Rethinking Wholesale Market Design for New Zealand's Clean Energy Transition*

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Abstract

This paper examines the New Zealand short-term wholesale electricity market and its capacity to support an increased share of intermittent renewable generation. Despite initial innovations, including early adoption of locational marginal pricing, the market design has remained largely unchanged since 1996. I demonstrate how the single-settlement market structure may create challenges for system reliability as renewable penetration increases. Drawing on the experience of markets in the United States, I argue that adopting a multi-settlement market design could improve system reliability, reduce system costs, and support investment in flexible capacity. These improvements will become increasingly important as New Zealand pursues its ambitious greenhouse gas emissions reduction goals.

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1 Introduction

The design of wholesale electricity markets is evolving as countries try to ensure a reliable electricity supply while encouraging the transition to a low-carbon energy system. New Zealand provides an interesting case study given the geographic separation between generation and load and the concentrated market structure. During the 1990s, the industry underwent a significant restructuring process. The reforms included the vertical separation of generation and transmission activities, the horizontal separation and full or partial privatization of government-owned generation plants, and the introduction of retail competition. A distinctive feature of New Zealand's approach was adopting a relatively simple market design with a reliance on decentralized decision-making by market participants. This was coupled with an emphasis on "light-handed" regulation that relied on competition rather than prescriptive rules to achieve efficient outcomes. These design choices set New Zealand apart from other countries undertaking similar reforms.

At its inception, several aspects of the wholesale market design in New Zealand were highly innovative, predating their adoption in other jurisdictions. Two features stand out in particular: the use of locational marginal pricing and the co-optimization of reserves and energy. The New Zealand wholesale electricity market was one of the first to implement locational marginal pricing, doing so more than a year before its introduction in the PJM market in the United States. These design choices aimed to address the geographical challenges of New Zealand's electricity system.

Despite this initial innovation, the New Zealand market design has remained relatively unchanged. Most features of the short-term wholesale market continue to operate as they did in 1996. The most notable difference when compared to the now-standard market design in the United States is that New Zealand operates a single-settlement market. In New Zealand, generators are paid only for the electricity they actually produce, based on real-time prices. One unique feature of the New Zealand market is the use of multiple "pre-dispatch" rounds, in which firms can repeatedly submit non-binding offers and observe how these affect prices and quantities. However, this process creates no binding financial commitments. This means generators must bear the full financial risk when conditions change unexpectedly, for example, when wind output differs significantly from forecasts. Generators with high startup costs may choose not to operate if they cannot be confident of recovering those costs.

These market design features have contributed to several supply security events in New Zealand. A stark illustration of this occurred on August 9, 2021, when record-high demand coincided with unexpectedly low wind generation and an unplanned hydro outage. The system operator declared a grid emergency, leading to rolling blackouts that affected 34,000 customers. A contributing factor to the shortage was that two major thermal generation units were not operating. One plant had not been started in the morning because the forecast prices in the pre-dispatch were too low to cover its startup costs.

A multi-settlement market design might have changed this outcome. In such a system, the thermal plant could have sold its expected output in a day-ahead market, securing revenue to cover startup costs before the wind forecast uncertainty was resolved. Even if wind output turned out to be higher than expected, driving down real-time prices, the plant would still recover its costs through its day-ahead revenue. This financial structure would have provided stronger incentives for the plant to commit, potentially avoiding the supply shortfall. Multi-settlement markets can better align private generator incentives with system reliability needs by allowing participants to manage the financial risks created by variable renewable output.

Security of supply has always been a critical issue in New Zealand due to its reliance on hydroelectricity and the periodic shortfalls in hydro inflows. Unlike most other restructured electricity markets, New Zealand has not implemented a capacity mechanism to address long-term resource adequacy. This challenge is set to become more acute in the coming years. The government's climate change goals envision a 64 percent increase in electricity generation by 2050, with almost all new capacity expected to come from intermittent wind and solar resources. New Zealand's policy preference is to achieve security of supply through efficient operation of the short-term wholesale market rather than through out-of-market mechanisms. This approach places greater importance on ensuring that market design supports reliable operation as the system transforms. Equally important, the market must deliver electricity at reasonable prices to encourage the widespread electrification that underpins New Zealand's climate goals.

The rest of this paper is organized as follows. Section 2 provides background on the New Zealand electricity industry, including its historical development and the restructuring process of the 1990s. Section 3 describes the operation of the short-term wholesale market design. Section 4 forms the core of the paper, highlighting both the innovative features of New Zealand's market and its shortcomings relative to the current best-practice market design in the United States. This assessment focuses on the benefits of locational marginal pricing, coordination issues inherent to single-settlement markets, the potential gains from multi-settlement design, and approaches to market power mitigation. Section

5 examines the future resource adequacy challenges facing the New Zealand electricity market, particularly given its ambitious decarbonization goals. Section 6 concludes.

2 Background on the New Zealand Electricity Industry

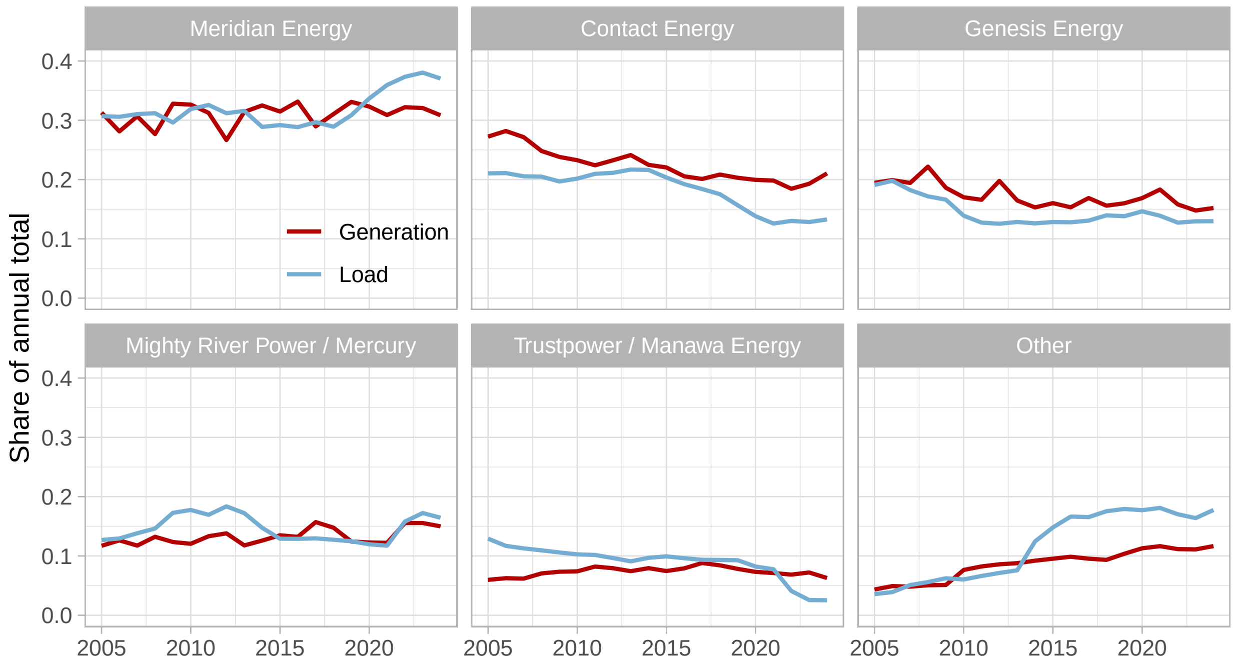
The New Zealand electricity industry developed during the twentieth century as a government-owned monopoly in generation and transmission. The government Electricity Department (later the Ministry of Energy) sold electricity at a bulk supply rate to more than 60 locally owned distribution companies. As part of market liberalization reforms during the 1980s, this entity was converted to a State-Owned Enterprise, the Electricity Corporation of New Zealand (ECNZ), which was expected to act as a commercial business. A stand-alone transmission company, Transpower, was carved out of ECNZ in 1994. ECNZ's generation assets were separated in two stages, with Contact Energy spun off in 1996 and the remaining portfolio split in 1999 into three competing companies: Meridian Energy, Genesis Energy, and Mighty River Power (renamed Mercury in 2016). Contact Energy was privatized in 1999. The other three generators were partially privatized between 2013 and 2014, with the government retaining majority control.

The wholesale electricity market began operation in October 1996. Section 3 describes several innovative aspects of the short-term market design, notably the use of locational marginal pricing and the co-optimization of reserves and energy. The market was designed as a so-called "energy-only" market with no explicit price cap or capacity mechanism. There have been few significant changes to the market design since 1996.

The next phase of industry restructuring occurred in 1999 with the introduction of retail competition and the forced separation of distribution and retailing businesses. Because distribution companies remained "lightly" regulated, there was concern about the potential anti-competitive effects of vertical integration between regulated and competitive businesses.[1] In a frenzy of acquisitions, most locally owned retailing businesses were acquired by one of the four major generation companies. This consolidation between generation and retail created the vertically integrated "gentailers" that remain a dominant feature of the New Zealand industry. The one exception to this pattern was the local retailer Trustpower, which became a gentailer after it sold its distribution business and

1. Bertram and Twaddle (2005) describe the so-called "light-handed" regulatory regime in the distribution sector which, in the absence of an industry regulator, relied on mandatory information disclosure and self-regulation. They found that price-cost margins of distributors increased by 62 percent in real terms between 1995 and 2002.

Figure 1: Mean Annual Load and Generation Shares by Firm, 2005–2024



Notes: Each panel in the figure shows the annual shares of total generation and load for the five largest generation firms. The remaining generation and load (including the smaller gentailer Nova Energy) are aggregated into the final "other" category. Retail load obligations of the large firms include their smaller subsidiary companies. Mighty River Power rebranded as Mercury in 2016. In 2022, Mercury acquired Trustpower's retail business; the residual generation company became Manawa Energy and was acquired by Contact Energy in 2025.

bought generation assets from ECNZ.

Unlike in other countries, retail competition was introduced abruptly without a phase-in period. All retailers (including incumbents) were free to set their retail tariffs. Regulated distribution tariffs were not explicitly separated in these tariffs. Competition between retailers was relatively slow to develop, and the retail market remains dominated by the gentailers. While new retailers have emerged and captured small market shares, several are owned by the gentailers and operated as distinct brands.

