Economic Review of the Electricity Authority's Analysis of Spot Prices

A report for Meridian

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Project Team

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1. Introduction

The Information Paper concludes the high spot prices are at least partly due to fuel supply scarcity and high fuel costs.

This report has been prepared by Axiom Economics (Axiom) on behalf of Meridian Energy (Meridian). Its subject is the Electricity Authority's (Authority's) review of 'whether electricity spot prices were determined in a competitive environment for the period from January 2019 until Q2 2021.' The Authority decided to undertake this review in response to the sustained high spot prices that have been observed since the outage at the Pohokura gas field in 2018.

The Authority's Information Paper[1] contains various analyses, including a linear regression of spot prices pre- and post-2018. This analysis indicates that the price increases observed over the period are at least partly attributable to fuel supply scarcity and higher fuel costs. However, the Authority also suggests there has been a sustained upward shift in spot prices that the regression cannot explain. The model could not reveal whether this shift was attributable to (amongst other things):

- limitations in the model itself;[2]
- uncertainty about the gas market influencing bids and prices; and/or
- generators exercising substantial market power.

Various other tests are then performed to look for any signs of the exercise of market power.

The Authority consequently performed a series of other tests to see whether it was able to shed more light on the reasons for the perceived uplift and, in particular, whether it could find any indications of the exercise of market power. Several of these analyses involved comparing generators' offers – and resulting spot prices – with various estimates of short run marginal cost (SRMC). We have been asked to review the robustness of those analyses and, where appropriate, to suggest alternative approaches for assessing the state of competition.

1.1 Key findings

The 'short-term' analyses of the 'price-cost' relationship do not provide any reliable insight into the state of competition.

Our key findings are as follows. First, the Authority's 'short-term' analyses of the relationships between prices and costs are incapable of providing any reliable insights into the state of competition in the New Zealand Wholesale Market (NZWM). Specifically:

- even in the very best of circumstances it is difficult to compare prices with short run costs because, when understood properly, SRMC includes both:
  - the operating and maintenance costs incurred in serving an additional unit of demand; and
  - the *opportunity costs* of *managing* demand when supply is limited (these costs are considerably more challenging to measure, in practice);

1 Electricity Authority, *Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market, Since the Pohokura Outage in 2018*, October 2021 (available: here; hereafter: 'Information Paper').

2 It is nearly impossible for any regression to perfectly capture all relevant variables, in practice.

- those challenges are multiplied manyfold in the NZWM, where the SRMC of generating is influenced by, amongst other things:
  - current lake storage levels (e.g., whether a storage lake is nearly full or nearly empty) and gas availability; and
  - forecast hydrological conditions (which will affect *future* storage levels and also the need to spill) and projected gas supplies; and
- these complexities make it impossible to produce objective estimates of SRMC against which to compare prices and, perhaps unsurprisingly:
  - the analyses of short-term 'price-cost' relationships are problematic in numerous respects, e.g., the SRMC benchmarks are unreliable; and
  - those assessments are consequently incapable of revealing whether generators have been exercising substantial market power.

More insights into the state of competition can be obtained by asking: are prices above long-run entry costs and, if so, why?

Second, in our opinion, more insights into the overall state of competition in the NZWM can be obtained by asking: are prices above long-run entry costs and, if so, *why*? The 'why' is important here because prices *have* been significantly above the *long run marginal cost* (LRMC) of adding new capacity in the NZWM and may remain so for some time yet. However, there appear to be good reasons for this 'gap'. Several factors have diminished incentives to invest in new generation, despite the high spot prices. These include uncertainties surrounding:

- the future of the Tiwai Point aluminium smelter (which accounts for ~13% of total annual demand), i.e., if this large customer had left (which it has threatened to do on multiple occasions) this would lead to near-term spot price *reductions* and a potentially tumultuous adjustment period; and
- government climate change policies, including the future of the natural gas sector, i.e., a prospective investor in, say, a new gas plant would be understandably concerned about obtaining access to a reliable supply of gas at a reasonable price, and the potential for that investment to be stranded.

Several factors have reduced incentives to invest in new generation, but the investment environment is improving.

Much of that uncertainty has now diminished – but in some cases, only relatively recently. For example, the smelter's immediate future has been secured and more clarity is emerging about the government's climate change policies. There has been an enormous recent increase in connection requests, surging development interest in solar farms and around $2 billion of investments either planned or under construction. This should all serve to realign prices with entry costs.

The 'investment deficit' will take time to eliminate but, when it is, prices should realign with entry costs.

However, this adjustment process may not be swift. It will take time for the 'investment deficit' that has built up during the recent period of extreme uncertainty to be erased. Obtaining resource consents, constructing plants and connecting to the grid all take time – such projects are multi-year endeavours. Even so, it would arguably be unnecessary and undesirable to intervene in a market that seems well on the way to addressing the divergence between prices and LRMC.

1.2 Structure of this report

We elaborate on our key findings in the remainder of this report, which is structured as follows:

- **section two** explains the often-misconstrued concept of marginal cost, which is of central relevance to the efficiency of pricing and the identification of substantial market power. It also sets out some key implications for comparisons between 'costs' and 'prices';
- **section three** explores the application of those economic concepts to electricity wholesale generation markets such as the NZWM. We then explain why it is difficult to undertake robust comparisons between prices and SRMC, due to the practical challenges associated with estimating the latter;
- **section four** examines a series of short-term analyses the Authority performed to see if it could find any signs that generators have been exercising substantial market power. Several of these assessments involved comparing generators' offers – and resulting spot prices – with estimates of SRMC; and
- **section five** provides a broader, longer-term assessment comparing spot prices with the long-run cost of adding new capacity. We conclude that there *is* a significant gap between prices and LRMC, but we then identify several potential reasons for this and explain why that gap could well disappear over time.

For the avoidance of doubt, the opinions expressed throughout this report are our own and do not necessarily reflect the views of Meridian.

2. Marginal cost and competition

In competitive markets, there is symbiosis between prices and marginal costs. Many of the *short-term* analyses contained in the Information Paper involve exploring that relationship. However, to be valid, such assessments require properly constructed estimates of marginal cost. These are not easy to produce. Marginal cost is simple enough to define; it is the additional cost that a firm incurs by increasing output by a specified increment. But from there, things quickly get more complicated.

Marginal cost can be estimated in either short run or long run terms.[3] When measuring *short run* marginal cost (SRMC), it is crucial to capture any *opportunity costs* associated with *managing scarcity.* However, these additional costs are very difficult to measure, in practice. This complexity makes it tricky to produce robust estimates of SRMC and diminishes the usefulness of short-run price-cost tests. We explain these challenges and explore some of the implications below.

2.1 Short run marginal cost (SRMC)

SRMC is the cost of meeting an incremental change in demand, holding capacity constant.

In the short run, at least one 'factor of production' is fixed, i.e., a hotel cannot instantaneously add rooms if too many customers want them on any particular day. This means a firm cannot increase the quantity of a product it is supplying by expanding. The only way it can increase supply is to use its existing capacity, i.e., to produce more with what it has already. Short run marginal cost (SRMC) can therefore be thought of as the cost of meeting an incremental change in demand, *holding capacity constant.*

When supply is plentiful, SRMC is equal to the operating and maintenance costs incurred producing additional units.

This is often construed simply as the extra operating and maintenance costs associated with producing more. At times, that is correct, *but not always*. When additional demand can be met by increased supply from existing capacity, SRMC *will* be equal to the operating and maintenance costs associated with producing the additional units. However, at other times, SRMC can be *well above* that level. It is this element of SRMC that is sometimes *not* as well understood.

When supply is scarce, SRMC rises to whatever level is needed to 'choke off' any excess demand.

A crucial but often overlooked element of SRMC is that, if supply *cannot expand* to meet the additional demand (e.g., once a hotel is full, it is full), SRMC rises to whatever level is necessary to 'choke off' any excess demand. In situations where there is an increased risk of shortages, the costs associated with this demand-side component can cause SRMC to rise *significantly above* variable costs. Importantly, it is during these periods of scarcity that firms can recoup some of their *fixed costs* that do not vary with output over the short-term (and are therefore not part of SRMC).

In competitive markets, there is no 'cap' on how high prices can rise during these periods of scarcity and, by extension, on the contribution that can be made to fixed costs during these windows. Professor Alfred Kahn supplied a useful example of this phenomenon. He postulated a scenario in which a bridge is contemplating

[3] The difference being the timeframe under consideration and the extent to which firms can adjust their production processes.

charging a toll on motorists. The incremental operating, maintenance and capital costs caused by each additional vehicle on the bridge were practically zero but, as he observed:[4]

> *'[W]hat if charging a zero toll would, at certain hours of the day, produce such an increase in traffic that cars lined up for miles at the bridge entrance and a crossing took an hour instead of a few minutes? In that event, the SRMC of bridge crossings, at those times,* ***is not zero****. It can be envisaged in terms of congestion: the cost of every bridge crossing at the peak hour is the cost of the delays it imposes on all other crossers. Or it can be defined in terms of opportunity cost: if A uses the bridge at that time, he is taking up space that someone else could use; therefore, the cost of serving him is the value of the space or capacity to others who would use it if he did not.'*

In times of scarcity, the cost of serving one customer must, by definition, include the value foregone by others who might miss out.

In other words, in times of scarcity, the cost of serving one customer must, by definition, include the value foregone by *other customers who consequently cannot be served.* For example, if a city's water supply began to run low, continuing to supply some customers might mean placing restrictions on the usage of others. The costs imposed by those restrictions may be very high and might include costs such as plant losses in residential gardens and parks, reductions in agricultural output, diminished quality of golf courses and higher production costs for breweries. All those costs form a part of the SRMC of serving one customer in circumstances where that implies restricting supply to others.

Although SRMC can be estimated at any particular point in time, it can fluctuate - quite dramatically - from one point to another. Its application to future decisions depends as much on *probability and expectation* as on fact. A forward-looking SRMC is the sum of the various extra costs arising under different scenarios (holding capacity constant), multiplied by the estimated probabilities of those things actually happening. Formally, the expected SRMC is given by:

SRMC depends as much on probability and expectation as on fact.

- the SRMC when supply exceeds demand (i.e., when it is equal only to the operating and maintenance costs of meeting that increment), multiplied by the probability that supply exceeds demand; *plus*
- the SRMC when supplies are less than demand (i.e., operating and maintenance costs *plus* the costs arising from shortages) multiplied by the probability that supply will be less than demand.

By way of simple illustration, suppose that:

- there is a **90%** probability that there will be enough existing capacity to meet an additional unit of demand at time *t* -- **(1)**;
- the short run operating and maintenance cost of supplying that additional unit of demand in that scenario would be **$100** -- **(2)**;
- there is also a **10%** probability that there *will not* be enough existing capacity to meet an additional unit of demand at time *t* -- **(3)**; and
- the opportunity cost to a customer who was unable to buy the product (due to scarcity) at time *t* would be **$1,000** -- **(4)**.

[4] Kahn, A, (1988), *The Economics of Regulation, Principles and Institutions, Volume 1* (MIT Press), p.87.

The SRMC of supplying an additional unit at time *t* would therefore be:

SRMC = [**(1)** x **(2)**] + [**(3)** x (**(2)** + **(4)**)]
= [90% x $100] + [10% x ($100 + $1,000)]
= **$200**

In other words, in this simple example, the $200 SRMC at time *t* is *double* the $100 of operating and maintenance costs incurred producing the unit in question. This simply reflects the non-zero probability of scarcity emerging and the substantial potential *opportunity costs* that scenario would entail. Therefore, in this example, when SRMC is understood properly:

Market prices that signal the opportunity costs of potential scarcity are 'cost-reflective', not 'above cost'.

- a market price of $200 would not involve *above cost pricing*; rather
- the $200 price is *cost reflective*, i.e., it reflects both operating and maintenance costs *and* the *opportunity cost* of managing scarcity.

To summarise, SRMC can be defined as the cost of an incremental change in demand, holding capacity constant. Importantly, its estimation takes account of the potential costs of shortages faced by customers. If supply cannot expand to match demand, SRMC rises to whatever price level is necessary to curtail demand to match available supply.

2.2 Long run marginal cost (LRMC)

In the long run, all factors of production are variable and so incremental changes in demand no longer need to be met from current capacity alone. Firms instead have the option of *expanding capacity* to meet additional demand and, equally, of reducing their capacity if patronage tapers off. LRMC can therefore be thought of as the cost of supplying a specified, permanent increment in demand, allowing for future augmentations in supply, i.e., additional capacity.

LRMC is the cost of supplying a permanent increment in demand, allowing for new supply, i.e., additional capacity.

In most industries it is not practicable to add capacity in very small increments.[5] Rather, there are often 'economies of scale' associated with augmentations. For example, once a business has purchased land it may make sense to construct a multi-level office building, even if not all that space will be used right away. This is because adding the extra levels at that time is likely to be cheaper than building them later. Taking this one step further, it is probably even more expensive (in unit cost terms) to add capacity 'room-by-room'.

In other words, in 'real world' markets, capacity is often added in 'lumps' rather than very small increments. The likely effect of a permanent increment in demand is therefore to *bring forward* the time at which a planned future 'lump' of capacity needs to be added – by firms that are already in the market and/or by new entrants. LRMC is therefore the costs – both operating and capital costs – associated with

5 The exception is industries in which assets are highly mobile and capacity can be added in very small increments. In these circumstances, any level of demand can be met by quickly adding (or subtracting) capacity, i.e., there is never any need to curtail demand. Of course, such industries are seldom seen in practice.

undertaking that expansion *sooner than would otherwise be the case* in response to the incremental change in demand, and the associated congestion costs.[6]

This means that when capacity has to be added in 'lumpy units', this gives rise to *time-dependent fluctuations* in LRMC. Specifically, the LRMC of supply will be relatively low when capacity utilisation is low (and the next expansion is some distance in the future). But it will start to rise as utilisation increases and the timing of the next expansion approaches:

Because capacity is often added in 'lumpy units' this gives rise to time dependent fluctuations in LRMC.

- in the period immediately following an expansion, the LRMC of the next increment to capacity is low because the value of any potential deferral of that future investment is relatively low due to discounting (i.e., a dollar spent today is 'worth more' than a dollar spent ten years from now); and
- as spare capacity declines over time and the need to invest in new capacity draws closer the LRMC of the next increment to capacity increases, because the value created through any potential deferral is closer in time and so less (negatively) affected by discounting.[7]

In summary, LRMC reflects the cost of serving an incremental change in demand in a market, assuming all factors of production can be varied. Importantly, because LRMC is a long run concept, it accounts for the fact that firms have the option of *expanding their capacity* in order to meet an incremental increase in demand. Measuring LRMC involves estimating the costs involved with undertaking a capacity expansion *sooner than would otherwise be the case* in response to that change in demand.

2.3 Relationship between SRMC and LRMC

We have seen that SRMC is the cost of an incremental change in demand, *holding capacity constant*, whereas LRMC reflects the cost of meeting that change in demand *assuming capacity can vary*. In competitive markets, unless assets are highly mobile, and capacity can be added in very small increments – conditions that are seldom seen[8] – there is *no reason* to expect SRMC and LRMC to be the same at any particular

[6] To be clear, LRMC does *not* equal the total operating and capital costs associated with that expansion. This is because an incremental increase in demand does not generally result in investment that would otherwise never be required; rather it usually serves to *bring forward the timing* of an expansion. LRMC is the additional cost incurred by *bringing forward the timing* of that expansion (that would otherwise have taken place later).

[7] In other words, LRMC changes over time as new capacity is added. This is because the cost today of, say, bringing forward by one year a $1m investment that would otherwise have taken place in 12 months' time is much greater than the cost today of that same one-year rescheduling applied to a $1m investment expected to be made in 10 years' time, because of the time value of money. Put another way, the value today of deferring by one year a $1m investment expected to be made in 12 months' time is much greater than the value today of that same one-year deferral applied to a $1m investment expected to be made in 10 years' time.

[8] When these conditions are present, there is no distinction between SRMC and LRMC since, by definition, there is no difference between the short run and the long run. Any level of demand can be met by quickly adding (or subtracting) capacity and so the need to curtail demand never arises. In these circumstances, SRMC and LRMC are always equivalent, and constant at all times. Of course, industries exhibiting these characteristics are almost never observed in practice.

point in time. However, there is still a strong 'in principle' link between SRMC, LRMC and capacity expansion decisions over time.

SRMC and LRMC can be different at a particular point in time but, in competitive markets, there is a symbiosis between them over time.

