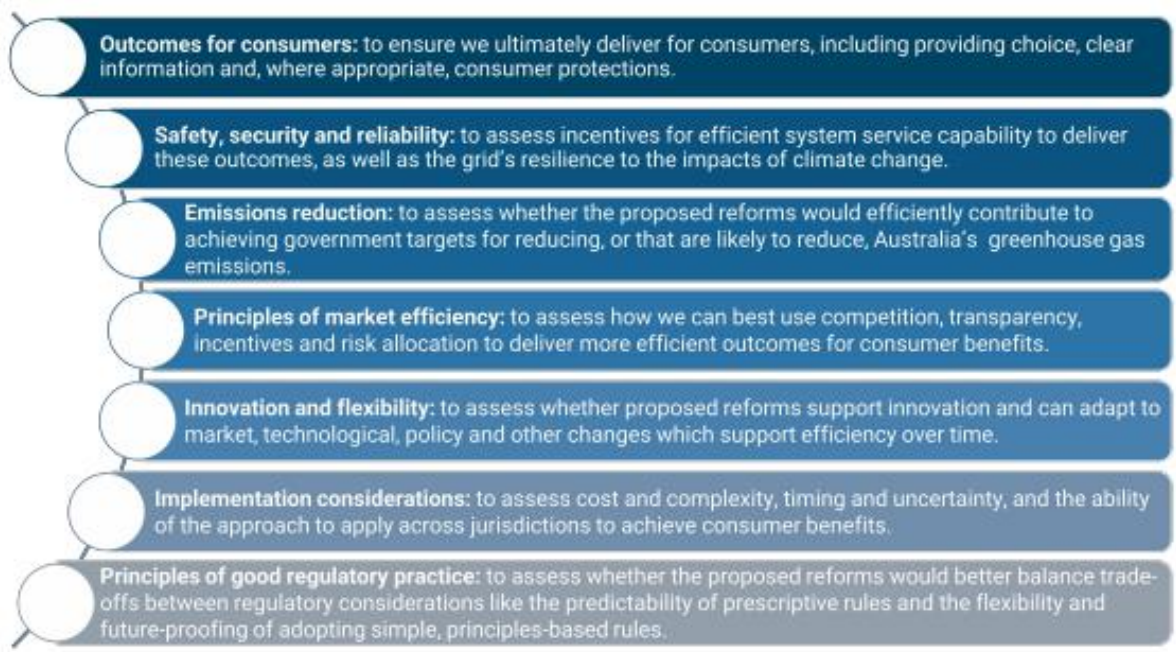
Source: COAG Best Practice Regulation: A guide for Ministerial Councils and National Standards Setting Bodies, October 2007 (the COAG Guide), page 4.

[256] The Competition Principles Agreement forms a part of a series of initiatives adopted by Australian governments to promote competitive markets in Australia. This agreement sets out principles for implementing competition policies, including the review and reform of restrictive regulation, competitive neutrality and third party access to infrastructure services.

As part of abiding by the COAG principles is examining whether there is actually an issue, and then deciding whether any action is in fact required, and if so, whether a rule change or new rule is the most appropriate response. Whilst a rule change may initially be seen as the only option to ensure certainty of results and deliver direct outcomes, unnecessary regulation can create another layer or complexity and red tape which should be avoided whenever possible. As such, it is important to adopt the most efficient and effective regulatory solution in a particular case. Other possible alternatives to a rule change that AEMC will consider include changes to existing guidelines or procedures, changes to standards or codes, agreements between market participants/representatives and administrators and regulators, some combination of these options.

AEMC have also developed assessment criteria for addressing its decisions against national energy objectives (Figure 71).

Figure 71: AEMC's rule change assessment criteria[257]



Source: AEMC

E.3 Summary of market monitoring arrangements in other jurisdictions

Western Australia, Australia (WEM)

Market design

The WEM includes both capacity and energy market mechanisms. On the capacity market side, there is the Reserve Capacity Mechanism through which AEMO procures capacity to ensure resource adequacy within the SWIS. On the energy market side, the market is a net pool with a day ahead market (STEM), which allows participants to trade around their bilateral energy positions one day in advance, and the real-time market (RTM), which is a gross pool dispatch

[257] https://www.aemc.gov.au/sites/default/files/2023-09/Publication2%20-%20Guide%20to%20AEMC%20decision%20making%20-%20Sep%202023.pdf

mechanism that balances out differences between participants' contractual positions and actual physical outcomes.