Figure 1 shows the market shares of the five largest gentailers from 2005 to 2024. The market structure has stayed remarkably stable over this time period, with the most important change being the acquisition of Trustpower's retail business by Mercury in May 2022. Meridian remains the largest generator and retailer, with about 30 percent market share in both segments. Contact and Genesis are the second and third largest generators and retailers. An important feature of the New Zealand market is that all gentailers are relatively balanced in terms of their generation output and their retail load obligations.[2] After the period shown in the figure, the residual generation business of Trustpower (renamed Manawa Energy) was acquired by Contact Energy in July 2025 (Contact Energy, 2025), reducing the number of major gentailers to the original four created from ECNZ.

The need for an electricity industry regulator was not envisaged when the restructuring occurred during the 1990s. The Electricity Commission was set up in 2003 after low hydro levels in 2001 and 2003 required voluntary savings campaigns to avoid forced blackouts. The Commission had a broad mandate to ensure the security of supply and reduce price volatility during dry years (Hodgson, 2003a). It was replaced in 2010 with the Electricity Authority which has a narrower focus on regulating the market. The five main functions of the Authority are to monitor market behavior, oversee daily electricity system operations, enforce compliance with relevant laws and regulations, promote market development, and protect the interests of small consumers (Electricity Authority, 2025h).

The average electricity demand in New Zealand in 2024 was 4.51 GW.[3] Demand has been fairly flat since 2004, with an average annual growth rate of total generation of just 0.3 percent between 2004 and 2024 (Figure 2). Since the beginning of the electricity industry in New Zealand, hydroelectricity has been the largest source of generation, supplying 60.6 percent of generation in 2023 and 53.7 percent in 2024. However, the installed hydro capacity has barely changed in the past 30 years, with the last large-scale hydro project commissioned in 1992.

Instead, most of the new generation capacity built in the past twenty years has been geothermal. The first geothermal plant in New Zealand began operation in 1958, with ten plants commissioned since 2000, increasing total capacity to 1200 MW. The share of geothermal in total generation grew from 7.2 percent in 2000 to 19.9 percent in 2024.

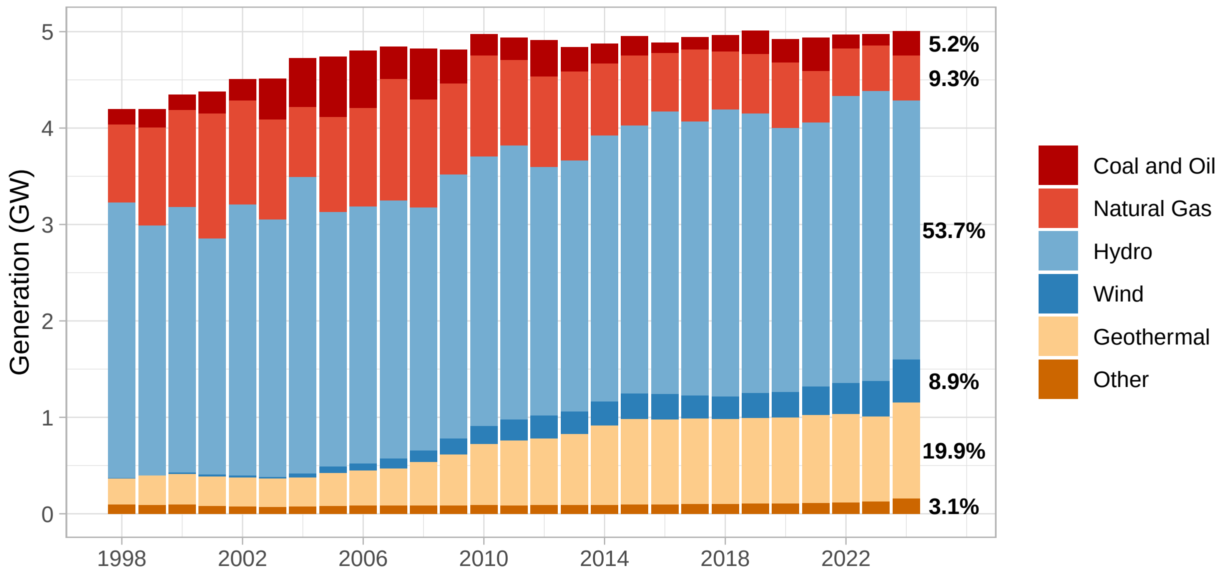
About 680 MW of wind generating capacity was built between 1996 and 2014, providing 5.4 percent of total generation in 2015. New Zealand has never had specific incentives for renewable investment, such as the Production Tax Credit and Renewable Portfolio Standards in the United States, so all wind generation has been built commercially without subsidies.[4] There was a lull in new investments during the 2010s, although two large wind

2. Using public data, it is not possible to know the exact net position of each gentailer in the wholesale electricity market, because (i) not all of their retail customers are on fixed-price contracts, and (ii) the gentailers buy and sell additional fixed-price forward contracts.

3. Electricity consumption in 2024 was 39.638 TWh (Ministry of Business, Innovation & Employment, 2025), giving average demand of $39638/(24 \times 366) = 4.51$ GW. Net generation was 43.996 TWh, an average of $43966/(24 \times 366) = 5.01$ GW (shown in Figure 2). Transmission and distribution line losses comprise most of the difference. Both demand and generation include estimated distributed solar production.

4. Early wind farm developers received tradable Kyoto emission units from the Government's Projects

Figure 2: Mean Annual Generation by Type, 1998–2024



Notes: The figure shows the mean annual generation in GW split by six types of generation. The "other" category includes solar (including estimated distributed solar generation), biogas, wood, and waste heat. The percentages on the right side of the figure show the share of each generation type in total generation in 2024. Source: Ministry of Business, Innovation & Employment (2025).

farms were commissioned in 2020 and 2021, increasing the share of wind to 8.9 percent of total generation in 2024. The first grid-scale solar power plant began operations at the end of 2023 with a nameplate capacity of 32 MW. The distributed solar sector has been more active, with about 3 percent of residential and commercial customers having rooftop solar systems, comprising 408 MW of generating capacity at the end of 2024 (Electricity Authority, 2025b).

3 Short-term Wholesale Market Operation

The New Zealand wholesale electricity market began operating in October 1996, and its central design elements have changed little over time.[5] In this section, I provide a simplified description of the market operation, split into three stages: dispatch, operation, and settlement. Dispatch refers to the process by which the system operator determines which generation units should be instructed to produce electricity and the quantity assigned

to Reduce Emissions scheme (Hodgson, 2003b), while the economy-wide New Zealand Emissions Trading Scheme, in force since 2008, benefits renewable generation through higher wholesale electricity prices.

5. Electricity Authority (2025e) says that the switch from ex-post to real-time pricing for settlement (Section 3.3) was "the biggest change to the wholesale electricity market since it started in October 1996".

to each. Operation is the real-time management of the system to ensure that supply continuously matches demand. Finally, settlement is the financial reconciliation of the market transactions, in which generators are paid for the electricity they produced and loads are charged for the electricity they consumed.

3.1 Dispatch

The dispatch process operates on 30-minute trading periods (Electricity Authority, 2025a, §1.1). Generation firms submit their offers to supply electricity to the system operator. The offers are specific to one trading period. Generators must submit their initial offers no later than 71 trading periods (about 36 hours) before the start of the corresponding period. They can choose to submit offers for each generation unit or a combined offer for the entire plant. Generation offers comprise up to five price and quantity steps per unit or plant. Offers contain the maximum rate at which their plant can increase or decrease their generation output ("ramping rate"). Finally, generators can also offer their plants to be used as operating reserves. Reserve offers comprise three price and quantity steps for each type of reserve that is offered (§13.6, Schedule 13.1).

On the demand side, large electricity consumers (typically major industrial plants) submit bids to buy electricity on the same timetable as the generation firms. These demand bids comprise up to ten price and quantity steps. The system operator prepares demand forecasts for most electricity demand that does not participate directly in the wholesale market (§13.7).

A novel feature of the New Zealand electricity market is that both generation firms and large consumers are free to revise their offers and bids at any time up until one hour before the start of the trading period. There are no limits on how many times the price and quantity components of the offers and bids can be revised. Revisions to the offer quantities (but not the prices) are allowed during the one hour before the trading period for intermittent generators and other generators in the event of a plant outage. Only the final offers and bids are used for settlement (§§13.17–13.19).

Starting 36 hours before the trading period, the system operator determines the market dispatch for each individual half-hour period. It does not optimize across multiple periods. The dispatch algorithm uses the latest generation offers, demand bids and forecasts, and expected grid conditions. The system operator runs the dispatch algorithm every two hours from 36 to four hours out, then every 30 minutes in the final four hours (Transpower, 2023). Each time it runs the algorithm, the system operator publishes the expected output of each plant, the reserve levels of each plant, the expected demand, and the nodal and reserve prices. Based on this information, as well as any changes to their private information, generators and large consumers are free to update the offers and bids. This updating and re-solving process is called "pre-dispatch" (Electricity Authority, 2025a, §13.62).[6]

In solving for the market dispatch, the system operator maximizes the benefits to consumers for each half-hour period, less the cost of generating electricity and the cost of the ancillary services. The maximization problem is subject to the ramping constraints of the generators, based on their expected generation at the start of the half-hour and the ramping rate reported on the generation offer. The problem is also subject to the configuration and capacity of the transmission grid, where the transmission constraints are modeled using a simplified DC (direct current) model of the grid (Schedule 13.3).

3.2 Operation

A unique feature of electricity networks is that the generation and consumption of electricity must be kept exactly balanced at all times. During real-time operation, the system operator runs the dispatch algorithm every five minutes and provides updated instructions to generators (Transpower, 2023). However, real-time system conditions can change much faster. There are second-by-second fluctuations in electricity consumption and generation output. In the worst case, there might be a sudden failure of a generation unit or transmission line. The system operator uses several mechanisms to ensure supply and demand remain balanced.

The grid frequency provides an instantaneous measure of the supply and demand balance in the electricity system. If demand exceeds supply, the grid frequency falls. If supply exceeds demand, the frequency rises. The system operator endeavors to keep the frequency as close as possible to the target value of 50 Hz. Large deviations from this target value can damage equipment connected to the grid, including the generation units themselves. Because generation units will automatically disconnect from the grid if the frequency changes quickly or falls outside a narrow window, and this disconnection reduces the frequency still further, the worst-case scenario is a chain reaction of disconnections leading to a cascading blackout.