If demand is growing, or subject to short term fluctuations, SRMC will start to increase. In the first instance, that growth can be met only through increased risk of congestion or via demand curtailment, because the existing capacity is fixed. However, as time passes, there will eventually be a 'tipping point' at which the expected SRMC of *curtailing demand* increases beyond the expected LRMC cost of *expanding capacity* to meet it. It is at that point, when LRMC is *less* than SRMC, that new investment *should* ideally occur.[9] Box 2.1 provides a simple example.

Box 2.1: Relationship between SRMC, LRMC and new investment

Imagine there is only one hotel in a small town, but the market is competitive, i.e., there is nothing stopping other hoteliers from entering. In the short run, the number of hotel rooms in the location is fixed. This means the most efficient way for the hotel to deal with excess demand during peak periods over the short term is to increase its room prices.[10] This is because:

In competitive markets, prices cannot exceed SRMC or LRMC for a prolonged period without prompting new investment.

- it is not possible to construct a new hotel or expand the existing building in the near-term, e.g., to find a site, obtain planning approvals, arrange financing, undertake construction, and so on; and
- those investment decisions would not be based solely on one period of high prices in any case – rather, the expected return over a longer time horizon is what is relevant for entry/expansion decisions.

However, if demand kept growing to the point where the hotel was constantly increasing its room prices to curtail demand (i.e., to 'manage congestion') then it may be more efficient to build more, i.e., to expand supply. When competition is effective, this tipping point occurs when the forward looking SRMC of curtailing demand increases beyond the forward looking LRMC of expanding capacity to meet it – either via new firms entering, or existing suppliers expanding.

This means that, in competitive markets, it should not be possible for prices to substantially exceed the forward-looking expected *SRMC of using existing capacity* and the *LRMC of adding new capacity* (which, as we have just seen, are equal on average in the long run) for a prolonged period. If a firm tries to charge prices higher than this level, it should lose market share – either to new providers entering, or existing competitors expanding. This promotes simultaneously:

[9] The same principles apply to a market in which demand is declining over time. In the first instance, declining demand can be met by firms continuing to supply the market with their existing capacity. However, there will again be a 'tipping point' at which the long run costs that would be avoided by reducing or redeploying capacity exceed the SRMC of continuing to supply the product at the current level of capacity. At that point, capacity should be redeployed to other markets where returns are more attractive.

[10] Similarly, if the hotel experienced a temporary period of low prices due to reduced demand it is hardly likely to respond in the near term by reducing the number of rooms or by exiting the market altogether.

- the efficient use of existing capacity, i.e., customers will only use an additional unit of capacity if the benefits they derive exceed the costs of providing it (the scope for over- or under-consumption is reduced); and
- the efficient investment in additional capacity, i.e., investments should occur when demand has grown to levels where the expected costs of managing congestion (SRMC) exceed the costs of expanding supply (LRMC).

In 'real world' markets there can be periods of disequilibrium where SRMC and LRMC are misaligned, but these should 'correct' in time.

In 'real world' markets, it is difficult to time capacity expansions and reductions to coincide perfectly with the emergence of inefficient levels of demand curtailment, i.e., when scarcity is either too common or too infrequent. This is particularly the case when capacity must be added and withdrawn in large increments that alter substantially the supply/demand balance. Even in the best of circumstances there may therefore be times when:

- forward-looking SRMC is *above* LRMC for a period as the market waits for new capacity to come on-stream; and
- forward-looking SRMC is *below* LRMC for a period as the market waits for redundant capacity to be redeployed elsewhere.

Misalignments between SRMC and LRMC can be prolonged by various factors, e.g., uncertainty over government policy.

These periods of misalignment can be prolonged – potentially by years – by various factors. For example, suppose speculation is rife that new government policy might be introduced that would threaten the financial viability of a particular productive activity. In those circumstances, investors might understandably be reticent to invest until more certainty emerged regarding that policy – even if prices (i.e., SRMCs) exceeded the cost of entry (i.e., LRMC) in the meantime. After all, it is long-term future cashflows that drive investment decisions, not just immediate returns.

Such instances of 'disequilibrium' are neither unexpected, given the imperfections that can affect real markets, nor a cause for concern, *provided they are transitory*. Even accounting for such periods there is no reason to expect SRMC to differ materially from LRMC in competitive markets, on average, provided they are properly defined and assessed over a sufficiently long timeframe. Equally, although both SRMC and LRMC can fluctuate over time, there is no reason to think that either will diverge materially over the long term.

2.4 Implications for comparisons of prices and costs

The preceding discussion has implications for the extent to which comparisons between prices and marginal costs can be used to draw inferences about the state of competition in a market. For the reasons set out above, when estimating SRMC it is crucial to capture any *opportunity costs* associated with *managing scarcity*. However, these additional costs are very difficult to measure. This can diminish the usefulness of *short-run* price-cost tests. More insight into the state of competition in a market can often be obtained by performing *longer run* assessments, i.e., that compare prices with estimates of *LRMC*. We elaborate below.

2.4.1 Short run comparisons

In competitive markets, prices should reflect SRMC. However, we have also seen that, when measured properly, SRMC includes the opportunity costs of *managing scarcity*. This makes it difficult to compare prices with SRMC in practice. The efficacy of such comparisons hinges crucially on (amongst other things) ensuring SRMC estimates incorporate all the relevant opportunity costs of managing scarcity. This is not easy to accomplish. Such analyses should therefore be undertaken sparingly and their results must be interpreted with caution.

This can be illustrated using a straightforward example. Suppose that to supply 'widgets' a producer must make an upfront investment of $100 and that, from then on, it costs $1 to manufacture each unit. Should we be concerned about the state of competition if, say, the market price was observed to be $2 per widget at a particular point in time? Or, put another way, should we be concerned about a price that exceeds short run production costs? The answer is: not necessarily.

It is difficult to compare prices with SRMC, since the validity of such exercises hinges on capturing all relevant opportunity costs.

If supply at that point of time happened to be *plentiful*, the SRMC for that particular firm of producing each widget would be $1, i.e., equal to its short run production costs – labour, materials and so on. And, if the market is competitive and the firm happens to be the 'marginal supplier' (i.e., the business that supplies the last units that 'clear' the market and therefore determines the market price), then we might expect the price of widgets to also be $1 (or near to it). However, in other circumstances, there are good reasons for the price to be *higher* than $1.

First, if the firm in question is *not* the marginal supplier in the market, then *its* short run production costs are irrelevant. If *more expensive* producers are instead needed to meet total market demand, then it is *their* costs that will determine the market-clearing price. If the 'marginal supplier's' short run production costs happen to be $2 per widget, then *that* should be the market price and all firms with *lower costs* ('inframarginal' producers) will then earn positive economic profits.

Second, as we explained earlier, if supply at the pertinent point in time was *scarce*, then *all* producers – marginal or otherwise – would earn positive returns. During those times of potential shortages, the SRMC of producing widgets would rise to whatever level was necessary *to curtail demand to match supply*. Specifically, the price would increase *above $1* until it reached a level at which balance (or 'equilibrium') was restored. During these times of scarcity:

- even the 'marginal' widget supplier could make a contribution to its fixed costs;
- all 'infra-marginal' widget suppliers (i.e., firms with operating costs below $1 per unit) would make *even greater* contributions to their fixed costs; and
- those higher prices would also provide a potential impetus for entry and expansion, i.e., if there was perceived to be profitable opportunities on offer.

Care must therefore be taken when drawing inferences about the state of competition in any market from comparisons of prices and short run cost estimates. Unless SRMC benchmarks incorporate appropriate values for the *demand-side costs of managing scarcity*, they will *underestimate* the prices that would prevail under workable competition. And because it is so difficult to accurately gauge those externality costs[11] this frequently diminishes the usefulness of such comparisons.

2.4.2 Long run comparisons

It is often useful to assess the state of competition in a market by making *longer-term* comparisons. Returning to our 'widget' market, suppose the LRMC of supplying widgets via new entry (or expanding existing capacity) was $2. Should we be concerned about the state of competition if the average market price over a significant period was $3 per widget? Again, the answer is: not necessarily. In real world markets, entry and exit take time and market frictions may abound.

There are *always* factors that impose costs on entry and exit decisions in competitive markets. Because new capacity cannot be added in infinitely small units, prices that depart from SRMC or LRMC will not prompt an immediate supply side response. Such reactions are simply infeasible. Put simply, things take time. Entry and exit decisions are also unlikely to be made simply because prices appear to be temporarily misaligned with underlying supply costs.

It is often useful to assess the state of competition in a market through longer-term comparisons.

For instance, suppose a prospective new entrant into the 'widget' market (or an existing participant considering expansion) saw high prices leading up to the Christmas period (when, for the sake of argument, demand for widgets is at its peak). That firm would not respond by quickly constructing a new production line to take advantage of those high prices. There are two simple reasons for this:[12]

- it would probably not be possible to construct a facility in that timeframe, e.g., to find a site, obtain planning approvals, arrange financing, undertake construction, etc; and
- that investment decision would not be based solely on one period of high prices – rather, the expected returns over a much longer time horizon would be the most germane consideration.

For these reasons, it is unremarkable to observe prices in competitive markets that are separated from LRMC. Various 'real world' frictions mean prices (and SRMCs) can be above the level at which new entry and/or expansion should *theoretically* be profitable (in this example, above $2 per unit), without swiftly prompting a supply side response. There are consequently many potential price outcomes in such markets that are consistent with workable competition *at a particular point in time*.

However, as we have seen, that does not mean there is *no* relationship between the prices that are observed and the underlying costs of production over the long term. Specifically, once firms are able to respond to changes in demand- and supply-side factors by adjusting their capacities, one would not expect to see prices that are

11 This requires the analyst to estimate - in quantitative terms – how much congestion/scarcity is affecting various customers, which is very challenging (and often highly subjective).

12 Equally, existing hotels are not going to respond by adding more rooms.

significantly and persistently *above the LRMC of adding capacity* for a *prolonged period*, i.e., allowing for those 'real world' frictions.

If average prices exceed the LRMC of adding capacity (e.g., because prices frequently increase to reflect the increased risk of congestion, or the need for demand curtailment) then, over the long term, we should see firms expanding and/or new entrants emerging to 'chase' the resulting profits. If that does not happen (e.g., if prices remain above LRMC for prolonged periods), this is a potential indicator of a lack of effective competition (and, on the flip side, of the existence and exercise of substantial market power).

Take our widget market as an example. Suppose entry typically takes a year, at most. If average prices remained at $3 per widget, on average (compared with the $2 per widget LRMC) for, say, *two* years then this gives rise to legitimate questions about the state of competition. In particular, it *might* indicate that incumbent 'widget makers' are insulated from effective competition by significant barriers to entry and expansion (as opposed to, say, minor differences in product attributes).

Before deciding to intervene in a market one should first consider whether a situation is likely to be perpetuating or self-correcting.

However, before any market intervention was contemplated it would first be necessary to consider whether the current market outcomes are likely to be perpetuating or self-correcting. For example, if widget making was characterised by strong economies of scale and scope and insuperable first-mover advantages, then incumbent suppliers may have enduring market power that is unlikely to wane over time. In those circumstances, some form of regulatory redress may be appropriate.

Conversely, if investors have been deferring any capital expansions until they have clarity on government policy likely to impact the economics of the sector, then the current prices may be temporary. Namely, once investors have more certainty, entry and expansion could occur to drive prices back down to levels commensurate with LRMC. Intervention in those circumstances might therefore be unnecessary and could give rise to unintended adverse consequences.

2.5 Summary

Marginal cost is the added cost of producing a specified increment in output. The fundamental difference between SRMC and LRMC is the timeframe under consideration and the implications of this for a firm's ability to adjust its production process. Specifically, SRMC is the cost of an incremental change in demand, *holding capacity constant*. LRMC relaxes this constraint and reflects the cost of an incremental change in demand assuming *everything* can be varied.

An important distinguishing feature of SRMC is that, in the event that current capacity may not be sufficient to meet all demand, SRMC rises to whatever level is necessary to curtail demand to match available supply over the relevant timeframe. It therefore takes account of the costs of shortages faced by customers. It is consequently unremarkable to see *prices rising above the short run production costs* of 'marginal suppliers' in competitive markets. This is quite normal.

The estimation of LRMC accounts for the fact that, in the long run, firms have the option of expanding their capacity in order to meet increased demand. Measuring LRMC therefore involves calculating the costs associated with undertaking a capacity expansion sooner than would otherwise be the case in response to a change in demand. Both SRMC and LRMC can fluctuate over time and there is no *a priori* reason to expect them to be equivalent at any particular moment.

However, there is a strong 'in principle' link between SRMC and LRMC over the long term. Specifically, when demand is growing over time, or subject to short term fluctuations, SRMC can be expected to increase to the point at which the cost of curtailing demand exceeds the cost of expanding capacity to *meet* that demand (i.e., when LRMC < SRMC). At that 'tipping point', one should expect to see new investment taking place by firms 'chasing' the profits on offer.

Of course, market imperfections mean that the timing of capacity expansions will not always be perfect, e.g., SRMC may rise above LRMC for a period if the optimal expansion is particularly lumpy. Entry and expansion take time and be hindered by countless 'real world' frictions. Investment can also be 'chilled' by various external factors, such as uncertainties surrounding government policies and/or the design and application of regulations. All this can lead to periods of 'disequilibrium'.

Nonetheless, provided things are measured over a sufficiently long timeframe, the link between SRMC, LRMC and new investment decisions should mean that, on average, there is no material difference between the value of SRMC and LRMC. This has important implications for the design and application of any price/cost tests intended to assess the state of competition in a market. Comparisons between prices and *SRMC* tend to be fraught, because:

- unless SRMC benchmarks incorporate appropriate values for the demand-side costs of managing scarcity, they will *underestimate* the prices that would prevail under workable competition; and
- in practice, it can be very difficult to accurately gauge these opportunity costs, which often leaves such analyses susceptible to errors (e.g., 'false positives'), diminishing their usefulness.

Longer-term comparisons of prices to *LRMC* are often more instructive. Once firms are able to adjust their capacities, one would not expect to see prices that are significantly and persistently *above the LRMC of adding capacity* for a *prolonged period*, i.e., allowing for those 'real world' frictions. If such a margin has persisted, this may indicate incumbent suppliers are insulated from effective competition by significant barriers to entry and expansion, i.e., it could suggest the existence and exercise of substantial market power.

However, before any intervention was countenanced, it would first be necessary to examine whether the observed market outcome was likely to continue unabated, or to self-correct. For example, if investors had been putting off capital expansions until clarity was obtained on government policy that would impact suppliers' profitability, then current prices may only be temporary. Intervention in such circumstances might be needless and potentially harmful.

3. Application to electricity generation markets

This section discusses the application of the economic principles described hitherto to 'energy only' wholesale electricity generation markets, such as the arrangements that exist in New Zealand. It begins by describing some of the distinguishing characteristics of such markets, and of the NZWM in particular. We then set out some of the key implications for assessing competition and testing for the misuse of substantial market power.

3.1 Characteristics of electricity generation

The electricity sector is characterised by a homogeneous, non-storable commodity-type product that has few (if any) close substitutes. These attributes deprive consumers of some of the usual means for adjusting to variations in price and supply, e.g., storing the product,[13] switching to alternatives and so on. Suppliers are also characterised by significant variation between the costs of the different generation technologies available:

The costs of available generation technologies vary significantly.

- base load plants (such as hydro, coal, solar and wind), have relatively low operating costs, but this intrinsic, short run cost advantage is offset by relatively high capital (fixed) costs (i.e., the cost per unit of potential output) and, often, a reduced ability to vary output in the short term (i.e., 'stopping' and 'starting' certain types of such plants is not straightforward);
- mid-merit plants, typically in the form of combined cycle gas turbines (CCGT) have higher running costs, but mid-range capital (fixed) costs; and
- peaking plants, typically in the form of open cycle gas turbines (OCGT) have relatively low capital costs, a high degree of short-term controllability (i.e., 'stopping' and 'starting' such plants is easy) but relatively high running costs.

The way that prices are set is also a distinguishing characteristic. In most workably competitive markets, prices do not continually change – primarily because of the associated transaction costs[14] and customers' general aversion to volatile, unpredictable prices.[15] The NZWM is an exception. Prices in the NZWM are highly dynamic and are set in a way that reflects the fact that:

- demand for electricity is highly variable and must be met at (almost) all times, i.e., it is highly undesirable for the 'lights to go out';

13 There are some limited exceptions. For example, battery technology is beginning to become more economic – although very few households have them. Moreover, hydroelectricity is sometimes considered to be a storable form of electricity – although this almost always done by generators, rather than final consumers.