WA's Reserve Capacity Mechanism (RCM) is a key component of the WEM to ensure sufficient capacity is available to meet peak demand. RCM operates on a 4-year cycle where AEMO procures capacity 2 years ahead before it is needed. RCM awards tradable Capacity Credits to projects in exchange for making capacity available in a specific Capacity Year. It is a price-based mechanism to determine the value of capacity needed in the system.[258]

As of October 2023, the real time market operates under security constrained economic dispatch via the WEM Dispatch Engine (WEMDE) with separate formal markets for energy and ancillary services.

Market monitoring and compliance

The WEM rules set out the ERA and AEMO's roles in monitoring of compliance in the WEM.

Every 3 years, the ERA conducts a review of the effectiveness of the WA WEM for the Minister for Energy. [259] The ERA regularly monitors how effectively the Wholesale Electricity Market meets the market objectives and investigates any behaviour that has resulted in the market not functioning effectively. This includes:

- Inappropriate and anomalous market behaviour, including the abuse of market power and exploitation of any shortcomings of the Wholesale Electricity Market Rules.
- Market design and market structure problems.
- The effectiveness of procurement processes of ancillary and balancing support services, including ancillary service contracts and balancing support contracts.

AEMO is responsible for collection of, and providing access to, data in accordance with this section 2.16. AEMO must compile the data identified in the Market Surveillance Data Catalogue and provide access to that data to the Coordinator and the Economic Regulation Authority. AEMO must develop a Market Surveillance Data Catalogue, which identifies data to be compiled concerning the market.

The ERA has a monitoring protocol market procedure which is relies on to monitor Rule Participants' compliance with market rules. [260]

The ERA prioritises WEM monitoring into three categories:[261]

- (a) Mandatory: Areas the WEM Rules mandate that the ERA must monitor.
- (b) Risk-based: Areas the ERA has identified as requiring monitoring from the risk assessment process.
- (c) Trend-based: Areas the ERA has decided to prioritise for monitoring based on its observations of the market.

[258] https://www.lantaugroup.com/files/ppt_wa_mtt.pdf

[259] https://www.erawa.com.au/cproot/23010/2/-WEM.Rep.2022---Triennial-review-of-the-ale-Electricity-Market-2022---Report-to-the-Minister-for-Energy---Clean-version.PDF

[260] https://www.erawa.com.au/cproot/24375/2/GB-SUB-77-2025-Attachment-2-Monitoring-Protocol-v7-0-WEM-Procedure-clean-version.PDF

[261] https://www.erawa.com.au/cproot/24375/2/GB-SUB-77-2025-Attachment-2-Monitoring-Protocol-v7-0-WEM-Procedure-clean-version.PDF cl 3.2.1

- The ERA will monitor Rule Participants' compliance using various methods, including but not limited to:[262]
- (a) Market intelligence: Assessing information received from stakeholders that may identify matters requiring further investigation.
- (b) Market monitoring: Analysing market related information, data and documents, including that provided by AEMO, through a suite of tools and systems (e.g., bidding and pricing information, dispatch data, outage data etc) which may identify potential areas of non-compliance.
- (c) Targeted compliance activities: Targeted reviews of Rule Participants may be carried out to assess compliance with specific WEM Rule obligations or groups of obligations, or areas identified as being of particular compliance concern, or where monitoring is required because the WEM Rules provide for special arrangements.
- The ERA will publish a list of: (a) The types of market related data, information or documents provided by AEMO under clause 2.13.4 of the WEM Rules (b) WEM Rules that AEMO monitors for compliance on the ERA website.

Compliance framework[263]

The ERA's compliance approach is published in its Compliance Framework and Strategy document which is updated from time to time.[264] This document is aimed at encouraging compliance by Rule Participants with the WEM Rules and WEM Procedures with the target of achieving high levels of compliance using a risk-based approach.

The risk-based approach involves assessing the compliance risk associated with an obligation or set of obligations under the WEM Rules and/or WEM Procedures. These assessments will assist the ERA in determining planning and monitoring activities, investigation priorities and compliance actions.