At the sub-second level, the rotational inertia of spinning generation units helps to

6. The pre-dispatch process in the New Zealand market is similar to that used in Australia's National Electricity Market (Billimoria and Leslie, 2025). One difference is that the Australian market uses five-minute trading periods for dispatch and settlement.

stabilize the grid frequency (von Meier, 2024, Ch. 11.1.1). For larger adjustments, the system operator assigns specific generators to provide frequency control services. The system operator procures at least one generator in each island to provide this service. These generators receive second-by-second instructions from the system operator to increase or decrease their output in order to keep the frequency stable (Transpower, 2025).

Even larger imbalances require reserve capacity. These reserves compensate for events like transmission line failures or unplanned generation outages. The New Zealand system uses two types of reserves: fast spinning reserves that must be available within six seconds and sustain their output for one minute, and sustained reserves that must be available within one minute (Electricity Authority, 2023b). The reserve generators ensure that the system keeps operating until the updated system conditions (for example, incorporating the generation unit failure) are fed into the dispatch algorithm and a new set of dispatch instructions provided to all generators. This updating process typically occurs within five minutes.

3.3 Settlement

Since the wholesale market opened in 1996, New Zealand has settled metered energy on a half-hourly trading-period basis. Generators are paid—and purchasers are charged—for the metered megawatt-hours they inject or withdraw at each grid injection or exit point. The settlement price is the locational marginal price calculated for that node and averaged over the trading period. Unlike in multi-settlement markets, the dispatch target itself does not create a financial position. Only the metered volumes affect financial payments. In other words, although participants are expected to follow dispatch instructions, there is no explicit financial cost of any imbalances. Nevertheless, significant deviations from dispatch instructions may be investigated and incur penalties.

The method for calculating the settlement prices has evolved. Before November 2022, prices were determined ex-post using the actual grid conditions, intermittent generation, realized demand, and the final offers for each half-hourly settlement period. The scheduling, pricing, and dispatch process was re-run using these realized inputs. These ex-post prices could differ substantially from the indicative prices announced during the pre-dispatch and real-time periods. Such price deviations created uncertainty for market participants. For example, a large industrial user might observe a very high real-time price and decide to curtail its operations to avoid paying the high price. However, the ex-post settlement price during the half-hour could turn out to be much lower. Similarly, a generator responding to a high real-time price during a scarcity situation might have received a much lower ex-post price (Electricity Authority, 2022b).

Starting in November 2022, the settlement process switched to using the five-minute real-time prices (Electricity Authority, 2025e). The prices announced from the last run of the dispatch model before each five-minute period are considered final, except in rare cases when there is a calculation error. These five-minute real-time prices are averaged over the half-hour period to calculate the settlement prices (Electricity Authority, 2025a, §13.134A). This process of averaging the five-minute prices is required because the quantities are metered and settlement occurs for half-hour intervals. As a result, it is still possible for settlement prices to be misaligned with market conditions. If supply or demand shocks occur during a half-hour window, the mean price for the half-hour can be different from the real-time price at the beginning or end of the period.

Because reserves and generation are co-optimized in the dispatch algorithm, reserves prices are calculated simultaneously with energy prices. There are four prices, corresponding to fast and sustained reserves for each of the North and South Islands. Generation units assigned to provide reserves are paid based on the half-hourly mean of the real-time reserve prices. If the reserve generators are required to produce electricity during the half-hour period, the additional generation receives the same settlement price as all other metered generation.

If forecast generation or reserves are insufficient to meet demand, the system operator may require emergency load shedding to keep the system in balance. When a shortfall is forecast, "scarcity pricing" is used to retain a signal from very high prices. This prevents the collapse in real-time prices that would follow demand curtailment, preserving the price signal for both the short-term operational response and long-term investment (Electricity Authority, 2025g). Since an April 2025 update, scarcity prices are \$7,000 and \$6,500 per MWh for fast and sustained reserves. Energy scarcity prices rise in three tranches to a maximum of \$50,000 per MWh (Electricity Authority, 2025a, §13.58AA). The prices were chosen to align with inflation-adjusted estimates of the value of lost load from a Transpower study in 2018. Scarcity pricing is a last-resort measure: between November 2022 and March 2025, it triggered in only 24 five-minute intervals for reserves and never for energy (Electricity Authority, 2025d).

Generators receive "constrained-on" payments when they are dispatched despite their offer price exceeding the final price at their location. While locational marginal pricing eliminates the need for most constrained-on payments by incorporating transmission constraints into nodal prices (Section 4.1), the payments remain necessary when generators are required for local reliability, voltage support, or other system security reasons. The payment equals the difference between the offer and settlement prices, multiplied by the constrained-on quantity (Electricity Authority, 2025a, §13.204). Unlike in many other markets, New Zealand does not provide "constrained-off" payments to generators that are not dispatched despite offer prices below the settlement price (§13.201).[7]

4 Assessment of the Short-term Wholesale Market

In this section, I compare the short-term wholesale market in New Zealand to the best-practice short-term market design used in the United States.[8] The most notable similarity is that both market designs incorporate transmission and operating constraints directly in the dispatch algorithm, so that the generation schedule produced by the algorithm is physically feasible. These constraints are reflected in the locational marginal prices used for settlement in both markets (Section 4.1).

The biggest difference in the short-term market designs is that New Zealand has a single-settlement market whereas the markets in the United States are multi-settlement, with separate day-ahead and real-time markets. As discussed in Section 4.2, slow-start thermal plants in a single-settlement market may face a significant risk of not recovering their startup costs, leading to higher generation costs and lower reliability. Section 4.3 provides a stylized numerical example of how a multi-settlement market would change these incentives. Finally, Section 4.4 compares the approaches to market power mitigation in the two market designs.

4.1 Locational Marginal Pricing

Locational marginal prices (LMPs) represent the as-bid marginal cost of supplying an additional megawatt-hour at a particular location on the transmission grid. If there were no transmission losses and no transmission constraints, then the LMP would be the same at every location and equal to the as-bid marginal cost of the marginal generating

7. Different from generators, dispatchable loads do receive constrained-off payments when they are curtailed despite their bid price being above the final price (Electricity Authority, 2025a, §13.201A).

8. Hogan (2021) says that the PJM market design, adopted in every organized wholesale market in the United States, "works in theory and practice" and "is the only electricity market design that integrates engineering and economics to support efficient markets under the principles of transmission open access and non-discrimination".

unit. In reality, LMPs vary across locations. One reason is transmission losses, which mean more than one megawatt-hour must be produced to deliver one megawatt-hour of demand. Furthermore, each transmission line has a maximum safe capacity, and because Kirchhoff's laws determine how power flows through the network, a constrained line can force expensive local generation to serve nearby demand even when cheaper generation is available elsewhere (Bohn et al., 1984).

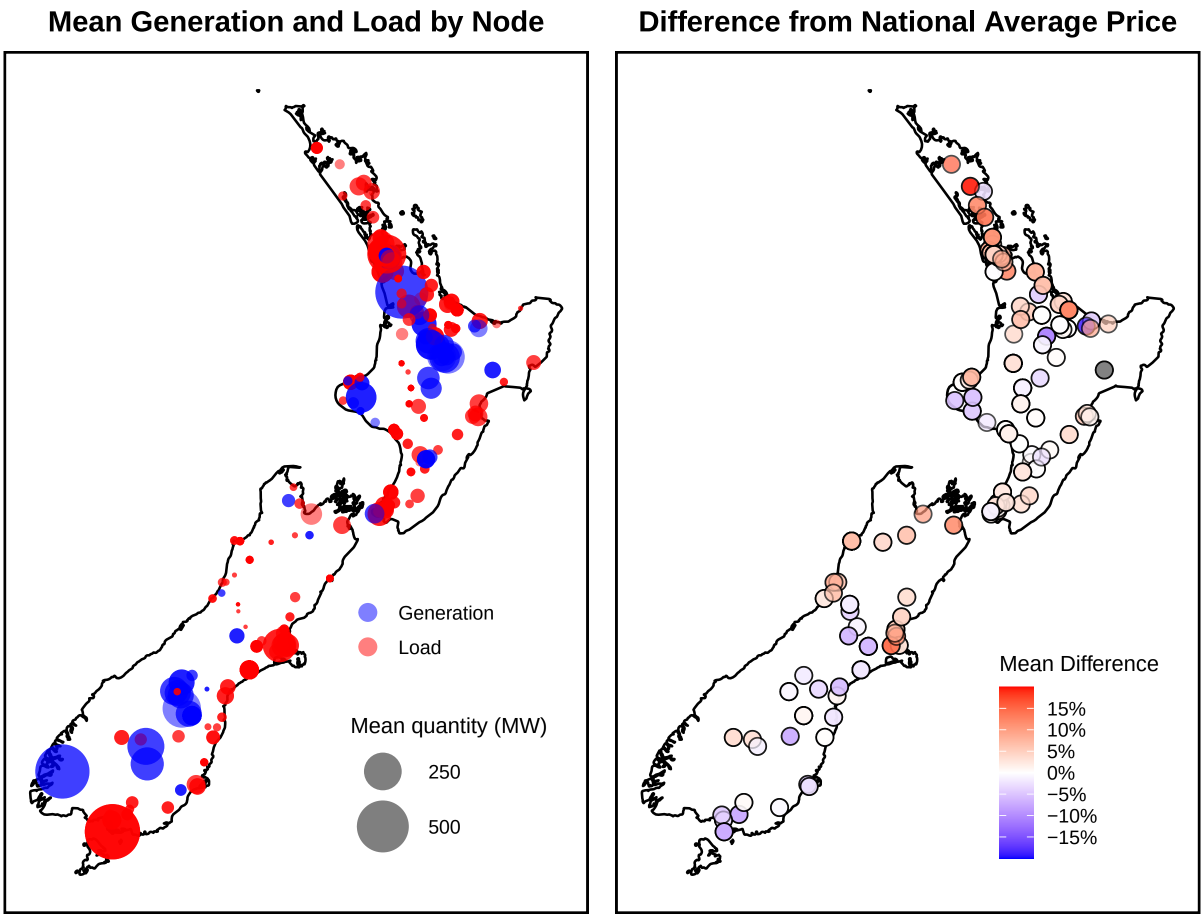
Electricity markets vary in how they handle transmission constraints and the extent to which they expose participants to locational price signals. In LMP markets, the dispatch optimization directly incorporates generation and transmission constraints, ensuring that the market-clearing solution is physically feasible. Retailers and large consumers pay the LMP at their withdrawal location, while generators receive the LMP at their injection point. These price differences reflect the as-bid marginal cost of serving load at each location, including transmission constraints and losses.

