Review of the NZ Electricity Market Performance

Peer Review Evaluation

Evaluation by:

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1 Introduction

Earlier this year, Frontier Economics was engaged by the Ministry of Business, Innovation & Employment (MBIE) to conduct a review of New Zealand's electricity market performance. Frontier has produced a report presenting the results of their review (which we refer to throughout as the "Frontier report"), and we have been engaged to provide a peer review of this report. Frontier's extensive report covers a very broad array of issues facing the New Zealand power sector today, particularly considering that they conducted the analysis in under four months.

Our review is focused on four of the key recommendations in the Frontier report, some of which we have significant reservations about. We should also stress that there is much within the Frontier report we agree with. Rather than devoting substantial space to highlighting all of the statements in this over-250-page report with which we concur, we largely focus our discussion on the points that raise concerns for us or we believe merit further analysis. Most importantly, we agree with Frontier's assessment that the New Zealand market is overall well-designed. We also agree that it appears to be reasonably competitive, except perhaps under stressed conditions. However, we discuss further analyses that would help shed more light on the competitiveness question. Frontier makes several recommendations to improve the transparency of both market information and the regulatory process that we also endorse.

While there are dozens of recommendations in the Frontier report, Frontier has highlighted five. Of all the recommendations, we consider there to be four distinct "major" recommendations insofar as they constitute a significant shift in either the structure of the industry or the direction of policy, or both. As such, each deserves much more scrutiny and analysis than can be accomplished within the timeframe of the current policy proceeding. That is, the theoretical merits behind them hinge on contestable assumptions, many of which require answers to empirical questions where sufficient analysis has not been conducted. We note that the scope of Frontier's report did not include the undertaking of original economic modeling, however, that does not mean that such empirical work is not a prudent undertaking before moving forward with the recommendations.

The four proposals we consider most impactful are

1. Create a new Crown corporation—called New Co. for purposes of discussion—that would purchase, build, and control key "dispatchable" and "firm" sources of energy supply.
    - Direct New Co. to provide "priority access" to its resources to independent retailers, generators, and large customers.
2. Pursue the divestment of government ownership stakes in three large vertically-integrated firms: Genesis, Meridian, and Mercury.
3. Encourage or require the consolidation of the current 29 Electricity Distribution Businesses into a much smaller number, such as 5.
    - Accompany the consolidation of EDBs with changes to the EDB regulatory regime intended to facilitate investment.
4. Remove the electricity sector from the New Zealand Emissions Trading Scheme (ETS).

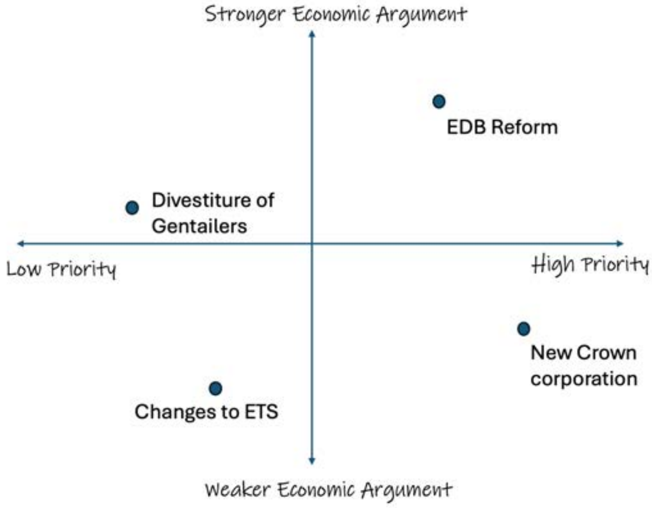


Figure 1: Qualitative Assessment of Key Proposals

In addition, the Frontier report recommends combining the Gas Industry Company with the Electricity Authority to create a unified energy regulatory body. Although this is listed as a major recommendation, we are not in a good position to judge the magnitudes of those impacts.

We summarize these four proposals along two dimensions. The first dimension divides the proposals into two categories: those that are supported by strong qualitative economic reasoning, but might not explicitly incorporate other considerations (economic or otherwise) that could not be fully vetted in this brief process, versus those proposals where the economic reasoning is less persuasive or even counterintuitive, but still might be meritorious if non-market considerations are decisive factors. The second dimension considers the priority of the proposals, incorporating whether they address the core issues that motivated this review and whether they would have significant economic impacts. This *very* qualitative assessment is summarized in Figure 1. We consider proposals two and three—the consolidation of EDBs and the divestiture of government ownership in gentailers—to be supported by qualitative economic logic, and proposals 1 and 4—the creation of a new Crown corporation and the restructuring of the ETS—to have weaker economic arguments that are inconsistent with our assessment of the conditions in the market.

As noted earlier, all of these proposals, if pursued, deserve more analysis before any implementation steps should proceed. However, this is especially true for those in the lower quadrants. In other words, we believe the "burden of proof" for the proposals we place in the lower two quadrants needs to be higher because the qualitative economic case behind them is weak. In addition, while we can see a case for divestment of the government's stake in three large gentailers, we were not persuaded by some of the specific reasons to do so that are given in the Frontier report. Of the four major proposals, the restructuring and reform of the EDBs strikes us as the most worthy of further consideration, given that it is backed by both qualitative economic logic and some empirical evidence.

1.1 Overview

In putting together this review process, MBIE highlighted that expected growth in New Zealand's electricity demand will require significant investment in new electricity generation and other infrastructure. It argued that this growth, along with technology changes, offers opportunities, but also presents risks to be managed. The Government is seeking to identify improvements to current market arrangements and possibly identify alternative market models or market designs that would support electricity market performance. The review is coming on the heels of several challenging years for the market. The Frontier report describes how dry hydro conditions have combined with a surprisingly rapid decline in local gas field production to create a period of high and volatile wholesale market prices relative to historical experience. The market was critically reliant upon the last remaining major plant capable of burning coal to help support supply through this period. The future of this plant, Huntly, is uncertain at best.

The Frontier report argues that conditions in the electricity market necessitate a series of dramatic shifts in the structure of the industry. While the evidence presented about the condition of the distribution sector is striking and Frontier's recommendations sound reasonable, we found the arguments presented about the generation sector far less convincing. We note that Frontier's assessment of the generation sector at times contrasts sharply with other reviews, such as those conducted by the Market Design Advisory Group (MDAG) that was convened by the Electricity Authority.

Our own assessment of the generation sector in recent years is that market signals are yielding what appear to be, at least directionally, an appropriate response to the supply conditions described in the Frontier report. While the Frontier report considers reduced output by gas generators and increased output by renewables as exacerbating dry year risk,[1] there is an alternative interpretation. The generation fleet is evolving to require less utilization of gas-fired capacity due to renewable entry. This is plausibly the most efficient allocation of resources. Gas generation would then be confined to a smaller set of periods that attract higher prices, but the increase in price volatility is neither unexpected nor inefficient.[2] By our reading, a key question is how well owners of existing fossil plants can adapt to an economic environment where these resources operate at very low overall capacity factors, with periods of intense use during dry-year conditions.

The scale and nature of the dry-year problem deserves more analysis than provided in the Frontier report before options such as a New Co. are seriously considered. By our calculations, the most severe quarterly deficit in hydro production, relative to a twenty-year seasonally adjusted average, was about 1675 GWh in the quarter ending September 2001. The coal capacity of Huntly alone, operating at an 80% capacity factor can produce about 1300 GWh quarterly. Other sources, including newly committed renewable energy, demand response, not to mention diesel generation, appear to fill the remaining gap, even if there is a continued decline in gas availability.

Given these figures, the dry-year issue appears to us as much more about *prices* than about reliability. Perhaps a large, government directed, push into new fossil investment would stabilize inter-year price volatility, but there is a wealth of evidence on electricity liberalization that this would come at the expense of efficiency and increased long-run average costs.

[1] *"Increasing the dominance of intermittent generation, and reducing supply from dispatchable thermal generation, intensifies dry year risk in New Zealand,"* Frontier report, Section 4.3.2

[2] MDAG, Final Recommendations, Figs 7 and 8

We acknowledge that, despite recent encouraging developments from the market, there are legitimate and serious concerns about the future of Huntly and possibly other aging fossil plants. However, there are policy options that would maintain the operation of those plants, such as reliability must-run (RMR) contracts at regulated rates, that are far less drastic than the proposed New Corporation. Beyond this, the dry year issues described by Frontier strike us as relating as much, or more, to the natural gas sector as the electricity sector. As such, one of the alternatives that might be considered is to limit any significant additional government intervention to the gas production sector, for example by supporting increased gas storage or even LNG.

We found the Frontier report to be somewhat opaque about the future market role for renewable energy and battery storage. There is brief acknowledgment that additional renewable energy helps manage dry year risk, *"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.*[3]*"* However, Frontier discusses the dry year risk as requiring a *"security of supply service"* and they limit their focus to geothermal and thermal generation.[4] We believe the question of managing inter-year volatility of hydro output, quantified above, to be a separate question from managing the increasing volatility of daily or weekly supply created by the combination of load growth and increased renewable supply. The technological options for dealing with the short-term firming are much broader than traditional thermal sources, and not subject to many of the barriers Frontier believes to be impeding investment in fossil capacity.

The report also provides mixed messages about the market environment for investment. At times, the report acknowledges the recent investment activity in renewable and battery sources, and concludes that there are no significant barriers to entry. Elsewhere, the report states that "independent generation developers struggle to sell their capacity without firming products, making them dependent on the flexible generation owned by the gentailers." The report recommends that government ownership in three gentailers be divested, partially motivated by an argument that divestment would *increase* investment by the gentailers.[5] Elsewhere, the report points to the Gentailer practice of inducing investment through signing power purchase agreements (PPAs) as anti-competitive and references the need to *"boost competition by ensuring that gentailers cannot hoard capacity"*[6], and notes that *"This practice reduces market competition and allows gentailers to control supply from independents."*[7]

Finally, we found the arguments in the Frontier report to be inconsistent with regards to the proper role of government ownership. When discussing the gentailers, the Frontier report argues that *"Government ownership constrains the ability to invest in larger projects."* Yet the report's central recommendation is to consolidate the government's stake in the industry into a government-owned New Co. who's primary mission would be to ensure the *"development of a secure and reliable source of fuel and appropriate generation assets."* While the report describes the *"Govern-*

[3] Frontier Report, p.40

[4] "*dispatchable long duration service . . . that needs to [be able to] operate continuously for long periods of time for there to be 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."* Frontier report, page 40.

[5] *"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."* Frontier report, page 37.

[6] Frontier Report, pages 54–55.

[7] Frontier report, page 32.

ment's involvement in the day-to-day operations of the [Gentailer] companies is relatively hands-off," it implies that inefficiency is introduced because *"relevant Ministers must be consulted on transactions."* By contrast, our understanding of the proposed New Co. is that its actions would be *entirely* dictated by the Government. Indeed, the message of the report is that such direct intervention is necessary to overcome the market's reluctance to invest in fossil-fueled capacity.

The Frontier report provides substantial coverage of retail competition and hedging questions, but other aspects of the market including the design of the short-term market, and wholesale short-term market competitiveness would benefit from further review. It is reasonable to ask if, and how much, supplier market power contributed to the price levels of the last few years. While we are not aware of direct evidence of market power, there are several tests that can provide information about the existence and extent of market power that we are not aware of being attempted recently in the New Zealand market. If there were evidence that market power, even if transient, resulted in significant transfers, then it would not be unreasonable to explore some form of structural solution, possibly the virtual divestiture that the Electricity Authority has signaled that it might examine.

1.2 Structure of this Peer Review

The primary function of our own report is to serve as a review of the Frontier report, not an alternate series of analysis or recommendations. We do at times present rough analysis in the form of summary statistics and also discuss our views on alternatives to some of the most significant recommendations in the report. Many of the conclusions and recommendations remain empirical questions that could not be answered in a review of this relatively modest length. More detailed analysis is required before serious consideration of the more significant proposals is undertaken.

Given the enormous amount of ground covered in the Frontier report, we have structured our review to focus on the proposals that we found to be most economically significant. Sections 2 through 5 in our review address the major proposals from the Frontier report. Sections 6 through 8 provide a discussion of several other topics covered in the Frontier report: competition and risk management, transmission pricing, and market monitoring. Some of these topics we consider to be more urgent than the proposals discussed in the previous sections. We summarize our overall conclusions of the major proposals in section 9.

2 New Crown Corporation (Proposals 1 and 2)

The first, and most significant, recommendation in the Frontier report is for the formation of a new Crown corporation (with the placeholder name of New Co.). The Frontier report does not specify exactly what the scope of the new company's mandate would be. It does describe how the company would *"fund thermal generation resources in New Zealand through either contracting or ownership of assets"* but also how the firm might pursue *"potential green options such as biomass or green gas/hydrogen."*[8] This implies that the vision for New Co. is quite broad, encompassing not just a role ensuring continued operation of the current thermal fleet, but also pursuing investment in a range of new resources.

It is our view that a fully executed version of this proposal would constitute a significant transformation to the nature of the New Zealand market, more so than several other options. Frontier argues otherwise,[9] but a key difference, and additional source of disruption and uncertainty, between New Co. and other options is the extent to which the newly formed corporation could dictate the long-run trajectory of the industry. This is because Frontier proposes that New Co. would play a central role in *new* investment, and not just in the maintenance of aging existing plants. Unfortunately, due possibly to the brevity of the review period, the weight of analysis supporting the proposal does not match the gravity of its implications. We did not find the details of this proposal to be sufficiently developed, or the logic behind it to be persuasive.

The main arguments in support of the formation of a New Co. are that there are market failures that prevent adequate investment directed at constructing and maintaining the types of supply resources that can properly manage dry-year risk. From our reading of the Frontier report, the significant market failures cited by Frontier are the following.

1. The policy uncertainty that is created by changes in central government policies, particularly with respect to energy and climate policy.
2. Uncertainty over the future supply of fossil fuels, notably natural gas.
3. A general aversion in the private sector to investing in fossil-fired capacity.
4. An incentive for firms to "free ride" on the investments of other firms (e.g., page 51)
5. Government ownership stakes in three large integrated firms.

Of the uncertainties listed above, our reading of the Frontier report is that Frontier places the most weight upon the policy uncertainty created by past, and potential future, actions by the Government on climate and energy policy. This extends to uncertainty over the future supply of natural gas, an issue that has elements of both policy and physical uncertainty.

The Frontier report also points to several other phenomena that may chill investment in new generation: demand uncertainty, supply uncertainty, and general fuel-supply risk. Our reading of the Frontier report is that Frontier does not consider these phenomena to be "market failures" per se, but rather explanations of why investment in new generation capacity is lagging behind the levels that might otherwise be expected in New Zealand given the high forward market prices over the last few years. Indeed, the Frontier report argues that the most recent surveys on generation investment point to *"low barriers to entry"* (page 31) and a market process that is working through these uncertainties. We largely agree with this assessment. Frontier's argument, therefore, is that

[8] Frontier Report, page 55

[9] Frontier Report, Appendix B

there are no major market failures (other than government ownership of gentailers) for the investment in new *renewable* generation capacity, but that there are prohibitive market failures for the investment in “firming” or “dispatchable” capacity, which is, to our minds, narrowly defined by Frontier as “*dispatchable long duration service . . . that needs to [be able to] operate continuously for long periods of time for there to be 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 definition of firming is different from that we have encountered in other markets, where firming is as much an intraday concern as an annual one.

We raise this clarification of the term firming capacity because the Frontier report proposes that a state-owned enterprise take leadership in, if not monopolize, the future investment in firming capacity. While most of the arguments supporting New Co. are linked to seasonal and inter-year firming requirements (i.e. the dry year problem), Frontier concludes that there are low barriers for investment in non-fossil sources. Therefore, the need for New Co. to be created and assigned the responsibilities proposed by Frontier is dependent upon at least two assumptions about future conditions holding true: (1) that existing fossil capacity (even if steps are taken to prevent retirements) will be insufficient to manage dry-year risk, and (2) that it is unlikely or impossible that market-based investment would provide new fossil capacity if assumption (1) holds and the investment becomes necessary.