Germany

Market design

The German wholesale electricity market is an energy only market. It features four 'control areas', each with its own transmission system operator (TSO). Electricity trade can occur within and between control areas as well as interconnected countries.

Germany has a forward market, a day-ahead market and an intraday market, although most volumes are sold OTC in long-term bilateral contracts[265]. The intraday market is 'real-time', with gate closure for intraday trading being five minutes within local control areas, 30 minutes between control areas, and 60 minutes across borders[266]. interconnected regions (i.e. other countries)[267]. Futures and forward products can be traded on exchanges or OTC respectively up to six years in advance.

Submarkets of the German electricity market are illustrated in Figure 72.

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262 https://www.erawa.com.au/cproot/24375/2/GB-SUB-77-2025-Attachment-2-Monitoring-Protocol-v7-0-WEM-Procedure-clean-version.PDF cl 3.2.2

263 https://www.erawa.com.au/cproot/24375/2/GB-SUB-77-2025-Attachment-2-Monitoring-Protocol-v7-0-WEM-Procedure-clean-version.PDF

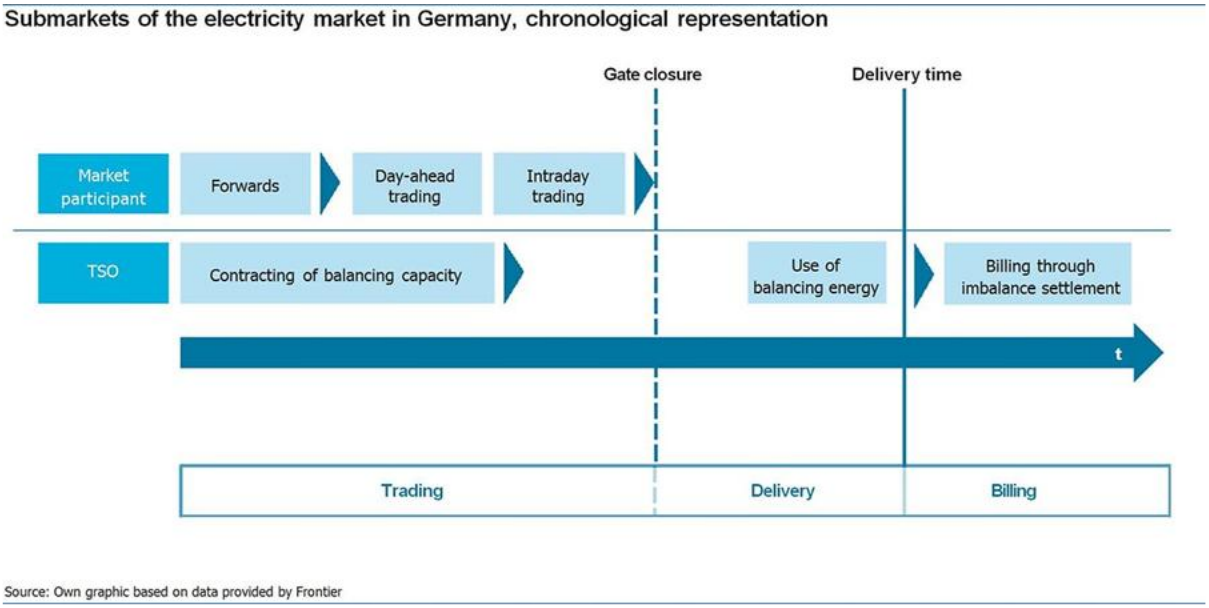
264 https://www.erawa.com.au/cproot/23587/2/Compliance-Framework-and-Strategy-WEM-GSI-and-PNR-v3.0.PDF

265 https://www.lexology.com/library/detail.aspx?g=7c115c26-2be2-4ff6-8916-a929c90b7b6d

266 https://www.smard.de/page/en/wiki-article/6076/5976

267 https://www.smard.de/page/en/wiki-article/6076/5976

Figure 72: German electricity submarkets



Source: smard.de

Market monitoring and compliance

The Bundesnetzagentur's monitoring tasks are set out in the Energy Act (EnWG). As part of its activities the Bundesnetzagentur conducts an annual survey of companies in the energy market. The Bundesnetzagentur is required to publish a report annually on the results of its monitoring activities, conducted in the performance of its regulatory tasks in the electricity and gas sectors, most notably to create transparency in the markets.[268]

Texas, USA

Market design

The Texas market is an energy-only market that balances competitive wholesale and retail electricity markets within the Texas grid. Wholesale participants include generators and Qualified Scheduling Entities (QSEs), while retail customers are served by Retail Electric Providers (REPs). ERCOT is independent of federal oversight and governed by the Public Utility Commission of Texas (PUCT), managing the grid's reliability, operations, and market functions.