14 Updating prices for stockkeeping unit codes (SKUs) in computer systems and 're-stickering' inventory takes time and resources.

15 For example, customers at McDonalds would be unlikely to react favourably if the price of Big Macs fluctuated significantly from day-to-day.

- output must change very rapidly, and by large amounts within the course of a day in order to meet that variable demand; and
- a suite of technologies is required to meet that variability efficiently, i.e., typically a combination of baseload, mid-merit and peaking plant.

Prices in the NZWM are highly dynamic and can change every five minutes.

Scheduled generators in the NEM are required to submit 'offer prices' for their capacity for every 5-minutes of the day. From all offers submitted, the system operator, Transpower, determines through a centralised process the generators that will be called upon to produce electricity based on the principle of meeting demand in the most cost-effective way, i.e., generators are dispatched in 'merit order' (from cheapest to most expensive). Prices are set as follows:

- a 'dispatch price' is determined every five minutes, based on the offer lodged by the most expensive generator that must be dispatched in order to meet prevailing demand in that period – the 'marginal generator'; and
- six dispatch prices are averaged every 30-minutes to determine the 'spot price' for each trading interval for each of the ~285 pricing 'nodes' throughout the NZWM, i.e., nodal spot prices are determined 48 times per day.

Because the NZWM is an 'energy only' market, the only way a generator can be paid for investing in plant is by being dispatched and producing electricity. It cannot be paid for having plant that is not being used, even if the existence of that capacity offers 'security of supply' benefits. This sets the NZWM apart from other wholesale market arrangements that *do* include payments to generators for simply offering capacity, such as the Western Australian market.

3.2 Competition in generation

The unusual features of the NZWM give rise to highly variable SRMCs.

The unusual features of the NZWM give rise to highly variable SRMCs. The market design is directed towards promoting competition between generators that produces prices that *reflect* those variable SRMCs. Specifically, the expectation is that most of the time generation plant should be 'dispatched' according to its economic merit order, as given by the ascending SRMC of running each type of plant (as determined by the respective operating and maintenance costs – the cost of managing scarcity is discussed subsequently).

Although generators in the NZWM are permitted to offer capacity at any price (subject to a 'scarcity pricing' mechanism[16]), the existence of competing offers by alternative plant owners normally constrains the prices that generators can bid. For example, a base load plant that bids capacity substantially above its operating and maintenance costs risks not being dispatched and being forced to incur the expense of shutting down and restarting. It will be foregoing the opportunity to earn positive economic profits in the meantime.

16 If the weighted average spot price exceeds NZ$20,000/MWh, then prices are adjusted down so that the weighted average price is equal to $20,000/MWh.

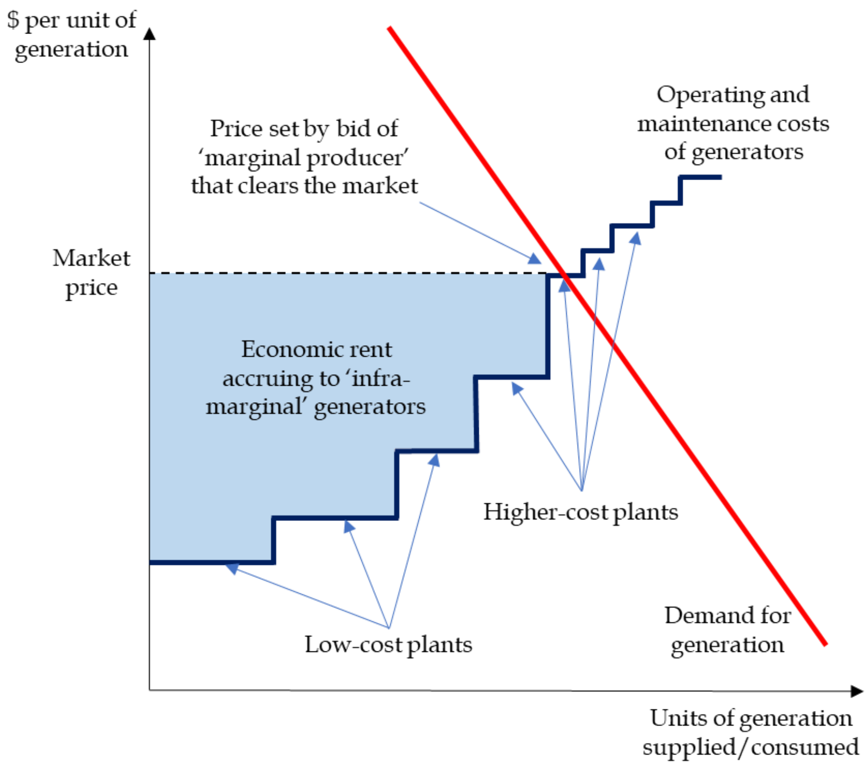
For this reason, provided there is ample generation capacity available to meet demand over the relevant time horizon (this is strong assumption that we will relax shortly when we explore the crucial issue of managing scarcity in the NZWM):

- generators have an incentive to offer to supply the market at prices that reflects their short run operating and maintenance costs; and
- if they do, plants will be scheduled to run in line with their economic 'merit order', i.e., from least-to-most expensive (in terms of $/MWh).

Figure 3.1 illustrates that, even when a generator offers its capacity at a price sufficient to cover only its operating and maintenance cost, the price it *receives* is equal to the offer of the last generator dispatched to meet demand (the 'marginal generator'). This means generators with lower running costs (base load and mid-merit plant that is 'infra-marginal') make a profit from the market price, allowing them to make a contribution to their fixed costs. But how does the *marginal generator* cover its investment costs? The answer is no different from that in any other competitive market.

Competition between generators should drive spot prices towards SRMC.

Figure 3.1: Economic merit order



When there is a possibility that the existing generation capacity will *not* be able to meet demand over the relevant timeframe, prices in the market *must rise* to reflect the increased SRMC of curtailing that excess demand. In situations where there is a risk of shortages, the costs associated with this demand side component can cause prices to rise *well above* the operating and maintenance costs of the marginal generator. It is during these periods that *marginal* generators are able to make a contribution to their fixed costs. We explore this crucial matter of prudently managing scarcity below.

3.2.1 Managing near-term scarcity

When there is enough capacity to meet demand over the relevant timeframe, prices should reflect the operating and maintenance costs of marginal plant.

Just as in any other competitive market, when there is expected to be sufficient capacity to meet demand over the relevant time horizon, prices in the NZWM should reflect operating and maintenance costs. More specifically, the price at each node should reflect the short run operating and maintenance costs of the marginal generator needed to meet demand at those locations. But equally, when there is a possibility that the existing generation capacity will be *insufficient* to meet demand over the relevant period, prices will rise *above* this level.

For the sake of illustration, imagine that generators only needed to supply one location *for a single time period* '*t*' (i.e., there is no need to worry about the future beyond this single point). How would one go about calculating SRMC – and therefore the expected spot price – in this time period? The approach is no different to in any other competitive market. Namely, the expected spot price can be estimated by undertaking a probabilistic assessment of possible future outcomes and the respective costs they entail. The formula is the same as previously; namely:

When there is a possibility that the existing generation capacity will be insufficient to meet demand over the relevant period, prices will rise.

- the SRMC of the marginal generator when supply exceeds demand over the relevant timeframe (i.e., operating and maintenance costs for that *single* period), multiplied by the probability of that scenario occurring; *plus*
- the SRMC of the marginal generator *plus* the SRMC of curtailing excess demand when supply is less than demand during that single period, multiplied by the probability of that scenario eventuating.

In electricity generation markets, the cost of curtailing demand to manage scarcity is termed the 'value of lost load' (VoLL). This reflects the amount customers would be willing to pay to avoid a disruption to their electricity service, i.e., it is the opportunity cost to them of being 'switched off'. For large industrial users (e.g., an aluminium smelter) that amount may be very high. VoLL estimates vary based on many factors – including the type of customer, plus the time and duration of outages.[17] To keep things simple, suppose VoLL is $10,000/MWh. The expected spot price at time *t* can therefore be expressed as follows:[18]

Expected spot price = [(1-LOLP) x OMC] x [LOLP x VoLL]

Where:

LOLP = Loss of load probability

OMC = Operating and maintenance cost of the marginal generator

VoLL = Value of lost load (assumed for simplicity to be $10,000/MWh)

By way of simple illustration, suppose that:

- there is a **98%** probability that there will be enough existing generation capacity to meet an additional unit of demand at time *t* -- **(1)**;

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17 For a comprehensive discussion of VoLL estimation issues, *see:* PwC, *Estimating the Value of Lost Load in New Zealand*, March 2018 (available: here).

18 Hunt & Shuttleworth (1996), *Competition and Choice in Electricity*, Wiley, p.173.

- the short run operating and maintenance cost of the marginal generator in that scenario would be **$10/MWh** -- **(2)**;
- there a 2% probability that there *will not* be enough existing capacity to meet an additional unit of demand at time *t* -- **(3)**; and
- the opportunity cost to customers who consequently miss out (due to scarcity) at time *t* would be **$10,000/MWh** (the assumed VoLL) -- **(4)**.

The costs of managing scarcity can have a strong influence on SRMC and, in turn, spot prices.

With these simplifying assumptions, the expected spot price at time *t* would be: (98% x $10/MWh) + (2% x $10,000/MWh) = **$209.50/MWh**. What this example illustrates is the strong influence the costs of managing scarcity can have on SRMC and, in turn, expected spot prices. Even though the probability of a shortage emerging at time *t* is only small (2%), the potential *opportunity costs* that would arise in that scenario are vast. The probability-weighted effect of those 'scarcity' costs is consequently the primary driver of the spot price in this simple example.[19]

Importantly, this example assumes that generators only need to supply in a single period – *t*. And we have seen that, even in this highly simplified world, estimating SRMC is challenging. It depends as much on probability and expectation as on fact – often more so. Of course, in reality, generators do *not* focus only on the current trading period when making supply decisions. They also need to consider the potential implications of *today's* decisions on *tomorrow's* decisions. This complicates matters significantly, as we explain below.

3.2.2 Longer-term intertemporal considerations

Using water or gas to generate now means it cannot be used to generate later. This gives rise to distinct opportunity costs.

Some generation technologies are 'non-depleting'. For instance, using the sun's rays or the wind to produce electricity today does not affect the probability of being able to generate using those same fuel sources tomorrow. However, that is not the case for hydro or gas-fired plants – at least not in today's NZWM. By definition, using water to generate *now* means that same water cannot be used to generate electricity *later*. This is also the case for natural gas (and coal). There are therefore distinct opportunity costs associated with managing those resources through time.

3.2.2.1 Prudent water storage management

Currently, more than half of New Zealand's electricity is generated from hydro-electric plants.[20] As noted above, water is *not* an infinitely renewable resource,[21]

19 More generally, when the probability of shortage is effectively zero, spot prices can be expected to resemble the operating and maintenance costs of the marginal generator. As the probability of a shortage begins to increase (which will happen if demand is approaching the 'outer limits' of the supply curve), spot prices will start to increase and begin approaching VoLL.In the extreme scenario in which a shortage is certain (i.e., if the LOLP=1), the expected spot price *is* VoLL and, under the conditions described above, a price of $10,000/MWh should transpire for the period *t.*

20 The percentages vary year-on-year but, on average, ~60% of total generation is hydro-powered, and nearly all the amount produced in the South Island – where many of New Zealand's hydro lakes are located.

21 As an aside, one frequently hears the claim that it is 'much cheaper' to generate electricity with hydro plants than, say, thermal plants because 'water is free'. This is a fallacy. It is true that hydro

The opportunity cost of using water to generate now rather than saving it for later is an important component of the current SRMC.

since using more now may mean there is less available later (unlike with, say, sunlight and wind). Therefore, one of the short-run costs of using water to generate *now* is the foregone opportunity to generate with it at *another* time. This constitutes an important component of the total *current* SRMC of generating.

The value of this lost opportunity at any given moment – and the extent to which it contributes to the prevailing SRMC – will depend upon a variety of things. For example, it will be influenced by:

- current storage levels, e.g., whether a storage lake is nearly full or nearly empty;
- forecast hydrological conditions which will affect *future* storage levels and also the need to spill, e.g., whether river inflows will be high or low; and
- expected future electricity prices which will, of course, depend upon the same conditions throughout the rest of the country's hydro schemes.

The opportunity cost of water can vary greatly across catchment systems, plants and time.

Hydro generators – especially those without their own thermal firming/back-up plants – will naturally be keenly aware of the potential impacts their offer behaviour *today* may have on *future* storage levels. For example, we understand that at any point in time, there is only a few months' worth of 'supply' stored in Meridian's South Island storage lakes. In other words, if Lake Pukaki is 'full' today and all rain and snowmelt ceased, it would be nearly empty in a matter of months.

A storage lake that is full at one point could be empty in a matter of months without prudent storage management.

This means that even if a storage lake is 'fullish' in, say, September (spring), using all available water to generate then could mean there is a non-zero probability of running out in February (summer). This introduces an *inter-temporal* element into the offer calculus described earlier. Generators – and hydro-generators in particular – are interested not only in the probability of shortages emerging in the *near-term*, but also over the *longer-term*. Put simply, they can be expected:

- to consider the effect that using water to generate *today* may have on the probability of scarcity emerging in the *future*, e.g., of storage running low; and
- to therefore factor the potential costs that would arise from any potential future scarcity (i.e., opportunity costs to customers) into their offers *today.*

These intertemporal effects have a direct impact upon SRMC and expected spot price. If using water to generate *now* increases the probability of shortages emerging *later* (in, say, three-months' time), this *increases* the current SRMC of hydro generation. A hydro generator that incorporates those potential future costs into its offers today – and consequently receives a price above its 'operating and

generators do not have to 'do anything' to make it rain or to make snow melt. But thermal generators also do not have to 'do anything' to make coal and gas exist in underground deposits. We are all used to thinking of gas and coal as having a market value and therefore being 'costly'. Transactions involving water are seen less frequently, which perhaps contributes to the mistaken impression that its use should be free, or near to it. However, this intuition is misleading. There is no economic basis for concluding that water-based generation is less costly than coal or gas-based generation. All these types of generators have to 'do something' to make best use of their fuel resources. As this section explains, there is no economic reason to believe that reservoir management (e.g., deciding whether to use water now or later) is necessarily a lower cost activity than managing gas/coal resources (e.g., deciding whether to burn gas/coal now or later), once all relevant costs (including, most importantly, *opportunity costs*) are considered.

maintenance costs' – is therefore acting *prudently*. Complicating matters further still, different generators may manage those risks in a variety of ways, for example:[22]

Different generators may manage those water storage risks in a variety of ways via their bidding strategies.

- some generators might elect to increase their offer prices for every tranche of capacity offered, i.e., elevate their bids 'across the board';
- others might choose to price a certain percentage of their offers at significantly higher levels, i.e., offer some capacity (a 'baseload' quantity) at a 'lowish' price and a smaller quantity at a much higher price; and
- some might choose simply to physically withhold a portion of their capacity, i.e., to not offer it to the market at all and 'save it for later'.[23]

All these 'scarcity management' strategies have the potential to result in prices that exceed the generators' operating and maintenance costs (i.e., if the plant turns out to be marginal). However, this is not necessarily 'above-cost pricing' (i.e., spot prices in excess of SRMC). Rather, those prices could instead reflect the endogenously determined *opportunity cost of water*. These complex inter-temporal factors make it very difficult to pin down precise SRMC values for hydro plants.

To complicate matters even more, different generators may have contrasting *expectations* about future supply risks, (i.e., these are not 'facts' – there is an unavoidable element of subjectivity). Hydrological conditions, the nature of drought and the intensity of spill *all vary* across the different catchment systems. Generators' approaches to *managing* those perceived risks may also be coloured by a plethora of other factors, including the combination of generation technologies comprising their respective profiles. For example:

Different generators may also have contrasting expectations about future supply risks and varying approaches to managing them.

- hydro generators with discretionary thermal generation (e.g., Genesis and Contact) may have a greater appetite for risk, safe in the knowledge they can rely on those assets as 'back-up' if water levels run low; whereas
- Meridian does not own any thermal 'firming' plants that it can fall back on if its southern storage lakes start to run dry, which may diminish considerably its willingness to needlessly elevate longer-term supply risks.