The Frontier report also describes an incentive for firms to free-ride on the investments of others. However, the standard free-riding concerns with which we are familiar (some retailers contracting for inadequate supply at peak demand times, knowing that any system-wide shortfall would be allocated randomly among customers) seems to be far less pronounced in New Zealand than in most other markets where resource adequacy concerns have been raised.[10] This is because the types of risks described in the Frontier report are as much or more *price risks* than physical reliability risks. Riding unhedged on the supply of others is therefore far from “free.” Frontier has implicitly described an economy of scale problem, where *“investment made by someone else has the effect of lowering prices.”*[11] Absent significant economies of scale, this is a phenomenon experienced in all competitive markets without constituting a market failure. While the New Zealand market is relatively small, free-riding has not prevented investment in utility-scale renewable and battery generation. Even fossil investment has been seen within the last half-decade. Todd Energy has invested in gas peakers as recently as 2020. The Frontier report describes Todd Energy’s vertical integration with gas production as being “unique,” but that does not mean it is not replicable, either by Todd or other firms with natural gas interests.[12] This vertical integration may be novel in the New Zealand context, but it is a demonstration that new capacity can be rationalized by investors, even when forecasts point toward capacity factors that are less than historical averages.

This is not to say there are *no* potential market failure concerns around the dry-year energy security problem. One concern would be the ability of retailers to default on their customer obligations, or of sellers to default upon their supply obligations, during dry years. Another potential market failure concern would be, in a way, the opposite of the free-riding problem. This would be present when participants in the NZ economy face highly correlated risks that, if experienced individually, one customer may be willing to bear, but if experienced collectively (simultaneously) can have negative macroeconomic impacts on the economy as a whole. Arguments about these kind of macro-economic shocks have been used to justify policies such as strategic petroleum reserves.

[10] Some have pointed to the option of unhedged retailers to declare bankruptcy as an additional free-riding concern.

[11] Frontier report, pages 51–52.

[12] Frontier report, pages 42–43.

2.1 Government Ownership Does Not Eliminate Government Policy Uncertainty

If uncertainty over government policy is the fundamental problem that is preventing investment in an optimal mix of generation sources, we do not see how placing a state-owned entity in a position to dominate a critical piece of the industry resolves this problem. The vision articulated for this new entity extends well beyond stewarding the existing aging fossil fleet, encompassing future investment in generation and perhaps even upstream fossil fuel infrastructure.

> *"Over the medium term, the primary function of the entity is to provide long-term assurance to the gas sector, and potentially coal sector... This means underwriting gas field drilling and exploration, as well as investigating the ability to mine additional coal at Rotowaro."*
>
> *– Frontier report, page 60*

This raises significant concerns over how the decisions of this firm would impact other market participants. One major source of government uncertainty in some electricity markets is the concern that publicly-owned firms will make investments based upon political, rather than economic, criteria. Decisions made by this firm could very well foreclose other investment paths that would have otherwise been pursued by a market-driven process.[13]

We believe that the example of California's strategic reliability reserve (SRR) represents a cautionary tale about the Crown corporation option. The SRR was originally conceived largely as a vehicle for continuing the operating life of aging thermal plants deemed critical as reliability reserves.[14] However policy preferences have had a strong influence over this multi-billion dollar program, and it has undergone mission creep into the procurement of imported energy and new clean energy sources. Ambiguity remains about the conditions under which its resources are offered to the market and how they should influence other regulatory requirements. In addition, the presence of the SRR has created a moral-hazard problem, where individual retail entities have a weaker incentive to ensure their own resource adequacy. We are concerned that the proposed New Co. Crown corporation would induce many of these same dynamics in New Zealand. Frontier suggest that this can be avoided by *"robust governance arrangements"* (page 55), but this will probably be difficult to circumvent in practice.

2.2 Access to Resources Should be Non-discriminatory

A second set of questions about this proposal surround the stated intent for the new Crown corporation to provide "priority" access to independent retailers, generators, and large customers. Follow up discussions indicate that the intent of this aspect of the proposal is to allow some form of *"first right of refusal"* (page 55 and 56) to a subset of firms. The report references a *"dedicated allocation"* (page 55) that at the same time is somehow *"not intended to provide capacity on more favourable terms of prices"* (page 55).

[13] For an Australian example, see the Financial Review: "Queensland tears up transition targets and will keep coal for longer", 8 April 2025.

[14] `https://www.newsdata.com/california_energy_markets/regulation_status/dwr-to-seek-approval-to-contract-for-2-9-gw-of-gas-fired-power/article_6410b36e-32ec-11ee-9b52-6bd55444db29.html`

It is still not clear exactly how this would work and these details would have to be fleshed out before any serious consideration of this option is pursued. However, we do not see how this aspect of the proposal could avoid bestowing preferential status to a subset of firms.[15] At the moment, this subset seems to encompass any firm that is not one of the big four gentailers. It is not clear to us, for example, what would happen if one or more gentailers are willing to buy output from New Co. at a higher price than an independent.

This raises several mid to long-term concerns. First, some of the capacity under consideration would be removed from the portfolios of the existing gentailers. To the extent their retail and wholesale positions are roughly balanced, any divestment would leave them perhaps as much in need of access to these resources as any other firm, particularly during a dry year. Second, it is not clear exactly how many, or what structure, of firms is the competitive ideal. Should Todd Energy, itself a gentailer through Nova Energy, also be denied priority access? If not now, then if they grow further? How large is too large? Is the intent to deny preferential access to *any* retail firm with a footprint in the generation sector? If so, does this not provide a perverse incentive to avoid integration?

Finally, we did not see a clear articulation of the magnitude of this problem or why this proposal is the best option for solving it. If the goal is to ensure all firms, not just the gentailers, have some access to the output of Huntly or other plants, we do not understand why the report is so hostile to proposals such as the EA's virtual disaggregation initiative.

Proposals of this nature risk forcing a specific market structure rather than having a structure emerge from competitive dynamics. Given these considerations, we believe that any publicly supported "firm" supply should be provided to the market under non-discriminatory principles.

2.3 No Definitive Evidence of Market Failure In the Current System

While we by no means dismiss the challenges to supporting investment in firm capacity in New Zealand given the uncertainty over future fuel supply and public policy, we also observe from anecdotes and data from the Frontier report and the collection of *MDAG* outputs[16] that participants in the New Zealand Electricity Market are making decisions consistent with what would be expected under a well-designed and well-functioning market. We observe a series of developments that, while not definitive proof that the market is "solving" the dry-year problem, nevertheless imply that market incentives are producing the types of decisions that at a minimum mitigate this problem.

First, market signals are producing operating decisions in advance of dry periods that appear to be, at least directionally, efficient responses. Future and spot prices in the lead up to the 2024 dry year, and the realized trough in storage levels, follow patterns consistent with economic theory, reproduced in Figure 2. These prices plausibly reflect expectations for the dry year and signal market participants to increase conservation and increase generation in the lead up to the trough. Likewise Huntly's increased output prior to the decline in controlled water storage levels seems consistent with competitive market economics, reproduced in Figure 3.

[15] In a competitive commodity market, a right of first refusal would only be valuable to a buyer if it allowed the buyer to procure the commodity at a below-market price. In a commodity market, each buyer is already able to procure their desired quantity at the market-clearing price.

[16] Final Recommendations Report (2023), Options Paper (2022), and Discussion Paper (2022).

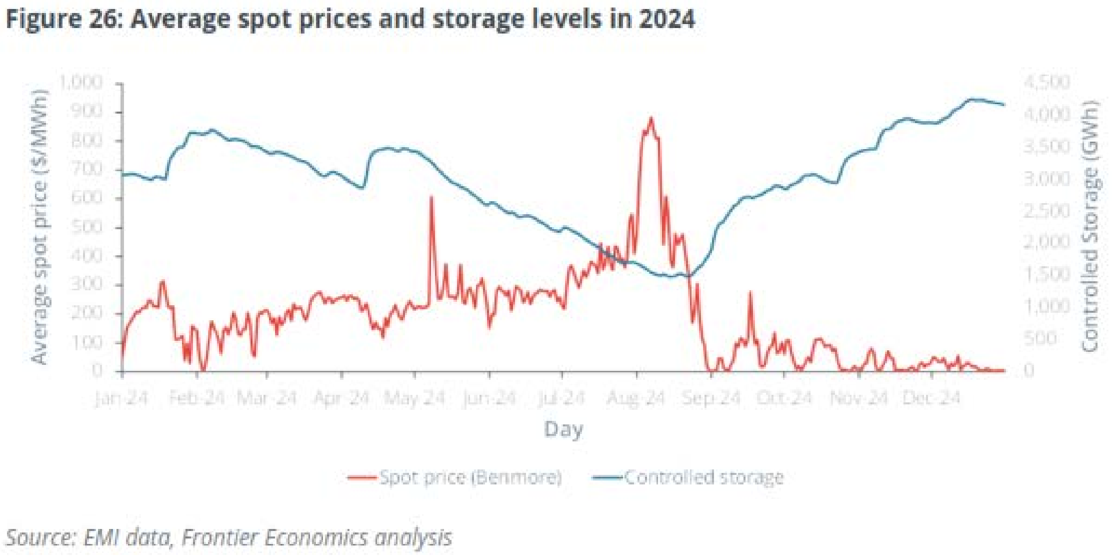


Figure 2: Reproduction of Figure 26

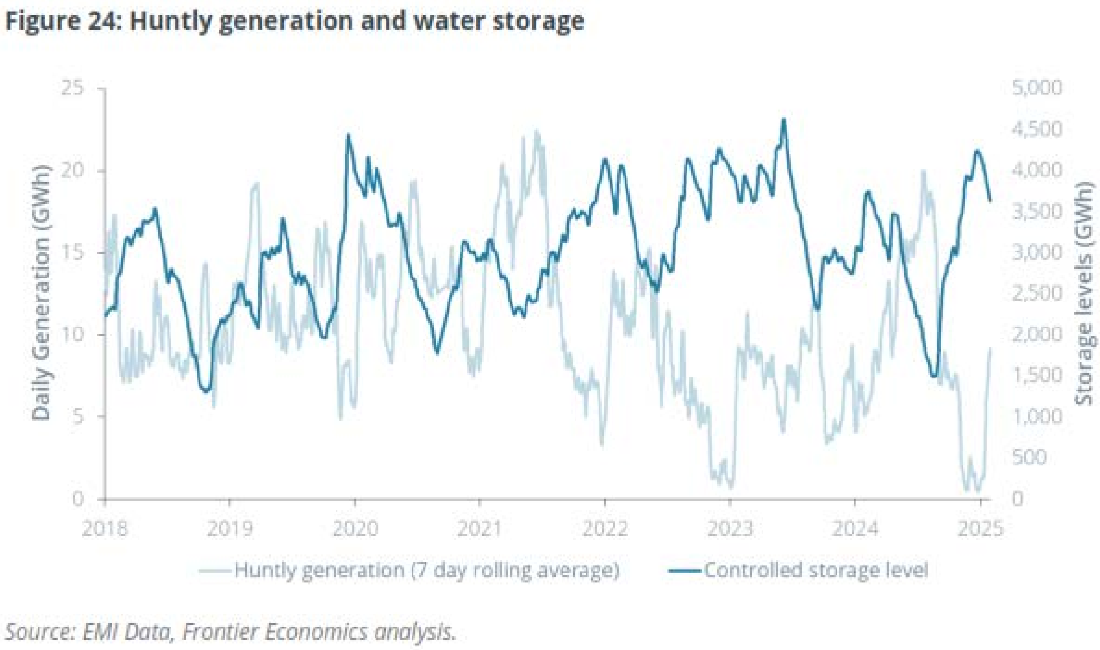


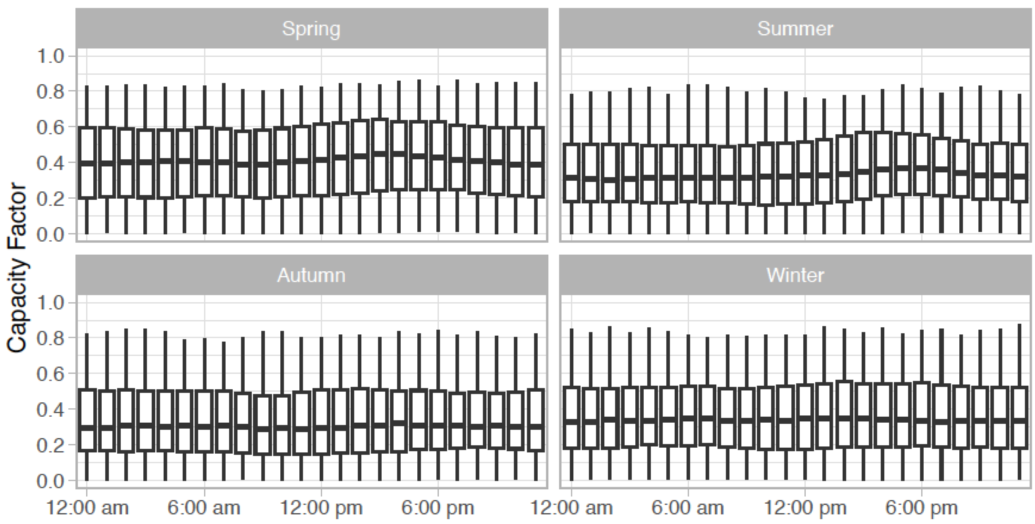
Figure 3: Reproduction of Figure 24

Second, the market features two very large consumers, one of gas and one of electricity, that can and do provide valuable long-term demand response: Methanex selling on its natural gas to generators and Tiwai aluminum reducing its electricity use.[17] These actions contribute to energy reliability, with market prices reflecting that the value was particularly high during, and in the lead up to, the dry period.

[17] Frontier report, pages 25 and 47. `https://www.ea.govt.nz/news/eye-on-electricity/the-tiwai-point-smelter-demand-response-in-winter-2024/`

Third, as the Frontier report acknowledges, there has been significant renewable investment, implying low barriers to investment in those technologies. The Frontier report at times seems to consider the expansion of renewable energy to be exacerbating the dry year problem. However, this view is not shared by the MDAG. It is not difficult to imagine a technology cost trajectory that yields an optimal resource mix where excess renewable energy is curtailed, or hydro is spilled. This prospect is viewed as inevitably inefficient in parts of the Frontier report, [18] but the MDAG again reach a different conclusion.[19]

Figure 8: Wind Capacity Factors by Season and Hour, 2014–2023



Notes: Each panel shows the distribution of the capacity factors for aggregate wind generation in New Zealand over the ten years from 2014 to 2023. For each season and hour, the box represents the interquartile range with the median line inside, while the whiskers extend to the minimum and maximum values. Only wind farms operating at the start of 2014 are included. Seasons in New Zealand: Spring (September-November), Summer (December-February), Autumn (March-May), Winter (June-August). Generation output is from Electricity Authority (2024b), and nameplate capacity values are from Electricity Authority (2024a) and New Zealand Wind Energy Association (2024).

Figure 4: NZ Wind Capacity Factors (Source: McRae 2025)

Frontier expresses some pessimism regarding wind and solar performance, but McRae (2025) observes that *"One advantage for New Zealand in expanding its wind generation capacity is the relatively constant distribution of wind availability across hours of the day and seasons"*.[20] Figure 4 (which reproduces McRae's Figure 18) suggests that wind production is remarkably consistent over the year, albeit with slightly higher output in Spring.

Beyond the prospect of large-scale conventional renewable investment, there are options that would rely upon periodic use of conventional diesel or bio-diesel, or other biofuels. We are concerned that forming a Crown corporation to make these decisions will likely foreclose the option of such answers emerging from a decentralized, market-driven process.

[18] *"Such overbuilding also increases the resource cost of supplying electricity, which is ultimately paid for by customers"*, page 44

[19] *"Spill will be more frequent, and that is OK"*. MDAG *Final Recommendations* page 36.

[20] McRae, 2025, "Rethinking Wholesale Market Design for New Zealand's Clean Energy Transition", *working paper*.

2.4 Alternatives for Mitigating Dry Year Risks

The Frontier report discusses several alternatives for dealing with the dry year risk problem, including capacity markets and strategic reserves. It concludes that each of these alternatives is insufficient or less preferred to the proposed Crown corporation. We largely agree with the assessment of the shortcomings of the approaches discussed here, but given our concerns about the Crown corporation alternative, we are not convinced the New Co. option is better. While, as discussed above, we do not see definitive evidence that the current market structure is not dealing with the dry year problem, we note that there are additional options that were also discussed in the Frontier report. Each would address some of the physical or economic concerns over the future supply of dry-year capacity. While Frontier concludes that New Co. is the superior option, we believe strongly that a more detailed and rigorous assessment of all options should be pursued before adopting one that requires government control of significant generation capacity and new investment.

2.4.1 Reliability Must-Run Contracts

The first option would be a reliability must-run (RMR) contract. The RMR contract paradigm, which is common in U.S. markets, was developed to deal with facilities that are deemed critical for system reliability, and are either credible threats to retire or are thought to have an unacceptable amount of market power.[21] Both of these latter circumstances represent a form of market failure in that firms are not incentivized to make choices that create maximum benefits for society. The general framework of these contracts is to compensate the operator of a critical power plant using the plant's going-forward average cost, in exchange for maintaining the ongoing availability of the plant and ensuring its competitive participation in the market. The costs of RMR contracts, net of the plant's revenues, are typically recovered through an assessment on load that is collected by the system operator.