The alternative approach, known as zonal pricing, sets a uniform price for generation and load across a region. These markets face considerable operational challenges. For electricity markets in Europe, where the market-clearing solution does not incorporate physical constraints, costly redispatch procedures are required to adjust the initial dispatch and ensure physical feasibility (Eicke and Schittekatte, 2022; Graf, 2025). The process creates opportunities for strategic behavior by generators exploiting their knowledge about the likelihood of their plants being required during redispatch (Graf et al., 2023). In Australia, zonal pricing can create an incentive for generation firms to submit offers at the price floor in order to maximize their dispatched quantity (Katzen and Leslie, 2024).

Electricity markets in the United States transitioned from zonal to locational pricing, providing an opportunity for empirical evaluation of the benefits of LMP markets. Wolak (2011) found a 2.1 percent reduction in total variable costs after the introduction of nodal pricing in California, while Triolo and Wolak (2022) found a 3.9 percent reduction in operating costs from nodal pricing in Texas. However, there is only limited evidence for the long-term benefits of LMP markets, with Brown et al. (2020) finding mixed results for the influence of higher LMPs on the location decisions of new generation.

New Zealand provides an early example of successful LMP implementation. The country has a marked geographic separation between generation and demand (left panel of Figure 3). Most hydro generation is in the southern part of the South Island, while the largest population centers are in the northern part of the North Island. Since the 1960s, a high-voltage direct current line has connected the islands. The need to price

Figure 3: Mean Nodal Quantities and Prices, 2005–2024



Notes: The left map shows the mean generation or load at each injection or withdrawal node between 2005 and 2024. Blue circles correspond to generation, and red circles correspond to load. Larger circles correspond to nodes with greater generation or load quantities. The right map shows the load-volume-weighted average price at each of the network connection nodes for 2005 to 2024. Prices are expressed as a percentage difference from the overall load-volume-weighted average price for the same period. Redder colors correspond to nodes with a higher-than-average price, while bluer colors correspond to nodes with a lower-than-average price.

transmission constraints on that line, along with the geographic mismatch of generation and load, motivated the use of LMPs in the original New Zealand wholesale market design, predating their use in the PJM market in the United States by more than a year.[9]

The mean LMPs reflect the geographical distribution of generation and demand (right panel of Figure 3). LMPs are lowest close to the hydro plants in the southern South Island and highest at the locations far from generation in the northern parts of both islands.

9. While Chile incorporated penalty factors for transmission losses at different network nodes in its 1982 electricity reform (Pollitt, 2004), these prices operated within a regulated cost-based dispatch system. New Zealand's implementation of locational pricing was the first modern LMP system in a competitive bid-based wholesale market.

These LMPs provide signals for efficient investment in new demand sites and generation. Large electricity consumers such as data centers (Overseas Investment Office, 2021) and hydrogen plants (Murihiku Regeneration, 2024) would prefer to be located in the southern South Island where LMPs are low. New generation would prefer to be located in places where LMPs are high.

One concern raised by opponents of nodal pricing is that the limited liquidity at individual nodes will make it challenging for market participants to hedge future price risk (Eicke and Schittekatte, 2022). In the New Zealand context, this issue hindered the development of a competitive retail market for electricity (Trowbridge Deloitte, 2002). Electricity retailers typically sell fixed-rate plans to their customers and pay the time-varying LMP at each customer's location. This exposes them to localized volatility in the LMPs. Between 1996 and 2011, Contact and Meridian were the only firms with large generation plants in the South Island. Without South Island generation to hedge against high prices during periods with low hydro inflows, the other vertically integrated firms were reluctant to compete for retail customers, leading to higher retail margins in the South Island.

Two reforms were designed to ameliorate this locational price risk problem. First, in 2010, the government mandated virtual and physical asset swaps between the then state-owned generation firms Genesis and Meridian.[10] Second, a market for Financial Transmission Rights (FTRs) was started in 2013.[11] FTRs are a financial product that pays out the holder based on the difference in the LMPs between two locations over a specified time period. They are assigned in an auction and traded on a secondary market. Electricity retailers, generators, and other market participants can buy FTRs as a hedge against locational price risk.[12] These two reforms may have supported retail competition, with the market share of non-gentailer retailers increasing after 2012 (Figure 1).

10. The explicit motivation for the asset swaps was to "provide a more stable wholesale purchase price for retailers in the island where they have little or no generation, thereby encouraging additional retail competition in both islands" (Brownlee, 2010).

11. The FTR Market was introduced to "promote competition in the electricity industry", providing "a solution to a key concern in that competition in the retail electricity market is inhibited by locational price risk in the wholesale market" (Energy Market Services, 2024).

12. In the New Zealand market, FTRs have sold for 56 distinct pairs of nodes. Despite the risk of inter-island price separation from constraints on the HVDC line, 78 percent of the FTR contract quantity has been for contracts between nodes within one island (42 percent in the South Island and 36 percent in the North Island). Only 21 percent of FTR contract quantity is inter-island.

4.2 Unit Commitment in a Single-Settlement Market

On the evening of August 9, 2021, New Zealand electricity demand peaked at a record high of nearly 7.2 GW. Wind generation was unexpectedly low: instead of the 500 MW forecast in the mid-afternoon, actual wind output was 300 MW. A further 188 MW was lost due to an unplanned hydro outage. The system operator declared a grid emergency. Several distribution companies implemented rolling blackouts, affecting 34,000 customers. A contributing factor to the shortage was that two major thermal generation units were not operating. Huntly Unit 4, owned by Genesis, required nine hours to reach its maximum output from a cold start and so would have to have been started that morning. However, the forecast prices on the morning of August 9 were too low to cover its startup costs (Electricity Authority, 2022a).

The generation shortfall in August 2021 was not an isolated event. Similar "near miss" events have occurred multiple times in subsequent years. Electricity Authority (2023c) said that "unit commitment issues appear to have been a contributing factor in most (if not all) of these events" and "unit commitment issues for slower-start thermal are likely to become more challenging in the [renewable energy] transition".

In this section, I define what is meant by "unit commitment" and provide a stylized model to illustrate how the short-term market design contributed to the blackout in August 2021. The "commitment problem" refers to determining which generation units to start, when to start them, and for how long to run them. Some generation plants, particularly thermal generators, have significant start-up costs that will not be recovered if the plant only runs for a short time. Generation plants may also have operating constraints such as minimum run times, minimum operating levels, and maximum ramping rates. In markets with centralized commitment, the objective of the system operator is to find the optimal schedule of start-up and shut-down to minimize the cost of meeting expected demand over a 24-hour period.

The New Zealand electricity market is an example of a market with self (or decentralized) commitment. As described in Section 3, the generation offers do not include start-up and no-load costs. Moreover, the system operator dispatches on a period-by-period basis, ignoring any potential complementarities across different trading periods. As a result, the dispatch calculated by the system operator is unlikely to minimize the cost of meeting expected demand over the entire day. Instead, the cost-minimization problem is "decentralized" by repeatedly providing price and quantity schedules to generators during the pre-dispatch process. Generators can calculate their profitability under the pre-dispatch

Table 1: Characteristics of generation plants in stylized example

Plant	Capacity (MW)	Marginal cost ($/MWh)	Startup cost ($)	Commitment lead time (periods)
Wind	60 (p = 0.8) 20 (p = 0.2)	0	0	0
Baseload	70	30	1000	1
Peaker	70	100	0	0

schedules, change their plans for starting or stopping their plants, and update their price and quantity offers.

However, repeated pre-dispatch rounds might not converge to the optimal schedule determined in a market with centralized commitment. The fundamental problem is that none of the prices and quantities reported during the pre-dispatch process create a financially binding position for the generators. Instead, generators are only paid the real-time price for the amount they physically produce during a half-hour period. If system conditions change, the real-time price might be very different from the pre-dispatch prices on which generators are expected to make their startup decisions. There is nothing in the New Zealand market design to compensate generators for any losses created by the difference between the pre-dispatch and real-time prices. This design forces generators with high startup costs to bear all the financial risk of demand and renewable output fluctuations.

I provide a stylized example to demonstrate the potential welfare cost of this single-settlement market design. Consider a market with three generation plants serving constant demand of 100 MW. Table 1 shows the plant characteristics. The wind plant has zero marginal cost and no startup cost, but uncertain output: 60 MW with a 80 percent probability and 20 MW with a 20 percent probability. The baseload plant has a capacity of 70 MW, \$30/MWh marginal cost, and \$1,000 startup cost. It requires commitment one period before the wind uncertainty is resolved. The peaker plant has 70 MW capacity, \$100/MWh marginal cost, and no startup costs or lead time. When demand cannot be met, customers experience blackouts valued at \$10,000/MWh. This value of lost load represents the economic cost of involuntary load shedding.

A social planner minimizing the expected system costs would commit the baseload plant. With the baseload running, the system costs are $\$1{,}000 + \$30 \times 40 = \$2{,}200$ in the high wind scenario and $\$1{,}000 + \$30 \times 70 + \$100 \times 10 = \$4{,}100$ in the low wind scenario, giving an expected total cost of $0.8 \times \$2{,}200 + 0.2 \times \$4{,}100 = \$2{,}580$. Without the baseload running, high wind scenarios cost $\$100 \times 40 = \$4{,}000$. Low wind scenarios will require 10 MWh of load shedding and incur a total cost of $\$100 \times 70 + \$10{,}000 \times 10 = \$107{,}000$. The expected cost without the baseload commitment is $0.8 \times \$4{,}000 + 0.2 \times \$107{,}000 = \$24{,}600$. By ensuring sufficient generation capacity even under low wind scenarios, the socially optimal choice to commit the baseload plant reduces expected costs by \$22,020.

If firms bid to reflect their marginal cost, then the single-settlement market fails to achieve the social optimum.[13] Generators are paid only the real-time price for actual production, creating a coordination failure. Consider the baseload plant's profit calculation. If it commits and wind output is high, it sells 40 MW at a real-time price equal to its marginal cost of \$30/MWh. Revenue covers operating costs but not the \$1,000 startup cost, yielding a \$1,000 loss. If wind output is low, the baseload plant produces 70 MW at \$100/MWh, earning \$7,000 revenue against \$3,100 total costs for a \$3,900 profit. The expected profit from commitment is $0.8 \times -\$1{,}000 + 0.2 \times \$3{,}900 = -\$20$. Because its expected profit is negative, the baseload plant will not commit.

Without baseload commitment, the single-settlement market creates two efficiency problems. First, even high wind periods require expensive peaker generation costing \$4,000 instead of \$2,200. Second, low wind periods trigger blackouts when the wind plant (20 MW) and peaker plant (70 MW) cannot meet 100 MW demand. The system operator will disconnect 10 MW of load. This stylized example parallels the August 2021 load shedding when thermal plants were unavailable due to insufficient startup incentives.