There is also an important relationship between lake storage levels – and, in turn, the opportunity cost of water – and the availability and flexibility of *gas supplies*. If gas becomes scarcer, or there is less flexibility surrounding its availability, then hydro generators may understandably factor this into their *own* offers. If less gas generation is available then, all other things being equal, hydro generators will be dispatched more regularly and deplete their water supplies more quickly. We explore gas market conditions below.

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22 To be clear, this is a non-exhaustive list of potential approaches.

23 However, as we explain in section 4.3.2, the Electricity Code sets out a number of explicit criteria for a generator to follow when it finds itself in a 'pivotal supplier' situation, i.e., where its capacity (or at least some of it) is needed to meet demand in a location. To stay within the 'high standard of trading conduct' safe harbours (and therefore avoid any possibility of a subsequent regulatory intervention), a generator must – among other things – offer all of its available capacity to the market. In other words, a generator that adopted this strategy when pivotal – i.e., physically withheld some capacity in reserve – would, technically, not be within the trading safe harbours.

3.2.2.2 Tightening gas market conditions

There has been a tightening of gas supplies as well as reduced flexibility around delivery.

If gas-fired generators were able to access all the natural gas they could ever possibly need in order to run (at reasonable prices), they would not need to worry about managing their fuel-stock. But, like water, gas is in limited supply. And those supplies have declined significantly in recent years. The prolonged outage at the Pohokura field in 2018 exposed the relatively fragile nature of New Zealand's gas supplies and the potential ramifications for spot prices.

The deterioration of output from the Pohokura gas field was not anticipated so early in the field's life cycle and has resulted in a marked tightening of supplies and reduced flexibility around delivery. All available gas is contracted and users – including some generators – have been forced to accept a reduction in their contracted quantities. There are strong indications that gas supplies will continue to tighten and may eventually cease altogether. For example:

- the government's 2018 decision to ban all new off-shore oil and gas exploration permits has placed a cap on new domestic off-shore gas supplies;
- the Maui field is diminishing rapidly and, as noted above, supply from the Pohokura field has proved to be less reliable than expected;[24] and
- the Climate Change Commission has recommended eliminating natural gas use in residential, commercial and public buildings[25] – which could also foreshadow the end of its use as a generation fuel stock.[26]

Decisions about what prices to bid today must be made with a clear eye on the potential implications for future supply.

Gas-fired generators therefore face a broadly analogous decision to that confronting hydro generators. Namely, thermal generators have access to a finite amount of fuel (in this case, gas) and they know that any of it they use now will not be available later – including potentially in the colder winter months when demand is highest. And so, just as with hydro plants, decisions about what prices to bid today must be made with a clear eye on the potential implications for future supply. If burning gas now increases the probability of shortages emerging later, then:

- this again increases the *current* SRMC of gas-fired generation, i.e., the SRMC is equal to the operating and maintenance costs *plus* the opportunity costs associated with any increased probability of future scarcity; and
- those (potentially steep) opportunity costs should, ideally, be factored into their bids (and potentially current spot prices, i.e., if gas-plants are 'marginal') to enable more efficient consumption decisions.

Furthermore, as foreshadowed above, one might also expect to see *hydro* generators factoring projected gas market conditions into *their own bids* in some fashion. In the

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24 For more detail on the long-term gas supply outlook, *see for example:* Concept Consulting Group Ltd, *Long term gas supply and demand scenarios – 2019 update*, 16 September 2019 (available: here).

25 Climate Change Commission, *Ināia tonu nei: a low emissions future for Aotearoa Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025*, 31 May 2021 (available: here).

26 Any ban on natural gas use in residential, commercial and public buildings would reduce local demand for natural gas, which could result in a significant reduction in domestic production, potentially reducing the availability of the fuel to generators.

NZWM, less thermal generation generally means more hydro generation and, in turn, a heightened probability of water shortages (and vice versa). Consequently, hydro generators can be expected to take these interdependencies into consideration when formulating their bids. There are many ways they might do so.

Hydro generators can be expected to factor gas market conditions into their own bids in some fashion.

For example, one approach would be to offer tranches of hydro capacity at prices commensurate with the estimated SRMC of gas generation. But here again, there is no 'right answer', since different generators may have varying views on (amongst other things), emerging gas market conditions. In addition, if a hydro generator *does not observe* gas-fired plants committing generation at the estimated SRMC of this type of generation, it may be forced to revisit the assumptions underpinning its water values.[27] About all that *is* clear is that any tightening in gas market conditions will flow-through *in some way* to SRMC and, in turn, to spot prices.

The preceding analyses illustrate there is a host of legitimate reasons for spot prices in the NZWM to rise above the *short run operating and maintenance costs* of marginal plants. This may reflect the underlying supply and demand conditions prevailing *in a particular trading period*. Or it may reflect potential *future* conditions, e.g., the probability-weighted average of a shortage emerging over the longer-term. Importantly, in neither scenario would a 'market power' problem exist.

3.2.3 Longer term

We have established that it is unremarkable to see periods of high spot prices in energy-only electricity wholesale markets – including the NZWM. Such periods are necessary to cover generation costs in the aggregate, to manage scarcity and, critically, to provide an *inducement for new investment* by firms chasing those high prices. When scarcity in the market causes spot prices to increase high enough, or frequently enough that the average spot price exceeds the LRMC of constructing additional capacity over that timeframe then:

The period over which spot prices rise to reflect the increased risk of near- or longer-term scarcity should be finite.

- firms already in the market have an incentive to expand their generation capacity so as to take advantage of those periods of high prices; and
- new firms have a stronger incentive to enter the market and offer new generation capacity, chasing those high prices.

In other words, provided that the electricity market is workably competitive, the period over which spot prices rise to reflect the increased risk of near-term congestion, or the need to manage longer-term scarcity, is *finite*. Specifically, once the cost of that curtailment/resource management (as represented by SRMC) has risen to a level that consistently exceeds the costs of adding capacity (as represented by LRMC), entry and expansion can be expected to occur over the longer-term to *meet* that additional demand.

[27] This may be *very* difficult when gas generators are observed at times not committing generation *at any price* – which can and does happen (presumably due to restrictions relating to either gas availability and/or deliverability).

Prolonged periods of prices above LRMC should prompt investment in new capacity.

In this respect, a workably competitive wholesale electricity spot market functions no differently from most other competitive markets. Any change in market conditions that results in spot prices significantly and persistently *above LRMC* should, in time, prompt a supply-side response that restores prices to that level. For example, if short-term price spikes (e.g., to manage 'competitive scarcity') occur with sufficient frequency to push average spot prices significantly above LRMC this should, in time, prompt new entry and expansion. This relationship between prices and costs is the same as that described in general terms in section 2.3.

Of course, one of the complications discussed in section 2.3 is that this supply-side adjustment process cannot necessarily be expected to be *perfect*. Because new generation capacity cannot be added (or removed) in 1MW increments, it can be difficult to time 'lumpy' capacity expansions (or reductions) to coincide precisely with the theoretical 'trigger points' described earlier. It takes time to plan expansions, obtain resource consents, construct plant, arrange connections and so forth. There may therefore be periods during which:

Prices that diverge from LRMC for significant periods of time may still be explicable in an electricity generation market.

- average spot prices (and SRMC) are *above LRMC* for periods, as the market waits for the next increment of capacity to come on-stream; and
- average spot prices (and SRMC) are *below* long-run *avoidable* costs for periods, as the market waits for redundant capacity to be redeployed.

In other words, prices that diverge from LRMC (or LRAC) for significant periods of time may *still be explicable* in an electricity generation market. And, just as in any other competitive market, these periods of disequilibrium can be prolonged (or potentially shortened) by a variety of exogenous factors. For instance, investors may be reluctant to invest large sums into new generation plant if significant uncertainty surrounds the availability and cost of a particular fuel source.

SRMC – and average spot prices – should not differ materially from LRMC, provided they are assessed over an appropriate timeframe.

Such instances of 'disequilibrium' are neither unexpected, given the imperfections that can affect real markets, nor a cause for concern, provided they are transitory. Indeed, if such misalignments are likely to be 'self-correcting' (i.e., if it is simply a matter of waiting for any uncertainty arising from exogenous factors to abate), then intervening in the market would be unnecessary and very likely counterproductive.

With those important qualifications in mind, there is no reason to expect SRMC to differ materially from LRMC in competitive markets, on average, provided they are properly defined *and assessed over a sufficiently long timeframe* (i.e., one that allows for the resolution of exogenous factors). Equally, although both SRMC and LRMC can fluctuate over time, there is no reason to think that either will diverge materially over the longer term, when it is defined appropriately.

3.3 Incentives to engineer price increases

Hitherto we have focussed on the demand and supply conditions that can lead to high spot prices in a *well-functioning* competitive spot market. Complicating matters, these conditions are also the most likely to encourage the *exercise of market power*. Specifically, it is in that same environment in which market participants can have the strongest incentives to engineer price spikes through creating – or signalling – *contrived scarcity*.[28] This can be achieved in two principal ways:

- by 'physically' or 'economically' withholding capacity that *would otherwise be dispatched* in order to create *artificial* scarcity in the market (rather than *true* 'competitive scarcity') that must then be curtailed through high prices; or
- by a generator anticipating it will be the marginal supplier in a location, and consequently increasing its offers above its 'true' SRMC (i.e., including opportunity costs) in order to increase the market clearing price.

Generators can sometimes have incentives to engineer price increases by creating – or signalling – artificial scarcity.

In terms of the former strategy, *physical* withholding involves a generator not offering all of its capacity and *economic* withholding is where it offers some of its capacity at a price that exceeds the operating and maintenance costs of the likely marginal generator. The objective of the two types of withholding is the same: to increase the market clearing price by creating *contrived* shortages. There are a number of different withholding strategies that can be employed by generators.

For example, withholding can involve a low-cost producer (e.g., a baseload plant) withholding part of its capacity to increase the price at which *the remainder* is dispatched. It can also involve the coordinated use of multiple generation units. For instance, a generator with both baseload and mid-merit or peaking plant might withhold the latter in order to produce a shortage that benefits the former. Successful implementation of either strategy depends on the concurrence of a number of factors, including:

Strategic withholding involves holding back some capacity in order to change the identify of the marginal plant and increase spot prices.

- whether the slope of the 'merit curve' is 'steep' or 'flat' around the market clearing price, since this determines the magnitude of any price increase;[29]
- the production costs of the low-cost suppliers that potentially could restrict output to increase profits and the total quantities supplied to the market; and
- the extent to which a reduction in supply by a low-cost supplier might be offset by increased supply by other low-cost so as to reduce any price effect.[30] and

The hedging position of the withholding generator is also relevant. If a vertically integrated generator (i.e., with retail load to serve) is:[31]

28 *See:* Joskow, P (2007), 'Competitive Electricity Markets and Investment in New Generating Capacity', *The New Energy Paradigm* (ed: Dieter Helm), Oxford University Press.

29 The shape of the merit curve in electricity markets can therefore be conducive to such conduct at high levels of demand. The shape of the demand curve is less relevant since consumers tend to be very unresponsive to short-term price increases.

30 This is not a possibility when a generator is 'pivotal', i.e., where demand cannot be met without it.

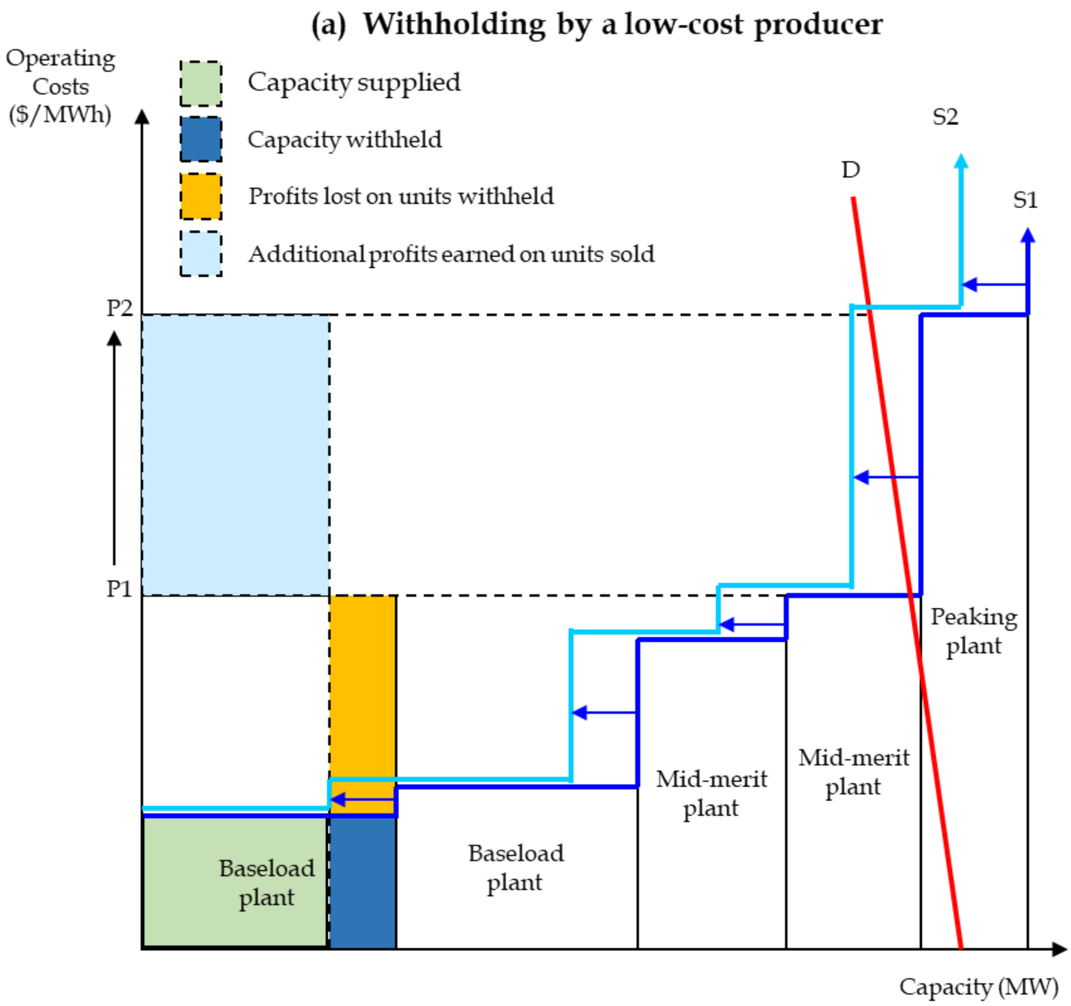
31 In principle, a generator may still have some incentive to withhold capacity and increase the spot price, even if the near-term financial benefit to it from doing so is diminished by its hedging position. The price of hedge contracts is determined primarily by the balance of expectations as to the level and volatility of future spot prices. Consequently, if average spot prices are seen to be increasing – e.g., because of the short-term incentives described above – this can usually be expected to result in higher contract prices, potentially creating a 'longer-term' pay-off.

- 'long' on generation,[32] then in the immediate term, it will only earn more on sales not covered by its existing contracts, i.e., the uplift in price will lead to an increase in profits only on its unhedged capacity; and
- 'short' on generation, then the near-term consequence of engineering the price increase will be that it pays *more* to purchase the additional generation it needs to meet its own commitments.

