Responding to matters set out in *Reviewing risk management options for electricity retailers – issues paper*

Toby Stevenson, Dr Stephen Batstone, Kieran Murray

20 December 2024

Contents

Figures

Executive summary

The Authority's *Reviewing risk management options for electricity retailers – issues paper* reports that to date, retailers have been able to secure substantial shaped hedge cover through over the counter (OTC) contracts, but the market for shaped cover is neither deep nor liquid. Over a third of the time, retailers only receive one offer to requests for shaped hedges.

The Authority notes the evidence points to fuel or capacity scarcity often being the driver behind the current thin and illiquid market for shaped hedge cover. While the evidence points to scarcity, the Authority seeks to understand why some gentailers elected not to respond to some requests for proposals for shaped hedges, or why gentailers sometimes provided non-conforming responses.

The Authority decided it should do something because:

> "while the evidence does point to scarcity being a driver, there is also a plausible driver that has competition implications, e.g., refusing to supply products on appropriate terms to counterparties who are downstream competitors, indicating that some level of market power could have been in play."

The Authority's analysis of the cost of OTC super-peak hedges indicates the prices for OTC baseload and peak hedge contracts are likely to be competitive. However, it was not able to determine whether the prices of OTC super-peak hedges were consistent with competitive prices, and whether the increase in OTC super-peak prices (as a percentage of ASX baseload prices) observed over the assessment period is justified.

The Authority recognises that OTC super-peak hedge contract prices will trade at a *substantial unquantified premium over ASX baseload prices adjusted for shape*. However, the Authority was not able to determine the efficient level of such a premium, explaining (in Appendix A of its report) that its estimates suffer from:

- likely underestimating the shape premia
- likely underestimating the illiquidity premium
- not estimating a spot price volatility premium
- adopting a scarcity premium that underestimates contract prices
- not adding a premium for ASX volatility.

Absent accurate estimates of these premia, commentary as to whether observed prices or terms for super-peak hedge contracts are impacted by market power becomes speculative. Revealed prices, for example, may have reflected the real-world considerations faced by sellers who underpin flexible contracts:

- with existing gas plant pricing in the uncertainty of whether they would have insufficient fuel
- with existing hydro plant pricing in the uncertainty of whether they would have sufficient inflows at all points during the contract term, and the uncertainty of whether gas-fuelled hydro firming would come online in this scenario due to the gas situation (i.e., August this year)

- by investing in peaking plant pricing in the uncertainty that their investment would be undermined by Tiwai exit or the Onslow proposed scheme.

The conceptual difficulty is that efficient economic costs of these premia cannot be accurately calculated because economic costs and prices are jointly and simultaneously discovered via the competitive process.

The practical difficulty is that the liquidity of flexibility products is limited by flexible generation capacity and the security of its fuel supply. In the New Zealand electricity sector, flexibility contracts cannot be physically backed by a number of prevalent fuels (e.g. geothermal, wind). Until now, super-peak contracts have only been able to be backed by gas and hydro – two fuels which, in the New Zealand context, are quite uncertain on a medium-term basis.

The 'elephant in the room', is that growth in peak demand has exceeded growth in any type of firm capacity for nearly a decade. This lack of investment must be a central feature in any analysis of flexibility contracts struck prior to now.

If peak prices in the spot market are insufficient over time to attract and maintain peak capacity, the Authority can be confident that market power could not have been in play. Market power allows an entity to obtain an 'economic rent'; that is, an amount that exceeds the amount needed to maintain the resource. Peak demand rising faster than peak capacity supports a presumption of *under-pricing* of super peak contracts and spot prices, at least at the margin which is what matters for an efficient market. If the revenue earnt by an existing supplier is less than that required by an efficient new entrant, the supplier cannot be said to have exercised market power in a manner adverse to the long-term benefit to consumers.

It is of course an unpalatable message, after the events of this year, that peak prices may have been too low in recent years to ensure supply will match demand in every half hour. But it is critical for the long-term benefit for consumers that the Authority retains a clear line of sight between demand and supply and pricing.

The forthcoming investment in industrial demand flexibility and batteries is encouraging. Our analysis suggests that some of substantial risks (notably policy and regulatory uncertainty) associated with firm capacity investment have reduced, and investment is coming to market in forms of demand response and battery storage that could plausibly back the standardised super peak contract. Liquidity in flexibility contracts like super-peak contracts should improve as these investments materialise. A caution is that the announced additional sources of flexibility—other than Meridian and Contact's 2024 demand response deal with Tiwai—are only coming to market over the next two years.

An intervention into the pricing of super peak contracts, when the problem is insufficient supply of flexible generation and demand, can only harm consumers, potentially severally. Recent history of the New Zealand electricity sector has shown that poorly conceived regulatory and policy interventions can undermine investment to the detriment of consumers.

1. Is there scarcity of super peak electricity supply, and, if so, why has it occurred?

1.1 Is there scarcity of peak electricity supply?

The issues paper leads with the following introduction:

> "The Electricity Authority commenced a risk management review in December 2023 to test whether the availability of over the counter (OTC) risk management contracts, in the context of other risk management options, is creating a barrier to entry to expansion in the retail electricity market and therefore harming (retail) competition."

A prerequisite for the availability of a peak-related contract is the availability of flexibility capacity (including demand reduction). Any peak-related contractual obligations that can't be met physically ultimately result in the supplier being exposed to wholesale market prices for any shortfall. Hence, when pricing the contract, the supplier will – necessarily – need to consider the potential exposure to the spot price, caused by the contract, under a range of future scenarios over the contract duration. This, in turn, must consider the potential scarcity in firm capacity across the whole market. The number of providers of super peak products is limited to three gentailers.[1]

Below we consider how firm capacity 'sufficiency' has evolved, and how market prices have responded.

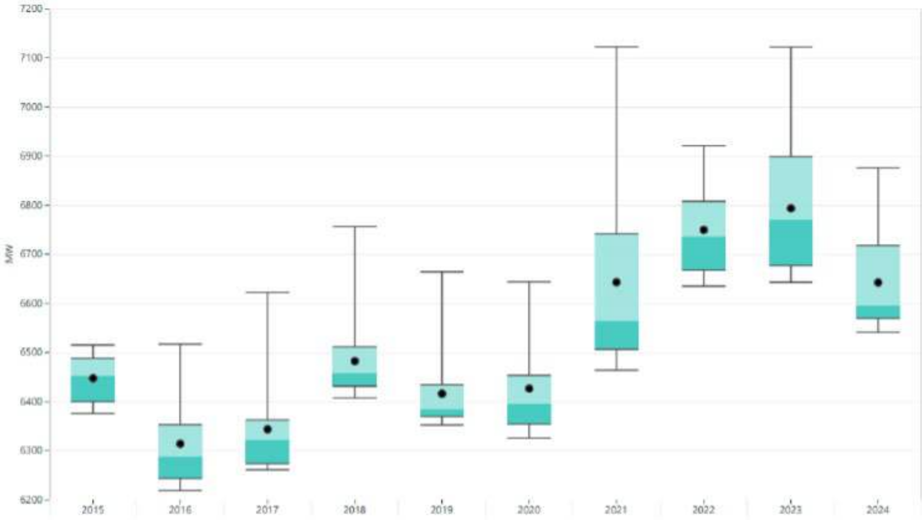
A change in peak demand growth

Little to no growth in peak demand in New Zealand between 2006 and 2015 meant that questions as to whether the electricity market would provide commercial incentives to maintain capacity to meet peak demand, remained unaddressed until very recently.[2]