ERCOT features both a Day-Ahead Market (day-ahead market) and a Real-Time Market (RTM). The day-ahead market allows participants to schedule electricity and ancillary services a day in advance, while the RTM addresses real-time adjustments to supply and demand using Security-Constrained Economic Dispatch (SCED).

ERCOT incorporates scarcity pricing through mechanisms like the Operating Reserve Demand Curve (ORDC), which increases prices during low reserve conditions to incentivise supply and demand adjustments. The grid integrates significant renewable resources, primarily wind and solar, with specialised forecasting and ancillary services to manage variability.

[268] https://www.bundesnetzagentur.de/EN/Areas/Energy/DataCollection_Monitoring/start.html

Market monitoring and compliance

ERCOT outsources the task of overseeing the Texas WEM to independent economic consultants to form an Independent Market Monitor team.[269] [270] For example, Potomac Economics is currently acting as the IMM for ERCOT as they recently published the 2023 State of the Market Report for the ERCOT Electricity Markets.[271]

In this role, Potomac Economics identifies conduct by market participants or market rules that compromise the efficiency or distort the outcomes of the markets. Additionally, Potomac Economics issues periodic reports providing an independent assessment of the competitive performance and operational efficiency of the market. [272]

The IMM shall monitor wholesale market activities so as to[273]:

(1) Detect and prevent market manipulation strategies and market power abuses; and

(2) Evaluate the operations of the wholesale market and the current market rules and proposed changes to the market rules, and recommend measures to enhance market efficiency.

Great Britain

Market design

The relevant components of the UK market are as follows:

- NESO operates a capacity market to ensure there is sufficient capacity available to meet demand.
- NESO operates a balancing market to ensure supply meets demand in a particular settlement period (30 minutes). The auction gate opens 60 to 90 minutes before real time.[274]
- Forward bilateral trades occur between or exchange traded contracts between suppliers, generators, and/or speculators (non-physical traders). Most energy is bought and sold in this way. Contracts must be notified to NESO by the submission deadline (currently at the start of a settlement period).[275]
- Forward bilateral trades are negotiated between NESO and counterparties under a "Grid Trade Master Agreement"[276]. NESO procures specific services (e.g. generation in a specific location) as part of its function as grid operator.

The rules that govern electricity trading in Great Britain are covered in the Balancing and Settlement Code.[277]

GB also currently has CfDs set up as contracts between the government-owned entity LCCC and low-carbon generators for the purpose of providing revenue certainty for low-carbon generators. CfD contracts are awarded through competitive, pay-as-clear auctions with the lowest bids being

269 https://www.utilitydive.com/news/ercot-texas-independent-market-monitor-bivens-resigns-puc/699465/

270 Independent Market Monitor (IMM)--Depending on the context, the office of the IMM or the director of the IMM and its staff.

271 https://www.potomaceconomics.com/wp-content/uploads/2024/05/2023-State-of-the-Market-Report_Final.pdf

272 https://www.potomaceconomics.com/markets-monitored/ercot/

273 https://www.law.cornell.edu/regulations/texas/16-Tex-Admin-Code-SS-25-365

274 https://www.neso.energy/what-we-do/systems-operations/what-balancing-mechanism

275 https://bscdocs.elexon.co.uk/guidance-notes/the-electricity-trading-arrangements-a-beginners-guide

276 https://www.neso.energy/industry-information/balancing-services/trading#Trading-Requirements

277 https://bscdocs.elexon.co.uk/bsc

successful and by 2023, CfD auctions had successfully contracted over 20GW of renewable capacity.[278] [279]

Market monitoring and compliance

Ofgem, the GB energy regulator, is in charge of actively monitoring the electricity market and promoting supplier compliance with market rules. In particular, Ofgem relies on several activities to carry out this task, including:[280]

- routinely collecting information from energy suppliers, such as information on the level and nature of complaints they receive. Suppliers are required to be open and cooperative with Ofgem, which includes self-reporting of potential non-compliance with licence conditions or other relevant requirements
- working closely with Citizens Advice, Advice Direct Scotland and Ombudsman Services to identify systemic issues and emerging trends
- conducting targeted consumer research (including surveys) and monitoring wider consumer sentiment on social media
- reviewing information from whistleblowers within the industry.