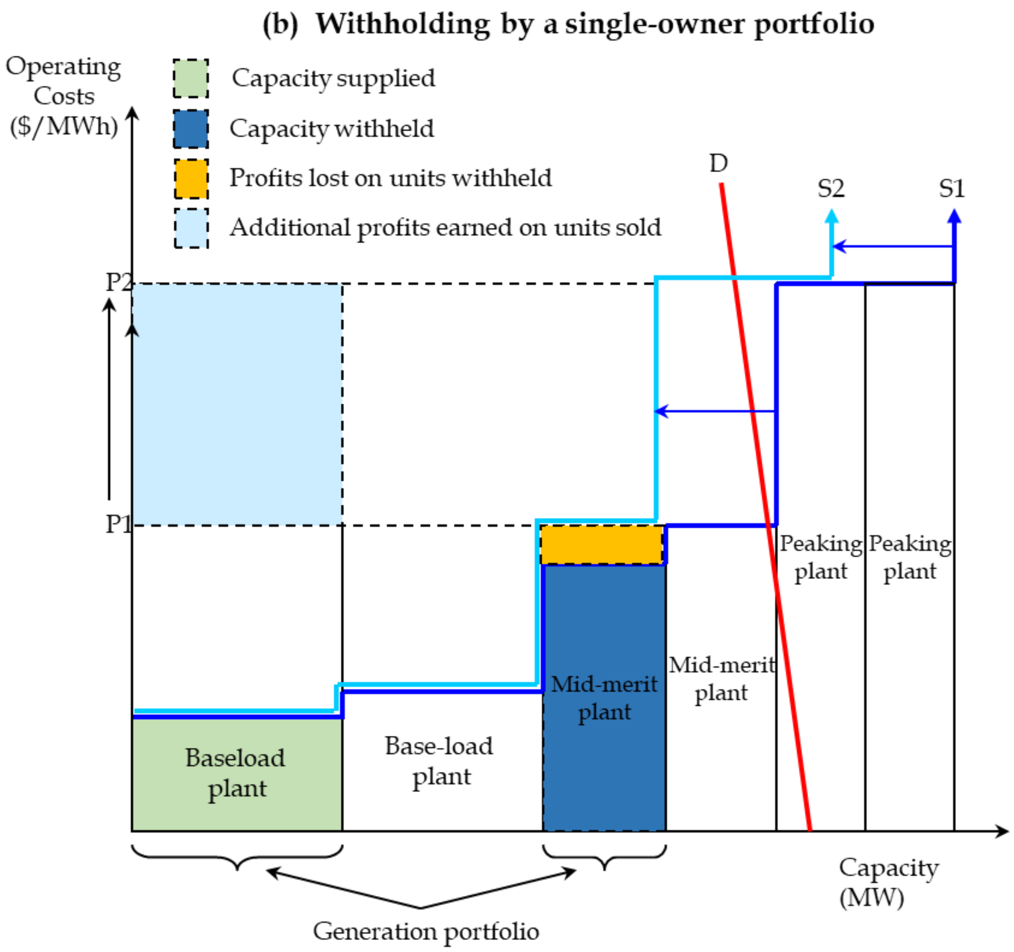
Figure 3.2 illustrates each of these withholding strategies, i.e., withholding by a low-cost producer and by a single-owner portfolio.

The withholding plant forgoes profits on the capacity it withholds but earns higher profits on the units it supplies.

Figure 3.2: Strategic withholding



32 A generator is 'long' if its wholesale revenue from generation and derivatives is greater than its wholesale costs from purchases and derivatives, i.e., if it is a net seller of generation. Conversely, a generator is 'short' if it is a net buyer of generation.



If a generator expects to be marginal, it can potentially increase its profits by increasing its offers above its 'true' SRMC.

The second principal means of engineering prices increases is far simpler. If a generator expects it will be the marginal supplier, then it can potentially increase its profits by increasing its offers above its 'true' SRMC (even if this might result in some of its capacity not being dispatched). Both strategies – strategic withholding and directly increasing marginal prices – can result in higher prices that *do not reflect* the underlying supply and demand conditions.

This begs the question: how can one distinguish *legitimate* price increases from *potentially problematic* ones in the NZWM? As we have seen, short-term price spikes will often reflect underlying supply and demand dynamics, yet they can also be symptomatic of artificial 'engineering'. In our opinion, the best way to draw these distinctions and to gauge the effectiveness of competition is by adopting a *broader, longer-term* perspective. We elaborate below.

3.4 Implications for assessing competition

Section 2.4 described the various challenges typically encountered when trying to compare prices with SRMC and draw inferences about the state of competition in *any* market. Foremost are the difficulties associated with estimating the opportunity costs of managing scarcity. Unless these costs are properly factored in when constructing SRMC estimating, those benchmarks will *underestimate* the prices that would prevail under workable competition. This risks 'false positives', i.e., erroneous findings that competition is less than effective.

There are many legitimate reasons for spot prices to exceed the short run operating and maintenance costs of marginal plants.

These difficulties are magnified manyfold in the context of the NZWM. There is a host of legitimate reasons (i.e., unrelated to the exercise of market power) for spot prices in the NZWM to rise above the *short run operating and maintenance costs* of marginal plants. For example, a temporary price spike may simply reflect the underlying supply and demand conditions:

- prevailing *in that particular trading period*, i.e., there may be a non-zero probability of an immediate or near-term shortage; or
- potential *future conditions*, e.g., the probability-weighted average of a shortage emerging over the longer-term if, say, water supplies wane.

The latter consideration in particular greatly complicates the estimation of SRMC in New Zealand's hydro-centric system. Hydro generators will be mindful of the potential impacts their offer behaviour *today* might have on *future* storage levels. The enormous costs associated with power shortages – and the inevitable negative publicity and scrutiny that follow – will factor heavily into water management strategies. Complicating matters further, as we have seen:

- different generators may have varying expectations about supply risks (these are not observable 'facts') – and hydrological conditions, the nature of drought and the intensity of spill all vary across the different catchment systems; and
- different generators may manage those risks in a variety of ways[33] and those strategies may be affected by a plethora of factors, including the combination of generation technologies comprising their profiles.[34]

It is impossible to produce objective measures of opportunity costs and, in turn, SRMC in the NZWM.

These complexities make it impossible to produce objective measures of opportunity costs and, in turn, SRMC in the NZWM – something the Authority acknowledges.[35] Even the most sophisticated models of SRMC will inevitably struggle to capture all the intricacies and complexities described above. This reduces considerably the utility of comparisons between spot prices and SRMC – regardless of how those benchmarks have been calculated. Such exercises are susceptible to errors (and 'false positives') and, in our opinion, are best avoided.

More reliable insights into the state of competition can be gained by adopting a *broader, longer-term* perspective. If competition is workable, the period over which spot prices can rise to reflect the increased risk of near-term congestion, or the need to manage longer-term scarcity, is *finite*. Once the costs of managing scarcity have risen to a level that consistently exceeds the costs of adding capacity entry and expansion *should* occur. More specifically, once expected *post-entry* wholesale spot prices[36] exceed the *LRMC* of constructing additional capacity then:

33 Some may elect to offer a portion of their capacity at much higher prices to signal to customers the potential scarcity value. Others may choose simply to physically withhold a portion of their capacity, i.e., to not offer it to the market at all and 'save it for later'.

34 For example, a generator with firming thermal generation may perceive and manage water storage risks differently to a generator without such assets in its portfolio.

35 Information paper, p.49.

36 If a firm expects that its entry would cause prices to drop to a substantial degree (e.g., due to the 'lumpy' nature of a capital expansion and the surplus capacity it may create), then it will focus on

More reliable insights into the state of competition can be gained by adopting a broader, longer-term perspective.

- firms already in the market have an incentive to expand their generation capacity so as to take advantage of those high prices; and
- new firms have a stronger incentive to enter the market and offer new generation capacity, chasing 'above normal' profits.[37]

However, those supply-side adjustments are not instantaneous. It takes time to build new plant, which means there may be periods when average spot prices are *above LRMC* for periods, as the market waits for the next increment of capacity. And, just as in any other competitive market, these periods of disequilibrium can be extended (or potentially shortened) by various exogenous factors. For instance, investors may be reluctant to invest in new plant if:

- significant uncertainty surrounds the availability and/or cost of a particular fuel source (e.g., due to potential government policies);
- there is significant 'sovereign risk' (e.g., a chance the government might invest public funds into generation, crowding out private investment);
- uncertainty surrounds the future of certain major customers, the departures of which might lead to near-term price drops and/or asset retirements; and/or
- there is material 'regulatory risk' (e.g., if uncertainty surrounds how regulators may intervene in the contestable and/or network elements of the supply chain).

Misalignments between prices and LRMC are not unexpected or a source of concern, provided they are transitory.

In those circumstances, investors might understandably delay expansions until more certainty emerges – even if prices (i.e., SRMCs) exceed the cost of entry (i.e., LRMC) in the meantime. Such instances of 'disequilibrium' are neither unexpected, given the imperfections that can affect real markets, nor a cause for concern, provided they are transitory. Indeed, if such misalignments are likely to be 'self-correcting' (i.e., if it is simply a matter of waiting for 'uncertainty' to wane), then intervening the in the market is unnecessary and likely to be counterproductive.

With those important qualifications in mind, there is no reason to expect spot prices to differ materially from LRMC in competitive markets, on average, provided they are properly defined and assessed over a sufficiently long timeframe (i.e., one that allows for the resolution of exogenous factors).[38] This suggests the best way to gauge the state of competition in the NZWM is ask two basic questions: 1) have spot prices been persistently above LRMC? And 2) if so, are likely to remain so due to enduring barriers to entry, or are they likely to 'self-correct'?

3.5 Summary

Energy-only electricity generation markets have some characteristics that distinguish them from many other markets. However, despite those differences, a

the expected *post-entry* prices when weighing its entry decision. This is an important nuance in the NZWM, when generator entry can have a significant impact upon prevailing nodal prices.

37 *Ibid.*

38 Equally, although both SRMC and LRMC can fluctuate over time, there is no reason to think that either will diverge materially over the longer term, when it is defined appropriately.

competitive wholesale electricity spot market functions no differently from most other competitive markets. Specifically, with certain limited exceptions, if prices are significantly and persistently *above LRMC* this should, given time, prompt a supply-side response that restores prices to these levels. The best way to gauge the state of competition in the NZWM is therefore to ask two basic questions:

- have spot prices been persistently above LRMC?; and
- if so, are spot prices likely to remain at that level due to enduring barriers to entry, or are they likely to 'self-correct', i.e., revert to LRMC over time?

If spot prices have *not* consistently exceeded LRMC, then this suggests strongly there is no competition problem. If they *have*, the question then becomes: *why?* Specifically, it is necessary to consider whether the observed margin between prices and entry costs is attributable to enduring barriers to entry, or transitory factors that may wane over time, e.g., investor uncertainty. If it is the latter, any perceived 'problem' may be self-correcting. Intervening in the market in such circumstances may therefore be needless and potentially harmful.

Conversely, few insights into the state of competition can be gleaned from comparing spot prices with estimates of SRMC. That is because it is impossible to produce objectively robust estimates of SRMC, given the complexities involved in measuring opportunity costs in New Zealand's hydro-centric system. Despite those challenges, much of the analyses in the Information Paper entail precisely these kinds of assessments. As we explain in the following section, unsurprisingly, those assessments are of little or no probative value.

4. Review of the Authority's short-term analyses

The Information Paper concludes the high spot prices are at least partly due to fuel supply scarcity and high fuel costs.

The Information Paper contains various analyses, including a linear regression of spot prices pre- and post-2018. This analysis indicates that the price increases observed over the period were at least partly attributable to fuel supply scarcity and higher fuel costs. However, the Authority also suggests there has been a sustained upward shift in spot prices that the regression *cannot* explain. The model could not reveal whether this shift was attributable to (amongst other things):

- limitations in the model itself;[39]
- uncertainty about the gas market influencing bids and prices; and/or
- generators exercising substantial market power.

Various other tests are then performed to look for any signs of the exercise of market power.

The Authority then performed a series of *other* analyses to see if it could determine the reasons for the perceived uplift. In particular, it looked for any indications that generators might have been exercising market power by exploring short-term 'price-cost' relationships.[40] However, as we explain below, these assessments exhibit many of the shortcomings foreshadowed in sections 2.4.1 and 3.4. They are consequently incapable of providing meaningful insight into the state of competition.

4.1 Percentage of offers over $300/MWh

The Authority's begins its examination of short-term price-cost relationships by looking at the percentage of offers that have exceeded $300/MWh over time. It reasons that: 'if significant quantities of a generators' capacity are offered at high prices, or above price and cost, this could indicate economic withholding, which is an exercise of market power.'[41] Its analysis reveals a significant increase post-2018 in the percentage of offers at higher prices for both hydro and thermal generators. The Authority then observes that:[42]

The Authority notes the percentage of offers over $300/MWh is higher, post-2018.

> *'The timing of most of these offer price increases seems consistent with the rise in the cost of thermal fuel, the increasing uncertainty surrounding gas supply from Pohokura and hydro storage conditions. However, the steadily increasing percentage of higher priced offers since 2014 at Meridian's (Waitaki) stations, the only slight decrease in 2020 at Contact's (Clutha) stations, and the quantity of higher priced offers at Mercury's (Waikato) stations since 2018 is not immediately explainable by underlying conditions.'*

The Authority notes also that a significant proportion of some hydro generators' capacity – including Meridian's – is consistently not dispatched, even during times of 'high' storage:[43]

> *'… it appears that Meridian (Waitaki) and Mercury* [sic] *(Waikato) higher priced offers are less related to storage than the other hydro generators. Meridian (Waitaki), Contact (Clutha)*

39 It is nearly impossible for any regression to perfectly capture all relevant variables, in practice.

40 Information Paper, p.49.

41 *Op cit.*, p.50.

42 *Ibid.*

43 *Op cit.*, p.51.

and Mercury (Waikato) always have, on average, above 30 percent of their capacity offered at higher prices than the final price (ie, above 30% of their generating capacity is not dispatched).

A simple analysis of the percentage of offers above $300/MWh reveals little – if anything – about competition in the NZWM.

In our opinion, a simple analysis of the percentage of offers above $300/MWh reveals little – if anything – about the state of competition in the NZWM. As we noted earlier, in New Zealand's hydro-centric system water shortages are only ever a few months' away. A storage lake can be full in September, but near-empty come February if an unexpected drought descends. Those risks must be factored into SRMC and into offers in some fashion. As we noted earlier, different generators might manage those supply risks in a variety of ways, for example:

- some generators might elect to increase their offer prices for every tranche of capacity offered, i.e., elevate their bids 'across the board';
- others might choose to price a certain percentage of their offers at significantly higher levels, i.e., offer some capacity (a 'baseload' quantity) at a 'lowish' price and a smaller quantity at a much higher price; and
- some might choose simply to physically withhold a portion of their capacity, i.e., to not offer it to the market at all and 'save it for later'.

Meridian offer a tranche of capacity at ~$300/MWh, but those offers are not intended to clear.

We have been advised that, broadly speaking, Meridian adopts the *second* strategy. Namely, it chooses to offer a tranche of capacity at ~$300/MWh – a volume that *is not intended to clear*. This 'high-priced' tranche is a quantity that Meridian chooses to systematically hold in reserve as part of its overall storage management strategy. The capacity is offered only really *as a back-up*, i.e., so that it is available to the system operator if an unexpected shortage emerges and it is needed (e.g., an event similar to that experienced in the North Island on 9 August).

We understand that Meridian maintains this strategy relatively consistently – even when storage levels are quite high. This is perhaps unsurprising given that, unlike some other generators in the NZWM it has no thermal-firming assets and only a few months' worth of storage available in the Waitaki catchments at any moment. It has consequently chosen to apply a 'smoothed/flattened' water value curve through time. An alternative approach would be for Meridian to have:

Meridian maintains this strategy as part of its storage management practices, i.e., to signal the potential costs of water shortages.

- more periods in which it offered a greater proportion of its capacity at prices below $300/MWh; and
- with this inevitably being offset by more periods with offers *well above $300/MWh* when its storage levels dropped.

There is no reason to think that this 'steeper' water value curve would result in different average prices, overall. It is also far from clear that customers would benefit from the greater price – and storage – volatility that might result. Another strategy would be for Meridian to *simply not offer* a proportion of its capacity, i.e., to physically withhold it. Ironically, this would serve to *reduce substantially* the proportion of its capacity offered above $300/MWh. We understand that this is precisely the strategy *already* adopted by some generators, which serves to undermine the analysis even further.[44]

Prior to June 2021, a secondary reason Meridian chose not to withhold a portion of its capacity (and opted instead to offer it at a price not intended to clear) was the 'high standard of trading conduct' (HSOTC) rules that were in place up to that point. As we explain in more detail in section 4.3.2, the Electricity Code set out certain criteria for a generator to follow when it found itself in a 'pivotal supplier' situation, i.e., where its capacity (or at least some of it) was needed to meet demand in a location. To stay within the HSOTC safe harbours, those rules required:

If Meridian physically withheld some of its capacity, it would be frequently trading outside the HSOTC safe harbours.

- a generator to offer *all* of its available capacity to the market; and
- when a generator found itself in a pivotal position, its offers had to be (amongst other things) generally consistent with how it bid when it was *not* pivotal.

As section 4.3 explains, in recent years Meridian found itself 'gross pivotal' in the South Island in ~90-95% of trading periods. Consequently, before June 2021, if it chose to manage its water resources by physically withhold a portion of its capacity from the market (one of the strategies described above), it would have been *trading outside* the HSOTC safe harbours ~90-95% of the time. All things considered, it is therefore easy to understand how it arrived upon the strategy of offering *all* its capacity – with some priced at levels *not intended to clear* in most circumstances.