In Figure 1, Transpower provides an assessment of peak demand growth over the past nine years. It notes the last four years. The reduced peak demand over winter 2024 was largely due to reduced industrial load resulting from higher spot market prices and warmer temperatures. This included up to ~205 MW of Tiwai aluminium smelter demand reduction through its contractual arrangements with Meridian Energy and Contact Energy.

[2] For example, the Authority's "Enduring an Orderly Thermal Transition" consultation paper; 13 June 2023, which reported an analysis of the cashflows associated with firm generation (CCGT, OCGT and Rankines) in 2025 and 2032. The 2025 analysis was based on a simulated set of market prices, and was not compared to actual spot market prices. It also contained a set of assumptions about gas that are quite benign compared to the situation we find ourselves in today.

Figure 1: Top 20 daily load peaks in each year since 2015[3]

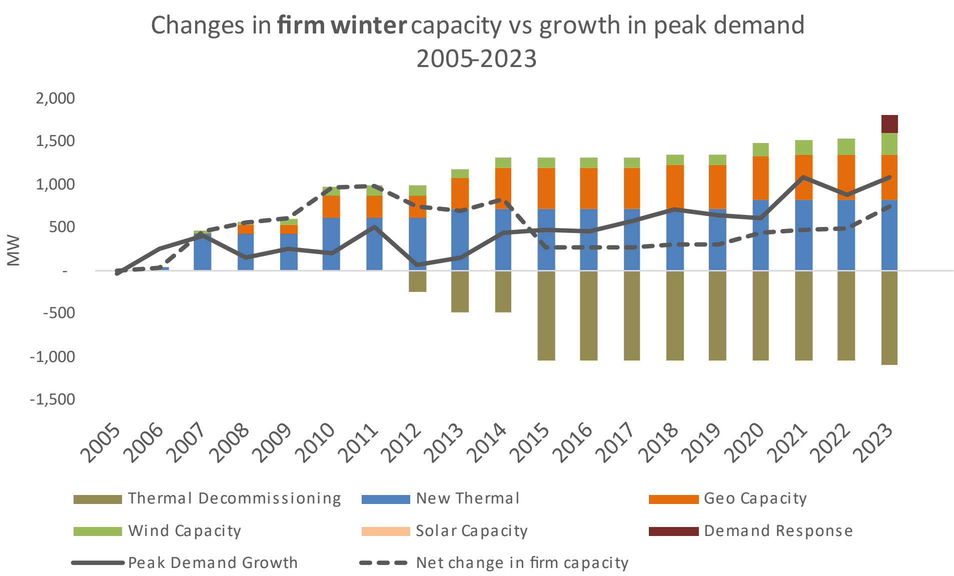


Did firm capacity keep pace with peak demand growth?

Figure 2 reproduces a chart that illustrates the changes in firm winter capacity compared to the growth in peak demand over the period 2005 to 2023.

While there was a significant net reduction in firm capacity in 2015, and only modest growth in firm capacity in the last few years, peak electricity demand resumed growing around 2013. As a result, growth in peak electricity demand consistently exceeded growth in firm capacity since 2015. Indeed, firm capacity barely grew for a period of four years following the decommissioning of Otahuhu and Southdown.

Figure 2: Changes in firm winter capacity vs growth in peak demand 2005-2023. Source: Whiteboard Energy Ltd



Source: Analysis provided by Whiteboard Energy

[3] Transpower Security of Supply Review - Winter 2024 November 2024.

The chart uses similar assumptions to the Authority's Security Standards Assumptions Document (SSAD), in particular that 25 per cent of wind generation (300MW) is deemed likely to be available at the peak. Whiteboard's assessment makes Huntly unit five available but only two Rankine units, whereas the SSAD derates all thermal by an average outage factor. The assessments do not allow for any derating of thermal generation due to gas supply shortages, but the third Rankine unit can offset some of this.

Although firm capacity has grown over the period since 2015, the balance of firm capacity to peak demand only improved in 2023 with the Authority's difference rule. This rule requires non-contracted water heating control to be offered in as difference bids, at a market price of $9,000/MWh. The rule means hot water control is available to offset the risk of an outage, but the capacity in the market to meet demand before prices reach (close to) scarcity prices, and therefore to mitigate financial risk, was reduced. The improvement in 2024 was due to the demand response arrangements in the New Zealand Aluminium Smelter (Tiwai) agreements. According to Whiteboard's analysis, despite some increase in firm capacity, the cumulative shortfall of firm capacity from 2005 to 2023 is around 400MW.

As we look forward, the next two to three years see new firm capacity coming to market. A number of grid-scale batteries will be commissioned by Contact, Meridian and Genesis. On the demand response front, a 'super peak' demand response deal between Contact and NZ Steel will come into effect as of December 2025. A number of retailers are developing the capability to manage hot water and electric vehicle charging[4] in a way that reduces peak demand. Baseload geothermal investments by Contact at Tauhara and Te Huka will add to firm capacity, although this will eventually be offset by the eventual decommissioning of Taranaki Combined Cycle[5]. Notwithstanding that, the last five to seven years has seen very little incentive to invest in firm capacity, and the pricing of historical super-peak contracts must be viewed through that lens.

Did the System Operator indicate concerns about future firm capacity?

Transpower, as the System Operator, is responsible for publishing the medium-term security of supply assessment (SOSA) annually. This assessment uses forecasts of electricity supply and demand to assess the ability of the electricity system to meet New Zealand's needs over the decade ahead. Transpower reports on the prospects for a winter energy margin and a North Island winter capacity margin. From 2018 on some scenarios were showing that the winter capacity margin was vulnerable to increasing peak demand because of electrification and the possibility of peaking capacity not keeping up with peak demand growth. More detail is provided in Appendix A.

[4] The capability to 'manage' hot water and EV charging we reference here is the ability for a retailer or flexibility aggregator to dynamically shift a customer's demand at their election. We note that a number of retailers have deployed time-of-use retail tariffs that incentivise non-peak EV charging (and other shiftable consumption) over the last two to three years, which will achieve a similar effect, but at the customer's election.