In Ofgem's monitoring of the wholesale energy market for gas and electricity, Ofgem collect and analyse a large range of data. Our wholesale indicators give a snapshot of this. They are derived from our monitoring framework which underpins Ofgem's ongoing assessment of the wholesale energy market in Great Britain.[281] This includes: wholesale forward delivery contracts price trends, security of supply metrics, access and liquidity, competition metrics,[282] investment and sustainability (e.g., spark and dark spreads) etc.

In terms of market compliance, in April 2022, Ofgem announced a series of Market Compliance Reviews to look at energy supplier performance to improve standards in areas such as customer service or support for vulnerable customers. For each review, suppliers had to submit:[283]

- performance data
- internal documents
- a self-assessment signed by their Board.

California, USA

Market design

The California Independent System Operator (CASIO) operates both a day-ahead market and a real-time market within the Western Interconnection, a grid spanning from Western Canada to Baja California in Mexico. The day-ahead market allows participants and 'Load serving entities' (LSEs) to submit offers and bids to schedule generation for the following day based on demand forecasts up to seven days earlier. The real-time market allows participants to balance deviations from their day-ahead schedules by making adjustments based on actual physical outcomes.

278 https://researchbriefings.files.parliament.uk/documents/CBP-9871/CBP-9871.pdf

279 https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/07/EL56-Contracts-for-difference-CfDs-in-the-energy-transition-Revised-version-clean-002.pdf

280 https://www.ofgem.gov.uk/energy-policy-and-regulation/compliance-and-enforcement

281 https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators

282 https://www.ofgem.gov.uk/blog/electricity-competition-wholesale-markets

283 https://www.ofgem.gov.uk/blog/time-suppliers-improve-standards-energy-consumers

In addition to this, CAISO operates the Western Energy Imbalance Market and extended day-ahead market, which are essentially extensions of the real-time and day-ahead markets respectively across multiple western states. While CAISO does not operate a capacity market, its resource adequacy framework requires LSEs to procure sufficient capacity on a monthly basis.

Market monitoring and compliance

Federal Energy Regulatory Commission (FERC) requires every regional transmission operator including CAIRO to have an independent market monitor. The CAISO has its own Department of Market Monitoring (DMM) that closely watches the efficiency and effectiveness of California ISO markets whilst the FERC remains as the primary regulatory authority overseeing market monitoring activities in California's WEM. CAISO's core functions include monitoring market performance to identify potential anti-competitive market behaviour or market inefficiencies conduct market efficiency and competitiveness analysis to remedy the potential exercise of market power. [284]

Some of the monitoring indices that CAISO refer to include market prices and costs, congestion impacts on prices, estimated competitive baseline energy prices and market costs, price-cost markup (market costs vs competitive baseline), impact of virtual bids on CRR revenues and screens for potentially anomalous or anti-competitive behaviour. [285]

CAISO's DMM publishes annual reports on market issues and performance and holds quarterly and annual calls which provide an overview of the reports. Some of the measures employed by CAIRO used to assess market competitiveness in the process of market monitoring include: [286]

- Pivotal supplier test - If supply is insufficient to meet demand with the supply of any individual supplier removed, then this supplier is pivotal; this is referred to as a single pivotal supplier test.
- Residual supply test - The residual supply index is the ratio of supply from non-pivotal suppliers to demand. A residual supply index less than 1.0 indicates an uncompetitive level of supply.

Ireland (SEM)

Market design

Participants in the SEM are required to participate in its capacity market wherein they receive payments in return for delivering on their capacity market obligations up to five years in advance of the trading day. This ensures sufficient generation capacity to meet forecast demand. The SEM then has a day-ahead market and an intra-day market that allow participants to trade on their positions and a balancing market to manage any differences between the market schedule and actual system demand.