[21] https://ir.talenenergy.com/news-releases/news-release-details/talen-energy-other-parties-reach-reliability-must-run-settlement

Box 1: Reliability Must-Run Contracts

In U.S. deregulated electricity markets, Reliability Must-Run (RMR) contracts serve as crucial tools to maintain grid stability when market mechanisms alone fail to ensure the continued operation of essential power plants. These contracts are typically enacted when Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs) identify that the retirement of specific generating units would jeopardize local or system-wide reliability. RMR agreements compensate these units on a cost-plus basis, ensuring their availability until alternative solutions, such as transmission upgrades or new generation, are implemented.

A notable instance is the 2025 RMR agreement involving Talen Energy's Brandon Shores and H. A. Wagner power plants in Maryland. Originally slated for retirement, these units were deemed critical for maintaining electricity reliability in the Baltimore area. Consequently, the Federal Energy Regulatory Commission (FERC) approved an RMR contract extending their operation through May 2029, allowing time for necessary transmission enhancements. In California, the California Independent System Operator (CAISO) has similarly utilized RMR contracts. For example, in 2018, FERC approved RMR agreements for three Calpine-operated gas plants, including the Metcalf Energy Center, to address local reliability concerns despite opposition from stakeholders advocating for cleaner alternatives.

In New England, the Mystic Generating Station near Boston was subject to an RMR agreement after its owner, Exelon (now Constellation Energy), announced plans to retire the facility. ISO New England determined that the plant's continued operation was necessary for regional reliability, leading FERC to approve compensation to keep the plant running through May 2024.

RMR contracts have at times been controversial, as they do represent a non-market intervention. The main areas of conflict concern the impact of RMR generation on energy and capacity market prices. Some parties argue that RMR contracts represent a non-market intervention and that priority should be given to limiting their (downward) impact on market prices. This logic led to the historical exclusion of RMR units from capacity auctions in markets such as PJM, a position that was recently reversed.[22]. Similar logic appears to have applied to the original offer price regulations originally applied to the Whirinaki unit. An alternative view takes the stance that RMR units have a place in the market when applied to assets that exhibit some form of natural monopoly characteristics due to their location, technology, or other considerations. Under this view, the perspective that the operations of the RMR plant prevents the market from signaling a need for new entry into that market niche is not inefficient, seeing as the presence of the RMR plant satisfies the requirements in that market niche.[23]

The exact terms and conditions of such arrangements would have to be tailored to the specifics of the NZ market. RMR units are typically contracted to system operators, meaning the natural counter-party for such a contract in New Zealand would be Transpower, with any residual (net of market revenue) costs recovered through its operations charges. This would expand somewhat the scope of Transpower's responsibilities, as there would need to be a transparent process for de-

[22] https://insidelines.pjm.com/ferc-approves-pjm-capacity-market-design-changes-to-support-reliability-affordability

[23] Bushnell, Harvey, and Hobbs, 2018 "Opinion on Reliability Must Run and Capacity Procurement Mechanism Enhancements." *CAISO Market Surveillance Committee*. https://www.caiso.com/Documents/MSC-Opiniononreliabilitymustrunandcapacityprocurementmechanismenhancements-Mar20_2019.pdf

termining when and how RMR plants engage with the market. Given that Transpower already has the responsibility of determining electricity supply risk curves that are used to determine various contingent storage release boundaries, there may be some coordination benefit to having a more transparent access to the output of RMR plants as well. In the case of Huntly there would need to be a process determining when and how much coal to import, and the implied energy offer cost associated with it. A remaining issue would be whether RMR units would be required to offer hedging contracts, something that has not typically been required of RMR plants in the U.S.

In summary, while RMR contracts constitute a non-market intervention in power markets, they are at times a useful, or even necessary, tool for dealing with resources that possess natural monopoly characteristics due to their location or other attributes. The Huntly plant, as the last remaining large dispatchable resource capable of operations during periods where both hydro and gas supply are limited, arguably fits that description. In theory, the prospect of potentially large operating margins during dry years could support continued operations through market incentives, but this raises market power concerns and Genesis is clearly signaling a desire for alternative, although still market negotiated, arrangements (e.g. the Heads of Agreement).

The Frontier Report considers what we take to be a version of an RMR contract, described as *"Genesis to be a regulated default provider of firm capacity"* (Appendix B.5). This option grades out reasonably well compared to other options described in this section, but Frontier considers the New Co. option to still be superior. Frontier raises concerns about the increased regulatory burden and need to closely oversee and regulate the regulated plant's interaction with other Genesis owned assets.

We agree that the implementation of an RMR arrangement for Huntly would require new regulatory responsibilities and expand the scope of responsibilities for Transpower as well as impose additional costs to customers backing the contract. The Frontier report also raises valid concerns about the need to police potential attempts to shift common costs onto the regulated plant, and the need for bidding requirements given the interaction of Huntly's operation and the profitability of other Genesis operations. However, we feel that the Frontier report is overly dismissive of the weak efficiency incentives and market power that would be concentrated in a completely government-owned New Co. Under either option, there would be concerns about cost-padding, and a need to set the conditions of engagement with the broader market.

A market solution would therefore be preferred if it were feasible and acceptable to the regulatory bodies. The Frontier report concludes that *"the currently proposed Heads of Agreement for Huntly would entrench the potential for market power in the market"*.[24] We are not privy to the details of this agreement but agree that there is a concern over an arrangement that could codify coordination between large suppliers that merits the careful scrutiny of the Commerce Commission. If such an agreement is indeed deemed unworkable or undesirable, we believe that moving Huntly into an RMR style arrangement should be seriously considered as a far less disruptive step relative to the proposed New Co.

2.4.2 Energy Hedging Requirements

A second, potentially more heavy-handed, regulatory option would be to impose a form of forward purchasing requirement onto retailers. Mechanisms like these have been proposed as alternatives to conventional capacity mechanisms in markets where periodic energy shortages, rather than ca-

[24] Frontier report, page 61.

pacity shortages, are the main reliability concern.[25] The principle behind these mechanisms is that firms that sell forward contracts to cover firm energy commitments, both baseload and shaped, would need to develop the physical assets to cover these financial obligations. The appeal of this potential solution depends upon whether it addresses the primary problem. Some argue that electricity markets suffer from a market failure in forward contracting, due, for example, to incentives for retailers to remain unhedged because bankruptcy limits their downside risk resulting from periods of high spot prices. A mandate that retailers acquire energy, via standardized contracts or possibly reviewed over the counter (OTC) agreements, would represent an intervention to overcome any perceived over-reliance on the spot market.

We note that some firms in New Zealand describe the opposite problem: retailers who want to hedge but cannot find counter-parties to sell them contracts. A requirement that retailers buy hedge contracts needs to be cognizant of the risk that such a mandate could bestow market power on sellers, at least in the short-term. Energy hedging requirements were central to the recommendations in an analogous review of the hydro-dominant Peruvian electricity market.[26]

2.4.3 Gas Market Intervention

A last option that is not explored in the Frontier report, but appears to us to be a logical policy direction if one agrees with the Frontier report's diagnoses of the problem, is government intervention to promote or secure the reliability of natural gas supply. We are not recommending this option, but raise it as an alternative to the Crown corporation. If fuel supply uncertainty is the primary barrier to developing dispatchable generation capacity, then policies that target this issue, such as public support for storage, development, or even an LNG facility, could be more narrowly targeted than a state-owned electricity company that directs fuels policy through its investment and fuels procurement decisions.

2.5 Summary

The New Co. proposal would constitute possibly the most significant disruption of the competitive environment since the market was first restructured. The proposed New Co. would be tasked with pursuing new investment as well as operating the existing aging fleet.

The case for a government entity dominating investment in new "firming" capacity is predicated upon at least two key assumptions both holding.

- The NZ market will definitely require new investment in geothermal or fossil-based generation to maintain reliability in the future, beyond extending the service lifetimes of existing fossil plants such as Huntly and Taranaki.
- No private market actor would invest in sufficient geothermal or fossil generation even if market conditions imply that investment is required for reliable operations in dry years.

[25] Wolak, 2022. "Long-Term Resource Adequacy in an Intermittent Renewable and Import Dependent Future in California.", *Environmental and Energy Policy and the Economy* `https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/cpuc_submission_wolak.pdf`

[26] Wolak, 2021. Final Report on Thematic Line 2: Transformation of the Peruvian Wholesale Electricity Market, *Report for the Ministry of Mines and Energy of Peru*. `http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/reportwolakJune`.

We believe that it is an empirical question beyond the scope of either the Frontier report or our review as to which mix of energy assets could best manage future dry-year risk for New Zealand. To begin scrutiny of these assumptions, in Appendix A we summarize statistics on energy production and potential capacity of both supply and demand response. From those, admittedly rough, calculations, it is not obvious to us that *new* thermal capacity is required for reliable supply during dry years, assuming the continued operation of Huntly, combined with demand response and diesel options. By our calculations, the most severe quarterly deficit in hydro production, relative to a twenty-year average, was about 1675 GWh in the quarter ending September 2001. The coal capacity of Huntly alone, operating at an 80% capacity factor can produce about 1300 GWh quarterly. Other sources, including newly committed renewable energy, demand response, not to mention diesel generation, easily fill the remaining gap, even if there is a continued decline in gas availability.

Our point is not that there is no dry-year issue, but that the issue strikes us as much more about *prices* than about reliability. Perhaps a large, government directed, push into new fossil investment would stabilize inter-year price volatility, but there is a wealth of evidence on electricity liberalization that contends that this would come at the expense of efficiency and increased long-run average costs.

As we have noted above, several studies have simulated a future with *zero* fossil generation. While these studies show that fully 100% zero carbon system could prove to be both technically challenging and expensive, such a goal goes considerably farther than a scenario where the existing fossil resources continue to operate.

It is quite likely that the capacity factors of these fossil fuel plants will continue to decline, and this may make their continued operation uneconomic. In such circumstances, a less severe intervention to prevent retirement, through a reliability must-run contract or other arrangement could be justified. All of this assumes a relatively pessimistic evolution of renewable and storage technology options.

With regards to the stance that only a government dominated firm could build new thermal kit, the Frontier report cites several quasi-economic barriers to fossil investment, ranging from ESG pressures to the reluctance of local banks and pension funds to finance fossil investments due to concerns over *“investing in stranded assets”* (page 50) and a preference to *“focus on low carbon transition plans”* (page 51). It is not a forgone conclusion that these barriers would continue to hold if market conditions signaled newly lucrative potential for fossil generation. We note that attitudes toward ESG and natural gas generation have shifted dramatically worldwide in the last couple of years. In the face of previous public pressure, private equity has taken an increasingly large stake in power generation in the U.S.

Conversely, if these stances by financial institutions truly continue to bind, a revealed preference interpretation would conclude that the NZ “market” has signaled a preference to avoid new fossil investment. Having a newly formed government entity apply publicly-backed funds to pursue investments that the market prefers to avoid would override this customer sentiment and shift the risk of stranded assets to the public company.

We do not claim to know the answer as to what mix of energy resources would most efficiently manage dry year risk. We are open to this being best managed by maintaining an infrequently used collection of diesel or coal plants, with fuel sourced internationally. It might be best managed by utilizing more domestic gas resources. It may involve building out more wind and solar resources, or by having electricity end users develop more flexibility. In any case, a well-functioning market will incentivize all of these possibilities to be developed if it is the most cost effective way to do so. If it does emerge that maintaining thermal capacity is the least cost option for managing dry-year risk, we do not believe that New Co. is the best option for reaching this outcome. Again, the argument presented for New Co. is that *new* fossil capacity is needed to managed dry year risk and that only a new, Government-led firm could make those investments. We do not believe, based upon the information we have reviewed, that this case has been made.

3 Government Divestiture of Gentailers

The Frontier report's second major policy recommendation is the government divest its 51% shareholdings of the three major gentailers that it maintains an interest in: Genesis, Mercury, and Meridian. While we can see potential benefits of divestiture, and do not object to the idea in principle, we also note that this proposal is not supported by very much analysis evaluating the costs and benefits of divestiture. The main reasons for divestiture cited in the Frontier report are the following (see Section 3.4.5).

- Constraints on the ability to raise additional equity capital stemming from significant government equity ownership.
- Pressure from government owners to provide higher dividends than might otherwise be demanded by market investors.
- Reliance of these gentailers on PPAs rather than direct investment into their own capacity.

Again, in light of the limited time and resources allocated for this review, the analysis relies heavily on stakeholder interviews and comments. Ideally these arguments would be supported by quantitative evidence such as a comparison of debt costs and dividend levels between the government owned gentailers and other comparable, investor-owned firms. Our exploration of financial data from the four gentailers raises questions about the first two arguments. For example, the Frontier report argues that the government-owned gentailers *"can raise debt and can apply retained earnings, but they struggle to obtain adequate equity injections."*[27] This implies that the government-owned firms may be overly reliant upon debt. However, of the four major gentailers, the fully privatized firm, Contact, carries the most debt relative to assets as of December 2024.

Gentailer	Assets	Debt	Debt/Assets
Contact	6208	3589	58%
Genesis	6026	3076	51%
Mercury	9795	4946	50%
Meridian	13543	5297	39%

Table 1: Leverage of NZ gentailer firms as at 31 December 2024. Note that Contact is privately owned, whereas Genesis, Meridian, and Mercury have 51% government ownership. Source: gentailer annual reports.

The Frontier report also cites government ownership as a source of pressure to *"provide stable and higher dividend payments"* than would otherwise be demanded of a fully investor-owned firm. A comparison of dividend payments for the four NZ gentailers again doesn't seem to support this contention. Contact seems to provide a higher dividend per share, and (in 2015) made a very generous dividend payout to its shareholders (Figure 5). The Frontier report argues that the government's preference for stable dividends will be reinforced by investors with similar preferences forming a clientele for the government owned gentailers. We note that paying high and steady dividends should not be considered unusual in the New Zealand context. Since New Zealand uses an imputation tax system, there is no tax penalty to paying dividends to domestic investors (unlike

[27] Frontier report, page 3

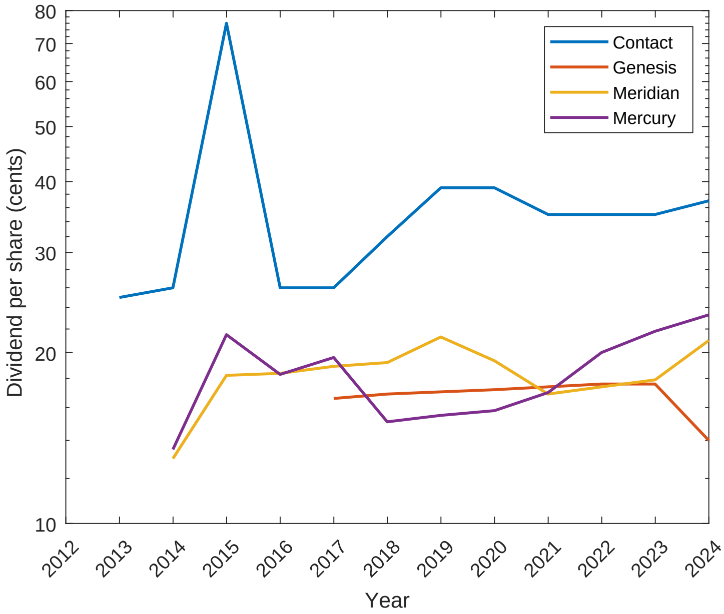


Figure 5: Recent dividends paid by gentailer firms. Source: gentailer websites.

in a classical tax system such as the US). Further, high and steady dividends serve two important purposes in a world where management and shareholders are separate. First, they serve as a discipline to management, discouraging wasteful expenditure by the firm. Second, they serve as a signal to shareholders of the firm's financial health: firms with unstable (or low) cash flows cannot afford to pay high/steady dividends. As such, it is neither surprising to see Contact Energy engaging in similar behaviour to its state owned counterparts, nor would we necessarily expect to see the state owned gentailers' behaviour change if they were fully privatised.

> *"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."*
>
> *— Frontier report, page 51.*

This comment posits that as well as state owned gentailers facing limitations on raising equity, banks may be increasingly reluctant to lend to fossil fuel-intensive firms. While this is possible, large firms such as the four gentailers are rarely dependent on banks for financing. As an example. Genesis Energy raises $120.3 million of its $1528.7 million from revolving credit. The remainder is sourced through bonds.[28]

The Frontier report further comments that

> *"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."*

[28] Genesis Energy Fiscal Year 2025 interim report, Section D1 Borrowings (page 20).