[5] Contact media release "Contact Energy (Contact) will keep its Taranaki Combined Cycle (TCC) 330MW thermal plant available over CY2025." Operation in CY2025 remains subject to a number of conditions notably "At this time, Contact does not intend to contract gas for the plant unless market participants express a demand for it, linked to a gas purchase arrangement". November 2024

How is this scarcity reflected in electricity spot and futures prices?

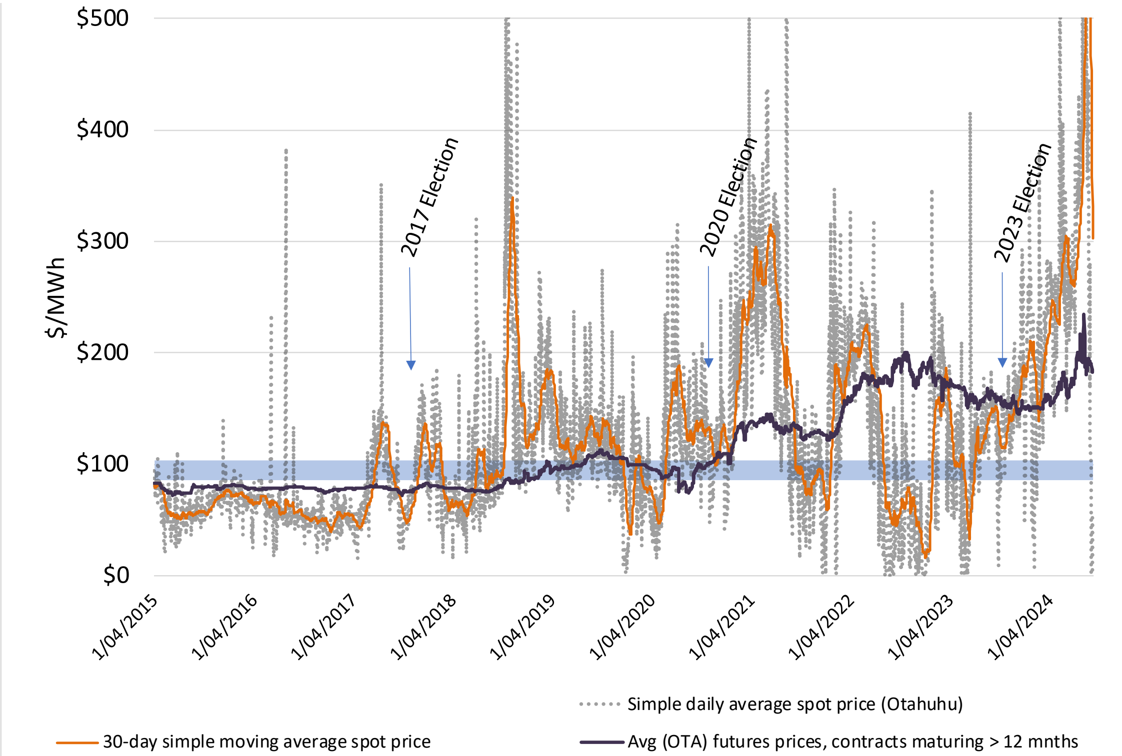
Wholesale spot market prices are the primary indicator of scarcity in fuel. Figure 3 plots daily average spot prices and average OTA futures settlement prices.

While spot prices are reflecting 'real time' scarcity, there are a number of ways in which concerns about future fuel supply will influence wholesale market conditions. The primary one is through opportunity cost – when fuel is limited (gas, hydro, coal), a plant owner's offer of that fuel to the market will reflect an inter-temporal trade-off: do I use the fuel today, or do I hold it for the future?

Futures prices are a more complete picture of expectations of future conditions, and will include expectations of supply, demand, outages and the impacts of government policy. However, most liquid electricity futures contracts are baseload products i.e., for the average price over a calendar quarter. While the spot prices and electricity futures prices are linked, they are not driven by the same factors, and futures impute risk and uncertainty about future matters to a greater degree than the spot market. However, it is useful to consider what they are both telling us simultaneously.

The timing of the past three generation elections is marked on the chart. Since 2021, the average price of electricity futures for the back three years has been increasing which suggests there were other factors (which we explain further below) that limited investor's appetite to invest. Prices also reflect seasonal hydrology. What we can't see from the chart is when or whether fuel scarcity became a critical issue for the market. That question is central to the hypothesis in the issues paper.

Figure 3: Spot and forward prices 2015 - 2024



It is clear that both spot and futures markets were signalling an unprecedented level of scarcity over the period 2019 to 2024.

We now unpack our analysis of the drivers behind this.

1.1.1 Why has the scarcity occurred?

In short, the reasons why this situation has emerged is a combination of:

- production of an important fuel used to underpin the contracts, gas, faced issues as early as 2018, and has declined markedly since 2021, and
- investment signals for building and maintaining peaking plant have been weak as a result of climate policy, energy policy and significant demand uncertainty in the case of the Tiwai aluminium smelter.
- Peak demand has grown.

The Authority has acknowledged a limited set of concerns to firm capacity. The Authority released a paper documenting potential solutions for peak electricity capacity issues earlier in 2024. There is no problem definition as such, but it does say: [6]

> "The management of capacity margins has not been the focus of the power industry historically as, until recent years, there was little growth in peak demand or energy consumption. This provided no signal that investment in new generation was needed.
>
> The recent drive for electrification of the economy has seen a sharp increase in peak demand over the last two years. This, coupled with thermal fuel supply issues and the displacement of thermal base-load generation, has led to resource coordination issues when managing peak demand periods. **In simple terms, there is not enough capacity available to be delivered to ensure electricity supply meets demand**."

As we outline in the following sections, we do not agree that the situation only emerged over "the last two years."

1.1.2 The removal of RCPD and its effect on peak demand growth

Changes to the Transmission Pricing Methodology (introduced 2022) included removing regional peak coincident demand (RCPD) charges. Previously EDBs and industrial users faced a commercial incentive to deploy demand response during periods when the regional peak was nearing its maximum. With the removal of this incentive the possibility arose that EDBs and industrials would cease to deploy this demand response, leading to an increase in peak demand.

The issues paper makes no mention of the removal of RCPD. This had been the subject of an earlier standalone study which observed: [7]

> "We found evidence that some large industrials have changed their electricity consumption over peak periods—they previously decreased or shifted consumption in peak periods to reduce their RCPD charge—but did not appear to do this in 2022. We estimate that removing the RCPD charge increased daily peak consumption by around 150MW during the top 300 consumption periods in 2022. This is much larger than the

[6] Electricity Authority Potential solutions for peak electricity capacity issues Consultation paper 12 January 2024.
[7] Electricity Authority The impact of the RCPD charge removal on peak demand 9 Mar 2023.