Most energy (around 84%) is traded on the day-ahead market[287].

Market monitoring and compliance

Market monitoring and compliance with market rules for the I-SEM is primarily conducted by the Market Monitoring Unit (MMU) which forms one part within the Market Power Mitigation strategy for the SEM. The MMU is a group of analysts housed within the Regulatory Authorities

284 https://www.caiso.com/market-operations/market-monitoring

285 https://www.caiso.com/documents/catalog-monitoring-data-indices.pdf

286 https://www.caiso.com/documents/2023-annual-report-on-market-issues-and-performance.pdf

287 SEM Annual Report 202-23 (latest published), p18, available https://www.semcommittee.com/files/semcommittee/2024-03/SEM%20Annual%20Report%202022-2023.pdf

(RAs) e.g., Utility Regulator (UR) for NI / Commission for the Regulation of Utilities (CRU) for RoI and is responsible primarily for monitoring: [288] [289]

- Short and long-term SEM outcomes (such as prices, quantities)
- Participant behaviour

The MMU reports to the SEM Committee on these matters on an ongoing basis, and produces internal and public reports as part of its function. The MMU publish weekly reports that summarise key areas of market performance and market activity. MMU also publishes monthly and quarterly detailed reports on market performance.

The objective of the MMU in its monitoring of the market is to collect, collate and analyse all relevant information relating to any suspected breach of licence, instance of market abuse etc. Its role is one of collecting the facts upon which any further decision may be taken. MMU does not issue binding directions but where necessary will present evidence to the relevant Regulatory Authority. The RA may then issue a binding direction based on MMU evidence.[290]

In carrying out the monitoring function, MMU aims to ensure detection of any potential market abuse by monitoring key areas including but not limited to compliance with bidding rules and licence compliance; evidence of potential-holding of capacity (both physical and financial); aggregated market data including prices and volumes and market concentration metrics; and evidence of potential market manipulation within and between markets.

The MMU will routinely monitor market activity and make routine request for information from market participants that do not entail a specific inquiry, but which may give rise to the identification of specific issue(s) that may will prompt such an enquiry.

The Nordic (Nord Pool)

Market design

Missing a Nord Pool is a cross-border power exchange that originally started off as a common pool market for Norway and Sweden in 1996 that has expanded to include sixteen countries across Europe including:[291]

- Nordic countries: Norway, Sweden, Finland, and Denmark
- Baltic countries: Estonia, Latvia, and Lithuania
- Other European countries: Germany, Poland, Luxembourg, France, Austria, Belgium, the Netherlands, and the United Kingdom

Nord Pool currently consists of over 300 market participants and offers two primary types of power markets: day-ahead market and intraday market:

- Day-ahead market: The day-ahead market is where electricity is bought or sold for the next 24 hours in a closed auction. Market participants submit bids to buy or sell the following day. The day-ahead market sets a price at each bidding zone for each hour.[292]

[288] https://www.semcommittee.com/market-monitoring

[289] The market is jointly regulated by the Utility Regulator (UR) in Northern Ireland and the Commission for Regulation of Utilities (CRU) in the Republic of Ireland. The SEM Committee (SEMC) is the decision-making body governing the market.

[290] https://www.semcommittee.com/files/semcommittee/media-files/SEM-21-020%20MMU%20Investigation%20Process%20Manual.pdf

[291] https://www.nordpoolgroup.com/en/message-center-container/newsroom/exchange-message-list/2025/q1/nord-pool-reports-encouraging-growth-in-2024/

[292] https://www.nordpoolgroup.com/en/the-power-market/day-ahead-market/

- Intraday market: In the intraday market, electricity is traded for delivery on the same day. The intraday market works together with the day-ahead market to help secure the necessary balance between supply and demand. This allows market participants to trade closer to the physical delivery within the intraday markets.[293]

Both the day-ahead and the intraday market are crucial for the European power markets. They provide market participants with an opportunity to hedge their positions as well as manage risks.