More generally, given the tightening gas market conditions, one might also expect to see *hydro* generators factoring projected gas market conditions into their bids in some fashion. In the NZWM, less thermal generation generally means more hydro generation and, in turn, a heightened probability of water shortages (and vice versa). Consequently, hydro generators can be expected to take these interdependencies into consideration when formulating their bids. There are many ways they might do so.

Tightening gas market conditions may have also resulted in more offers exceeding $300/MWh.

For example, one approach would be to offer tranches of hydro capacity at prices commensurate with the estimated SRMC of gas generation. This would also contribute to a growing percentage of offers in excess of $300/MWh – including from hydro plants. This could be especially the case if there was a growing level of uncertainty about gas market conditions and future gas prices. For those reasons, we do not consider that anything useful can be gleaned from the Authority's examination of offers exceeding $300/MWh, in isolation.

4.2 Comparisons to short run costs

The Information Paper contains a series of analysis comparing generators' offers with two estimates of SRMC – or, rather, what the Authority *characterises* as SRMC. These short-term analyses appear to be beset by the types of problems foreshadowed earlier. For example, the estimates of SRMC do not appear to be

44 Physically withholding capacity from the market is the economic equivalent of offering that capacity at an infinite price. Yet, the analysis in the Information Paper is incapable of capturing this critical nuance.

objectively reasonable measures of the *true* short-term costs of generation. The way offers have been formulated for comparison purposes is also problematic. This can be illustrated using some simple 'sense checks'. We elaborate below.

4.2.1 Quantity-weighted offer price (QWOP) values

To compare generator's offers to SRMC, the Authority constructs a single 'quantity-weighted offer price' (QWOP) value.

In order to compare generator's *offers* to underlying estimates of their short run costs, the Authority constructs a single 'quantity-weighted offer price' (QWOP) value. This QWOP metric collapses all generation offers across different price and quantity bands into a single, quantity-weighted value. Table 4.1 provides a simple illustration, using a hypothetical hydro generator's offers. The generator is assumed to offer tranches of capacity at four price points. Most relevantly:

- at the bottom end of the range is a 'baseload quantity' of 1,000 units offered at a zero price, intended to (all but) guarantee this volume is dispatched;
- at the top of the range, 20% of the generator's capacity is offered at a 'high' price of $500/MWh, which is *not intended to clear* in ordinary circumstances; and
- to that end, the generator anticipates it will be marginal at ~1,500MW, i.e., beyond that point no more of its capacity is expected to be required.

As we explained above, the $500/MWh price could serve a number of purposes. It could signal the potential future costs of scarcity (and/or represent the 'shadow cost' of thermal plant). Offering that capacity could also allow the generator to stay within the HSOTC safe harbours if it expects to be 'gross pivotal' in the period. It might also serve as a source of 'back-up' capacity if, say, there was an unexpected outage and more supply was suddenly needed.[45] All these purposes are perfectly legitimate in a competitive market.

Table 4.1: Calculation of QWOP value

Price ($/MWh)	Quantity (MW)	% of Quantity	QWOP ($/MWh)
$0	1,000	50%	$0 x 50% = $0
$50	400	20%	$50 x 20% = $10
$100	**200**	**10%**	**$100 x 10% = $10**
$500	400	20%	$500 x 20% = $100
		Overall QWOP value	**$120**

QWOP values and SRMC estimates must incorporate opportunity costs in the same ways for comparisons between them to be valid.

Despite the fact that the generator has no serious intention of supplying 400MW at $500/MWh (the price signal *discourages* customers from using that capacity unless they are prepared to bear those opportunity costs) that tranche has a substantial impact upon the QWOP estimate. Indeed, it accounts for ~*83%* ($100 ÷ $120) of the final value. Consequently, unless this QWOP value is compared to estimates of SRMC that factor in the opportunity costs of managing scarcity *to the same extent*, it is unclear whether any useful information will be conveyed.

45 The recent events of 9 August (when ~20,000 households across the North Island lost power on one of the coldest nights of the year) being a salient example.

The intrinsic volatility of the QWOP value makes this very difficult to achieve. To illustrate, consider how the QWOP value calculated earlier changes if three simple changes are made. First, suppose that instead of offering its 'baseload' quantity of 1,000MW at $0, the generator prices this tranche at $40/MWh. Second, imagine that instead of offering its top tranche at $500/MWh the generator offers it at $5,000/MWh. And, finally, suppose that instead of offering 400MW at $500/MWh the generator decides to not offer that capacity at all, i.e., to physically withhold it from the market. Table 4.2 illustrates these scenarios.

Table 4.2: Volatility of QWOP value

Bottom offer tranche increased from $0/MWh to $50/MWh			
Price ($/MWh)	**Quantity (MW)**	**% of Quantity**	**QWOP ($/MWh)**
$40	1,000	50%	$40 x 50% = $20
$50	400	20%	$50 x 20% = $10
$100	200	10%	$100 x 10% = $10
$500	400	20%	$500 x 20% = $100
		Overall QWOP value	**$140 ($20↑)**

Different bidding strategies designed to achieve the same things can cause large changes in the QWOP value.

Top offer tranche increased from $500/MWh to $5,000/MWh			
Price ($/MWh)	**Quantity (MW)**	**% of Quantity**	**QWOP ($/MWh)**
$0	1,000	50%	$0 x 50% = $0
$50	400	20%	$50 x 20% = $10
$100	200	10%	$100 x 10% = $10
$5,000	400	20%	$5,000 x 20% = $1,000
		Overall QWOP value	**$1,020 ($900↑)**

Top offer tranche removed, i.e., the 400MW is not offered			
Price ($/MWh)	**Quantity (MW)**	**% of Quantity**	**QWOP ($/MWh)**
$0	1,000	50%	$0 x 50% = $0
$50	400	20%	$50 x 20% = $10
$100	200	10%	$100 x 10% = $10
		Overall QWOP value	**$20 ($100↓)**

Crucially, *none of these changes* would be expected to influence the market-clearing price, since neither the bottom nor the top tranche is likely to be 'marginal' in the trading period (under the above assumptions). Furthermore, each bidding strategy is intended to fulfil the *same basic purposes* (described previously). Most notably, these strategies are simply (amongst other things) different ways of managing scarce water resources. Indeed, in each instance, the overall *opportunity cost* that is being signalled through the generator's offers may be *identical*.[46]

Yet, despite these strategies' uniformity of purpose and their identical impacts upon price, the final QWOP values vary substantially depending upon which of them is being employed. This means that even if the SRMC estimates to which those QWOP values are being compared *are robust* (e.g., appropriately incorporated scarcity values, etc.), the results would still be of little or no use. For example, if a generator's QWOP value was found to have exceeded the underlying estimates of SRMC, it may be difficult to discern whether this is because:

The sensitivity of QWOP values to changes means comparisons to SRMC may not be robust, even if opportunity costs are properly captured.

- a generator has been attempting to exercise substantial market power; or
- it has been employing a *legitimate* bidding strategy that inadvertently skewed the calculation of the QWOP value (such as in the examples in Table 4.2).

To reiterate, those challenges exist *even when SRMC has been estimated accurately*. If SRMC benchmarks are *not* robust, this will lead to *further* problems. For instance, even if the QWOP value *does* accurately capture the opportunity cost of managing scarcity (despite the practical problems identified above), unless the underlying SRMC benchmarks *also* appropriately incorporate those opportunity costs, the exercise will be 'comparing apples with oranges'. The Authority's analyses appear to have been affected by this problem, as we explain below.

4.2.2 Estimates of SRMC

In a hydro-centric system such as New Zealand's it is impossible to produce objective measures of the SRMC of generating. We explained why in section 3.4. Most importantly, Hydro generators will be cognisant of the potential impacts their offer behaviour *today* may have on *future* storage levels. The substantial costs associated with power shortages can be expected to weigh heavily on water management strategies. Different generators may also have varying expectations about supply risks[47] and adopt a variety of mitigation strategies in response.[48]

The SRMC benchmarks used throughout the Information Paper do not appear to be reasonable.

We suggested earlier that the difficulties involved in producing robust estimates of SRMC in the context of the NZWM greatly reduced the usefulness of short-term price-cost comparisons. Even the most sophisticated models of SRMC will inevitably struggle to capture all the intricacies and complexities described hitherto and risk producing 'false positives and negatives.' The SRMC benchmarks adopted

46 The differences between the scenarios in which the generator offers its top tranche at \$500/MWh and \$5,000/MWh, respectively, could be explained by the underlying 'water value curves' guiding their offering behaviour. For example, as noted earlier, one approach would be to 'smooth-out' or 'flatten' the water value curve over time by consistently offering a portion (here, 20%) of capacity at \$500/MWh. An alternative might be to offer *much higher* prices with *less frequency* (i.e., at lower storage levels) – here, at \$5,000/MWh. These are two different ways of managing scarcity and, ultimately, signalling the same overall opportunity cost (albeit, in different ways over time).

47 Specifically, different generators may have varying expectations about supply risks (these are not observable 'facts') – and hydrological conditions, the nature of drought and the intensity of spill all vary across the different catchment systems.

48 For example, a generator with firming thermal generation may perceive and manage water storage risks differently to a generator without such assets in its portfolio

by the Authority throughout its Information Paper appear to be no exception. Two forms of SRMC estimates are employed:[49]

- water values provided by the generators themselves – in Meridian's case, its so-called 'minimum sell values'; and
- water values produced using a Dynamic Outer Approximation Sampling Algorithm (DOASA) model.

Meridian's 'minimum sell values' do not represent reasonable estimates of the SRMC of hydro generation.

We cannot comment on the water values provided by other generators but, insofar as *Meridian's* are concerned, its 'minimum sell values' are plainly *not* measures of SRMC. We have been advised by Meridian that these values provide *non-binding* guidance for traders as they look to price a *certain sub-set* of its capacity. Crucially, those minimum sell values do *not* influence:

- generation offers that are priced at close to zero to cover Meridian's contracted volumes (i.e., the equivalent of the 'baseload' quantity described in Table 4.1); or
- even more importantly, generation offers that are priced at a level *not intended to clear* (i.e., at $300/MWh and above) in a typical trading period, i.e., offers that:
  - are intended to signal the *opportunity costs* of scarcity (i.e., consistent with prudent management of storage lakes and reservoirs); and
  - are made to assist in the management of unexpected shortages (an alternative being to not offer that capacity at all[50]).

If Meridian offered all its capacity at its 'minimum sell values' the probability of shortages would increase substantially.

In other words, the 'minimum sell values' do not capture one of the chief means by which Meridian signals to customers *the opportunity cost of scarcity* – namely, the prices in its more expensive tranches (i.e., bids $300/MWh and upwards). The resulting SRMC benchmark is consequently almost certainly *too low*. Meridian has advised us that if it (hypothetically) consistently offered *all* its available capacity at these minimum sell values it would be at grave risk of running out of water.

By way of simple illustration, if Meridian's full generation capacity had been offered at the *market-clearing* prices from, say, November last year (i.e., at prices likely to have *systematically exceeded* Meridian's minimum sale values), the potential consequences would have been highly undesirable. Meridian has informed us that the drought experienced in the first half of this year would have seen Lake Pukaki *fully depleted* by late March or shortly thereafter if it had adopted this bidding approach, with forced customer outages inevitably following.

Meridian's 'minimum sell values' consequently *do not represent credible estimates of SRMC.* And, by extension, neither do the estimates produced by the DOASA model. The results reported in the Information Paper indicate the DOASA estimates tend to

49 Information Paper, pp.58-59.

50 Remembering that this would cause Meridian to fall outside the HSOTC safe harbours during the many periods in which it is 'gross pivotal' in the South Island (~90-95% of the time). See further discussion in section 4.3.2.

Using the DOASA model's SRMC estimates as the basis for offers would elevate the risk of shortages further still.

be *even lower* than Meridian's minimum sell values.[51] We understand Meridian has modelled (using the vSPD model[52]) the storage outcomes that would have resulted throughout 2021 if its hydro plants had offered to generate at the water values produced by the DOASA model. Meridian also examined what would have transpired if it had replicated this bidding strategy in 2008 and 2012 – both of which were 'drier years' with a reduced inflow sequence. The results are striking:[53]

- Meridian estimated that, in 2021, storage levels would have come perilously close to the level at which an official conservation campaign would have been triggered, which would have been an extraordinary occurrence given the hydrological conditions (2021 was drier than average, but not overly so); and
- Meridian concluded that, in 2008 and 2012, New Zealand would have run out of controlled hydro storage and there would have been insufficient total thermal generation available to avoid energy shortages, i.e., it is likely that load shedding would have been required over significant periods of time.

The DOASA values and Meridian's 'minimum sell values' appear to underestimate the true SRMC of generation.

Given the severity of the potential consequences in each case, it is implausible to think a prudent hydro generator would contemplate offering its capacity at the DOASA-based prices. If the circumstances described above had actually transpired in any of those years, hydro generators would have undoubtedly faced a sharp backlash from stakeholders, regulators and politicians – and rightly so. In our opinion, it is consequently inaccurate for the Information Paper to characterise the DOASA model as providing 'a lower bound for water values.'[54]

Rather, what these simple 'sense checks' illustrate is that the DOASA values – *and* Meridian's 'minimum sell values' – represent *implausibly low* estimates of the *true* SRMC of generation. In each instance, those benchmarks would *systematically under-signal* the opportunity costs of the scarcity that might emerge if those metrics were used as the basis for Meridian's – and probably any other generator's – offers. As we have just seen, they could have resulted in storage levels dropping to dangerously low levels *earlier this year* – despite it not being especially dry.

Tellingly, the Information Paper notes that Meridian's 'raw' QWOP values are not correlated with the Authority's SRMC benchmarks (i.e., the DOASA values and the 'minimum sell values'). However, it then states that if all of Meridian's offers above $300/MWh *are removed*, then there *is* a positive correlation between the *revised*

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51 For example, in Table 12 of the Information Paper application of the DOASA values results in a higher percentage of offers 'above cost' than use of the 'minimum sell values' in all but one scenario (the 'high hydro storage/pre-2018' scenario). And, even then, the difference is minimal (40% versus 38%). *See:* Information Paper, Table 12, pp.62-63.

52 The vectorised Scheduling, Pricing and Dispatch (or 'vSPD') is the market-clearing engine used by Transpower in the administration and operation of the NZWM, i.e., it is used to identify and select the generation units to dispatch at each node.

53 Meridian has explained to us that the fundamental problem in each instance is that the DOASA water values do not rise promptly enough to dispatch enough thermal plant to prudently conserve hydro storage, resulting in substantial reductions in storage lake levels.

54 Information Paper, p.59.

QWOP and the SRMC estimates. This is *exactly what one would expect to see* if, as we suggested above:

- Meridian's 'raw' QWOP values are influenced by the presence of those $300/MWh tranches which, as we explained earlier, are intended to signal to customers the *opportunity costs* of limited water suppliers;[55] but
- the underlying SRMC/water values to which those QWOP values are being compared *do not* adequately incorporate the opportunity costs of potential future shortages (which, as we noted earlier, appears to be the case).

The claim that Meridian's offers priced above $300/MWh are not related to its water values misconstrues how SRMC is set in competitive markets.

One would not expect to observe a strong correlation between these two variables, because the comparison is between 'apples and oranges'. The first metric incorporates opportunity costs (albeit in a sporadic and unpredictable way that reduces its reliability) and the second appears to substantially *underestimate* those costs. Stripping out the opportunity costs (imperfectly) wrapped up in the former by removing all bids above $300/MWh is therefore likely to produce a more 'apples-with-apples' comparison and, in turn, a stronger positive correlation.

In other words, all this is showing is that if two variables are examined – *neither of which account for opportunity costs* (because the $300/MWh prices no longer influence the QWOP value once they are removed) – then a positive correlation emerges. The potential *corollary* of this is that if the QWOP and SRMC estimates had *both* appropriately accounted for opportunity costs (which, currently, they do not), then a similarly strong positive correlation might also be seen. Specifically, if the $300/MWh offers were left untouched, the QWOP figure remained the same and:

- the *SRMC estimates* were *increased* to reflect more accurately the opportunity costs of managing scarcity; then
- *both* variables would incorporate some measure of opportunity costs (albeit imperfectly) and a positive correlation is more likely to emerge between them.