> underlying growth in peak consumption, but relatively small in the context of the New Zealand electricity market."

This seems conspicuous by its absence from a discussion about whether scarcity (peak capacity less peak demand) has an impact on the supply of flexibility products. Whatever the expectations were and whatever the reduction in contribution to meeting peak demand, this regulatory measure has contributed to the pressure on the physical capacity and fuel scarcity problem during periods of peak demand.

1.1.3 Gas – what did we know and when did we know it?

In the middle of 2018, the Minister of Energy wrote to the GIC following a meeting with Andrew Knight the GIC Chief Executive. The Minister raised the issue of information disclosure requirements for market participants where information could have an impact on the downstream gas market:[8]

> "I am concerned, in light of the recent outage at Pohokura, the requirements may be insufficient and that if information is not required to be disclosed in a timely manner it may have a material impact on the wider market for gas."

The GIC replied:[9]

> "If we conclude that existing information disclosure is not sufficient we think part 4A of the Gas Act should be amended to clearly provide for the regulation making powers contemplated in your letter.
>
> Gas Industry Co intends to create an information disclosure workstream to progress this issue."

The resulting changes to information disclosure focused on unplanned outage or planned outage at a gas production facility or a gas storage facility for all gas and related market participants but not on the prospects for future production.[10]

The issue of the prospects for future gas production was, however, the subject of many presentations and papers from then through to the present day.

For example, GIC told the SRC in 2019:[11]

> 1. "Parallel to the work on the unplanned outage or planned outage disclosure process, upstream parties and Flex Gas (First Gas) are working together to develop a voluntary, industry-led disclosure regime for production and storage outage information. This information was identified as the largest information gap in the industry.
> 2. We set up an industry notifications webpage on our website and the industry is taking the opportunity to post notifications. As an example, notifications on reduced

---

[8] Hon Megan Woods letter to Andrew Knight Chief Executive Gas Industry Company 25 Jul 2018
[9] GIC Chief executive to Hon Dr Megan Woods Minister of Energy Resources
[10] Gas (Facilities Outage Information Disclosure) Rules 2022.
[11] GIC Andrew Knight - Chief Executive and Paul Cruse - Senior Adviser Update on Information Disclosure to the Security and Reliability Council 24 October 2019

production from the Kupe Production Station were posted by Beach Energy who have been regularly updating the industry on the status of the repairs.

3. GIC is working with the EA on thermal (gas and coal) fuels disclosure in the electricity sector.
4. GIC has held some initial discussions with MBIE around the frequency and availability of information on gas production forecasts and storage in Ahuroa."

In 2020, the GIC prepared a Briefing to the Incoming Minister. GIC told the Minister:[12]

> "Long term gas supply and demand scenarios commissioned by Gas Industry Company identify that natural gas supply conditions are likely to tighten over the next several years. New Zealand has around 2000 petajoules of reserves currently booked, however those reserves will only be available to meet demand requirements if industry invests in development of existing production.
>
> Gas Industry Company estimates that **industry will need to invest around $300-500 million every 3 to 5 years to produce existing reserves** and maintain production levels. Current gas and oil prices are at a level that incentivises the required investment. **Without ongoing investment in development, currently expected gas reserves will not be available for expected demand.**
>
> During the transition to 100% renewable electricity, some customers currently utilising gas for fuel will exit.
>
> After gas exits baseload generation, some gas will continue to be used to provide flexibility for renewable generation.
>
> Today, when renewables availability is insufficient to supply electricity demand, flexibility is provided by reducing gas demand from petrochemical manufacturers (and by releasing stored gas from the Ahuroa storage facility). Thus, gas used in peaking generation (when renewables availability is insufficient) is met mainly from demand side, not by 'turning on' extra gas supply.
>
> In a 100% renewable electricity system, gas can be available as the most cost-effective and efficient energy source to provide flexible security of supply in dry years. This is because gas can be brought to market quickly at a competitive lower cost than alternatives (such as renewables overbuild). For gas to provide that flexible energy security, new contracting arrangements are needed to ensure that gas is available when needed."

It was around this time that an early physical manifestation of constrained gas production and gas supply impacting on electricity generation emerged. The canary in the mine might have been a 20 December 2020 media release from Contact Energy to the stock exchange:[13]

> "OMV advises Contact of reduced gas supply estimate for 2021

[12] Gas Industry Company Briefing to Incoming Minister of Energy and Resources October 2020

[13] Contact Energy NZX Announcement OMV advises Contact of reduced gas supply estimate for 2021 02 December 2020

> Gas producer OMV New Zealand ('OMV') has revised down its estimates of the gas available to Contact Energy ('Contact') from the Maui and Pohokura fields in the 2021 calendar year by 3.7 petajoules (PJ) to 10.6 petajoules."

In isolation this might have been missed or treated as a one-off situation but we now know this was the beginning of gas producers recalibrating their supply arrangements to meet declining volumes.

The SRC Forward work programme in 2021 ranked reliability and resilience of the gas industry (with implications for electricity generation capacity and energy security) as its third highest risk, based on a June 2019 report from the gas industry.[14]

In 2021 many commentators including electricity generators Meridian, Contact and Mercury were warning the Authority that the government's interventions were damaging the gas market with severe implications for security of supply in electricity. That year the GIC reported on its Gas Market Settings investigation: [15]

> "We have assumed that natural gas will not be used as fuel for electricity generation beyond 2030 (which is a different approach than most modelled scenarios), but that it will be needed for some petrochemical, industrial, commercial, agricultural and residential use for longer.
>
> Despite the outlook showing there are sufficient reserves in the ground to meet New Zealand's gas demand, without ongoing **investment well in advance of when the gas is needed**, there is a real risk that not enough gas will be able to be delivered to major gas users, including electricity generators, during the transition out to 2030 and beyond."

At the SRC's meeting on 21 October 2021, an updated gas reliability and resilience paper was provided and presentations were made by the joint authors Enerlytica, The Gas Industry Co (GIC), OMV, Todd and First Gas.

Enerlytica observed:[16]

> **"No free lunch** –Capex of $2-3 bln required during the 2020s alone to maintain continuity. Policy direction since 2018 has made winning this capital from international investors now far more challenging. It is the retention of Methanex that will continue to underwrite the flow of this investment, with other users including powergen as beneficiaries."

The GIC observed:[17]

> "Without ongoing investment (well in advance of when the gas is needed), there is a real risk that not enough gas will be able to be delivered to major gas users, including electricity generators, during the transition out to 2030 and beyond."