Market monitoring and compliance

Nord Pool has a dedicated team of market surveillance experts who work on detecting, analysing and reporting any suspected market activity. The team works towards ensuring market integrity and transparency through the detection and prevention of market manipulation. Any suspicious activity must be detected and reported to respective National Regulatory Authorities (NRAs) and the Agency for Cooperation of Energy Regulators (ACER). Nord Pool has implemented arrangements and procedures to detect any potential cases of market manipulation or insider trading.[294]

Nord Pool adopts a risk assessment approach to conduct its market surveillance. This is done by identifying the various types of market manipulation or insider trading that may occur, estimating the likelihood and consequences of such activities and ensuring that the identified risk areas are covered by specially developed automated tools and/or specific checks. Examples of risk areas that the team especially focuses on include generation capacity withholding in the day-ahead market, or transmission capacity hoarding in the intraday. All market monitoring procedures are reviewed and updated at least once a year, and regular audits are performed to also ensure that monitoring arrangements continue to remain effective.

Additionally, the Nord Pool market surveillance team also focus on educating market participants and regulators on market integrity and transparency as well as appropriate trading practices through courses, workshops and regular meetings.

Whilst Nord Pool's market surveillance team is the first line of defence in detecting and reporting suspicious activities in the market, REMIT (the Regulation for wholesale Energy Market Integrity and Transparency) formulates the legal responsibility for power exchanges to establish and maintain a market surveillance function.

Singapore (NEMS)

Market design

Singapore's Wholesale Electricity Market (SWEM) operates as a real-time spot market with half-hourly auctions for energy and ancillary services (regulation and primary and contingency reserves), that is operated and administered by the Energy Market Company (EMC).

The bidding process involves generators firstly submitting their price-quantity offers for each half-hourly period. This is then proceeded by the Market Clearing Engine (MCE) that is used to co-optimise to ensure that the least cost mix of energy, reserves and regulation is purchased from the wholesale market to meet electricity demand in each dispatch period.[295] There are several unique features of the SWEM:

- Firstly, nodal energy prices/locational marginal pricing (LMP) is applied and represents the prices received by generators. These prices are determined according to demand and supply characteristics of each of the injection nodes (market network nodes), taking into

293 https://www.nordpoolgroup.com/en/the-power-market/Intraday-market/

294 Market surveillance | Nord Pool

295 https://www.home.emcsg.com/glossary

consideration transmission losses and congestion on Singapore's electricity network. Consumers are charged a common price i.e., the Uniform Singapore Energy Price (USEP), which is the weighted-average of all nodal prices at all off-take nodes.

- Secondly, the SWEM includes vesting contracts, which are contracts structured as bilateral two-way CfDs between the SP Services (the Market Support Services Licensee) and the holder, who is typically a power generation company. The aim of vesting contracts is to enhance economic efficiency in the electricity market by mitigating the exercise of market power by the large power generation companies. SP services purchases electricity from the SWEM at half-hourly prices to supply to non-contestable consumers at the regulated tariff.
- Thirdly, it was recently announced that the EMA would be going forward in charge of planning and coordinating capacity building at the system level via a Centralised Process.[296] To ensure that there is sufficient generation capacity to serve demand in a secure and reliable manner, EMA will be introducing a Centralised Process to coordinate the planting of new generation capacity in Singapore by the private sector.

Market monitoring and compliance

The Market Surveillance and Compliance Panel (MSCP) is an independent body established under the Singapore Electricity Market Rules that is responsible for monitoring and investigating the conduct of market participants, the Market Support Services Licensee (MSSL), the Power System Operator (PSO), and EMC, as well as the structure and performance of, and activities in the wholesale electricity market that provide indications of the following scenarios:

- potential breaches of market rules and market and system manuals;
- actual/potential design or other flaws and inefficiencies in rules and manuals;
- actual/potential design or other flaws in the overall SWEM structure

The Market Assessment Unit (MAU) of EMC provides support to the MSCP by monitoring the SWEM regularly to ensure that the market is functioning efficiently, identify areas of inefficiencies and recommend changes or remedial actions to address them. The decisions made by the MSCP rely heavily on the monitoring, evaluations and analyses undertaken by the MAU from EMC who regularly report their findings to the MSCP.