The single-settlement design systematically transfers risk from wind to baseload plants. Wind profits are stable: \$1,800 when wind is high versus \$2,000 when wind is low, due to the negative correlation between prices and quantities for the wind plant. When wind produces more, prices fall. When wind produces less, prices rise. Conversely, baseload profits are extremely volatile: \$3,900 profit when wind is low versus \$1,000 loss when wind is high. This volatility is because high prices coincide with high baseload output and low prices with low baseload output.

This risk transfer undermines investment incentives for baseload generation. Baseload plants in this example are essential for satisfying demand at a reasonable cost when renewable output is low, yet they absorb most of the financial volatility created by renewables.

13. For this example, each "plant" denotes a technology class composed of many small, price-taking units that bid their marginal cost. When load is fully served, the real-time price equals the marginal cost of the highest-cost dispatched plant.

This problem worsens as the penetration of intermittent renewables increases. Baseload plants face higher profit volatility, higher cost of capital, and weaker investment incentives at exactly the time when the system needs additional backup capacity.

Does the pre-dispatch process used in the New Zealand wholesale market solve this problem? The stylized example shows that it does not. In the example, the baseload plant has perfect information about the probability distribution of wind output and future real-time prices under each possible wind realization. This is more information than is provided in the real-world pre-dispatch process, which provides a single price at the expected wind output, not the distribution of prices. But the level of information does not matter. The baseload plant does not start, not because it is uninformed about future prices, but because there is no financially binding commitment that will allow it to recover its startup costs under the likely high-wind outcome.

The lack of theoretical support for the pre-dispatch mechanism may appear to conflict with the empirical findings of Bergheimer et al. (2023), who study the performance of the pre-dispatch mechanism in the New Zealand market between 2014 and 2018. They show that the pre-dispatch prices and quantities become increasingly informative of final prices and quantities in each successive pre-dispatch round. Generators appear to revise their offers to optimize their intertemporal production profiles. In particular, the number of coal plant startups decreases between the first and last pre-dispatch period. There is a smaller effect for combined-cycle gas startups and no effect on hydro startups.

These findings are suggestive of private cost savings for thermal generators, but they miss the crucial point: private profit maximization does not equal social welfare maximization. Bergheimer et al. (2023) do not compare pre-dispatch outcomes to the social optimum that minimizes expected system costs. In the stylized example, the socially optimal outcome requires baseload commitment, yet private incentives lead to no commitment. Therefore, the finding of fewer coal startups could indicate the market moving further from, not closer to, the social optimum. Finally, as Bergheimer et al. (2023) note, the repeated rounds of pre-dispatch reports and offer revisions create opportunities for strategic behavior. It is difficult to distinguish a generation plant not starting to reduce operating costs from a generation plant not starting to exercise market power.

Given these shortcomings of the single-settlement market design, especially with a larger share of intermittent renewables, the following section describes how a U.S.-style multi-settlement market works. It extends the stylized model to show how a day-ahead market can realign private incentives with social welfare.

4.3 Potential Benefits of a Multi-Settlement Market

Multi-settlement markets, such as those used in the United States, solve the coordination failure by creating financially binding positions before uncertainty resolves. Generators submit offers to a day-ahead market, and the system operator prepares a dispatch schedule for the following 24 hours. A real-time balancing market then handles any deviations from the day-ahead schedule. Generators receive the day-ahead price for their scheduled generation, then pay or receive the real-time price for any deviations from that schedule.

This design directly addresses the startup cost problem. Thermal generators can sell their expected output in the day-ahead market, securing revenue before wind and demand uncertainty resolves. They are guaranteed to recover startup and operating costs, making commitment profitable even when real-time conditions turn unfavorable. Intermittent renewable generators, should they be eligible to participate in the day-ahead market, face incentives to submit accurate forecasts, as deviations between actual output and day-ahead sales are costly.

Multi-settlement markets also incorporate centralized commitment using three-part offers that include start-up costs, no-load costs, and marginal operating costs.[14] This cost information enables two mechanisms. First, make-whole payments compensate generators when day-ahead revenues are insufficient to cover total operating costs. Second, the system operator can solve for the optimal 24-hour dispatch that minimizes expected generation costs subject to operating constraints, although this optimization is computationally challenging for large systems.

I extend the stylized example from Section 4.2 to show how a multi-settlement market achieves the socially optimal outcome.[15] Suppose the wind farm sells 40 MW in the day-ahead market, the baseload plant sells 60 MW, and the peaker plant sells nothing. The day-ahead price equals the expected real-time price: $0.8 \times 30 + 0.2 \times 100 = \$44$. At this price, the wind farm will earn \$1,760 in the day-ahead market and the baseload plant will earn \$2,640. Because the as-bid costs of the baseload plant are $1000 + 60 \times \$30 = \$2{,}800$, it will receive a make-whole payment of $\$2{,}800 - \$2{,}640 = \$160$, giving total day-ahead revenue of \$2,800.

If the realized wind output is high, the wind plant sells an additional 20 MW in real-

14. Start-up costs are the fixed costs of fuel and other inputs to bring a power plant online from a cold or a warm state. No-load costs are the theoretical hourly costs of keeping a plant running without supplying electricity to the grid. Finally, marginal operating costs are the costs of producing each incremental unit of electricity.

15. This discussion is based on a similar example in Wolak (2021).

Figure 4: Average Prices for Wind and Baseload generators under high and low wind output conditions for different day-ahead wind commitments

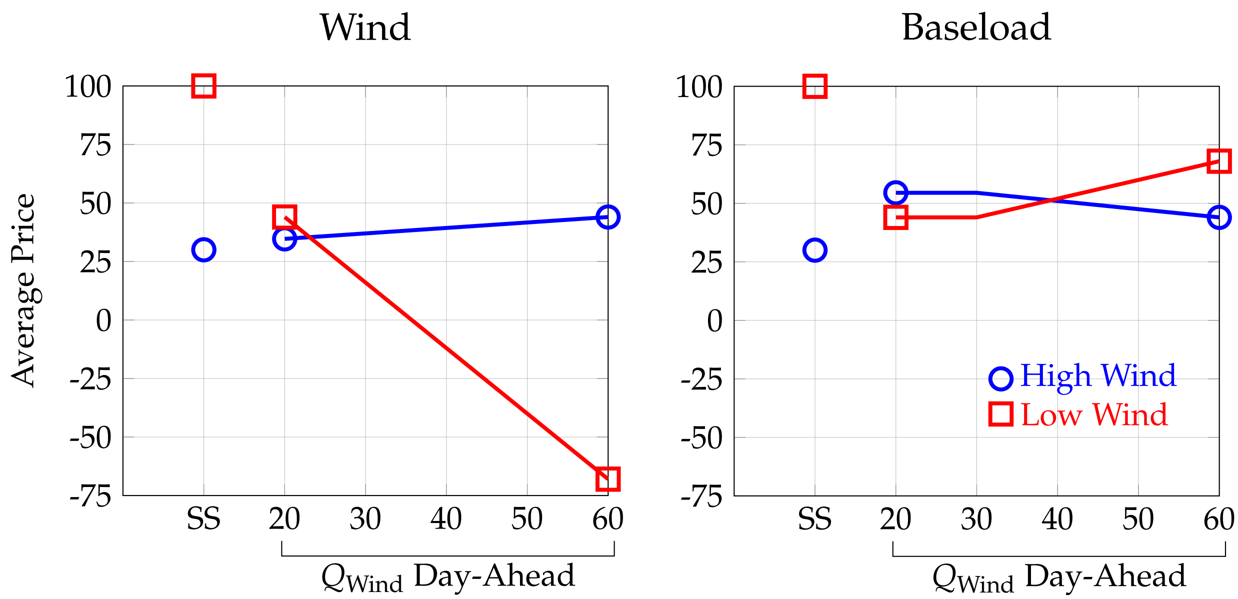
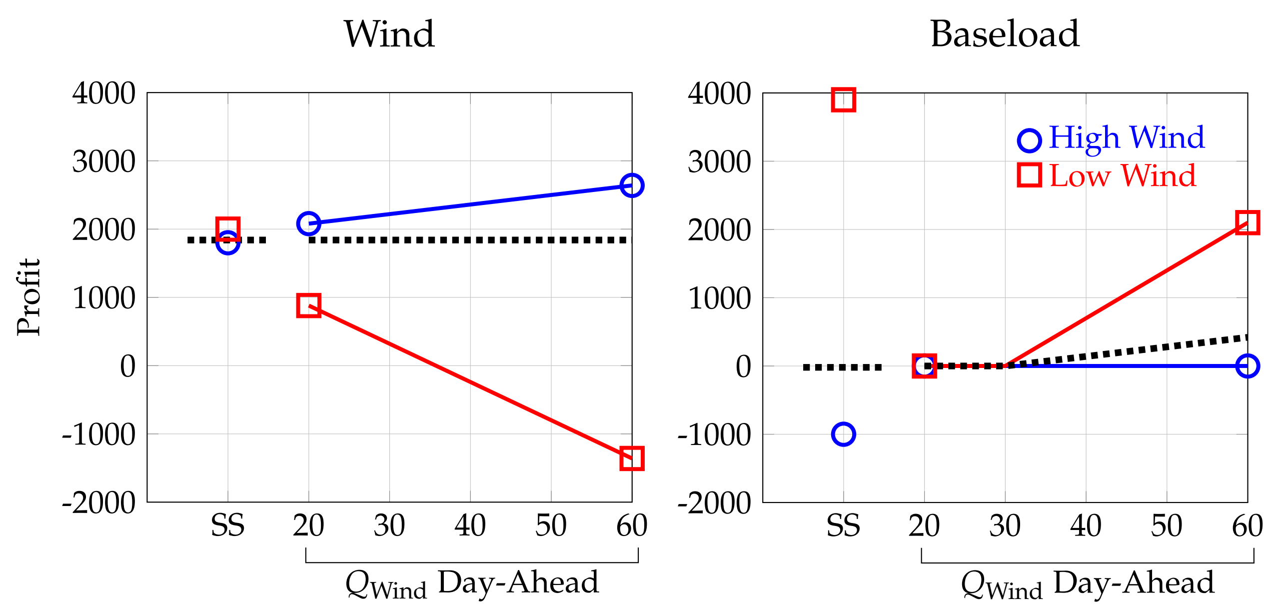


Figure 5: Profits for Wind and Baseload Thermal generators under high and low wind output conditions for different day-ahead wind commitments



Note: "SS" refers to the single-settlement results from Section 4.2. Q_{Wind} is the quantity of wind sold in the day-ahead market for the example in Section 4.3. The dotted line is the expected profit given probabilities of 80 percent for high wind output and 20 percent for low wind output.

time at \$30, earning total profit of $\$1{,}760 + 20 \times \$30 = \$2{,}360$. The baseload plant produces only 40 MW but sold 60 MW day-ahead, so it buys back 20 MW at \$30. Its revenue is $\$2{,}800 - 20 \times \$30 = \$2{,}200$, total costs are $\$1{,}000 + 40 \times \$30 = \$2{,}200$, leaving the baseload plant with zero profit.