Gentailer	Fossil fuel generation (%)	Beta (β)
Contact	30.1%	0.92
Genesis	59.5%	0.68
Mercury	0.0%	1.04
Meridian	0.0%	1.25

Table 2: Fossil fuel generation (diesel, gas, and coal/gas) as a percentage of overall generation capacity. Source: Electricity EMI as at June 2023, with Manawa/Trustpower assets added to Contact. Beta measures systematic risk of the company's equity. Source: Tradingview, beta calculated with 1 year's data and using NZX50 as benchmark.

— Frontier report, page 51.

However an examination of the data suggests the opposite effect (see Table 2). Genesis, with the largest fossil fuel capacity has the lowest β, while Mercury and Meridian (with no fossil fuel capacity) have higher βs.

Frontier's Figures 14 and 15 are reproduced as Figure 6. These show the amount of investment undertaken by the gentailers, measured in MW and GWh. Frontier concludes that *"Contact Energy is clearly investing more than the gentailers with Government ownership"* (page 33).

In both cases, it is true that Contact has a larger total amount of investment. However once "actively pursued" is removed, it is less clear that their concrete investments have been much larger than other Gentailers. In fact, Mercury/Mighty River Power has made more investments that are committed or in service.

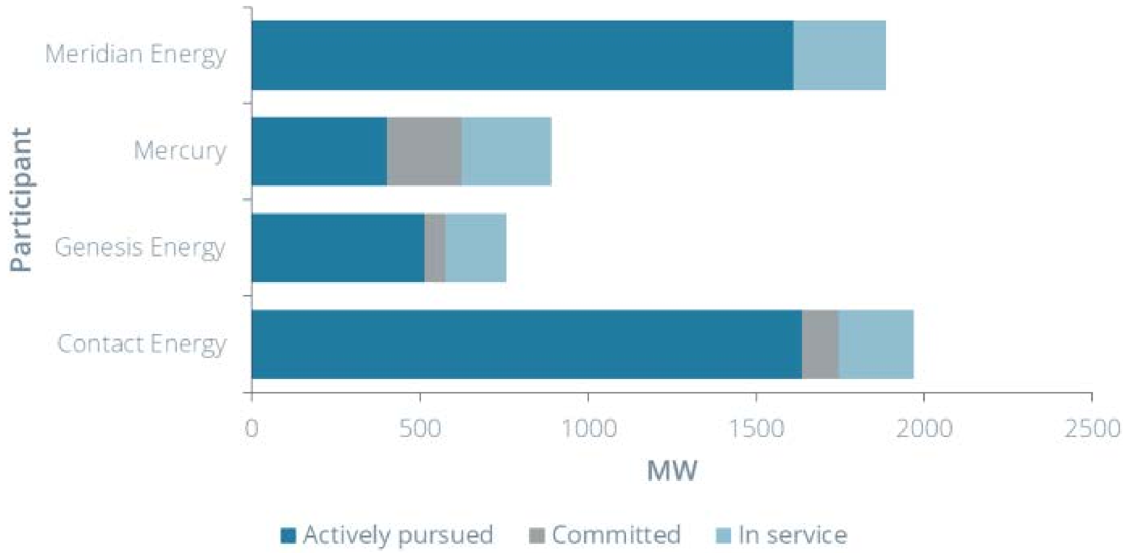
Power Purchase Agreements

With regards to the third point, concerning gentailers with significant government ownership relying on PPAs to a greater extent (*"this approach means that independent operators and industrial customers must remain dependent on the gentailers for capacity rather than being able to go directly to the developers of that capacity"*, pp. 32–33), we do not see why this is a competitive concern. The question is whether this practice distorts the equilibrium quantity of capacity, relative to a setting where gentailers directly own, rather than contract for, new capacity. The report describes a *"competition for capacity"* that allows gentailers to control supply from independents who would *"otherwise emerge."*[29] This implies a counterfactual where gentailers would have built their own capacity instead of signing PPAs *and* independent developers would have also built capacity as well.

It strikes us as more likely that direct gentailer investment would simply crowd out the investments that would otherwise be made by third-party developers in support of a PPA signed by the gentailers. Therefore, the question here concerns the relative merits of third party versus gentailer developed projects. Further, in many electricity markets PPAs support investment in a baseline level of capacity but developers can find it profitable to size capacity beyond that required by a

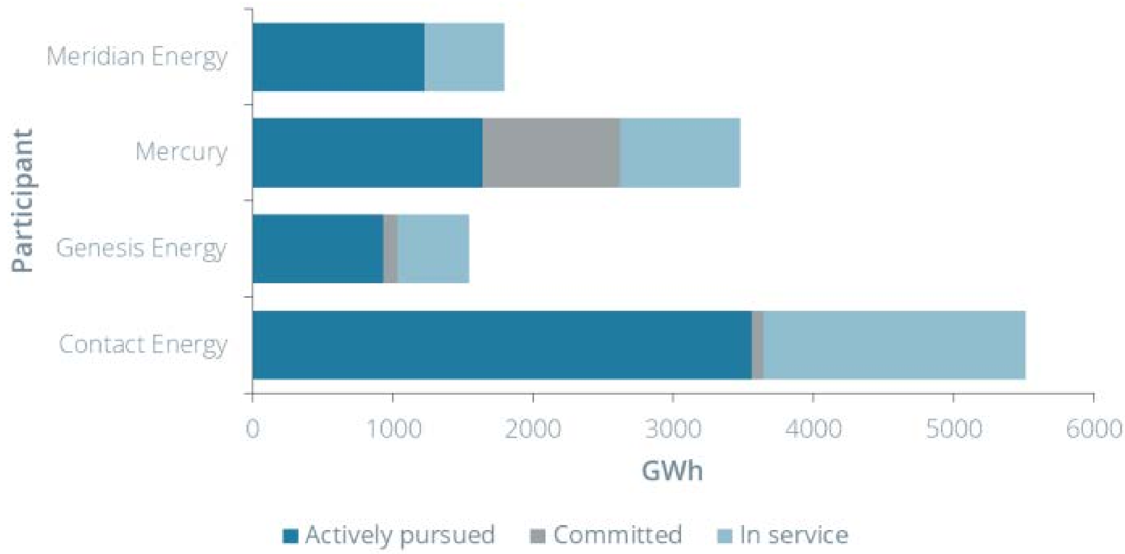
[29] Frontier report, page 32

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



Source: Frontier Economics, various sources

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



Source: Frontier Economics, various sources

Figure 6: Gentailer investments, measuerd in MW (top) and GWh (bottom). Reproduced from Frontier report Figures 14 and 15.

specific PPA. In this way a PPA can help an independent developer mitigate the risks of developing merchant capacity or capacity that could be marketed to other firms.

If, alternatively, Frontier means to imply that it would be preferable that independents develop new capacity *instead of* the gentailers, then this contradicts the stated purpose of the proposal, which was to unleash the investment funded by additional gentailer equity that Frontier fears is being held back by the Government's 51% ownership in these firms.

3.1 Other Potential Reasons for Divestment

There are other strong reasons many countries have sought to divest state-owned enterprises. In some cases, government influence can be a drag on productivity. For instance, government ownership can result in pressure to maintain inefficiently high levels of labour staffing. As discussed earlier, government-controlled firms could increase market uncertainty when the level and form of their investment decisions are influenced by political priorities. Government ownership can leave a firm exposed to undue political influence over fuel sources or other technology choices. The Frontier report does not raise these concerns as a motivation for their proposal, and indeed comments: *"We understand the Government's involvement in the day-to-day operations of the companies is relatively hands-off"* (page 26). Indeed, as we understand it, the logic behind New Co. is that "hands-on" Government oversight of this new entity would override the market and invest in resource types the market is choosing to avoid.

Finally, the Frontier report makes the argument that divestment of the gentailers would be a convenient way to raise the capital necessary to execute the vision of forming a new Crown corporation that controls all thermal generation. The optimality of such a sale as a source of public funds would obviously depend upon the terms and conditions under which a sale could be executed. A sale would produce a one-time supply of capital but at the expense of the stream of profits currently earned by these firms. If the newly formed Crown corporation does not enjoy the same margins as the divested gentailers, given that its mission and operating parameters would be very different, the changes in ownership would create an ongoing opportunity cost for the Government.

3.2 Summary

A number of difficulties are raised regarding the capital structure (and ability to raise capital) of the government owned gentailers, and this is seen as both a motivation for their divestment, and a source of problems in financing future investment in the sector. Our own (cursory) investigation suggests that these may not be the sources of trouble that the Frontier report suggests:

- There is no evidence that the gentailers are constrained in terms of equity relative to debt.
- Contact energy pays higher dividends than the state owned enterprises.
- More fossil fuel intensive gentailers have *lower* betas than fossil fuel free gentailers.
- Gentailers are large enough to issue their own bonds, and hence have minimal dependence on bank lending.

While mismanagement by gentailers as state owned enterprises could be a motivation for divestiture, that does not appear to be the case here.

4 Consolidation of Distribution Businesses

The third major recommendation in the report is to induce the consolidation of Electricity Distribution Businesses and make significant changes in how those businesses are regulated. Based upon the information presented, we found this to be the most persuasive of the major recommendations. The dual challenges of electrification and decarbonization are creating stresses for distribution networks around the world. We agree with the assessment of a need for a structure that is more conducive to innovation and investment. We also note that other reviews, notably the MDAG, also highlight the importance of unlocking innovation in the distribution sector. Our comments on these proposals are more brief, largely because we agree with the recommendations raised here, with the usual caveats that a more rigorous process is necessary to pursue implementation.

One fact to note is that, despite the apparent economic benefits to EDB consolidation, to date it hasn't happened. This could very well be due to political or other non-economic factors, but at the same time those deserve some consideration. If consumers were well informed and actually perceive benefits from the service quality or possibly responsiveness, of the "local" EDB to their issues and concerns, then we can interpret the current structure as the revealed preference of those customers. Our suspicion is that this interpretation is a stretch, and that most customers do not spend much time considering the structure or governance of their local electricity distributor, but these considerations cannot be completely dismissed. As we note below, the characteristics of rural EDB trusts in New Zealand is not that different from the many rural electric co-operatives in the U.S. These institutions have proved quite durable.

4.1 US Co-op and Municipal Utilities Share Characteristics with NZ EDBs

The Frontier report makes several comparisons to the distribution sector in Australia, particularly Victoria, that starkly contrasts the size of EDBs in the two regions. The US, however, does feature many EDBs, mostly municipal or co-operatively owned, of comparable size to NZ EDBs. We do not consider this evidence of the superiority of this structure, but felt we should point out that New Zealand's small and rural EDBs are not necessarily unique in advanced economies.

4.2 Reform of Regulatory Incentives is Advisable

The report makes several recommendations relating to the regulation of EDBs that we find sensible and agree should be pursued. We summarize these as

- Replace the current two-tier price-cap regulation scheme with a new incentive regulation scheme.
- Remove the prohibition on benchmarking in the regulatory process.
- Rationalize and improve the transparency of the regulatory Input Methodologies, including a potential financeability test.
- Remove the regulatory exemption for small EDBs.

We note that there is another regulatory approach, rate-of-return regulation, which compensates distribution utilities based upon their allowed costs plus a regulated rate of return on investments placed into a rate base. The advantage of ROR regulation is that it does not discourage investment, at least when the regulatory environment is amenable to it. This regulatory environment reduces any incentive for a utility to "cut corners" in spending in ways that could degrade service or reliability. The disadvantage is that it provides a far weaker incentive for cost savings and efficiencies.

We are far more familiar with the rate of return regulation typical of the US than the forms of revenue-cap, performance, and incentive based regulatory instruments adopted by the U.K., Australia, and New Zealand, and we do not propose such a dramatic shift in paradigm for New Zealand. Among other factors, ROR regulation typically requires a more cumbersome review process that creates significant workload for both utilities and regulators. The regulatory changes described in the Frontier report strike us as reasonable and merit serious attention, with the possible exception of removing the exemption for small, consumer owned EDBs.

If consolidation is not possible, then the regulatory capacity of the commission may be a constraint on implementing the other regulatory changes. While monopoly consumer trusts may not have strong incentives for efficiency, they are also not classic, profit-maximizing investor-owned firms. The majority of municipal and cooperatively owned distribution utilities in the U.S. are "self-regulated" through elected or appointed community councils.

4.3 EDBs Should Not Own Supply in Their Own Regions, Except as a Network Substitute

We share the concerns raised by Frontier over the prospect of the relaxation of ownership limitations for EDBs that would allow these firms to invest in supply and retail operations in their own operating territories. There is an inherent risk of conflict of interest and the prospect that network investment could favor EDB resources in subtle ways that may be hard for regulators to detect. There would have to be a compelling case about cost savings to overcome these concerns.

We also agree with Frontier's stance that this recommendation should not prevent the investment in batteries or other technology that could serve as cost-saving substitutes for traditional distribution infrastructure. Having said this,it does raise difficult questions about if and how those resources should be utilized, and when such utilization may be construed as unfair competition with other sources of supply. Regulators in several locations have been grappling with these questions.

4.4 Frontier Option 3 Could Gain Some Scale Economies

If community interests and other concerns prevent the full consolidation of New Zealand EDBs, other arrangements short of full mergers could capture at least some of the scale economies outlined in the Frontier report. Options for coordinated operations are discussed by Frontier as a consolidation "Option 3."[30] We note that many small electric cooperatives in the United States participate in umbrella organizations, or "collectives of collectives", that are owned and governed by the member co-ops. Typically, these organizations focus on wholesale and policy issues, but they can also provide regulatory and technical expertise that might be difficult to host within a very small individual firm.

In addition, expertise on specific technologies does not always have to reside within the firm that consumes them. It is possible that arrangements with distribution specialists could aggregate demand and take advantage of a larger scale than individual small EDBs could achieve. Again, we do

[30] Frontier report, page 139.

not claim these options would be superior to actual consolidation, but note that there is some middle ground between completely-siloed EDBs and the fully merged “super-EDB” vision laid out in the Frontier report.

5 Electricity Generation and the ETS

One other significant recommendation made by Frontier is to remove the electricity sector from New Zealand's Emissions Trading Scheme for greenhouse gasses (GHG). We are not persuaded by the arguments made to support this proposal. The New Zealand ETS is somewhat unique, with a much broader scope than other comparable trading systems, but lacking a firm emissions cap. As we discuss below, an ETS can play an important role in reflecting the relative costs of GHG across multiple sectors of an economy. Because of this, any further review of the interaction of the ETS with the electricity sector needs to consider these broader design elements.

We recognize that smaller jurisdictions, such as New Zealand, make very small contributions to global GHG emissions, and there can be a legitimate debate about the costs and benefits of a country such as New Zealand pursuing a unilateral GHG mitigation policy. Having decided to adopt and maintain a policy to reduce GHG emissions, however, we believe that an economy-wide carbon tax or ETS is an excellent mechanism for pursuing these goals. There is a significant risk that removing one key sector, electricity, from the ETS could distort the impact of carbon pricing across all sectors.

The Frontier report argues that the Emissions Trading Scheme (ETS) raises electricity prices but has virtually no impact on physical outcomes in the electricity sector. It argues that the ETS has *"no meaningful impact on generator output or investment decisions."*[31] For context, we note that amongst emissions trading programs that cover the electricity sector, New Zealand is about in the middle in terms of carbon price.

Region	Mechanism	Price (USD)
European Union	Cap	80.30
Washington	Cap	40.26
New Zealand	ETS	36.48
California	Cap	31.91
RGGI	Cap	20.05
China	ETS	13.85

Table 3: Approximate Carbon Prices: December 2024.

Our opinion is that, despite the Australian experience, emissions trading systems can be more durable as climate policies than technology mandates, goals, and tax credits, all of which can be, and have been, adjusted or revoked with changing political sentiment. An under-appreciated aspect of emissions trading systems is that regulated parties become stakeholders to the regulations, either through the purchase or allocation of emissions credits. The establishment of a price floor through an Auction Reserve Price (ARP) and price-ceilings through a containment reserve should also enhance the stability of expectations. These dynamics can make an ETS less susceptible to the type of environmental policy uncertainty the Frontier report points to as a key detriment to investment. Indeed, removing the electric sector from the ETS could increase that uncertainty.

[31] Frontier report. Page 37.