On 8 May 2024, the day prior to Transpower requesting consumers reduce electricity demand, the Gas Industry Company released figures showing a 12.5 per cent reduction in gas production during 2023,

---

[14] Security and Reliability Council FORWARD WORK PROGRAMME Meeting Date: 25 February 2021

[15] Gas Industry Company Gas Market Settings Investigation - Report to the Minister of Energy & Resource 30 September 2021

[16] Security and Reliability Council Gas Reliability and Resilience meeting date 21 October 2021

[17] ibid

and a 27.8 per cent reduction in gas production in the first three months of this year beyond what was projected. The Gas Industry Company's advice to large gas consumers was to expect gas supplies to be constrained throughout the decade. Some industrial consumers may not be able to secure expected gas volume and prices are likely to be significantly higher.[18]

Following the events of winter 2024 Transpower reports: [19]

> "Peak capacity risks are ever-present and will persist until there is sufficient investment in flexible resources such as batteries, demand response and peaking generation.
>
> Growth in peak demand and increasing intermittent renewable generation makes balancing supply and demand more challenging and increases reliance on slow-start thermal generation to provide flexible resources into the market. Over 90% of the unconsented generation pipeline is made up of intermittent generation sources that will exacerbate this challenge. This highlights the need for investment in new flexible peaking capacity batteries, demand response and enabling market settings.
>
> To manage capacity risks and reduce their impact on consumers supply, a well-informed and coordinated industry response is needed to offer more resources into the market to balance supply and demand while maintaining system security."

1.1.4 Electrification and reducing fossil fuel contribution to security

During the period 2018 – 2023 the Minister pushed a commitment to achieve 100 per cent renewable electricity by 2030 but it never became policy. It was an aspirational goal in the Green party's 2017 coalition agreement and became a policy goal in the Labour Party's 2020 campaign but never became binding in the sense of a government policy statement or any equivalent mandate to the sector.

The 2017 coalition agreement between Labour Party and the Green Party[20] signalled the government would proceed to introduce a zero carbon 2050 Act and establish a Climate Change Commission (CCC). Both the interim and fully established CCC disputed the economic validity of the 100 per cent renewable goal – let alone its achievability by 2030 – but themselves proposed actions that would limit the uptake of natural gas.

Notwithstanding that, the Government remained resolute in its commitment to 100 per cent renewable electricity by 2030. The Minister's repeated references to this goal impaired investment signals for the gas market, and fossil fuel baseload and peaking capacity.

1.1.5 Onslow and the NZ Battery Project

The centrepiece of the commitment to 100 per cent renewable electricity was the NZ Battery Project, and the potential answer it provided to the main criticism of 100 per cent renewable electricity: the

[18] GIC reference Quarterly Update: April 2024
[19] Transpower Security of Supply Review - Winter 2024 November 2024
[20] New Zealand Labour Party & Green Party of Aotearoa New Zealand Confidence and Supply agreement (See here) October 2017

dry year problem. The NZ Battery project was announced following a discussion about the potential for a pumped hydro storage scheme contributing to a low carbon electricity system in the ICCC report:

> "The NZ Battery Project was established in late 2020 to find innovative solutions to the 'dry year problem,' when hydro-electricity lakes run low, leading to the burning of more fossil fuels to cover the electricity shortfall."

One key project considered was pumped hydro storage scheme at Lake Onslow in Central Otago. While the governance and operational models of the lake Onslow Scheme were never confirmed the widespread assumption—confirmed in later documents released—was that it would be allowed to act in market including providing peaking capacity.

The prospect that the Government would support the entry of a 1,200MW peaker into the electricity market can only have further undermined the signal for private sector investment in peaking capacity, especially as the government maintained its position that Onslow could be in place by 2030. Only when the business case for Onslow was released in 2023 did it become apparent that construction completion would not be completed prior to 2037.

In December 2023 the incoming government axed the $16 billion pumped hydro scheme at Lake Onslow, removing a significant uncertainty.

1.1.6 Tiwai exit uncertainty

As the Authority writes, the uncertainty around whether the smelter would close has not been helpful. It was especially unhelpful that Rio Tinto made the announcement to close the smelter in 2020, then in 2021 announced it would keep the to the end of 2024.

On 31 May 2024 Meridian Energy and New Zealand Aluminium Smelters (NZAS) announced they, along with Contract and Mercury, had agreed a long-term fixed price power contract until 2044. The new agreement contained provisions for the smelter to cut power usage at times when there was peak demand but insufficient supply in the country.[21]

If the smelter had closed there would have been a 12 per cent reduction in energy demand in every period of the year. The pressure on peak capacity would have eased. The uncertainty associated with whether the smelter would close therefore would have had a very large impact on confidence to invest. The news that it will stay open for 20 years adds to the pressure on energy supply and peak capacity, noting the presence of the demand response agreements.

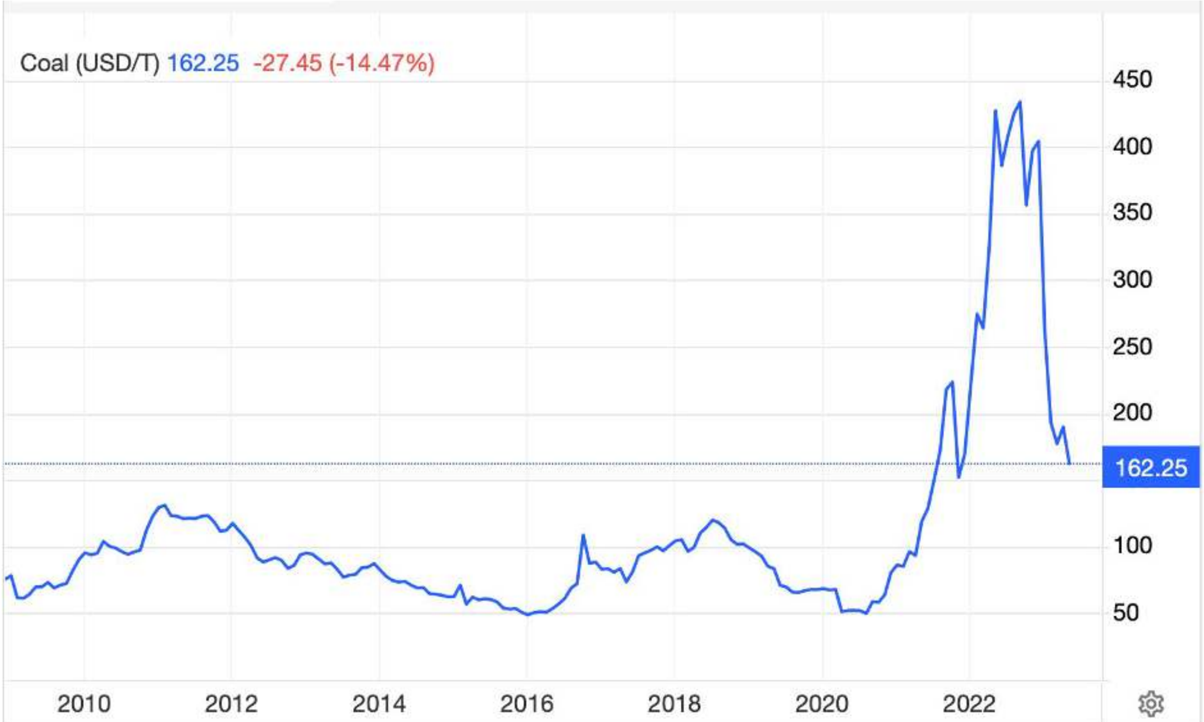
1.1.7 Ukraine and international fuel prices