If the realized wind output is low, the wind plant produces only 20 MW but sold 40 MW day-ahead, so it buys back 20 MW at \$100, earning $\$1{,}760 - 20 \times \$100 = -\$240$. The baseload plant sells an additional 10 MW in real-time at \$100, earning total revenue of $\$2{,}800 + 10 \times \$100 = \$3{,}800$. After deducting costs of $\$1{,}000 + 70 \times \$30 = \$3{,}100$, baseload profit is \$700.[16]

The baseload plant's expected profit is $0.8 \times \$0 + 0.2 \times \$700 = \$140$.[17] Unlike the single-settlement case where expected profit was $-\$20$, the multi-settlement design with make-whole payments ensures it is expected-profit-maximizing for the baseload plant to commit. Baseload commitment provides the socially optimal outcome and the \$22,020 welfare gain identified earlier.

One feature of the multi-settlement design is that dispatchable generators always receive higher average prices than intermittent renewables. In the high wind scenario, the wind plant receives an average price of \$2,360/60 MWh = \$39.33/MWh, while the baseload plant receives \$2,040/40 MWh = \$51/MWh (before make-whole payments). In the low wind scenario, the wind plant faces a negative average price, while the baseload plant receives \$3,640/70 MWh = \$52/MWh. This price premium reflects the economic value of dispatchability in a system with uncertain renewable output.

Figure 4 generalizes the above calculation to show average prices received by wind and baseload plants as a function of the quantity sold by the wind plant in the day-ahead market. Figure 5 shows profits under high and low wind outcomes. Both figures include single-settlement outcomes (labeled SS) from Section 4.2 for comparison.

The multi-settlement design consistently provides baseload plants with higher average prices than wind plants. This price premium reflects the value of dispatchability. When wind sells less in the day-ahead market than it produces, real-time prices fall below day-ahead prices. Wind sells excess output while baseload buys back its day-ahead

16. For this stylized example, I assume that the baseload plant keeps the day-ahead make-whole payment, regardless of its revenue and costs in the real-time market. In practice, most wholesale markets, including PJM, employ offset mechanisms to prevent double-recovery of commitment costs (PJM Interconnection, 2025).

17. Without make-whole payments, if day-ahead prices equal expected real-time prices, then the expected baseload profit would be $-\$20$, identical to the single-settlement case. However, even without make-whole payments, a small day-ahead price premium could ensure profitable commitment.

commitment at low prices. When wind sells more in the day-ahead market than it produces, real-time prices exceed day-ahead prices. Wind must buy back its shortfall while baseload sells additional output at high prices. In both cases, the price movements favor the dispatchable baseload plant over the variable wind plant.

A striking feature of Figure 5 is how multi-settlement markets reallocate risk between generators. In the single-settlement market, the baseload plant bears almost all profit risk from intermittent wind output, varying from −$1,000 to $3,900. The multi-settlement design reduces this volatility by allowing baseload plants to sell most output at day-ahead prices before wind uncertainty is resolved. As wind's day-ahead sales decrease, baseload's day-ahead sales increase, and baseload's profit risk (the gap between the high and low wind profit lines) shrinks correspondingly.

A common misconception is that centralized commitment in multi-settlement markets sacrifices generator control to system operators. This is incorrect. Day-ahead markets create financial positions, not physical obligations. A baseload plant that sells 60 MW day-ahead can still choose not to start, but faces financial consequences from doing so, as it must buy back its day-ahead commitment at real-time prices. Conversely, if the baseload plant chooses to produce its day-ahead quantity, it will neither buy nor sell in the real-time market, and its entire revenue comes from the day-ahead market. The financial structure of multi-settlement markets aligns private incentives with system needs without removing operational control.

For the case of New Zealand, the Electricity Authority has consulted with market participants about shifting to a two-stage market design with an "hours-ahead" market and a real-time balancing market. One objection expressed is that this design "could be detrimental to parties that cannot readily predict their output or demand to balance themselves from volatile balancing prices" (Electricity Authority, 2023a). However, this is a feature, not a bug, of a multi-settlement market. In a single-settlement market, generators with unpredictable output or consumers with unpredictable demand impose costs on other market participants. Multi-settlement markets internalize these costs, creating proper incentives for forecast accuracy and system reliability. By potentially solving the coordination failure that led to the August 2021 blackouts, this market design can deliver substantial welfare gains ($22,020 for one event in the stylized example), particularly as intermittent renewable generation increases.

4.4 Market Power Mitigation

Unilateral market power refers to the ability of a single firm to influence prices without the need to coordinate with its competitors. The characteristics of the electricity industry, especially the need to continuously balance supply and demand at every location on the transmission network, make it particularly susceptible to the exercise of unilateral market power. The early experiences with restructured electricity markets in the United States were tarred by the exercise of market power, most notoriously in California in summer 2000 (Borenstein et al., 2002). As a result, the standard wholesale market design in the United States has evolved to include mechanisms that limit the ability of generation firms to exercise market power.

The New Zealand wholesale electricity market has several structural features that increase the ability of firms to exercise market power. There are a small number of competitors, the elongated transmission network has multiple bottlenecks, and there are periodic shortfalls in hydro inflows. Moreover, the design of the short-term market facilitates the exercise of market power. Generators make multiple rounds of non-binding offers during the pre-dispatch process and can evaluate their effect on expected prices and quantities. The level of information disclosure is greater than in many other electricity markets, with final generation offers made public within 24 hours after the trading period.[18]

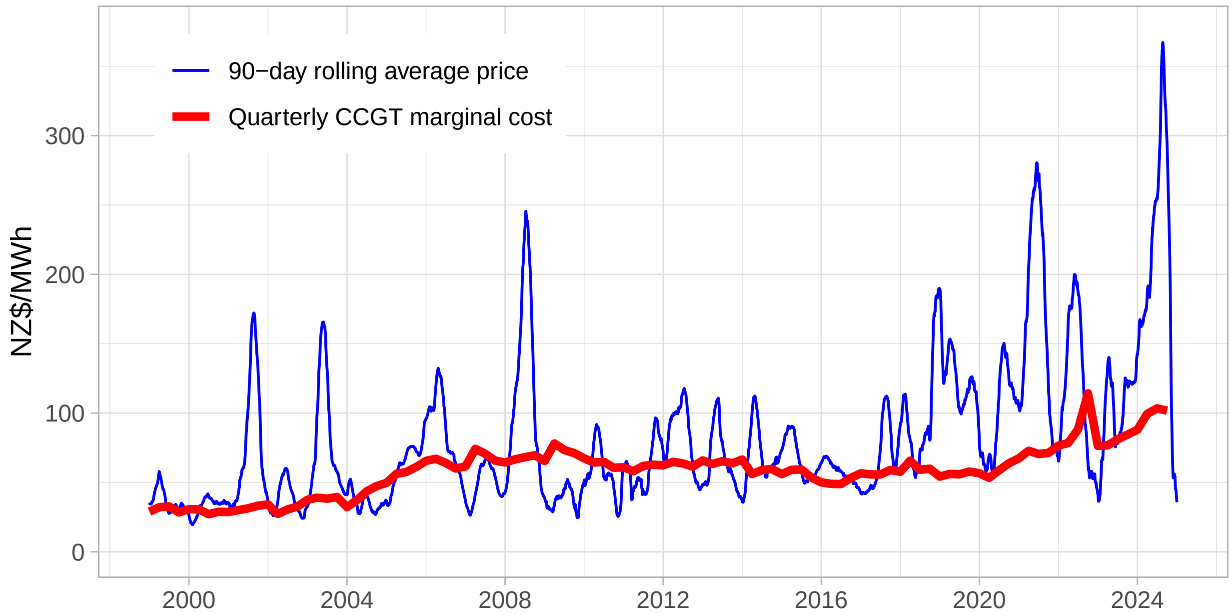
Three studies by academics have quantified the extent of market power in the New Zealand electricity market. Wolak (2009) applied the methodology of Borenstein et al. (2002) to the New Zealand setting for the period from 2001 until mid-2007.[19] He used two approaches to computing a competitive counterfactual accounting for the large share of hydro generation. In the first counterfactual, hydro generation quantities were fixed at the actual generation level. In the second counterfactual, hydro generation offers were capped at the maximum marginal cost of thermal generation on the system. Both approaches gave a similar estimate of market power rents of NZ$4.3 billion over the six-and-a-half-year period, or 27 percent of total wholesale market revenue.

Many of the modeling assumptions of Wolak (2009) were challenged by market participants and local academics. These criticisms included the underestimation of the opportu-

18. For the Alberta market, Olmstead et al. (2020) show that the publication of offer data at the end of each hour led to a 4.2 percent increase in final prices. Based on this finding, the system operator was ordered to stop publishing the near-real-time offer data. Using a later period in the same market, Brown et al. (2025) show that market-level data (such as demand forecasts) are more useful for updating offer prices than disaggregated data on rival firms.

19. For the same period, McRae and Wolak (2014) show that offer prices for the four largest generators were higher during periods when they have a greater ability and incentive to exercise market power.

Figure 6: Average Prices and Combined Cycle Generation Costs, 1999–2024



Notes: The thin blue line shows the 90-day rolling average of the hourly generation-volume-weighted average price in NZ$ per MWh. The thick red line estimates the marginal cost of the combined cycle natural gas generation plants. This is calculated using the quarterly average natural gas price for industrial users (Ministry of Business, Innovation & Employment, 2024) and the heat rate and variable operating and maintenance (O&M) costs for these plants (Ministry of Business, Innovation & Employment, 2020). Dollar amounts are shown in nominal terms. Variable O&M costs are adjusted using the utility sector input PPI.

nity cost of water, the assumption of perfectly inelastic demand, and the assumed absence of transmission constraints. Using data for 2006 and 2008, Browne et al. (2012) applied an agent-based modeling methodology to relax many of these simplifying assumptions. Their approach led to larger, not smaller, estimates of market power rents. For 2006, they estimated market power rents to be 30 to 37 percent of wholesale market revenue, compared to 25 percent for that year in Wolak (2009). Poletti (2021) subsequently applied an agent-based modeling approach to estimate market power for the 2010–2016 period. He estimated that market power rents were 37–39 percent of wholesale market revenue for that period.