5.1 Impacts of ETS on the Electricity Sector

We agree that *existing* renewable resources would produce energy regardless of the level of a carbon price, given the fact that they are zero (or near-zero) marginal cost. The Frontier report also argues that the carbon price would not impact the merit order of currently operating Fossil units, although this can change with fluctuations in gas and coal prices and the carbon price itself. Relative prices across hours, determined in part by the carbon emissions of the marginal resources and the price of emissions, are likely to have an impact on the value and use of battery technology in the timing of both charging and discharging.

The greater impact of carbon pricing, however, is to incentivize investment and operation in new low and zero emission technologies. The Frontier report acknowledges that the ETS is *"providing a windfall"* to non-emitting generators, but at the same time dismisses the prospect that this windfall provides an incentive to further develop renewables or other low-carbon energy sources. The Frontier report cites data using 2021 point estimates of the levelised cost of energy (LCOE) of several common resource options, but the LCOE can be misleading as a metric for comparing the value of conventional and alternative generation sources.[32] By contrast, material provided to us from Concept consulting cites the uncertainty in the carbon prices as potentially chilling investment.[33]

As important, the LCOE estimates provided in Figure 16 of the Frontier report represent a single value for a single point in time. There are no error bars. There is no way to know exactly how much a carbon price might influence low-carbon investment in the future given unknown trends in future technology costs. The main advantage of market-based environmental mechanisms, like the ETS, is that they do not rely upon any specific government agency, or outside experts, to specify the optimal technologies to achieve environmental goals. The carbon price provides a market incentive, and firms can choose their options for compliance. Thus, we do not agree with the Frontier report that the carbon price is having *"no meaningful impact on generator output or investment decisions."*[34]

Finally, we note that Frontier's stance that there are "no significant barriers to entry" in renewable generation is incompatible with the view that the ETS is creating durable windfalls that have no impact on the entry of renewable supply. In a competitive market, investment will continue to the point that the expected revenues roughly balance the expected costs (adjusted for risk). This lack of long-run windfall profit is a foundational result of competitive markets. If Frontier's view is that the market is currently on a trajectory to equilibrium, then removing the ETS would lower the expected margins of future renewable investment and threaten the large amount of new renewable capacity currently under consideration.

5.2 ETS design considerations

Our understanding is that an Auction Reserve Price that effectively sets a lower bound on allowance prices was adopted in recent years and that prices in recent auctions appear to be set at this price floor (figure 7). The primary benefit of price containment mechanisms in emissions trading mar-

[32] Borenstein, 2012, "The Private and Public Economics of Renewable Electricity Generation," *Journal of Economic Perspectives*

[33] *"Low and/or material uncertainty on carbon prices will also reduce extent of renewable build,"* from: Concept Consulting, 3 February 2025, "Electricity Review Workshop 1: Wholesale and Retail Market Issues".

[34] Frontier report, page 37.

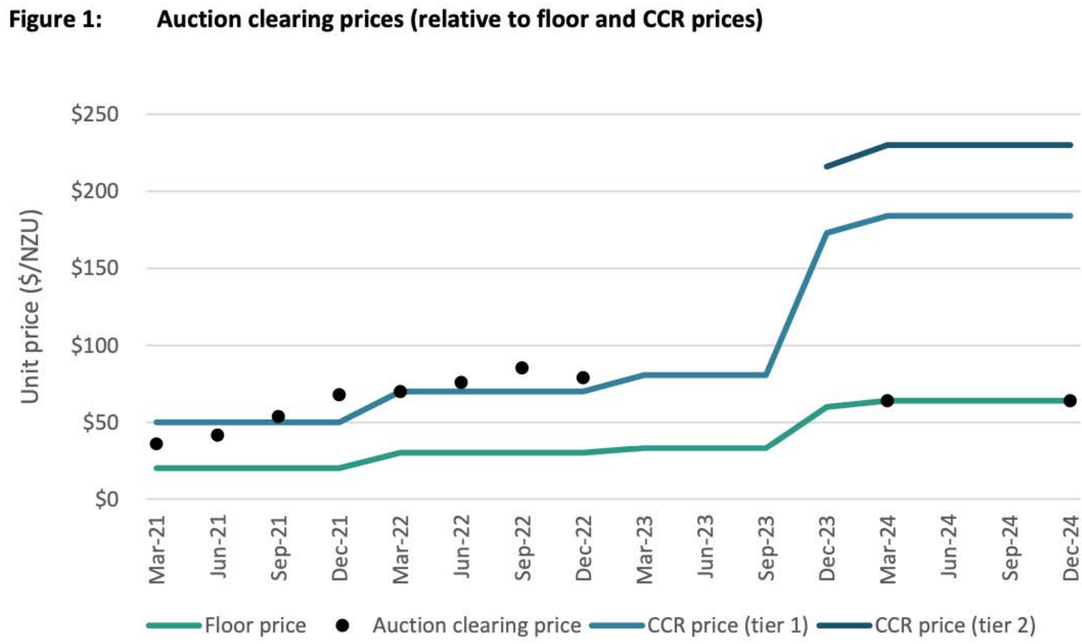


Figure 7: Recent ETS Auction Prices

kets is that they help reduce the uncertainty about future compliance costs. If allowance costs really are creating an undue economic burden on the New Zealand economy, a process that revisits the level of these price bounds would be a less drastic option than removing the electricity sector from the market.

One additional consideration is the growing consideration of ETS systems in the context of international trade. The European Union is moving to adopt a "Carbon Border Adjustment Mechanism" (CBAM) that would apply a carbon tax to imported goods *unless those goods are subject to carbon prices in their home market*. These measures are intended to both reduce emissions leakage and promote the international use of carbon pricing.[35] These schemes may apply to the indirect scope 2 emissisons associated with electricity supply. While NZ trade with the EU is not significant, it is quite possible that countries such as China and India will participate in the system as well.

5.3 The ETS provides a price signal across all covered sectors

Beyond its potential influence on the long-run make up of the electricity sector, the ETS has broad coverage in New Zealand, encompassing forestry as well as transportation and heating fuels.[36] A well-designed ETS allows the relative costs of compliance to be efficiently distributed across all of these covered sectors, thereby reducing the overall cost of compliance required to reach a specific emissions reduction goal. The resulting carbon price is internalized by both producers and consumers across multiple sectors, impacting decisions in a multitude of ways both large and small.

[35] Clausing and Wolfram, 2023, "Carbon Border Adjustments, Climate Clubs, and Subsidy Races When Climate Policies Vary." *Journal of Economic Perspectives*.

[36] Leining, Kerr, and Bruce-Brand, 2019, "The New Zealand Emissions Trading Scheme: critical review and future outlets for three design innovations", *Climate Policy*.

Removing one sector from this system can distort this balance in ways that are not examined or discussed in the Frontier report.

Ultimately, decisions about the ETS should be coordinated with broader national carbon policy. If NZ maintains its commitment to reducing carbon emissions, limiting the scope of the ETS will likely only increase costs on other sectors of the economy, and risks raising compliance costs overall. We believe a decision to remove the electricity sector from the ETS is not supported by the evidence presented in the Frontier report, and should only be considered in the context of a comprehensive examination of the ETS as a whole.

6 Competition and Risk Management

Several sections of the Frontier report touch on different topics relating to the competitiveness of the New Zealand market. While not among the top 5 recommendations, many of these topics are covered in the Frontier report's "additional recommendations" and have been identified as issues for both this review and related proceedings. The Frontier report reaches several strong conclusions in these areas.

6.1 Hedging and Competition

Access and transparency to forward markets has been a priority area of focus for the EA. It is worth noting that, as a result of this focus the NZ market has a relatively high level of transparency and forward market activity for a market of its size. The information requirements on OTC contracts and the ASX trading platform have made significant contributions.

However, we are struck by the emphasis placed upon market liquidity and transparency in the forward market relative to conditions in the physical spot market. Hedging is not the only role of forward markets. In our view, two other critical functions of forward markets are to provide information on market expectations and, in the electricity industry, to mitigate incentives of dominant generators to exercise their potential market power in the spot market. Forward markets are ideally a window into expectations about the underlying physical market. However, if the underlying physical market has scarcity or severe market power, financial markets cannot conjure additional competitive supply out of thin air. Our reading of the Frontier report is that Frontier is more concerned with the provision of financial firming instruments rather than the competition in the spot market, and that their solution is to create competition through a new Crown corporation.

Our recommendation on hedging would be to continue to push for additional transparency on OTC contracts, as the Frontier report describes, and to examine the possibility of adding market making requirements (i.e. an obligation for gentailers to be willing to both buy and sell contracts at reasonable spreads) to the super-peak or other perhaps future types of "shaped" contracts. Market making obligations have been implemented in New Zealand and Singapore.[37]

Finally, as we discussed above, if Huntly or other aging fossil resources become quasi-regulated under the terms of an RMR contract, this would provide a significant amount of competitive flexible capacity to the spot market. That alone could make the super-peak hours sufficiently contested and allow for financial products to be formed around a reasonable expectation of competitive, or at least contested, outcomes in peak periods. An additional step would be to have the regulated RMR plants auction off hedging contracts. Revenues from the sale of these contracts could be used to partially offset the operating costs recovered from the regulatory process.

6.1.1 Level Playing Field

There is a legitimate potential concern that as the NZ market evolves toward a mix of more renewable and less dispatchable sources, the ability of dispatchable generation to exercise market power in periods of low renewable production could increase. We agree with the Frontier report's diagnoses of this problem, but not with the solution of a new Crown corporation. We are also

[37] Wolak, 2019, "The benefits of purely financial participants for wholesale and retail market performance: lessons for long-term resource adequacy mechanism design", *Oxford Review of Economic Policy*.

sympathetic to the Frontier report's skepticism of the potential for some parts of the proposed "level playing field" proposals. Specifically, we do not expect the accounting separation and non-discriminatory pricing rules to help much with these problems, although we see less support for the claim that conduct rules will *"increase prices for customers"* (page 82).[38]

A more significant step (proposed as a possible escalation if non-discriminatory pricing failed) would be some kind of virtual divestiture of flexible generation assets. Again, we think any serious examination of such a proposal should start with an examination of the existence of, or potential for, market power in the physical spot market. Forward market outcomes feed back from the expected supply and demand conditions in the underlying spot market.

Analysis of the availability of, and price for, certain types of forward contracts therefore needs to be cognizant of the fact that availability of those contracts might be limited because there is a limited amount of actual physical capabilities to hedge these risks. High prices for these contracts could serve to spur additional entry in the types of technologies that could serve these periods. Absent new physical capacity, however, a forced sale of these contracts would constitute a shifting of physical supply from one party to another.

There may be competitive benefits to shifting some dispatchable assets around. The Frontier report appears not to acknowledge this possibility. We were surprised at the Frontier report's hostility toward the EA's exploration of virtual divestiture, given that Frontier's proposals that New Co. acquire and then sell off slices of firming generation capacity are not dissimilar. We have not seen convincing analysis one way or the other. Considering that vertical integration can have a pro-competitive influence on the wholesale market, a poorly implemented virtual divestiture could make things worse. Such proposals should proceed with caution.

6.2 Retail Competition

The link between the conventional proxy measures of competition, such as measures of market share, and the competitive ideal is particularly unclear when the subject is retail market competition, which is the primary focus of this section. The retailing of electricity is an unusual business, given that the "quality" and location of the *physical* commodity provided by retailers is effectively homogeneous. Therefore it is even harder to define what the desirable outcome of competition is for retail electricity, beyond charging margins that are as small as possible.

The frequent entry of retail firms might be seen as a sign of competitive health, but this is less obvious in the case of retail electricity than in the retail of physical goods. There has been a lot of churn in this market - the draft report cites 62 entries and 29 exits of retail businesses since 2000. A more encouraging sign is the list of significant retail service innovations over the years (Table 5), although we note that many of these services have been rolled out in other jurisdictions with limited retail competition.

It appears to us that the current focus of the EA competition review is devoted to combating a risk of foreclosure of retailers in the forward market that could be a problem in theory, but has not been solidly demonstrated to in fact be happening. The theoretical problem is that independent retailers can only viably compete for business if they can procure power at reasonable prices during periods that match their customer's demand. The focus of the competition task force initiative,

[38] For more details on the Level Playing Field policies, see "Level Playing Field measures Options paper", Electricity Authority, 27 February 2025.

however, appears not to be on the potential market power of generation during super-peak periods, but rather over the prices of financial *hedges* that cover super-peak periods. To wit, analysis in the Frontier report and by the EA focuses on the gap between forward prices and spot prices during these periods and not on the underlying level of those spot prices. Lack of access to hedge contracts could possibly be a barrier to entry in the retail business, but if there were *no* market power in the spot market it is unclear how to interpret the forward price premium. If there is substantial market power in the spot market, we doubt that forcing financial market transactions will rectify it.

Our opinion is that analysis of retail competition should start with a measure of margins between retail prices and wholesale costs. In this case the fundamental underlying costs are the wholesale prices of energy (at the relevant Locational Marginal Prices) and the associated network delivery charges. There are of course other real costs (billing, meter reading, etc.) but they are typically small compared to wholesale cost and delivery charge, and one result of competition would presumably be to keep those costs down.

We found the information in Figure 41 comparing retail margins in EU countries to be intriguing and encourage the EA to pursue more analysis along these lines. The EU data aggregate both gas and electricity margins and represent the margins in terms of annual bills. Given the concern over foreclosure in this market, further effort at comparison with markets that do not share the same level of vertical integration, or feature other important differences could provide valuable insights.

We are not sure how to interpret Frontier's data on the state of retail market competition based on the evidence offered, which we detail in the context of market monitoring later in Section 8.1. In particular, we are not convinced that reported contract prices are the best, or most informative, measure of costs for retailers. Spot market prices are a function of a transparent market clearing process whereas forward prices (especially those generated from internal pricing) may be opaque and subject to manipulation, particularly when they reflect internal transfer prices.

Further, even if retailers make extensive use of hedging, wholesale financial hedge contracts are typically for fixed quantities of electricity, whereas retail obligations typically supply a variable demand at a fixed price. Given that demand is not known ex-ante, there will always be a mismatch between financial hedges and retail obligations. At the margin, this will be settled using the spot market, and spot electricity prices will hence be relevant even to market participants that hedge.

6.3 Wholesale Competition

We generally agree with the draft report that there is no glaring evidence of severe market power in the wholesale market, but our sense is that more analysis could be done to confirm this. We believe it would be helpful to see more extensive analysis of spot market outcomes along the lines of those we describe in section 8. These could start with competitive benchmark simulations but could also investigate the behavior of large firms during periods where their residual demand becomes very inelastic relative to more competitive periods.[39] We believe such an examination should pay particular attention to the vertical and hedging positions of the large producers. This would be helpful, perhaps even critical, information to inform any efforts to effect vertical divestiture, financial or otherwise.

[39] See McRae and Wolak, 2009, "How do firms exercise unilateral market power? Evidence from a bid-based wholesale electricity market", *Manufacturing Markets: Legal, Political and Economic Dynamics* for an analysis of residual demand curves in the NZ market.

One area that has periodically been raised as a concern is the single settlement market with multiple pre-dispatch rounds. This is an element of market design shared by Australia and New Zealand that contrasts with the “two settlement” design in U.S. markets. Two settlement markets feature a day-ahead market with binding financial commitments followed by a real-time “balancing” market where firms true-up their day-ahead positions and adjust to last minute changes in market conditions to ensure a security constrained dispatch. The single settlement market in New Zealand is run multiple times without financial commitment before a final run where the bids and outcomes are binding.[40] In other markets the ability of firms to use their bids and offers as “cheap talk” to signal their intentions to competitors has created concerns about tacit collusion. We are not aware if this concern has been investigated in the New Zealand market, but more study of the single-settlement approach versus the two-settlement seems warranted.[41]

[40] Bergheimer, Cantillon, and Reguant, 2023, “Price and quantity discovery without commitment,” *International Journal of Industrial Organization*

[41] See McRae, 2025, “Rethinking Wholesale Market Design for New Zealand’s Clean Energy Transition”, *working paper*.

7 Transmission Pricing

The Frontier report discusses potential conflicts of interest for Transpower, but it is a state-owned entity and it is not clear, as such, how it would respond to such conflicts. System operators can take a cautious approach to reliability given the negative attention they experience during periods of low-reliability can overwhelm any positive feedback from keeping costs fractionally lower, even when an objective cost-benefit analysis would favor lower cost. But in our experience, this bias can exist even when the operator does not own the grid assets. In fact it can even be exacerbated by separation as the reliability mandates determined by fully Independent System Operators are imposed on the owners and users of the grid and do not show up on the books of the ISOs themselves. This can divorce pressure for cost containment from the impulse to pursue high-cost reliability policies.