As cited by the Authority, Russia's invasion of the Ukraine has significant impacts on global fuel prices. The direct effect on New Zealand was through the price of Indonesian coal, ordered by Genesis. Figure 4 shows the significant escalation in coal prices 2022/23. The increased price of coal had a direct effect on Huntly's SRMC, and a very plausible impact on water values (which contain signals

[21] RNZ "Tiwai Point aluminium smelter to stay open until 2044" See here 31 May 2024

about the expected market price in the event that Huntly is required to firm hydro). Further, in the early months of the war, it added significant uncertainty in futures markets about the future price of electricity, as traders weighted different scenarios relating to the need for coal. There was no credible information globally about how long the war would last, and what the medium-term impact on coal price would be. Studies are beginning to emerge in the academic literature about the far-reaching impact of the war on distant wholesale electricity spot and futures contracts, with many generalising these to include demand, supply and policy uncertainty (see e.g., Kaur et al, (2024)[22]).

Figure 4: International price of coal, 2010 – 2023, USD



1.1.8 Lithium prices – high prices delayed BESS investments

The COVID-19 pandemic caused significant disruptions to global supply chains for lithium-ion batteries, leading to increased prices and constrained supply worldwide. In 2020, China was the largest manufacturer of lithium-ion batteries and accounted for 73 per cent of annual production.[23] China's central role in battery manufacturing and distribution caused global repercussions when the country faced national shutdowns during the initial months of the pandemic, as quarantine measures caused production lead times to more than double for most goods. These challenges were exacerbated by labour shortages and border restrictions, which impacted distribution networks and intensified supply shortages. Lithium prices increased by 830 per cent in the Chinese spot market from December 2020

[22] Kaur, C., Siddiki, J., & Singh, P. (2024). The asymmetric impact of input prices, the Russia-Ukraine war and domestic policy changes on wholesale electricity prices in India: A quantile autoregressive distributed lag analysis. *Energy Economics*, *132*, 107428. https://doi.org/10.1016/j.eneco.2024.107428

[23] Dyatkin, B., & Meng, Y. S. (2020). COVID-19 disrupts battery materials and manufacture supply chains, but outlook remains strong. MRS bulletin, 45(9), 700–702. https://doi.org/10.1557/mrs.2020.239

to April 2022, ultimately slumping growth for renewable energy technologies and delaying investment in many global economies.[24]

While lithium-ion battery prices have been volatile in recent years, prices have trended downwards since the pandemic. International evidence shows that lithium spot prices declined more than 80 per cent from December 2022 to January 2024.[25] As a critical component in battery production, the decline in lithium prices has increased investment in battery energy storage systems (BESS). The International Energy Agency reported that battery storage was the fastest growing technology in 2023, with global deployment more than doubling from the previous year.

These trends impacted investment in New Zealand. As outlined earlier, within the last two years, a number of gentailers have announced investments in grid-scale batteries. These will be commissioned over the next two to three years. However, as technology-takers, we expect the dynamics in lithium and battery markets have impacted the pace at which these gentailers have been able to bring these investments to the electricity market,

[24] Sun, X., Ouyang, M., & Hao, H. (2022). Surging lithium price will not impede the electric vehicle boom. *Joule*, *6*(8), 1738-1742.

[25] Bradley (2024). Lithium Prices in Free Fall: Implications for Clean Energy Transition in the Private Sector. https://www.bradley.com/insights/publications/2024/02/lithium-prices-in-free-fall-implications-for-clean-energy-transition-in-the-private-sector

2. Is pricing of OTC super peak contracts as expected in a competitive market?

2.1 How to price a peak or super peak product

The approach the Authority has taken to pricing peak products is theoretical, but even so they haven't been able to estimate values for the premia of peak prices over baseload electricity futures. This section steps through the process of pricing a peak or super peak product. It is a generic description but reflects the reality facing traders. The perspective taken is that of a gentailer, as these are the participants who have priced super-peak products assessed by the Authority.

Each portfolio will have a unique combination of fuel sources for its electricity generation and each of those comes with its unique variability.

Each gentailer will have a book of physical (e.g., retail demand) and financial contracts that, once balanced with its ability to generate, creates a net 'exposure' to the wholesale market. That book will be made up of some retail load, some commercial load and some industrial load and, in each case, there will be a mix of terms and conditions priced to reflect the risk taken by either seller or buyer. Notably, some contracts such as residential contracts will be a fixed price for a variable volume of offtake so the volume risk remains with the seller, and some will be financial products such as contracts for differences (CFDs) where the volume risk is taken by the buyer.

Looking forward (e.g., over the period of a flexibility contract being priced), each of these components are uncertain; hence, the degree of financial exposure to the spot market is uncertain. Like any market participant, a gentailer must manage this risk in order to remain within the organisation's risk appetite. Gentailers have very large capital exposures which must be managed prudently.

When a buyer such as an independent retailer seeks a peak or super peak product, a gentailer who offers product has to account for:

- its ability to generate at peak times to meet contractual obligations
- the risk that fuel or capacity is not available in a future winter peak when the product is in force
- its ability to secure the electricity futures volume required to cover its risk using baseload electricity futures
- future shape risk between the hours the contract is effective and the cover from the electricity futures contract
- the exposure for off peak cover acquired using baseload futures as a hedge for the peak of super peak contract
- the opportunity cost of adding baseload electricity futures for this purpose and not for the balance of the book
- location risk
- any additional margin required to adequately account for the cumulative risk.

These factors reinforce that pricing hedge contracts is fundamentally a forward-looking analysis, and hence involves the pricing of risk.

2.1.1 Premia

It is well established in the economic literature that risk manifests in price by way of risk premia.

The Authority writes:

> "Offer prices for super-peak contracts could be consistent with a lack of competition, or simply reflect scarcity. Reasons for this uncertainty include:
>
> (a) There have been some accepted prices that were substantially higher than ASX prices (plus shape premium). This could be because the contract was competitively priced, or because the buyer had no other viable alternative.
>
> (b) Our risk premia are based on historical data, but these should ideally be forward-looking. There is also uncertainty around how risk premia will change in the future.
>
> (c) We have been unable to estimate other premia (e.g., premia for scarcity, volatility, and illiquidity) that could have a big impact on super-peak contract prices (and are likely increasing)".