These three studies estimate genuine economic rents from the exercise of market power, representing transfers from consumers to producers. A common misconception is that market power is necessary in wholesale electricity markets to enable fixed cost recovery. However, in competitive markets, the price can exceed the marginal cost of all production, including the marginal cost of the last unit produced (Borenstein, 2000). The competitive rents from the revenue earned above marginal cost allow for the recovery of fixed costs.

The academic studies focused on earlier periods when market power exercise was concentrated in dry years with scarce hydro generation. Figure 6 shows a 90-day rolling average of the generation-volume-weighted average nodal price from 1999 until 2024. The figure also includes an estimate of the marginal cost for a combined-cycle gas turbine plant. For the 2001 to 2007 period studied by Wolak (2009), the figure shows that wholesale prices were similar to the marginal costs of an efficient thermal generation plant during years with plentiful hydro inflows. During dry years such as 2001 and 2003, wholesale prices exceeded the cost of even the most expensive thermal generation plant. The high prices in those two years gave rise to the substantial market power rents estimated by Wolak (2009).

Figure 6 shows that pricing behavior in the electricity market appeared to change after 2018. Except for a few months in late 2022 and early 2023, prices have remained consistently higher than combined-cycle marginal costs. Prices during 2024 reached unprecedented levels. Electricity Authority (2021b) reviewed possible explanations for the sustained higher prices after 2018. One contributing factor was a major outage at the Pohukura offshore gas field in 2018, which caused natural gas spot prices to double. However, the report also found that the largest generation firms had considerable ability to exercise market power, with Meridian being a gross pivotal supplier in more than 90 percent of hours.[20] Thermal offers exceeded the estimated short-run thermal marginal cost in a higher share of hours after 2018 than before. Hydro offers were also more likely to exceed the estimated opportunity cost of water after 2018. Despite these results, Electricity Authority (2021b) concluded that the generation firms appeared to have behaved within the parameters of the Electricity Industry Participation Code at the time.

There is a wide range of opinions about the role of market power in the New Zealand electricity market. One response to the publication of Wolak (2009) was that "there is no evidence of sustained or long-term exercise of market power" (quoted in Poletti (2021)). Another common opinion is that market power is a "tolerated mechanism for recovering the long-run marginal costs of generation" (Philpott et al., 2019). Finally, the regulator has expressed a view that market power exists, but nothing can be done about it, saying "some degree of strategic pricing, which may be undesirable in other markets, is unavoidable" (Electricity Authority, 2021b).

20. A generator is gross pivotal if total market demand exceeds the combined quantity offered by all other participants, meaning the generator must be at least partially dispatched to meet demand. Although gross pivotal suppliers have extreme ability to exercise market power, they may lack the incentive to do so. The pivotal quantity equals the difference between total demand and the quantity offered by other participants. A generator is net pivotal if its pivotal quantity exceeds its fixed-price forward contract obligations. Net pivotal generators have both the ability and incentive to exercise market power (Wolak, 2009).

These views reflect the inherent difficulty of addressing market power given New Zealand's concentrated market structure. Market power arises from fundamental structural features such as transmission constraints, demand inelasticity, and barriers to entry. Regulatory decree cannot eliminate these structural conditions. While policies can mitigate market power, they cannot switch it off. Moreover, any regulatory intervention comes with costs that need to be weighed against the benefits.

The New Zealand market design provides few restrictions on the ability of generators to exercise market power. There is no explicit offer price cap or automatic market power mitigation mechanism. Instead, the Electricity Authority has relied on ad hoc investigations following formal complaints by market participants, typically large consumers or electricity retailers, about so-called Undesirable Trading Situations. These are defined as an event that threatens (or may threaten) confidence in the integrity of the wholesale market (Electricity Authority, 2025f). One example of such a complaint occurred in December 2019. Beginning in November 2019, Meridian and Contact both spilled large quantities of water from their hydro generation stations in the South Island, while simultaneously setting high offer prices for their generation from those stations. After a 20-month investigation, the Electricity Authority decided to cap the hydro offer prices from December 2019, recompute the market-clearing prices, and resettle the market (Electricity Authority, 2021a).

More recently, the Electricity Authority has started publishing weekly market monitoring reports. These reports include information on energy and reserves prices, estimated short-run marginal costs of thermal plants, estimated opportunity costs of water, and generator offer behavior. The Electricity Industry Code was amended in June 2021 with a new trading conduct rule, stating that all generation offers must be consistent with the offers that a rational generator would make if no generator could exercise market power. Despite this change, there is no regulatory mechanism to ensure compliance with the rule.

The limitations of conduct-based regulation have led other jurisdictions to adopt automated market power mitigation mechanisms. These automated mechanisms are standard in all short-term wholesale electricity markets in the United States, though implementation details vary. Graf et al. (2021) categorize two main approaches. The "conduct and impact" approach checks if offer prices exceed a reference level and whether the offer has a significant impact on market price. The "structural" approach bypasses generation offers, instead identifying when suppliers become jointly pivotal with significant ability to exercise market power. Both approaches replace problematic offers with reference prices based on estimated marginal cost plus a typical 10 percent adder.

Graf et al. (2021) favor the structural approach because it relies on market fundamentals rather than arbitrary regulatory thresholds. The mechanism triggers when transmission constraints create conditions that enable market power exercise. The targeted nature preserves competitive pricing when genuine competition exists, substituting offers only when market structure temporarily breaks down. This precision avoids the broader distortions created by blunt regulatory instruments like price caps.

However, approaches developed for the United States may not translate well to New Zealand's concentrated market structure. With only a handful of large generators, structural thresholds based on jointly pivotal tests would likely trigger continuously, defeating the purpose of targeted intervention. Reference price setting poses additional challenges for hydro-dominated systems, requiring contentious assumptions about the opportunity cost of water. Moreover, automated mechanisms might not catch more sophisticated behavior by hydro generators, such as the coordinated water spilling and high offer prices observed in 2019.

Developing effective mitigation mechanisms for small, concentrated electricity markets requires balancing genuine market power concerns against the costs and limitations of regulatory intervention. Getting this balance right has implications beyond the short-term effects of high prices on consumers. As I discuss in the next section, high electricity prices, whether caused by market power or other market inefficiencies, discourage the electrification efforts central to the clean energy transition.

5 Achieving Long-term Energy Transition Goals

A short-term wholesale market design delivering a reliable electricity supply at the lowest possible cost provides the foundation for the long-term generation mix. In this section, I discuss New Zealand's ambitious goals for the clean energy transition, the resource adequacy challenges that these goals create, and how short-term market design choices affect the prospects for meeting these long-term objectives.

In 2019, the New Zealand government created the Climate Change Commission as an independent agency to provide research and analysis on issues related to greenhouse gas emissions and climate change. Figure 7 shows the commission's demonstration path for achieving the government's target of net zero greenhouse gas emissions (excluding biogenic methane) by 2050. Achieving this target requires large-scale electrification to eliminate almost all fossil fuel consumption in the transportation, manufacturing, and residential sectors. Higher electricity demand in these sectors will require a 64 percent increase in total electricity generation from 2023 levels (top panel).

Given the insurmountable challenges associated with building new large-scale hydro plants, the demonstration path assumes that hydro generation will remain at its current level. Instead, the increase in total generation will be met by a rapid expansion in wind and solar generation (bottom panel of Figure 7). In this scenario, wind generation would increase from 8 percent to 28 percent of total generation by 2050, while solar generation would increase from less than 1 percent to nearly 20 percent of total generation. By 2050, almost half of total generation will be supplied by wind and solar energy.

Long-term resource adequacy refers to the process of ensuring that supply equals demand at all times and under all possible demand conditions. The major resource adequacy challenge in the New Zealand electricity market has been the high share of hydroelectric generation and the intermittency in water inflows.[21] Because New Zealand has less than one month of storage capacity in its hydro reservoirs, dry years lead to either cuts in demand or higher generation from other fuels.

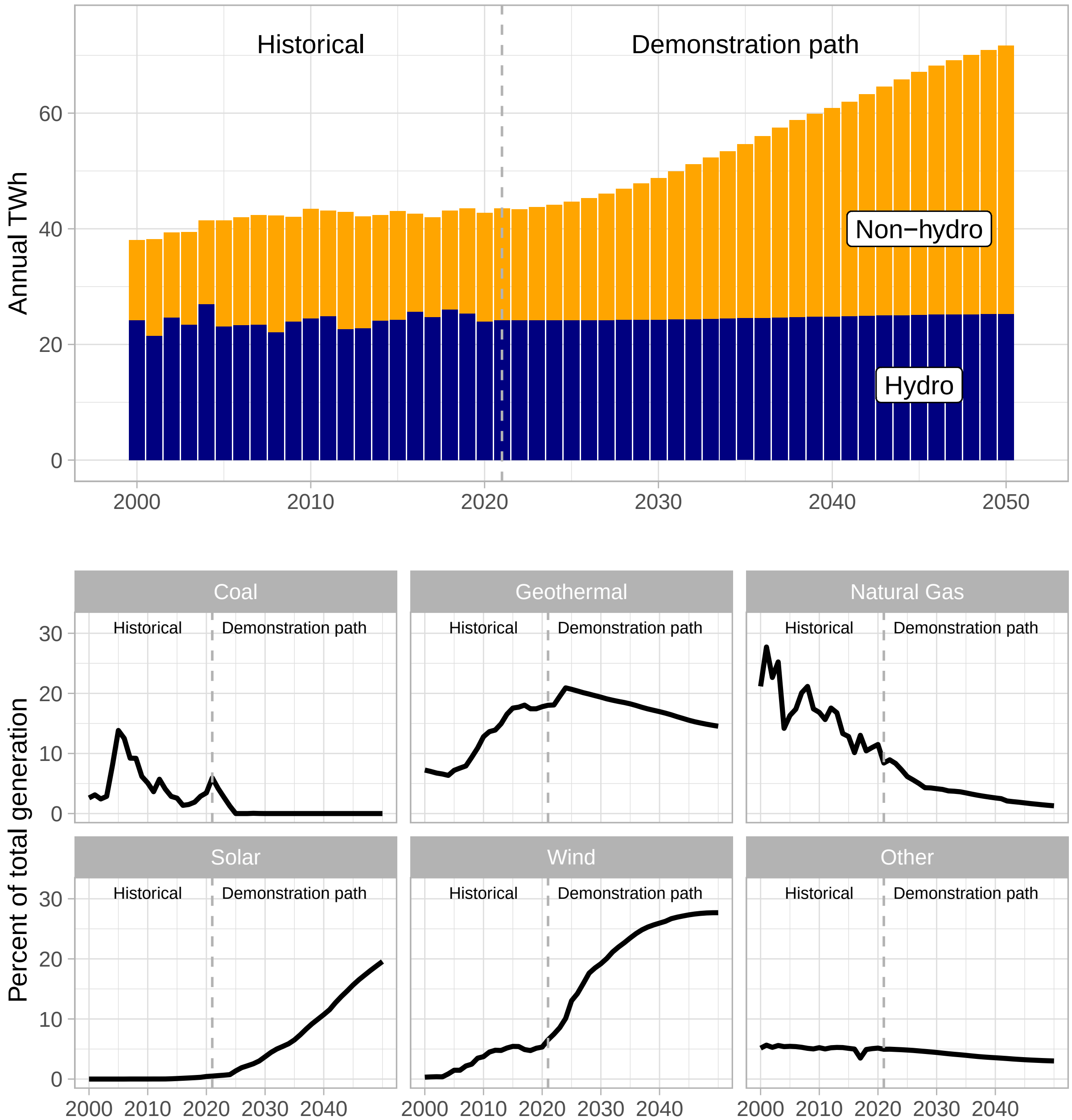
Historically, thermal generation from coal and natural gas has provided the backup for low hydro inflows (Figure 2).[22] However, thermal generation capacity has declined during the past decade due to the closure of several plants. Going forward, the demonstration path incorporates a rapid phase-out in coal generation and a small share of natural gas generation remaining out to 2050. Two issues are unresolved. First, it is unclear whether generation owners have a financial incentive to retain sufficient natural gas generation capacity to act as a backup for dry years. Second, there are concerns about the future availability of natural gas. New Zealand has declining production of natural gas, a ban (recently lifted) on new offshore oil and gas exploration, and currently no infrastructure to import liquefied natural gas.