With regards to the Transmission Pricing Methodology, we agree that there are shortcomings to trying to allocate transmission costs according to benefits, and some of us have advocated for a more "socialized" cost recovery structure for major transmission projects as long as they are not being induced by generation location decisions. In our view, much of electricity transmission service is "common" to all users of a regions network, and attempts to parse the costs or benefits of specific users can be counter-productive.[42] An alternative approach would combine a transparent and inclusive transmission planning process to develop a "master plan" for the network backbone that would be recovered through a socialized fixed charge. Direct connection costs beyond would be borne by resources, but deep interconnection considerations would be dealt with through the planning process.

That said, we agree with the sentiment in the report that it's "too early to tell" if the recently adopted TPM scheme is or is not working. While the newly adopted approach can mitigate the first-mover disadvantage, this comes at the risk of discouraging the entry of any other movers. It would be inefficient if entry into some locations is deterred by attempts to recover the sunk costs of existing transmission lines.

Along these lines, we felt the draft report's rejection of Renewable Electricity Zones (REZ) was too strong. There are circumstances where a REZ approach makes sense, namely when it is very clear where new renewable resource potential is and where new projects will likely be developed. Under these circumstances a REZ would not be "picking winners" per se, and would result in the same infrastructure outcomes as other approaches but with potentially less delay and without the risk that generation location decisions would be distorted by incentives to game transmission charges. While we have not followed this proceeding closely, it is quite plausible to us that such circumstances apply to wind development in New Zealand.

[42] Bushnell and Wolak, 2017, "Beneficiaries pay pricing and 'market like' transmission outcomes", *UC Davis White Paper*.

8 Market Monitoring

We agree with many of the foundational statements in section 11 about market monitoring. The section, however, makes a number of statements about the different methods of analyzing market competition that might lead the reader to misunderstandings about their uses.

We wholeheartedly agree with the Frontier report that:

1. Market monitoring is difficult and requires extensive data analysis.
2. High prices when a market is in scarcity are critical if it is to achieve an efficient allocation of scarce supplies. High prices due to real market scarcity also play an important role in incentivizing efficient investment.
3. When supply is constrained and prices rise due to scarcity, that is often an opportune time for firms to exercise market power. Furthermore, it is difficult to distinguish high prices attributable to scarcity from high prices attributable to the exercise of market power.
4. Complete absence of market power is not a realistic goal.
5. All of these factors are particularly relevant to electricity due to the fact that demand is quite inelastic, capacity constraints are quite binding (in part due to the high cost of storage), fixed costs are a significant share of total costs, and demand and supply must be in balance second by second.

That said, the report suggests some understandings of market monitoring that deserve further discussion.

8.1 Measures of the Impacts of Market Power

The Lerner Index is defined as the percentage difference between a firm's price and short-run marginal cost (SRMC). A positive Lerner Index is a standard definition of market power. Another (equivalent) definition of market power is a firm producing a quantity at which its SRMC is below the market price, but choosing not to increase its output. A competitive firm produces every unit it can for which SRMC is less than the market price. These are definitions of competition and market power.[43] Calculation of a Lerner Index therefore does not require counterfactual scenarios or simulations, other than estimating a competitive market clearing price. This does require calculation of the firm's SRMC, which at times can be quite difficult.

Many market monitors deploy some form of competitive benchmark model to compare wholesale market outcomes to an estimate of perfectly competitive outcomes. This is more challenging in a

[43] Two important applications of these concepts come up frequently in electricity markets. First, in a uniform-price auction (as is used in New Zealand and most other electricity markets) a competitive firm would bid its SRMC of generation. They receive the market-clearing price tied to their location in the network, so, absent an attempt to exercise market power, they have no incentive to bid above their SRMC. The key distinction is between the bids of a specific unit, and the prices earned by the output of that unit. This assumes the market design has scarcity pricing so that firms are able to earn scarcity rents without elevating their offer prices to scarcity levels. In addition, the measure of SRMC must recognize opportunity cost, such as hydroelectric producers face in using water that is stored behind a dam, or a thermal generator might face if they have an option to sell into a different market. Second, a firm that bids its SRMC might find itself operating at full capacity and receiving a price much higher than its SRMC. Such a firm is not exercising market power so long as it is producing every unit it can for which the market price is greater than its SRMC.

hydro-dominated system where the opportunity cost of stored water plays such a large role. That opportunity cost is in turn dependent upon assumptions about future rainfall and it is difficult for a market monitor to second guess a market participant's expectations. Nonetheless the EA has utilized JADE, a stochastic optimization model of the NZ electricity system as a form of competitive benchmark model. The modeling challenge in New Zealand is also more difficult due to the fact that fossil fuel markets are neither very liquid nor transparent. Given these limitations, such measures are only rough estimates of competitive prices, but can still be valuable benchmarks for testing changes in market conditions and rules. For example, if there has been a large shift in the contract cover of a given firm, or an outage of a generation unit or transmission path, these benchmarks can measure the change in wholesale margins, if not the exact levels.

The Frontier report suggests using an alternative to the Lerner Index that would compare an average price over a year to long-run marginal cost (LRMC). The definition of long-run marginal cost (LRMC) is simply marginal cost when all inputs are completely flexible. The gap between average price and long-run marginal cost can be an approximation of marginal profitability in the long run. In electricity production, however, adjusting all inputs can take years, so it would be quite common for price to be above or below LRMC without it having any particular competitive interpretation.[44]

The fact that firms must recover significant fixed costs is not a reason that a market cannot operate competitively.[45] Production of many natural resources is very capital-intensive—gold, natural gas, copper, among others—yet no firm is thought to have significant market power. Such markets, however, do at times exhibit significant scarcity rents. Very low market shares, combined with greater demand elasticity than we see in electricity, and storability of the good, put a significant check on the ability to exercise market power.

Competition in wholesale electricity markets must be analyzed on a short-term basis as well as a long-term basis. Entry of new generation can take many years, during which time huge transfers of wealth can occur due to the exercise of market power. See, for instance, the 2000-2001 California electricity crisis, which lasted less than one year, but created unexpected wealth transfers to generators that were many times the typical annual wholesale market volume.[46]

8.2 Behavioral Indicators of Market Power

In addition to what we term quantitative measures of market power, such as a market level competitive benchmark or Lerner index, there are many analyses that can detect behavior that is consistent with market power without quantifying exactly what the impacts of that behavior were. Such metrics are indicators of the presence of market power. There are both market level tests, and firm level tests.

The most basic indicators are measures of concentration, such as market shares or the HHI. These can be useful rough first-cut approaches to examining the competitiveness of a market. As such

[44] See Borenstein, 2019, "Pricing for the Short Run", *Energy Institute at Haas Blog*, https://energyathaas.wordpress.com/2019/08/19/pricing-for-the-short-run/

[45] See Borenstein, 2000, "Understanding Competitive Pricing and Market Power in Wholesale Electricity Markets," *Electricity Journal*.

[46] See Bushnell, 2005, "Looking for Trouble: Competition Policy in the U.S. Electricity Industry" in Griffin and Puller, eds., *Electricity Deregulation: Choices and Challenges*, Chicago: University of Chicago Press, and Borenstein, "The Trouble with Electricity Markets: Understanding California's Restructuring Disaster," 2002, *Journal of Economic Perspectives*.

they are more a test of the *potential* for market power than the actual *exercise* of market power. They can also be highly misleading, particularly in markets where capacity constraints play an important role. A large market share might imply very little market power if either the supply of other firms can change rapidly or demand is very elastic. On the other hand, as we have seen in electricity markets, even a small market share can deliver significant market power if other firms cannot expand output (*i.e.,* are at a capacity constraint) and demand is very inelastic. Rules of thumb about market shares or HHIs have not proven to be good guides to market power, as clarified in the 2010 update to the US Department of Justice and Federal Trade Commission merger guidelines.[47]

One broad set of metrics examines the extent to which the bids of firms respond to changes in their competitive environment, rather than to changes in their cost. For example if gas prices are stable, or rainfall forecasts have not changed, one would not expect dramatic changes to the bids of perfectly competitive gas or hydro generation, respectively. By contrast, if supply bids do respond, in way consistent with profit maximization, to changes in the availability of the generation of *other firms*, or to transmission conditions, or even load, these are indications of strategic behavior.

A more nuanced approach to testing for the presence of strategic behavior is based upon the concept of residual demand. Residual demand considers the demand for the output of one specific firm that is "left over" after accounting for the possible supply of all other firms. In markets where firm-specific bid data are available, it is possible to trace out a detailed residual demand by subtracting the supply bids of all firms but one from the market demand for given interval. Figure 8 from Wolak (2009) illustrates Meridian's residual demand in a particular interval in February 2006.

Residual demand is a useful metric for detecting firm-level market power because it measures conditions that are important to a profit-maximizing strategic firm, but much less relevant to a perfectly competitive firm. An indicator of market power would be supply bids that are highly responsive to residual demand under conditions where costs are not changing. Profit-maximizing strategic firms would be expected to increase the margins in their supply bids as their residual demand becomes less elastic.

Pivotal supplier tests are simplified measures of residual demand that focus on the most extreme cases of inelastic residual demand. A firm (or group of firms) is pivotal when there is not enough supply offered by other firms to satisfy market demand at any price. The pivotal firm (or firms) would be able to monopolize at least this residual quantity. Given the extremely inelastic nature of demand in electricity markets, pivotal suppliers enjoy significant short-term market power. Many U.S. markets have rules restricting the bidding behavior of firms during periods in which they are considered to be pivotal.

However, pivotal supplier tests should feature an adjustment for net position, something that is not usually done in the U.S. This would examine a firm's residual demand net of the supply is committed to provide through forward contracts and retail commitments.[48] For example, a supply only analysis might find that a firm may be a pivotal supplier of 200 MW of residual demand in a given

[47] https://www.justice.gov/atr/file/810276/dl

[48] Bushnell, Mansur, and Saravia (2008) found net position to be a key determinant of competitive outcomes in U.S. markets in the early 2000s. See Bushnell, Mansur, and Saravia, 2008, "Vertical arrangements, market structure, and competition: An analysis of restructured US electricity markets," *American Economic Review*. McRae and Wolak (2009) also discuss in detail the relevance of the net position adjustment.

Figure 3.5: Calculation of residual demand for Meridian on 18 Feb 2006, period 36

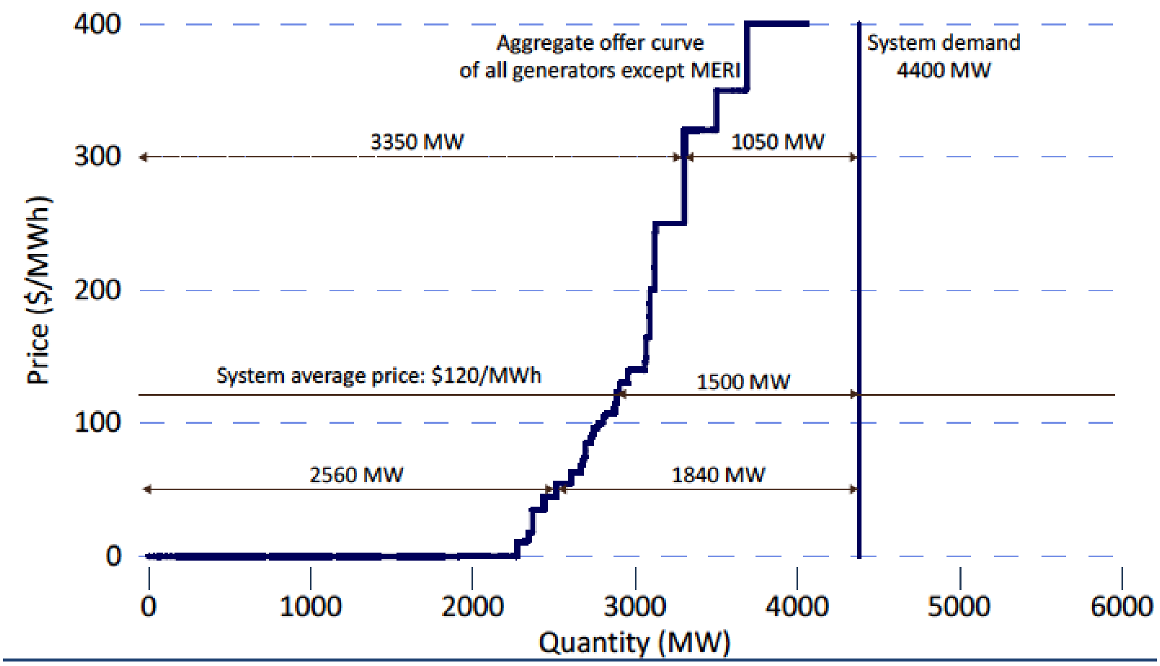


Figure 8: Residual demand for Meridian 18 February 2006, period 36. Source: Wolak, 2009, "An assessment of the performance of the New Zealand wholesale electricity market", ***Report for the New Zealand Commerce Commission*****.**

hour. This means that the firm would have to reduce its output to 200 MW or lower to induce shortage prices. However, if that same firm has retail obligations of 400 MW, then it would not be profitable for this firm to reduce its output to its pivotal level. Doing so would leave this firm net short in the spot market. Wolak (2009) found that, while Meridian was *gross* pivotal (e.g. only generation) in roughly 50% of half-hourly intervals between 2005 and 2007, it was *net* pivotal in less than 1% of intervals during the same period.[49]

Cournot Competition

Cournot competition is a specific framework of strategic behavior described in the Frontier report. Cournot behavior is generally not expected to represent the strategic thinking of a single firm precisely, but the equilibrium that results from Cournot assumptions can be useful in studying potential outcomes in markets. In a Cournot equilibrium, each firm is producing its profit-maximizing quantity given the quantities that every other firm is producing. Cournot firms set their output under the assumption that their behavior has no impact on the quantity of output of other firms.

Residual demand analysis is therefore *not* a special case of Cournot. Residual demand analysis explicitly assumes that a firm believes other firms will change their output as price changes. Aside from the special case where one firm has market power and all others are price takers (known as a dominant firm with a competitive fringe), residual demand analysis is not typically used to calculate an equilibrium. Rather, it is useful for analyzing a firm's incentives to raise price given a reasonable approximation of the likely output response of its competitors.

8.3 Retail Market Performance

Market monitors in many retail markets have focused on switching and market share statistics to form a baseline of the health of the retail market. But these statistics, at best, measure the means through which competitive outcomes might arise and are not ends in and of themselves. The key question about retail markets is whether the margins between retail prices and wholesale costs are reasonable, or unduly large. The analysis of retail competition in the Frontier report provides much information but still left us with basic questions. Figure 40 of the Frontier report (reproduced here as Figure 9) summarizes retail margins against wholesale purchase cost, but these costs reflect contracting costs and do not capture the actual underlying opportunity (spot) cost of wholesale energy being resold to customers. This figure implies that gentailers earn lower margins, but it was not easy to discern how much of this was because independent retailers are charging higher prices, and how much was due to gentailers reporting higher costs. The very fact that gentailers report higher wholesale electricity costs raises questions about the quality of information being conveyed by transfer pricing statistics and highlights the value of comparisons to wholesale spot prices as well.

While it is reasonable to expect customers with an annual fixed price to pay a price premium relative to customers on variable or real-time prices, comparisons could and should be made across firms for relatively comparable contract terms (*e.g.,* annual, variable, etc.) and across markets with different firm numbers and composition.