One of the key ways in which the MAU assesses the effectiveness of the NEMS (National Electricity Markets of Singapore) is by developing:

- a catalogue of the data it acquires; and
- and a catalogue of the monitoring indices required for market performance evaluation.[297]

Examples of the types of data required by MAU for its catalogue include: data on generators (such as on generation capacities, ramp-up rates, reserve capacities, fuel types, forced outage durations), transmission system data, supply (such as offers/bids submitted at gate closures, real-time solar output forecast, security constraints) and demand data (such as real time load forecasts), pricing data etc.[298] These catalogues serve as an information requirements system and criteria for evaluation, to enable effective monitoring of the market. The catalogue of data is

[296] https://www.ema.gov.sg/partnerships/consultations/2023/centralised-process-to-ensure-sufficient-generation-capacity

[297] The Singapore Electricity Market Rules requires the MAU, under the supervision and direction of the MSCP, to undertake this task.

[298] https://www.home.emcsg.com/about-the-market/governance/market-surveillance-and-compliance/catalogue-of-data-and-indices/catalogue-of-data

published annually publicly on EMC's website.[299] These catalogues are also reviewed by the MSCP in consultation with the industry and EMA to incorporate any new data to the catalogue.

The catalogue of monitoring indices is used by the MSCP and the MAU to evaluate the data collected. These monitoring indices include supply indices (e.g., capacity ratios, outage frequency, market shares and HHI ratios), demand indices (e.g., real-time load forecasts compared to metered generation quantity) and price indices (e.g., correlation of wholesale prices with system demand and fuel price, trends in USEP).

The MAU is required to submit regular market performance monitoring updates to the MSCP. MSCP is required to provide a publicly available general assessment of the state of competition and compliance within, and the efficiency of, the Singapore wholesale electricity market, for transparency purposes.[300] This publicly available report includes analyses and observations relating to Singapore's electricity market, such as on the current market structure and competitive landscape, market price behaviour, market efficiency etc.

[299] https://www.home.emcsg.com/about-the-market/governance/market-surveillance-and-compliance/catalogue-of-data-and-indices/catalogue-of-data

[300] https://www.home.emcsg.com/about-the-market/governance/market-surveillance-and-compliance/publications

F Terms of reference

F.1 Introduction

This Appendix sets out our terms of reference for this review.

F.2 Introduction

The Ministry is seeking a review of the performance of New Zealand's electricity markets, initiated by the Government (the Review).

Through this Review, the Government is seeking advice on the impact of market structure, market design and market rules, as set out in the Electricity Industry Participation Code 2010 (Code). The Review also seeks options to improve market performance in terms of the Government's objectives.

The Ministry is seeking to engage a New Zealand Expert Advisor (the Supplier) who has local expertise to advise the Lead Reviewer (as engaged by the Ministry) on the New Zealand electricity markets.

Particular matters to be addressed are set out in the table below:

Investment and access to capital	Q 1. How does business ownership, structure or design of markets affect incentives or opportunities to invest in generation, storage, transmission and distribution?
Hedging	Q 2. Since 2017, how have developments in the gas market and government policies including the offshore oil and gas exploration ban affected the availability of hedge contracts? Q 3. Can an expectation that major electricity users are sufficiently hedged for dry years encourage greater investment in generation?
Market rules and competition	Q 4. What is the impact of market design and market rules on competition, market entry and expansion?
Managing risk	Q 5. Do market participants have access to sufficient information (including gas and other fuel supply chain information) and risk management products to effectively manage risks?
Market institutions	Q 6. Do the regulator and system operator have the right roles and responsibilities to promote security of supply and affordable prices?
Market performance monitoring	Q 7. How does our market monitoring and compliance enforcement system (roles and approach) compare with international best practice?

In addressing the matters above, the Review must:

a. Assess electricity markets performance against objective in the Government's Policy statement on electricity, with particular attention to the questions set out above.

b. Review and comment on relevant recent reports and current regulatory developments, including the December 2023 report by the Electricity Authority's

Market Development Advisory Group (MDAG) on pricing in a renewable-based electricity system, and more generally by the Electricity Authority.

c. Draw on the evidence and insights from public resources, supplemented where necessary by targeted information gathered from officials, regulatory agencies and sector stakeholders.

d. Draw on international electricity market experience, while considering distinctive aspects of the New Zealand system including the absence of generation or retail subsidies and the operational independence of the sector and identify relevant lessons for New Zealand

e. Identify key market performance issues and make recommendations on the 'top ten' priority actions in terms of urgency and impact for improvements to New Zealand's current design of markets.

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