The issues paper quotes the Australian Energy Market Commission's (AEMC) description of risk premia. However, this description focuses on the premia one might pay for a baseload contract over forecast spot prices. It doesn't address the premia of peak and super peak products over a base load contract.

The issues paper focuses on the relativity of peak and super peak prices to base load hedges and in each case (except location premium) it notes it can't quantify an estimate of the premia that the Authority might expect:

> "Shape premium
>
> Since there is more uncertainty about how shape factors will change in a more renewable world, there is more risk associated with selling shaped contracts for the future. This means these shape premia could be even higher.
>
> Illiquidity premium
>
> We note however that our estimated competitive OTC prices will therefore likely be underestimated.
>
> Spot price volatility premium
>
> Again, due to the complexities involved, we have not attempted to estimate this premium, and therefore our estimate of competitive contract prices is a lower bound.
>
> Scarcity premium
>
> But it must be considered when comparing our estimated competitive contract prices to actual OTC prices that a lot of the time (especially due to current scarcity in the market) we will be underestimating contract prices.
>
> ASX volatility premium

> We did not attempt to add this premium to our estimated competitive contract prices due to the uncertainty involved in the calculation and in keeping with not adding other premia."

Having stated there is no evidence to say flexibility product prices are anything other than competitive the Authority says it can't estimate the premium but then wants to test if quantifying the premia would reveal whether the prices are competitive or not.

2.1.2 Impact of scarcity on contract prices

Above we have established that a wide range of factors have increased the risk associated with:

- A flexibility seller estimating their own wholesale exposure over the period of a potential flexibility contract, due to the combined concerns about the availability of hydro, gas and – at times – coal;
- A potential investor in firm capacity estimating the profitability of such an investment, in the context of gas uncertainty, demand uncertainty and policy uncertainty.

Scarcity of financial flex products is a function of physical scarcity in the sense of capacity and limits or uncertainty around fuel especially when the system is tight. Here, we are surprised that in 2023 the Authority concluded that:

> "The Authority is not aware of any reason to expect a shortfall in the ability to provide such contracts. This is because projections by Transpower and others indicate there should be sufficient generation physically available to meet energy and capacity standards for the next few years. This suggests that there should be the physical base to support the sale of contracts to meet likely demand. We also know that contracting can occur (and has occurred) using exchange-traded products, or on a bilateral basis….While the Authority does not have sufficient information to form a definitive view, it notes there is a long history of participants entering into backup contracts underpinned by thermal generation."[26]

As outlined earlier, by this time, concerns about the availability of gas supply were well known and the analysis conducted by Whiteboard Energy (see above) would have reported the gap that had emerged between peak demand and firm capacity. At that point, the Authority's proposed response was to make improvements to the electricity contract disclosure system.[27]

Throughout their "Price discovery in a renewables-based electricity system" project over 2021-2023, the Market Development Advisory Group (MDAG) routinely stressed the importance of contract markets in transmitting investment signals (underpinning capital investment and associated fuel contracts) through contracts. Their 2022 Options paper reported:

> "Effective risk management and efficient investment are heavily dependent on the contract market. Contracts are a key tool that wholesale buyers and sellers can use to manage their exposure to spot price risks. Forward contract prices also provide vital

[26] Electricity Authority (2023) "Ensuring an Orderly Thermal Transition: Consultation Paper", 13 June 2023, para 4.37, 4.39.
[27] Ibid, para 4.38.

> signals about where and when to invest, and about the best type of resource to develop."[28]

MDAG's proposed option in 2022 was:

> "We propose that the Authority work with market participants to co-design a standardised product (or products) which meets the needs of buyers and sellers (including providers of DSF) (Option B5). If trading of such products develops in the over-the-counter market, Option B1 would provide the **necessary transparency of the forward price of flexibility**. Alternatively, the outcome of this design process may be to list these products on a futures exchange."[29]

To MDAG's point, the only transparent forward curve today is the ASX; and the only product that is liquidly traded on the ASX is a baseload contract. A baseload contract hedges the average price level (over a season or a year); as argued above, the economics of peak supply bear little relation to the average price level – it is peak prices that matter. This is the fundamental reason MDAG argued strongly for a standardised flexibility contract – to provide price discovery of the upper part of the PDC.

We are encouraged that this process has just, at the time of writing,[30] resulted in a super-peak product being chosen by the Authority as the standardised flexibility product MDAG recommended in 2022.

However, over the period which the Authority has analysed super-peak prices (Q4 2022 to Q2 2024), no such standardised contract or transparent discovery of the price of flexibility was in place, and – at least for the first half of that period – all of the attendant uncertainties described in Section 2.1.1 were manifesting. While the change of government in Q4 2023 removed the prospect of Lake Onslow, gas concerns only intensified., and the risk of Tiwai existing remained until the end of May 2024. Drawing on Kaur et al[31], the consequences of energy policy uncertainty, Onslow, gas availability, coal pricing and Tiwai risk would have been imputed into the availability and pricing of the few peak and super peak products that were being traded bilaterally.

Ideally, a potential investor in peak capacity should have been able to underpin an investment in peak capacity through the supply of peak and super peak contracts. However, there are two issues:

- Bilaterial contract markets are 'dark', in the sense that only the counterparties to deals (traded or not traded) discover prices. Hence these prices were undiscoverable to the broader set of investors who may have been able to invest in firm peak capacity

---

[28] MDAG (2022), Price discovery in a renewables-based electricity system: Options paper, para 3.28
[29] Ibid para 3.38
[30] https://www.ea.govt.nz/news/general-news/energy-competition-task-force-announces-new-standardised-super-peak-hedge-contract-trading-begins-in-january/
[31] Kaur, C., Siddiki, J., & Singh, P. (2024). The asymmetric impact of input prices, the Russia-Ukraine war and domestic policy changes on wholesale electricity prices in India: A quantile autoregressive distributed lag analysis. *Energy Economics*, *132*, 107428. https://doi.org/10.1016/j.eneco.2024.107428

- Even if peak and super peak prices were transparently 'high', the challenge for an investor wanting to respond to this signal was the demand, supply and policy uncertainty over the medium term.

It comes as a surprise that the Authority reports the evidence on prices for flexibility products shows they are competitive but may elect to pursue a "plausible driver" that prices or availability may somehow not be consistent with a competitive market.

The Authority expresses concern that "offer prices for super-peak contracts could be consistent with a lack of competition, or simply reflect scarcity."[32] The Authority considers a premium would be payable for scarcity in a competitive market but is unable to estimate that premium.[33]

One of the basic themes of economics is that resources available to decision-makers are always limited. With limited resources, a decision to have more of something is simultaneously a decision to have less of something else. Hence, the opportunity cost of any decision is the foregone value of the next best alternative that is not chosen.