Another valuable piece of information would be the dispersion of prices charged by a single firm in a given market. Figure 39 (reproduced here as Figure 10) of the Frontier report might be an

[49] Wolak, 2009, "An assessment of the performance of the New Zealand wholesale electricity market". `https://fawolak.org/pdf/new_zealand_report_redacted.pdf`

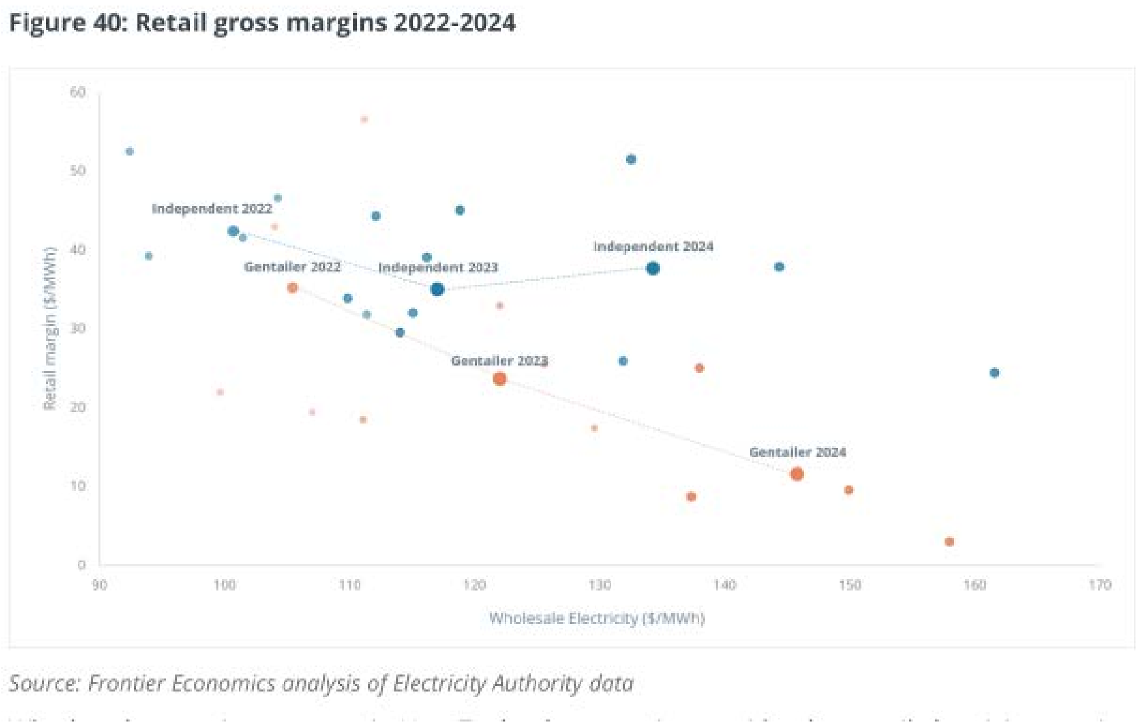


Figure 9: Figure 40 from the Frontier report.

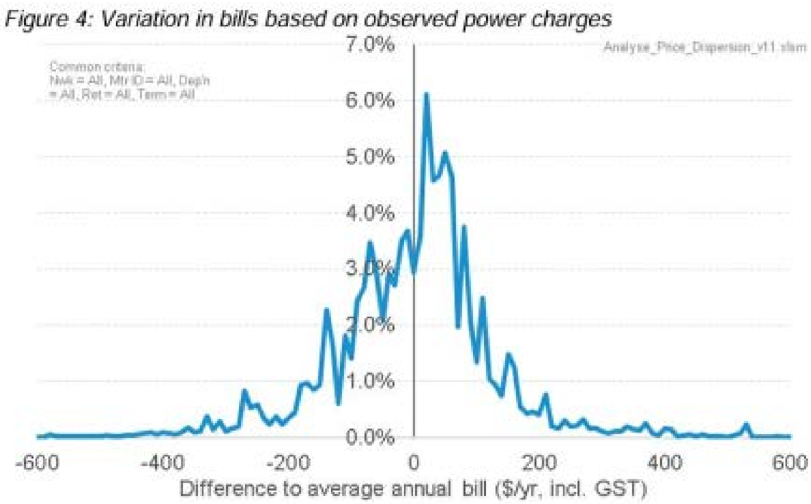
attempt to address this, but it presents annual bills, not prices, across all firms so it is not possible to infer whether the variation shown is due to differences in quantities consumed or in prices charged, as well as differences in retail margins. If, within a firm, retail margins are largely supported by a small number of inattentive customers, that would be reflected in a dispersion of prices offered by a given firm in a given market. Our understanding is that the EA has begun collecting detailed billing data from all providers. It would be helpful to produce benchmarks along these lines.

It is worth contrasting competition in wholesale electricity markets with competition in retail electricity markets to illustrate the importance of considering market-specific factors. Unlike wholesale markets, sellers in retail markets can expand output rapidly without facing technical capacity constraints. Retailers can easily accommodate additional sales as customers switch among them. For these reasons, a significant market share in a retail market confers substantially less market power than in wholesale electricity markets. However, unlike wholesale markets that are centralized and sell a standardized commodity, retail markets suffer from information frictions and costs of switching sellers. These factors are unlikely to lead to the sort of extreme price spikes that we have observed in wholesale electricity markets, but they are more likely to lead to continuous lower-level Lerner indices as buyers find it more difficult to locate the lowest-cost seller. This illustrates how market monitoring must be targeted at the specific attributes of the retail market and illustrates why rules of thumb are unlikely to work well.

8.4 The Role of Hedging

The Frontier report also makes a couple of comments about forward contracts and hedging that require a somewhat more nuanced interpretation. It is not necessarily the case that sellers in a

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

Figure 10: Figure 39 from the Frontier report.

forward market receive a premium for signing fixed-priced forward contracts, also known as hedge contracts. Both buyers and sellers benefit from price certainty from such contracts. In some cases such contracts sell at a premium to the expected spot price and in other cases at a discount.

Importantly, though hedge contracts allow the buyer and seller to lock in a price for a fixed quantity of the good, they do not change either party's marginal cost. Because the quantity sold under contract is fixed, a buyer's marginal cost of acquiring an additional unit is still the market price.

The fixed quantity associated with standard forward or hedge contracts is important in drawing a contrast between such wholesale arrangements and that of a retailer selling at a fixed price to a customer. The Frontier report suggests that the standard fixed-price contract offered by many retailers is analogous to a hedge contract sold by a generating firm to a retailer. A very important distinction, however, is that the wholesale hedge contract is a fixed quantity, while the retail arrangement is what is known as a "requirements contract" under which the purchaser can choose the quantity they require and the seller is obliged to supply it. This sort of retail arrangement can be quite risky for the seller because high quantity demanded tends to be strongly correlated with high wholesale prices.

8.5 Market Monitoring in the U.S.

In the United States, the role of independent market monitoring evolved organically, driven originally by concerns over ISO governance and then by the disaggregated regulatory roles arising from the U.S. Federal system and a need for the Federal regulator to have expert "eyes on the ground" to inform policy. In general, market monitors do not have regulatory enforcement authority. The Federal Energy Regulatory Commission (FERC) retains statutory authority to regulate wholesale electricity markets and enforce Federal energy competition laws. When market monitors detect behavior that may violate Federal regulations, they refer these cases to FERC for adjudication.[50] In some cases, monitors do act as "agents" for FERC when they impose bidding restrictions in real-time upon some market participants. These actions follow largely algorithmic rules that have been reviewed and approved by FERC.

Market monitors were initially focused on competition issues in the wake of the 2000–2001 California electricity crisis, but the majority of their time now is spent reviewing the performance of existing markets and recommending (or opposing) changes to the market design. The focus has shifted as U.S. markets have become increasingly complex. However, it is important to emphasize that the task involves the monitoring of not just market participants but also the market operator. In the New Zealand context, therefore, proposals to shift more responsibilities to Transpower need to be mindful of the need to maintain an independent information and decision making function.

In the U.S., each ISO overseen by FERC (all but ERCOT in Texas) must have an independent market monitor, which is either a separate firm hired by the ISO or a division of the ISO that does not report to the CEO. Most also have some form of internal market monitor that is part of the ISO organization, though the size of these departments vary substantially across ISOs. Every U.S. ISO employs market analysts with training in economics and/or power systems engineering and optimization. Because electricity markets are complex and many of the issues can be unique to the power industry, expertise is in high demand and there is a fair amount of churn across institutions and between monitors and industry. In addition, the scale necessary to monitor these markets have led to the prominence of firms like Potomac Economics that specialize in monitoring but remain independent. They are able to do this at scale, without seeking business with market participants, through monitoring contracts with multiple market operators.

8.6 Summary

While there is no single ideal structure for market monitoring there is great value in expertise and in independence. The challenge is in finding both. Engagement with market participants through various stakeholder processes is extremely useful as it is often the market participants who have the most expertise, knowledge and information about market conditions and performance. Our sense is that this is even more true in New Zealand, which has unique local characteristics. The obvious challenge is to balance the advocacy that is inherently part of such a process with the valuable insights that can be provided. We see no reason why the current institutions (the EA, Commerce Commission, and MBIE) would not be capable of filtering through the advocacy, but these institutions need to maintain some technical expertise in order to do so. We do think that EA can continue, or even expand, the roles of academic experts - particularly local New Zealand experts.

[50] The one exception is ERCOT, which is not subject to FERC jurisdiction for technical reasons.

9 Summary

The Frontier report has covered a wide range of issues and topics. This was an immense amount of ground to cover in a very short period of time. The primary recommendations in the report address what Frontier views are the two most pressing problems in the market: the supply of firming capacity and the structure of EDBs. While we agree with Frontier on the current value of the existing fossil generation fleet, we are less convinced that there are significant market failures that would prevent investment in the types of capacity that will be needed going forward. We have significant reservations about the proposal to place responsibility for the existing fossil fleet, and particularly future investment decisions, entirely in the hands of a newly formed Crown corporation. If the market is deemed insufficient, there are other less drastic options such as the deployment of reliability must-run contracts, or targeted intervention in the gas sector, that would be less extreme and preserve more flexibility for both the government and market participants.

Our rough calculations find that existing resources, particularly Huntly, Whirinaki, and demand-response are capable of filling the energy gap between even a severely dry season and the seasonal average. Given these figures, the dry-year issue that motivates the New Co. proposal appears to us as much more about *prices* than about reliability. Perhaps a large, government directed, push into new fossil investment would stabilize inter-year price volatility, but there is a high risk that this would come at the expense of efficiency and increased long-run average costs.

On the other hand, we found the case made in the Frontier report for reforming the structure and regulation of the EDBs to be reasonable and persuasive. However, we note that local governance concerns may imply a much higher “cost” to consolidation than simple economic measures might indicate. In either event, we agree with the Frontier report that further review into questions regarding changes to how the EDBs are regulated, especially the regulation of customer interconnection costs, are called for. Two other proposals concerned the divestment of the government’s interest in three large gentailers, and the removal of the electricity sector from the emissions trading scheme. Neither proposal seems to address the most pressing issues that motivated this review. While there are theoretical benefits to divestment, to the extent that it is motivated largely by the need to generate capital for the new Crown corporation, opting for a different solution to the latter would make divestment a far less urgent concern. Similarly, the merits of the emissions market should be considered holistically. We do not see a strong case for removing a single sector from the ETS.

We reiterate that before pursuing any of these proposals, more analysis is needed. This is especially true in the case of New Co. and the removal of electricity from the ETS.

Appendix A: Dry Year Energy and Capacity Shortfall Summary

As we discuss in our review, the need for a New Co. to be assigned the responsibilities proposed by Frontier is dependent upon at least two assumptions about future conditions holding true: first, that existing fossil capacity - even if steps are taken to prevent retirements - will be insufficient to manage dry-year risk, and second, that it is unlikely to impossible that market-based investment would provide new fossil capacity if assumption 1 holds and it is proven to be necessary.

In this Appendix we examine the first assumption with some rough cuts of publicly available data. We *by no means* imply that such a rough analysis is sufficient and, as stated earlier, believe that more detailed modeling and other analysis is required before undertaking measures as significant as either a New Co., or interventions such as an RMR contract for Huntly. We present these rough calculations as evidence that it is not obvious, at least to us, that *new* fossil capacity is absolutely necessary to manage future dry year risks.

We approach this rough calculation in two ways. First we examine energy production statistics from recent quarters, then we compare potential hypothetical energy shortfalls to the potential capability of alternative resources to replace those shortfalls.

A.1 Energy Sources in Recent Years

First, we present data on quarterly energy output by various sources in New Zealand for 2024 (dry year, total energy production 43.8TWh), 2020 (average year, 43.2TWh), and 2021 (wet year, 43.3TWh). These years are chosen following Frontier's Figure 18, rainfall difference to mean, reproduced below as Figure 11, where 2020 is recent but close to "mean" and 2021 is the wettest year. 2024 is described as a dry year but is not in the rainfall figure. Despite the likely COVID impacts on electricity demand in 2020 and 2021 those years ultimately have comparable total generation to the years before and after (within 300GWh of 2022 and 2023). All calculations are based on MBIE Electricity Statistics, which are disaggregated by quarter and by generating fuel source.[51]

We begin by describing hydro generation in figure 12. We see that the September quarter is most affected, with the wet year and dry year $\approx \pm$ 500-700GWh of generation departure from the average year. Regardless of how the sector responds to the events in these years, there will always be an expectation that prices will be higher in dry periods, and lower in wet periods, with those producers or users of electricity that can respond to these conditions incentivized to do so and therefore providing reliability benefits in dry years.

Figure 13 displays an analogous figure to figure 12 for output by coal and gas resources. We note that coal resources generated 150GWh more in the September quarter of the dry year than the average year, and unsurprisingly 230GWh less in the wet year. Gas, on the other hand, generated 500-600GWh less in the September quarter of the dry *and* wet year than the average year. The wet year is explainable by the increase in hydro generation and likely low electricity prices. The dry year decline in gas is not expected all else being equal, but all else is **not** equal in these figures. The 2024 dry year relative to earlier dry years occurred in an energy system with more installed

[51] `https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics`

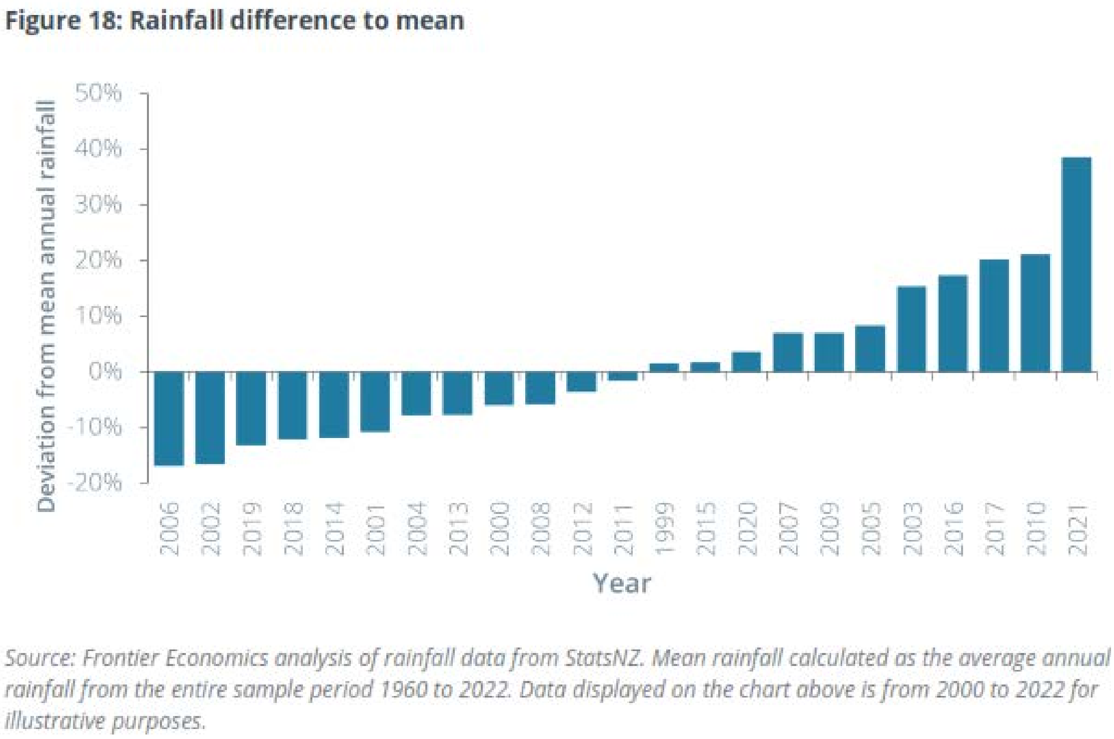


Figure 11: Reproduction of Figure 18 in the Frontier Report

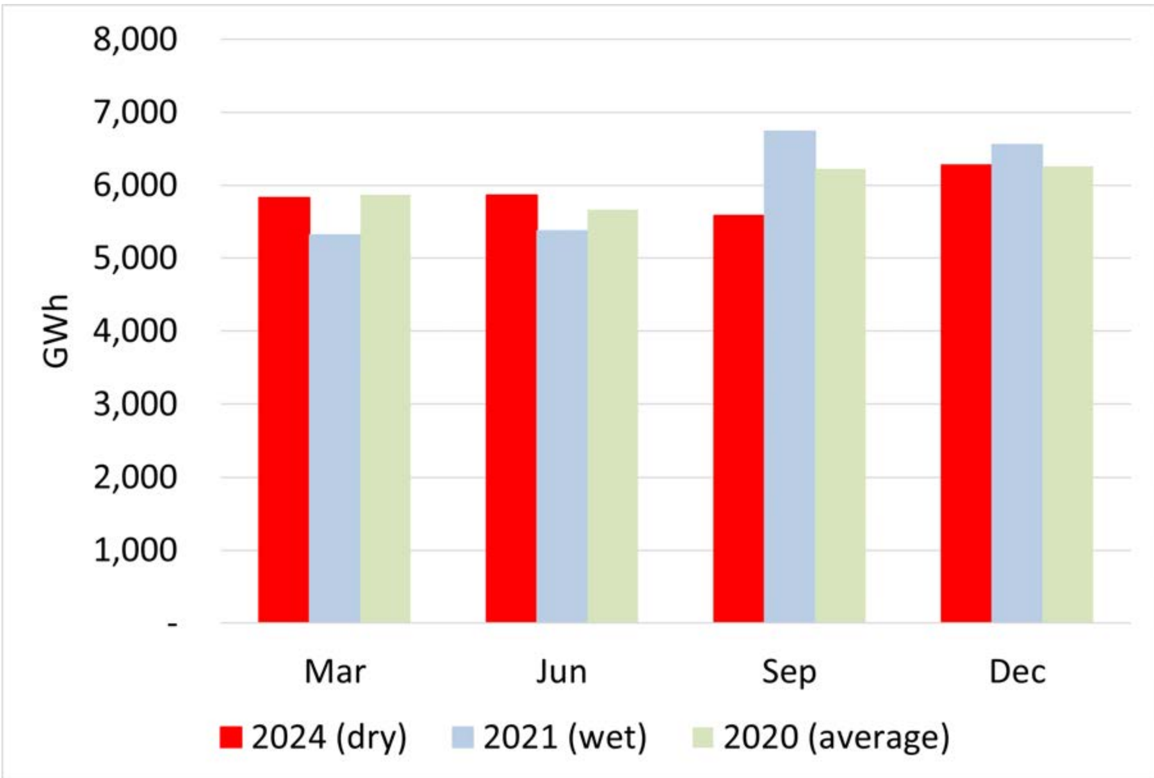


Figure 12: Energy generated by hydro (Source: MBIE Electricity Data Tables)

wind and geothermal capacity (discussed next), and, as emphasized in the Frontier report, decreased gas availability and consequently higher gas prices. This suggests there is a differential of approximately 700GWh - 150GWh + 600GWh = 1150GWh to be made up in the September quarter of the example dry year relative to the example average year by the remaining energy sources (not hydro, not coal, not gas).