In other words, the Authority's statement that: 'Meridian's offers priced above $300/MWh are not related to its water values'[56] misconstrues how SRMC is set in a workably competitive wholesale market. As we explained at length in section 3.4 and elsewhere, it is precisely *through its offers priced above $300/MWh* that Meridian provides a signal to the market of the *scarcity value* of its water. The simple 'sense checks' described above showed what can happen if these costs are understated or ignored: the probability of *shortages* rises.

55 Remembering that the resulting QWOP value can vary substantially depending on the particular strategy a generator adopts for signalling those opportunity costs, i.e., there is no 'single right way' and many options exist.

56 Information Paper, p.66.

4.2.3 Implications

The short-term comparisons contained in the Information Paper do not establish that generators' offers or resulting spot prices have systematically and significantly exceeded the *true* SRMC of supplying generation, accounting for all relevant opportunity costs (including impacts on storage). In particular:

The short-term comparisons do not establish that offers have systematically exceeded the true SRMC of generation.

- the QWOP methodology is a highly imperfect means of collapsing generators' offers into a single value, since legitimate differences in bidding strategies can result in large divergences in the resulting QWOP value; and
- the SRMC benchmarks used in the Authority's comparisons do not appear to appropriately capture the opportunity costs of managing fuel (water or gas), as reflected by the simple 'sense checks' described above.

These problems also undermine the reliability of the Lerner Index estimates.[57] In our opinion, the spot prices observed over the period may simply reflect the prevailing supply and demand conditions and, potentially, perceived structural shifts in the gas market (e.g., greater uncertainty surrounding future prices).

4.3 Withholding analysis

The Information Paper also contains a series of analyses examining the incentives generators may have had to strategically withhold supply. As we explained in section 3.3, this involves a generator either 'physically' or 'economically' withholding capacity that *would otherwise be dispatched* in order to create *artificial* scarcity (rather than true 'competitive scarcity') that must then be curtailed through higher prices.[58] In other words, this *contrived scarcity* does not reflect the *true* underlying supply and demand conditions in the market.

4.3.1 Incentives to strategically withhold

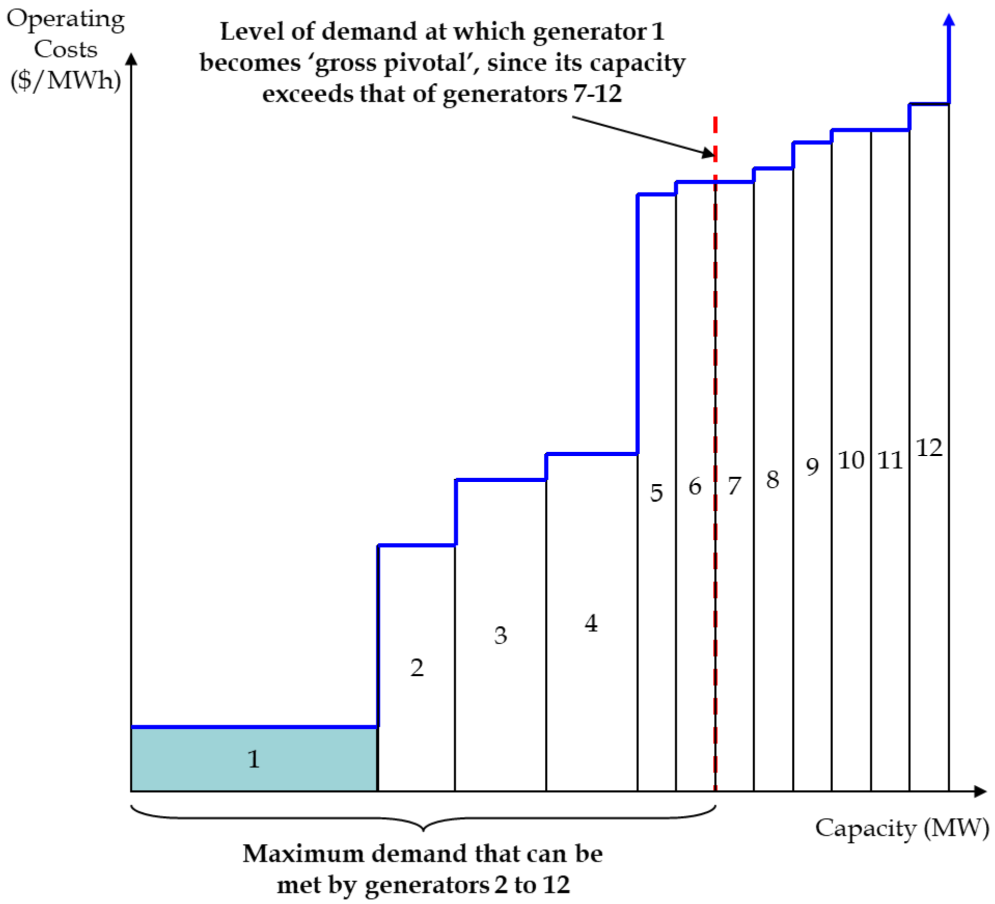
The first metric the Information Paper considers is the 'pivotal suppler index' (PSI). The PSI measures the proportion of time a generator *must* be dispatched (even if only partially) in order to meet demand in a particular location. If a generator becomes 'gross pivotal' this (theoretically[59]) creates an incentive for it to withhold supply to try and boost the market price. Figure 4.1 highlights the level of demand at which a generator becomes pivotal, i.e., for generator 1, this occurs where its capacity exceeds that of generators 7-12.

57 The Lerner Index measures the mark-up a firm is able to charge over its SRMC. The Authority employs the same SRMC benchmarks described above to calculate its Lerner Indices. Ergo, those estimates are equally unreliable. *See:* Information Paper, pp.68-73.

58 Recall that physical withholding involves a generator not offering all of its capacity and economic withholding involves it offering some of its capacity at a price that exceeds the operating and maintenance costs of the likely marginal generator.

59 We explain below some of the practical considerations that may diminish or eliminate a generator's ability to act on that notional incentive.

Figure 4.1: Gross pivotal generation unit



A generator is 'pivotal' when its capacity (or part of it) is needed to meet demand in a particular location.

The fact South Island plants may have had more incentive to withhold capacity in recent years reveals little about the state of competition.

The Information Paper points out that Meridian was 'gross pivotal' in the South Island ~77% of the time from 2016 to 2018, but that this has increased to ~90-95% of trading periods from 2019 to 2021 (to 30 June).[60] In itself this is unremarkable. For example, this uplift could be attributable to a several factors, including:

- increases in South Island load, e.g., electrification of industrial heat and summer irrigation load;
- fuel constraints being experienced by other generators meaning Meridian's generation is needed more frequently, e.g., constraints arising from low North Island hydro inflows and gas supply/delivery constraints; and
- limited recent investment in South Island baseload plant (e.g., new windfarms) due to (amongst other things) the uncertainty surrounding the future of the Tiwai Point aluminium smelter.[61]

The Paper also includes an analysis that suggests the incentives of South Island generators (including Meridian) to strategically withhold may have been higher in

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60 Information Paper, p.42.

61 As we explain in more detail in section 5.1.1, if the smelter had exited this would be likely to have resulted in substantial near-term reductions in spot prices – especially in the lower South Island. There is strong evidence that this has significantly delayed a number of new generation investment projects. When those plants come online, this may reduce the number of periods in which Meridian is 'gross pivotal' in the South Island.

recent years, i.e., because the potentially achievable spot price increases appear to have been higher (based on the Authority's simulations).[62] In opinion, in isolation, these analyses reveal little, if anything, about the state of competition in the market.

The 'gross pivotal' metric may overstate the near-term incentives generators have to withhold, since these will be affected by their hedging positions.

First, the 'gross pivotal' metric itself is potentially problematic because it can provide a misleading picture of the near-term incentives a generator may have to withhold supply. The *hedging position* of the withholding generator is also relevant to this near-term withholding calculus. As we explained earlier, if a vertically integrated generator (i.e., with retail load to serve) is:

- 'long' on generation,[63] then in the immediate term, it will only earn more on sales not covered by its existing contracts, i.e., the uplift in price will lead to an increase in profits only on its unhedged capacity; and
- 'short' on generation, then the near-term consequence of engineering the price increase will be that it pays *more* to purchase the additional generation it needs to meet its own commitments.

It follows that a generator may be 'gross pivotal' yet have little or no immediate financial incentive to withhold supply. A more accurate indication of generators' near-term incentives to withhold could potentially be obtained by examining when they were *net pivotal*, i.e., accounting for hedging positions. Indeed, this is the metric the Authority has used when undertaking such assessments previously.[64] However, the Information Paper does not contain such an analysis. But even if it did, and those analyses revealed that generators were frequently *net* pivotal, that may not signify a competition problem, for the reasons we set out below.

4.3.2 No compelling evidence of withholding

The Electricity Code includes explicit provisions relating to pivotal supplier situations.

Just because a generator is *net pivotal* (a metric the Information Paper does not examine) that does not mean it will *act* upon any incentive to withhold capacity. As noted earlier, prior to June 2021, the Electricity Code included explicit provisions relating to pivotal supplier situations. These criteria conveyed to market participants how they could remain within a 'safe harbour' in such scenarios, thereby avoiding an undesirable potential regulatory response. To qualify for a 'high standard of trading conduct (HSOTC) safe harbour':[65]

- a generator had to offer all its available capacity (energy and reserve);

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62 The Authority ran simulations of a 2% reduction in demand in the South Island (the equivalent of increasing demand). The average simulated price reduction was higher during the post-2018 period, suggesting that incentives to *withhold* that supply to *increase* the price by that magnitude may have been stronger.

63 A generator is 'long' if its wholesale revenue from generation and derivatives is greater than its wholesale costs from purchases and derivatives, i.e., if it is a net seller of generation. Conversely, a generator is 'short' if it is a net buyer of generation.

64 *See for example:* Electricity Authority, *Market Performance Quarterly Review October-December 2020 Information paper,* 2 February 2021, Figure 12, p.12.

65 Electricity Authority, *Improving the efficiency of prices in pivotal supplier situations*, 4 June 2014, p.2.

- it had to submit, revise, or withdraw an energy or reserve offer in a timely manner after receiving the information that triggered these actions; and
- when a generator found itself in a pivotal position, it had to ensure that either:
  - the prices and quantities in its offers did not result in a material increase in the price in the region where it was pivotal;[66]
  - its offers when pivotal were generally consistent with its offers when it was not pivotal; and
  - it derived no financial benefit from an increase in the price in the region where it was pivotal.

The HSOTC safe harbours have since been superseded by new trading conduct rules set out in 13.5A of the Code. These rules state that it is expected that offers (and reserve offers) will *generally* be subject to competitive disciplines, such that no party has significant market power.[67] However, they then note that, from time-to-time, there may be locations where, or periods when, one or more generators has significant market power.[68] To that end, the Code specifies that:[69]

> *"…where a generator submits or revises an offer, that offer must be consistent with the offer that the generator, acting rationally, would have made if no generator could exercise significant market power at the point of connection to the grid and in the trading period to which the offer relates"*

The Authority has considered – and upheld – several complaints arising out of pivotal supplier situations.

Industry participants have displayed a clear willingness to lodge claims with the Authority alleging 'undesirable trading situations' (UTS) whenever they suspect a generator (or group of generators) has strategically withheld supply. The Authority has likewise been prepared to uphold those claims and impose corrective actions when it determines those responses are warranted. For example, a UTS was deemed to have occurred when:

- on 26 March 2011, Genesis found itself in a pivotal supplier situation within the Waikato area and caused spot prices to reach spot prices to reach approximately $20,000/MWh over several hours in and around Hamilton; and
- in December 2019 Meridian responded to heavy flooding by spilling more than the Authority estimated was necessary, pushing up spot prices (an extra 82MW of generation was said to be possible at the Benmore power station).

In both these instances, spot prices during the time of the UTS were 'reset' to considerably lower levels. In other words, even if a generator does find itself 'net pivotal', it may have no real ability to *take advantage* of that situation in practice. Specifically, the Code therefore:

66 Assessed by comparing prices in the immediately preceding trading period or another comparable trading period in which it was not pivotal.

67 Electricity Code, clause 13.5A(1)(a).

68 Electricity Code, clause 13.5A(1)(b).

69 Electricity Code, clause 13.5A(2)(a).

- contains clear *ex-ante* guidelines setting out what generators should do when they find themselves 'pivotal'; and
- allows for a (now reasonably well-traversed) *ex-post* process to address situations where firms stray from those guidelines.

The Code provisions – and the Authority's willingness to enforce them – reduce the ability to profitably withhold supply.

To that end, the Information Paper contains no strong evidence to suggest generators have been engaging in strategic withholding, despite their *ostensibly* strengthened incentives to do so in recent years. For example, the Authority looked at trading periods where there was price separation[70] in pre-dispatch but not in final prices.[71] It observed:[72]

> *'…no evidence of systematic changes in offers in pre-dispatch for these trading periods. Any changes observed in pre-dispatch were consistent with underlying conditions at the time (mainly hydro storage levels). This suggests these generators do not change their offers in pre-dispatch to increase the quantity they economically withhold in these trading periods.'*

The Authority also looked at trading periods with high spot prices (over $300/MWh) to investigate whether these could be attributable to strategic withholding. It concluded that:[73]

The Information Paper found no evidence that generators had been strategically withholding capacity.

> *'All of the changes in prices during these trading periods (compared with surrounding trading periods) could be explained by changes in market conditions at the time. There were no obvious signs that changes made to offers in pre-dispatch during these periods were inconsistent with market conditions. The majority of high priced offers that were dispatched were either priced as they usually were or reflected the fuel scarcity and opportunity cost of operating at the time.*

The Authority does mention again that some generators – particularly Meridian – offer a significant portion of their capacity above $300/MWh *regardless* of the conditions or trading period.[74] However, as we explained in section 4.1, there is no reason to assume this is part of some broader 'withholding' strategy. It may instead simply reflect prudent water storage management. The Authority also concedes that this could be partly symptomatic of gas supply uncertainty.[75]

Taking all this into consideration, the Authority concluded that although there may have been an increased *incentive* over the period to engage in strategic withholding:

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70 The Authority also looked at the *frequency* of price separation between the North and South Islands but was unable to draw any robust inferences from this assessment. *See:* Information Paper, p.76.

71 In Meridian's case, this *ostensibly* provides it with an incentive to change its offers to avoid that price separation.

72 Information Paper, p.77.

73 *Op. cit.*, p.79.

74 *Op. cit.*, p.77.

75 Information Paper, p.79. As we noted previously, given the tightening gas market conditions, one might also expect to see *hydro* generators factoring projected gas market conditions into their bids in some fashion. One way to do so would be to offer tranches of hydro capacity at prices commensurate with the estimated SRMC of gas generation. This could result in a larger percentage of offers in excess of $300/MWh – including from hydro plants.

‘the evidence to show any generator did this is weak’.[76] We broadly agree with that assessment but we would go further. In our opinion, the analyses contained in the Information Paper do not provide *any* meaningful insights into whether generators have strategically withheld supply over the assessment period.

4.4 Summary

The Information Paper contains a linear regression of spot prices pre- and post-2018. This analysis indicates that the price increases observed over the period were at least partly attributable to fuel supply scarcity and higher fuel costs. However, the Authority also suggests there has been a sustained upward shift in spot prices that the regression cannot explain. It consequently performed a series of other tests to see whether it was able to shed more light on the reasons for the perceived uplift.

In particular, the Authority looked for any indications that generators might have been exercising market power by performing a series of analyses exploring short-term ‘price-cost’ relationships. However, these assessments exhibit many of the shortcomings that often plague analyses of this nature, which substantially diminishes their usefulness. For example:

- the simple analysis of the percentage of offers above $300/MWh reveals little – if anything – about the state of competition in the NZWM, i.e., those offers may simply be signalling to customers the opportunity costs of managing scarcity;
- the various comparisons to short run costs do not reliably establish that generators’ offers or resulting spot prices have systematically and significantly exceeded the *true* SRMC of supplying generation, because:
  - the QWOP methodology is a highly imperfect means of collapsing generators’ offers into a single value, since legitimate differences in bidding strategies can result in large divergences in the resulting QWOP value; and
  - the SRMC benchmarks used in the Authority’s comparisons do not appear to appropriately capture the opportunity costs of managing fuel (water or gas), as reflected by the simple ‘sense checks’ described above; and
- even if generators’ incentives to strategically withhold supply have increased in recent years, there is no evidence they have been systematically doing so – and the Code sets out clear provisions to deal with ‘pivotal supplier’ situations.