The high reliance on intermittent wind and solar generation in the demonstration path will create additional resource adequacy challenges. Although New Zealand has a relatively constant distribution of wind availability across the day and year (Figure 8), the extreme values of this distribution are more important for the security of the electricity supply. The wind capacity factor fell below 10 percent during one out of nine hours

21. The year-to-year variation in hydro generation is related to the ENSO (El Niño–Southern Oscillation) climate cycle. Since 2000, annual hydro generation peaked at 27.0 TWh in 2004, more than 25 percent higher than the minimum of 21.5 TWh in 2001.

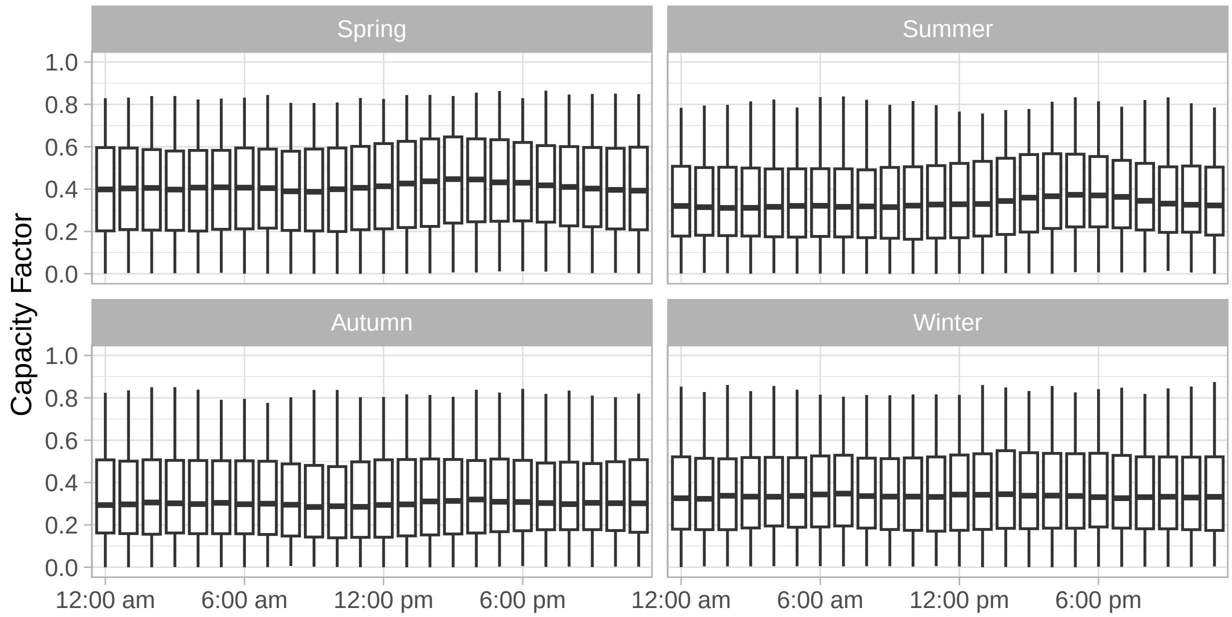
22. Geothermal is used as a baseload generator and has a high capacity factor, leaving no spare capacity to replace hydro in dry years.

Figure 7: Electricity Sector Demonstration Path for Achieving Greenhouse Gas Emissions Targets



Notes: The figures show the historical and future sources of electricity generation under the demonstration path used by the New Zealand Climate Change Commission to prepare its recommended emissions budgets (Climate Change Commission, 2023). The top panel shows the total generation split between hydro and non-hydro sources. The bottom panel shows the split of the non-hydro generation sources as a share of total generation.

Figure 8: Wind Capacity Factors by Season and Hour, 2014–2024



Notes: Each panel shows the distribution of the capacity factors for aggregate wind generation in New Zealand over the eleven years from 2014 to 2024. 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).

between 2014 and 2024, with low wind conditions lasting more than a day on several occasions. As shown in Figure 8, extremely low wind conditions can occur at any time of the day and year.

The resource adequacy problem is not unique to New Zealand. Every electricity market faces the challenge of ensuring there is sufficient supply to meet demand, especially given a greater share of intermittent renewable generation. A particular problem in restructured electricity markets is that there is no single entity responsible for achieving this goal (Wolak, 2022). The typical approach to long-term resource adequacy in most wholesale electricity markets is to use a capacity payment mechanism that makes payments to generators to keep their capacity available, even if they do not produce electricity.[23]

Although New Zealand does not have a capacity payment mechanism, there have been two attempts to provide a solution to the resource adequacy problem outside of the

23. The original capacity market designs only provided weak incentives to generators to provide capacity during critical system conditions (Bushnell et al., 2017). However, newer capacity instruments such as reliability options also create distortions through their interaction with the short-term spot and long-term forward contract markets (McRae and Wolak, 2024).

short-term wholesale market. First, the government established the Electricity Commission in 2003 with a goal of ensuring the security of supply. The Commission built a 155 MW oil-fired generation plant at Whirinaki, funded by a levy on all electricity consumers. This plant operated as a strategic reserve (Holmberg and Tangerås, 2023), offered into the wholesale market at a very high price to ensure that it only ran under critical system conditions. Seven years later, the government disbanded the Commission and sold the reserve generator. This policy change was driven by fears that the reserve discouraged investment in peak capacity and fostered over-reliance on the Electricity Commission for security of supply.

The second attempt was a proposed large-scale pumped-hydro storage facility at Lake Onslow in the South Island, known as the NZ Battery. This project was criticized for its extremely high cost and potential adverse effects on wholesale market participants. After four years of consultations, the project was canceled at the end of 2023.

The demise of the strategic generation reserve and the NZ Battery spelled the end to centrally planned efforts to ensure the security of supply in the New Zealand electricity market. Instead, the Electricity Authority has focused on achieving this goal by ensuring the efficient operation of the existing wholesale market. For example, it is undertaking projects to enhance demand response products (Electricity Authority, 2024c) and improve forecasts of intermittent generation (Electricity Authority, 2025c). The Authority has ruled out any payments for reliability products outside of the short-term market because of their potential for unintended consequences, such as creating an incentive for generators to withhold their plants from the market to receive higher out-of-market payments (Electricity Authority, 2023a).

New Zealand's policy preference to achieve security of supply through the short-term wholesale market dovetails with the discussion of market reforms in Section 4. These reforms would support the envisaged expansion and transformation of the electricity sector. In particular, a multi-settlement market can provide financial certainty for generators that have long lead times and whose operation needs to be planned many hours in advance. Although such generators are thermal plants in the current market, there might be a greater role over time for storage facilities such as batteries. Moreover, a multi-settlement market provides strong financial incentives for intermittent generators to reduce their forecast errors.

Reforms to the short-term wholesale market would not only bolster reliability, but may also reduce the cost of electricity provision. One such example is limiting the ability and incentive for the exercise of local market power (Section 4.4). Both price and reliability will be important considerations for the envisaged electrification of the economy. Firms and households may be unwilling to make investments to switch from a cheap, reliable fuel to an expensive, unreliable fuel. For example, a household that cooks or heats with natural gas may not find it optimal to switch to electric cooking and electric heating if electricity prices are high (McRae and Wolak, 2021) or if there is a risk of electricity blackouts during harsh winter conditions. Overall, creating a market that delivers reliable, low-cost electricity will support the clean energy transition with minimal regulatory intervention.

6 Conclusion

Despite innovative origins, the New Zealand wholesale electricity market design has changed little since 1996. Recent supply shortfalls highlight the growing challenges this market structure faces as the share of intermittent renewable generation increases. The single-settlement design creates coordination problems that can undermine system reliability, particularly for thermal generators with high startup costs that provide essential backup capacity during low renewable output periods.

The standard market design that has evolved in the United States offers potential solutions to many of these problems. A multi-settlement market with a day-ahead market and real-time balancing would provide greater financial certainty for generators about recovering their startup costs. It would also create stronger incentives for renewable generators to improve their output forecasts. Centralized optimization of the generation schedule over a full day could enhance system efficiency by better coordinating the startup and shutdown of generation plants. These reforms would better accommodate the uncertainty inherent in intermittent renewable output, improving both system efficiency and reliability.

Market design reforms alone cannot deliver New Zealand's clean energy transition. However, the evidence presented here suggests that the current market structure creates unnecessary barriers to renewable integration and system reliability. A well-designed wholesale market can support the transition by ensuring reliable electricity supply at reasonable prices, encouraging the widespread electrification that underpins New Zealand's climate goals.

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