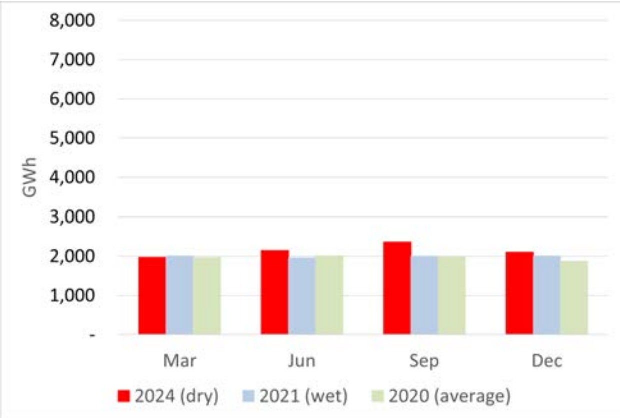
(a) Coal **(b) Gas**

Figure 13: Energy generated by coal/gas resources (Source: MBIE Electricity Data Tables)

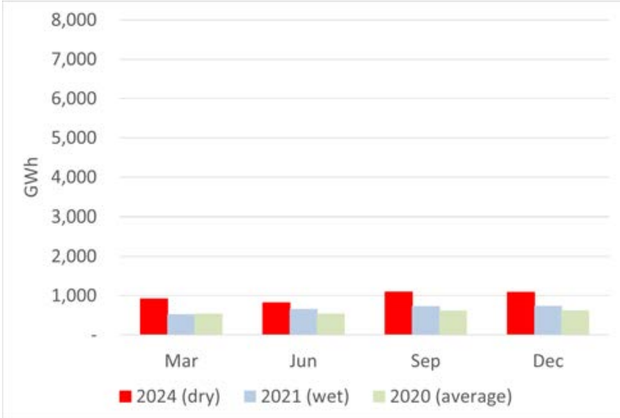
Figure 14 displays an analogous figure to figure 13 for output by geothermal and wind resources, along with industrial load. We note that the Tauhara geothermal facility was added mid-year in the dry year, resulting in geothermal resources generating 300GWh more in the September quarter of the example dry year than the example average year.[52] The output from wind resources is greatest in the September and December quarters of each year, and is lowest in the June quarter of the dry year. Output from wind is 500GWh greater in the September quarter of the example dry year than the example average year, but this is not driven by capacity factors, rather due to the substantial amount of investment that has been connected during 2020 to 2024. Finally, there is a reduction in industrial demand (likely driven by the Tiwai Point smelter) of 400MWh in the dry year relative to the average year. Unsurprisingly, industrial demand flexibility may work both ways, with their usage 100-200GWh greater in the September quarter of the wet year relative to the average year, suggesting that some facilities may be able to make productive use of the more abundant cheap energy resources in wet years. This $\approx$ 300GWh + 500GWh + 400GWh = 1200GWh net energy differential from these three sources matches that from the changes experienced by hydro, coal and gas.

Figure 15 aggregates the renewable resource output (hydro, wind, geothermal, solar) and also the fossil resource output (coal and gas). This demonstrates that the New Zealand grid is in transition, in such a way that the output of renewable resources in aggregate was greater in the September quarter of the 2024 dry year than it was in the 2020 average rainfall year. Naturally, for this to balance, aggregate output from fossil sources were lower in the September quarter of the 2024 dry year when compared to the 2020 average rainfall year.

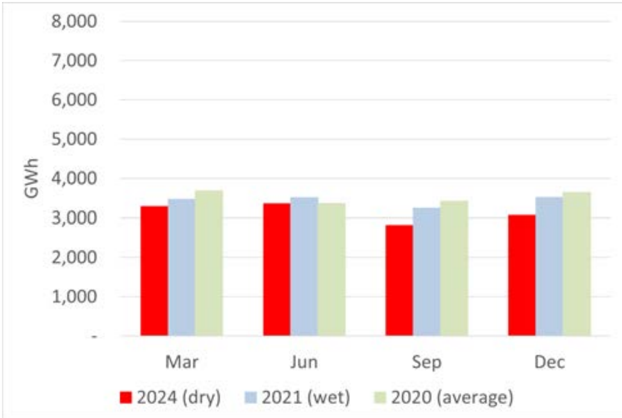
[52] See Electricity Authority Market performance Quarterly review July-September 2024 for discussion of Tauhara's operations.



(a) Geothermal

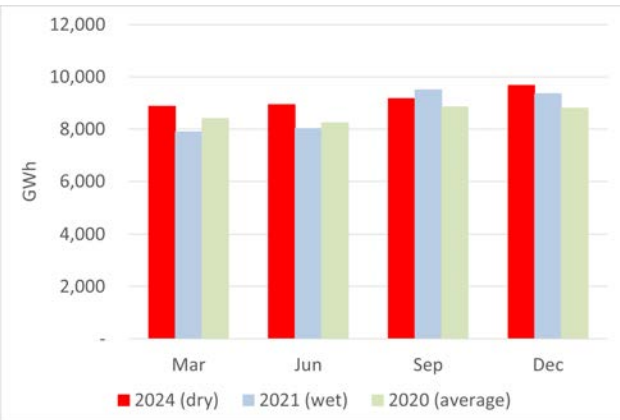


(b) Wind

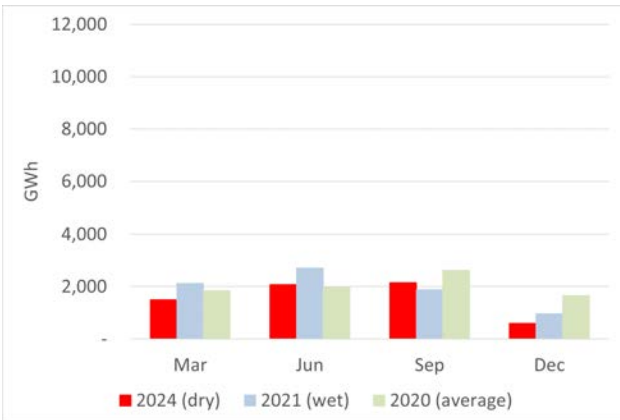


(c) Industrial loads (usage)

Figure 14: Energy generated and used by other energy assets (Source: MBIE Electricity Data Tables)



(a) Hydro, Geothermal, Wind, Solar



(b) Coal, Gas

Figure 15: Energy generation: Aggregated renewable and fossil resources (Source: MBIE Electricity Data Tables)

A.2 Hypothetical Dry-Year Energy Shortfall and Replacement Options

In this subsection we perform a slightly different calculation. We consider the potential “energy gap” that can emerge in a dry year combined with a future possible negative shock to natural gas availability. Again this is just a simplistic calculation meant to illustrate the relative magnitudes of the problem and current capabilities, it should not be construed as a modeling exercise adequate to the task of evaluating the need for government-supported fossil generation investment.

In this calculation we perform the following steps. We first calculate the potential energy needs in a “dry quarter” with a gas shock.

- Calculate the largest quarterly difference in hydro energy by taking the difference between the (2001 - 2024) average GWh for that respective quarter and each quarter’s observed GWh since Q1 2020. We define the “hydro energy gap” as the difference between the wettest quarter and actual production. We also plot the “max hydro gap” observed since 2001, which according to our reading of the data, was 1675 GWh in the quarter ending September 2001.
- Given the concerns over declining gas production, we also consider a scenario where actual gas production is curtailed by half. In other words an additional energy gap in each quarter quantified as 50% of observed gas production in that quarter.

We then consider the potential options for replacing the missing energy. We consider five sources of replacement energy, some new and low marginal cost, and some high cost.

- Newly committed geothermal and wind
- Huntly coal generation (assuming 80% capacity factor)
- Tiwai demand response tiers 1 and 2
- Tiwai “extraordinary” demand repsonse
- Diesel generation (Whirinaki)

Again noting that wind production, while not reliable on a day-to-day or hour-to-hour basis, should provide a more predictable band of replacement energy over the course of a quarter, we consider the roughly 3500 GWh/year of new geothermal and wind energy, and roughly 1000 GWh of utility scale solar listed as “committed” in Concept consulting’s 2023 update to the generation investment survey.[53] To simplify, we assume daily output is, in expectation, evenly distributed but recognize the potential for seasonable variability in new wind resources. To be conservative, we then apply an arbitrary 20% discount to this future renewable energy.

For Huntly, we assume it is prevented from retiring through some mechanism and assume 750 MW of coal capable capacity operating at an 80% capacity factor for a quarter. This yields roughly 1300 GWh of energy in a quarter, consistent with coal output in the quarter ending June 2021.

For Tiwai, we consider the demand response steps that were activated in 2024, but acknowledge that existing contracts limit the ability to implement such levels of response repeatedly.[54]

Finally, we include an assumed 150 MW of diesel capacity operating at an 80% capacity factor, recognizing that the marginal cost of Whirinaki is extremely high (although below price levels occasional reached in 2024). The point of this exercise is to ascertain the magnitude of the reliability implications of dry-year energy short falls, combined with a dramatic reduction in gas production.

[53] `https://www.ea.govt.nz/documents/4414/Generation_Investment_Survey_-_2023_update.pdf`, slide 12. Note we did not include any projections of distributed solar, although Concept anticipates continued growth in this segment as well.

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

Obviously if Whirinaki were called upon to operate for substantial periods this would coincide with extremely high spot prices.

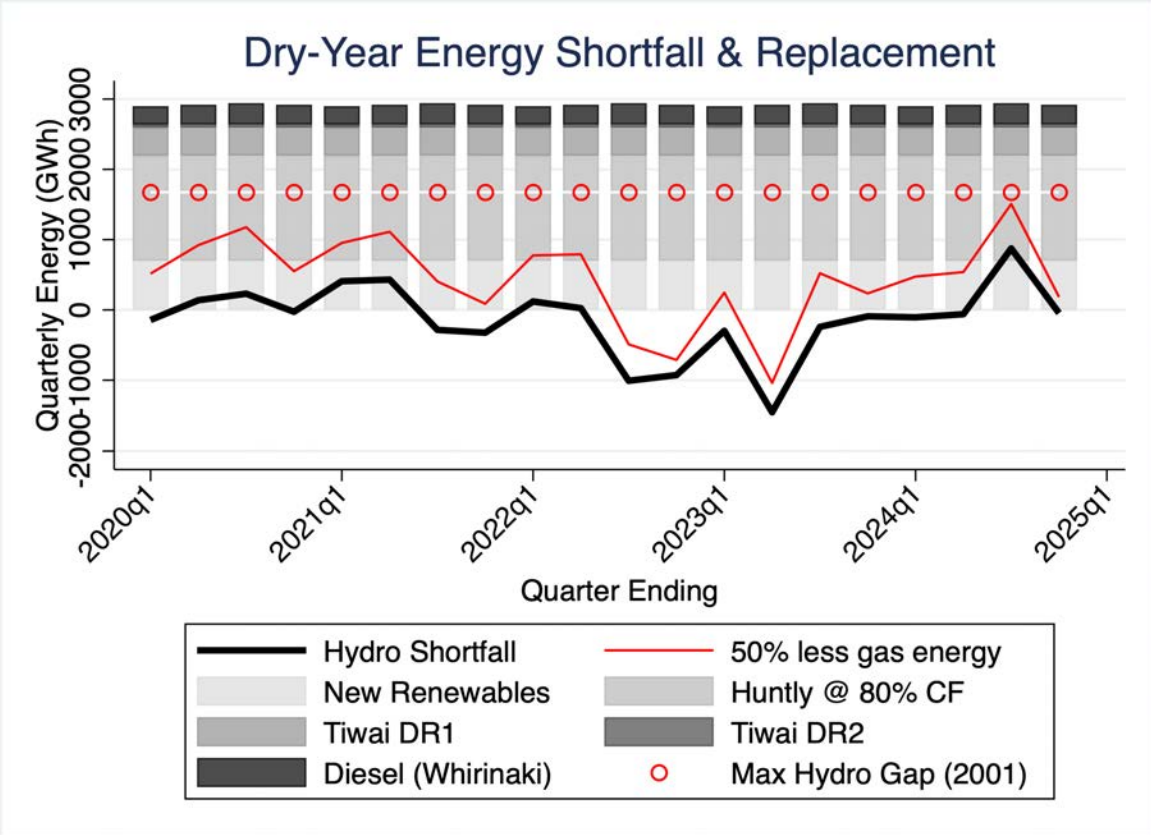


Figure 16: Energy Gap and Replacement Options for Dry-Season + Gas Shortfall Scenarios

The net results of these assumptions are illustrated in Figure 16. In the event that a sharp dry season coincided with a 50% drop in gas generation (due to fuel supply limitations or other reasons), existing options would have been easily sufficient to cover the worst such quarters over the last half decade. If gas supply were not reduced by this substantial amount, dry years could be managed by a combination of Huntly and demand-response. In general the quarterly energy output capability of Huntly roughly mirrors the gap between a “good” and “bad” hydro quarter.

Going forward, the question is whether investment in new energy sources can keep pace with demand growth. In this exercise we counted newly committed (but not planned and uncommitted) renewable GWh but did not adjust for future load growth. Others may want to make different assumptions. While much demand growth is forecast, the realization of such is not a foregone conclusion. Nonetheless, our reading of materials from Concept and others is that the pace of investment, which lagged prices for the last several years, is picking up rapidly.

A.3 Summary

We believe that more analysis, beyond what we have been able to review, is necessary to determine the magnitude of the dry year problem and the best options for dealing with it, even given currently available estimates of costs. Clearly, investing in wind will deliver *some* energy in dry years, allowing more water to be stored when compared to the counterfactual that the wind resource is not built, all else being equal. Similarly, so will a coal, gas or diesel plant that is built with some fuel procurement plan that allows it to operate throughout a dry season. There are important reliability benefits from fossil options relatively to renewable sources, but these are focused much more on the question of short-term availability, rather than dry-year risk. Finally, investors may find that the answers are best provided on the demand side.

Such an analysis would benefit from a clearly articulated set of goals, such as a specific reliability standard, or expected price impacts, if the latter is the true underlying concern. Once this is identified, probabilistic models are probably required to properly quantify the range of uncertainty around these metrics.

Beyond the need for more coordinated modeling, however, remains the question of whether the current market is incapable of providing the necessary solutions to the long-term or even short-term firming needs of the New Zealand system.