In a well-functioning market, the observed market price of a service will likely be closely tied to its opportunity cost. A provider of a service is unlikely to maintain the service if it does not receive at least what it would earn utilising the resource in its next best alternative. Prices would need to rise to at least match those obtainable in the next best alternative to maintain the service, including attracting new investment if the service is to be provided over time. If the provider attempts to raise prices above opportunity cost, it would risk losing market share to providers willing to provide the service for less (that is, at a price that reflects their opportunity cost) or suffer falling demand if the price exceeds consumers opportunity cost.

A payment over and above opportunity cost is called in economics a 'rent'. A 'scarcity rent' is said to occur when the supply of a (fixed) product is limited in relation to demand. If all units of a (fixed) product are homogeneous—the textbook example is land—and demand exceeds supply, all units of the product will earn an economic rent.

In a competitive market with low entry costs (an important assumption), scarcity rents will on average equal the cost of new capacity over time. However, the efficient level of scarcity rents in the short-term is not observable and is measurable only in hindsight; that is, if the present value of relevant prices turn out to equal the LRMC of new capacity of over the observation period.

These economic concepts highlight two difficulties in the Authority's musing:

- It has not attempted to estimate whether the revenue earned by a supplier of super-peak capacity would exceed the LRMC of new entrant *firm* capacity—if the revenue earnt by an existing supplier is less than that required by a new entrant, the supplier cannot be said to have exercised market power in a manner adverse to the long-term benefit to consumers.
- The tightening of firm capacity relative to peak demand clearly evident in the market in recent years suggests barriers to investment either due to regulatory uncertainty (e.g., Onslow) and

[32] Electricity Authority, (2024), *Reviewing risk management options for electricity retailers – issues paper*, para 2.7
[33] ibid, footnote 6.

market uncertainty (e.g., Tiwai) or *under-pricing* of peak capacity or some combination of both. There are indicators that regulatory and market uncertainty has reduced, but whether market prices provide a sufficient signal for firm capacity remains unclear.

2.2 What should the Authority do?

In summary, it is our view that the challenges of determining the quantum of market power in a small sample of super peak contract pricing during a period of significant scarcity risks a mis-diagnosis. This, in turn, may lead to a regulatory intervention which is disproportionate to the problem. Pursuing forward price transparency and liquidity for flexibility products is a better use of resources; achieving these objectives means continued close attention to investment incentives.

We recognise that this will be cold comfort to flexibility purchasers (e.g., independent retailers) who are feeling the brunt of high super-peak prices. Our analysis above suggests that some of the risks associated with firm capacity investment have passed, and investment is coming to market in forms of demand response and battery storage that could plausibly back the standardised super peak contract.

This investment is a prerequisite for the availability and efficient pricing of peak-related contract is the availability of flexibility capacity (including demand reduction). Any peak-related contractual obligations that cannot be met physically ultimately result in the supplier being exposed to wholesale market prices for any shortfall.

As recommended by MDAG[34], there may be a role for market-making at a future date following the release of the standardised flexibility contract. MDAG reinforced that the Authority should not move straight to market making, referring to this as a 'backstop measure for use if required'. While MDAG didn't propose specific metrics, we recommend that the Authority should make it clear to the market how long it would allow for liquidity to grow, and on what basis it would judge that trading and price discovery of flexibility was insufficient, if the expected workings of a competitive market had not succeeded.

Any move to market making, should it be necessary, would require consideration of the likely costs of market making, and a range of other design features. Absent sufficient investment in flexible capacity, regulatory interventions such as market making can risk unintended consequences. If the underlying problem is scarcity of peak supply (as has been the case), an entity subject to market making could be at risk of being caught with a trade that cannot be backed by physical generation and the inability to purchase cover. Unless carefully designed, the result could exacerbate regulatory risk in the market and discourage new entrant investors (who would reasonably be concerned they would be subject to the same intervention), the opposite of what was intended from the intervention.

Appendix A Summary of historical System Operator security assessments

- SOSA 2018 - Reduced generation availability in conjunction with the Low Carbon and Electrification scenario will mean the North Island WCM may fall below the North Island WCM security of supply standard in 2020, and a significant amount of new generation options would need to be developed from 2023 as currently known options would be insufficient from this point. With only currently known generation options, the margin may fall below zero in 2026.
- SOSA 2019 - The North Island WCM is forecast to remain above or within the security standard until 2022, with existing and committed generation in the base-case scenario.

  Under the medium demand scenario New Zealand will need to commission around 150 GWh of new winter generation by 2024. In all three scenarios new generation will need to be consistently added in the mid to late 2020s, up to 1,700 GWh of winter generation in 2028 in the medium scenario.
- SOSA 2020 - In all four scenarios, investment in new generation will be required by 2025 to 2026 in order to maintain North Island Winter Capacity Margins at an efficient level of reliability (that is, where the expected cost of supply shortages is equal to the expected cost of new generation).

  For the medium demand and High demand scenarios new generation is required earlier to maintain North Island Winter Capacity Margins in part due to the type of generation projects that are currently being actively progressed. Over half of this capacity is wind generation, which contributes a relatively smaller amount to North Island Winter Capacity Margins than to the Winter Energy Margins.
- SOSA 2021 - On the evening of 9 August 2021 record high peak demand and unexpected supply shortages lead to demand curtailment. Our North Island winter capacity margin analysis assumes all thermal generation is able to contribute its full capacity and that peak demand is assessed as the average of the top 200 half hourly demand winter peaks. In contrast, on 9 August market conditions were such that not all thermal generation was available and peak demand was well above the average of the top 200 half hourly demand winter peaks.

About Sapere

Sapere is one of the largest expert consulting firms in Australasia, and a leader in the provision of independent economic, forensic accounting and public policy services. We provide independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

'Sapere' comes from Latin (to be wise) and the phrase 'sapere aude' (dare to be wise). The phrase is associated with German philosopher Immanuel Kant, who promoted the use of reason as a tool of thought; an approach that underpins all Sapere's practice groups.

For more information, please contact:

Toby Stevenson

Mobile: 021 666 822

Email: tstevenson@thinkSapere.com

Wellington	Auckland	Sydney	Melbourne	Canberra	Perth	Brisbane
Level 9 1 Willeston Street PO Box 587 Wellington 6140	Level 20 151 Queen Street PO Box 2475 Shortland Street Auckland 1140	Level 18 135 King Street Sydney NSW 2000	Level 11 80 Collins Street – The Tower Melbourne VIC 3000	GPO Box 252 Canberra City ACT 2601	PO Box 1210 Booragoon WA 6954	Level 18 324 Queen Street Brisbane QLD 4000
+64 4 915 7590	+64 9 909 5810	+61 2 9234 0200	+61 3 9005 1454	+61 2 6100 6363	+61 8 6186 1410	+61 7 2113 4080

www.thinkSapere.com

independence, integrity and objectivity