These short-term analyses are consequently incapable of providing meaningful insights into the state of competition or whether generators have been exercising market power. In our opinion, the spot prices observed in the NZWM over the period may simply reflect the prevailing supply and demand conditions and, potentially, perceived structural shifts in the gas market (e.g., greater uncertainty surrounding future prices).

76 Information Paper, p.74.

5. A broader, longer-term assessment

The preceding sections have illustrated why it is often inadvisable to focus on short term comparisons between prices and short run costs. In our opinion, more insights into the overall state of competition in the NZWM can be obtained by asking: are prices above long-run entry costs and, if so, *why*? The 'why' is important here because prices undoubtedly *have been* significantly above LRMC in the NZWM and may remain so for some time yet. However, as we explain below, there are many reasons for this, and good reason to think it will change if given time.

5.1 Factors that may have hindered new investment

Prices in the NZWM have been above LRMC for some time, but there appear to be good reasons for this, and cause to think it will change in time.

There is no doubt that average spot prices in the NZWM have outstripped long-run entry and expansion costs for some time. The average monthly spot price is more than twice as high this year as it was three years ago (~$240/MWh vs. ~$110/MWh, nationally).[77] Meanwhile, the Ministry of Business, Innovation and Employment (MBIE) estimates the cost of new wind generation as ~$60/MWh. And new gas peaking plant is said to be ~$175/MWh.[78] This disparity between prices and entry costs is expected to persist (albeit to a diminishing degree) for at least another year – possibly longer.

This begs the question: why has this not spurred a swifter supply-side response to eliminate that differential? There would *appear* to be profitable opportunities for new investment, so why has it not been happening in recent years? Could it be because enduring barriers to entry and expansion exist and have allowed generators to persistently earn 'above normal' returns? Or could it be something else? In our opinion, there are many good reasons for investors to have been reluctant to invest over the last few years, despite the returns ostensibly on offer. These can be expected to have contributed to the 'lag' that we are now observing.

5.1.1 Uncertain status of Tiwai Point aluminium smelter

The characteristics of the NZWM mean that the exit of major load customers can have profound effects on market participants. Because the NZWM is an energy-only market with prices struck at ~285 nodes, the addition or subtraction of large chunks of demand or supply can have profound effects on locational spot prices. If a large user disconnects from a node (or a large generator connects) and there is not enough transmission capacity to transport the surplus power further afield, local nodal prices will fall – perhaps precipitously.

Uncertainty about the future of a major customer may diminish investment incentives, despite high spot prices.

Any uncertainty surrounding the long-term future of a major customer can therefore have a profound impact upon generation investment decisions. New plant that would be profitable at today's prices could be rendered uneconomic if a large customer leaves. If investors are therefore unsure about the future of a major load customer, they might understandably eschew from building new plant, even if

77 Data sourced from the 'Electricity Market information (EMI)' website (available: here).

78 Based on MBIE's 'Interactive Levelised Cost of Electricity Comparison Tool' (available: here).

prices are above the cost of new entry (i.e., LRMC). The seminal case of this in the NZWM is the Tiwai Point aluminium smelter.

The smelter is New Zealand's largest electricity customer. It accounts for ~12-14% of total annual national electricity consumption and ~1/3 of South Island demand (an amount equivalent to around 704,000 households). It currently has 622MW contracted from Meridian (supported by bi-lateral back-to-back contracts with other generators, including Contact and Genesis), of which it is currently consuming 572MW.[79] For nearly a decade, the smelter has repeatedly signalled its willingness to exit the market. For example:

- during the period of Meridian's initial public offering (its partial privatisation) in 2013 the smelter threatened to leave – a move which would have significantly compromised the proceeds from that sale; this resulted in:
  - a renegotiated supply agreement with Meridian at a reduced price (and other revised non-price terms); and
  - a $30m subsidy being paid by the then National government;
- in 2015, the smelter was unable to find an alternative supplier for 172MW of capacity that Meridian was not obligated to supply from 1 January 2017[80] - this could have resulted in the smelter exiting entirely; and ultimately led to:
  - Meridian and the smelter reaching a new commercial agreement for the supply of *all* its electricity requirements (then 572MW); and
  - Meridian striking bi-lateral contracts with Contact (80MW), Genesis (50MW) and others covering 'close to 172MW'; and
- in October 2019 the smelter's owner, Rio Tinto, announced it was commencing a 'strategic review' into whether to exit the market and, in July 2020, it gave notice terminating its electricity contract; but subsequently:
  - in August 2020 (about 1.5 months before the general election) Rio Tinto disclosed that it was still negotiating with the government; and
  - on 14 January 2021, Meridian reached a new supply agreement with the smelter, extending the life of the smelter to at least the end of 2024.

For nearly a decade, the Tiwai point smelter has repeatedly signalled its willingness to exit the market.

Had the smelter exited, prices would have dropped, and a tumultuous transition period might have followed.

The potential exit of the smelter has loomed over the generation sector like a proverbial Sword of Damocles. If it had left, the ramifications would have been substantial. Spot prices – particularly in the South Island – would have dropped sharply. Transpower may have been left scrambling to upgrade the high voltage network to enable surplus power to get further north. Generators may have looked to decommission plant. And, possibly, new energy-intensive customers might have considered moving onto the vacated site.

79 The smelter's fourth potline is not currently being used.

80 This was an element of the renegotiated contract in 2015, i.e., from 1 January 2017, 172MW was scheduled to be 'released'. The smelter also had the right to terminate the contract from 1 July 2015 (giving 12-months' notice).

How this all would have shaken-out in the longer term is unclear. But what *is* clear is the adverse impact this uncertainty has had on generation entry decisions. A recent analysis by Concept Consulting ('Concept') identified several large, consented generation projects (amounting to nearly 1,000MW) that have likely been delayed by the uncertainty surrounding the smelter; namely:

Several large, consented generation projects have been delayed by uncertainty surrounding the smelter's future.

- Tilt Renewables' Kaiwera Downs (240MW) and Mahinerangi II (160MW) wind farms are both in the region that would be most affected if the smelter was to exit – Mercury (which acquired Tilt in August 2021) is said to be currently working on the sequencing of its wind projects;[81] and
- Meridian's Harapaki wind farm (176MW) was only committed *after* greater certainty emerged around the smelter's future, i.e., after the January 2021 announcement that it would continue operating until the end of 2024 (the project was in hiatus prior to that point);[82] and
- Todd Energy's Otorohonga Peaker (360MW) was delayed due to (amongst other things) uncertainty surrounding the potential closure of the smelter.[83]

More generally, it is impossible to know how many other nascent generation projects were cancelled or deferred before they reached even the consenting stage. In our opinion, when faced with such uncertainty it is easy to understand why investors may have been reluctant to commit capital, in spite of the ostensibly attractive spot prices. They would have been aware that, if Tiwai exited, many generators might suddenly be looking to *decommission plant* to mitigate wholesale price *reductions*, rather than build new ones.

5.1.2 Uncertainty over thermal fuels and decarbonisation policies

There has been substantial upheaval in the gas sector in recent years – and considerable uncertainty surrounds the long-term viability of this fuel-source. As we explained earlier, the prolonged outage at the Pohokura field in 2018 exposed the relatively fragile nature of New Zealand's gas supplies. The deterioration of output took the industry by surprise and, when coupled with the rapid diminishment of reserves from the Maui field, casts significant doubt over the level of domestic supply.

There has been upheaval in the gas sector in recent years and uncertainty surrounds the long-term viability of this fuel-source.

The government's 2018 decision to ban all new off-shore oil and gas exploration permits also limits considerably the scope to tap new domestic sources (any fields must, by definition, be on-shore). The potential implications of carbon prices on thermal fuel prices are also a matter of considerable uncertainty – although more clarity is likely to be forthcoming once new targets are announced. More generally, the government's climate change objectives are highly germane. For example:

81 Concept Consulting, *Review of generation investment environment*, August 2021, pp.4, 5 and 12 (hereafter: 'Concept Investment Environment Report').

82 *Op cit.*, p.12.

83 *Op cit.*, p.11.

- the government has a target of reaching 100% renewable electricity by 2030 which, if implemented and enforced, would effectively ban coal and gas generation; and
- separately, the Climate Change Commission has recommended phasing out natural gas use in residential, commercial and public buildings (the initial report recommended a 'hard sunset' of 2050).[84]

This would also have potentially profound ramifications for natural gas transmission and distribution pipeline owners. Those infrastructure owners do not currently know whether there will be enough downstream demand for gas in, say, twenty years' time, for them to be able to cover the ongoing costs of operating their networks. If there is not, and those networks cannot be deployed to alternative uses (e.g., shipping hydrogen or blended fuels), then it quite plausible that they would shut down and be decommissioned. The Commerce Commission and industry working groups are currently grappling with these issues.

These factors can be expected to have weighed on any investor contemplating investing in gas peaking plant. Investors would presumably be asking questions like: will I be able to access a reliable supply of gas (including shipping via a transmission network, if necessary)? How much is that gas likely to cost me over the lifetime of the facility? And, perhaps most importantly of all: is it possible my investment could be stranded due to the impacts of government climate change policies? In recent years, there has not been clear answers to these questions.

At least one gas project has been delayed by uncertainties surrounding government decarbonisation policies.

This is again reflected in Concept's findings. Todd Energy's Otorohonga peaker is a 360MW gas-fired plant. It is consented (until 2027) but has not been committed – in large part because of uncertainties surrounding government decarbonisation policies (and the ongoing status of the smelter).[85] This is unsurprising. As Concept notes, uncertainty around government policy – and the future supply/price of thermal fuels – can delay new investment decisions and cause investors to require a higher rate of return before committing capital.[86]

5.1.3 Other uncertainties

Several other factors could have had a material bearing on generator investment decisions in recent years. For example, the Authority has been reviewing the transmission pricing methodology (TPM) for over a decade (including when it was the Electricity Commission). During that time, five variants of 'benefits-based' charging have been proposed as potential replacements to the current TPM. Each of these methodologies would have had very different ramifications for generators. The status of the HVDC charge under each proposal (i.e., whether it was to remain

[84] Climate Change Commission, *Ināia tonu nei: a low emissions future for Aotearoa Advice to the New Zealand Government on its first three emissions budgets and direction for its emissions reduction plan 2022 – 2025*, 31 May 2021 (available: here).

[85] Concept Investment Environment Report, p.4.

[86] *Op cit.*, p.16.

and the form it took), and the proposed times at which each option was intended to come into effect would also have had significant impacts on business cases.

Early variants of the Authorities proposal involved generators being allocated 50% of the so-called 'residual charge', which would have represented a very material impost. More recent versions saw this shift entirely to load customers. Each iteration of the proposal also seen the costs of different groups of existing assets being reallocated amongst generation and load customers – resulting in large swings in projected wealth transfers. This has meant that, until recently, generators are unlikely to have had a good understanding of:

Until recently, generators did not know how much new plants would have to pay to access the transmission network.

- what they would be required to pay to connect to – and use – the transmission grid, i.e., how their connection and 'benefit-based' charges would be set; and
- what the potential financial ramifications might be for certain forms of investment, e.g., batteries and solar investments.[87]

The potential conversion of Lake Onslow into an enormous virtual battery adds another layer of uncertainty to the NZWM. In August 2020, the government announced that it would spend $30m investigating a multi-billion dollar pumped hydro scheme that could be in operation by 2030. The scheme would, in effect, convert the South Island location into a 5,000GW rechargeable battery that could supply electricity during peak periods – including times of little rainfall (and snowmelt) or wind.

Lake Onslow may, at some point, be converted into a huge virtual battery that could supply during peak periods.

In October 2021, a contract was awarded to undertake the engineering, environmental planning and geotechnical feasibility investigations. However, there is no guarantee that the project will proceed. Many crucial questions also remain unanswered, including who might own and operate the scheme if it were to go ahead, and whether it would run on a commercial basis. If the facility was to be publicly owned or operated by, say, Transpower (a state-owned business), this would clearly have widespread ramifications for the NZWM.

Regulatory uncertainty may have also diminished generators' incentives to invest.

Regulatory uncertainty may have also played a role. Certain market participants have long called for substantial regulatory intervention in the NZWM – including the structural separation of the vertically integrated generators[88] – sometimes based on questionable analysis.[89] Until recently, generators did not know whether this lobbying had gained any significant traction with the Authority – including within the context of the current review. Put simply, generators did not know if the Authority would make recommendations that would restrict their ability to contract to manage risk or prompt divestments. These factors may have all served to diminish generators' incentives to invest in new plant.

[87] *See for example:* Concept Investment Environment Report, p.16.

[88] For example, earlier this year Flick Energy called upon people to sign a petition calling for the structural separation of the vertically integrated generators.

[89] *See for example:* Green., H. 'Analysis of Meridian's profits generates more heat than light', in *Energy News,* 3 September 2021.

5.1.4 Overall implications

Prices in the NZWM have exceeded LRMC in recent years and will continue to do so for some time. But there appear to be good reasons why. Multiple factors may have diminished incentives to invest in new generation capacity. These include uncertainty surrounding the future of the Tiwai point smelter and government decarbonisation policies. These factors may have discouraged investors from committing capital, despite the ostensibly attractive returns on offer. However, as we explain below, investment conditions appear to be improving.

5.2 The investment climate appears to be improving

The near-term future of the smelter was recently secured, which has already prompted new investment.

There are positive signs that some of the uncertainty that has plagued the market in recent years is waning. For example, as noted above, the near-term futures of at least two large customers are now much clearer. Namely, the smelter will remain in business until at least the end of 2024, and the Marsden Point oil refinery will be converted to a terminal storage facility from mid-2022. The greater certainty surrounding the smelter is particularly beneficial. As Concept explains: [90]

> *'More generally, many parties considered the risk of market dislocation from a Tiwai exit was lower now than in the past. This was because there were credible prospects of other forms of demand, such as hydrogen production and data centres, that could offset some (or all) of the reduction in demand if Tiwai exited. In addition, underlying demand growth is expected to quicken in the next few years as decarbonisation gathers pace. This would mean that any temporary supply surplus is absorbed more quickly than in the (former) environment of little or no growth. Finally, many parties considered that Tiwai was more likely to stay than exit at the end of 2024.'*

To that end, as we noted above, shortly following the January 2021 announcement that the smelter would continue operating, Meridian committed to opening the Harapaki wind farm (176MW) – a project that had previously been on hiatus. Following its recent acquisition of Tilt Renewables, Mercury is currently working on the sequencing of its wind projects – including Kaiwera Downs (240MW) and Mahinerangi II (160MW) wind farms. It is reasonable to expect these projects are more likely to proceed now that the smelter's future is clearer. In addition:

- in May, Lodestone Energy unveiled plans to build five solar energy farms in the upper North Island at a cost of $300 million which, collectively, will deliver approximately 400GWh (or ~1% of the country's electricity supply);[91] and
- earlier this month it was announced that the country's largest solar farm – a facility known as Kowhai Park – would be constructed on 400 hectares of land adjacent to Christchurch Airport.[92]

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90 Concept Investment Environment Report, p.17.

91 Pullar-Strecker, T., '$300m plan for five solar energy farms, providing 1pc of country's supply', in *stuff.co.nz*, 12 May 2021 (*see*: here. *See also:* here).

92 McDonald, L., '$100m 'world-leading' solar plant will be 50 times bigger than any in New Zealand', in *stuff.co.nz,* 1 December 2021 (*see:* here).

More certainty is also emerging on the government's climate change policies, with a clear focus on renewable forms of generation.

More certainty is also emerging regarding the government's decarbonisation policies. For example, in June, the Climate Change Commission released its final report, in which it recommended (amongst other things) transitioning away from fossil fuel generation. The government is scheduled to release its responding 'emissions reduction plan' in May next year. Meanwhile, it has indicated a commitment to achieving 100% renewable generation by 2030 and reducing net emissions to 50% below gross levels by 2030.

Taken together, these policy announcements suggest the future for *non-renewable* generation in the NZWM could be quite bleak. This is reflected once more in Concept's analysis. Nearly every project mentioned within it is a renewable energy development. And the one gas project listed – Todd Energy's Otorohonga peaker – has been delayed (perhaps indefinitely) by (amongst other things) the government's climate policies. Although this is likely to be unwelcome news to proponents of, say, gas-fired generation, it is beneficial for the investment environment overall, since:

- investors who have been considering investing in new *non-renewable* generation projects, but holding off until greater clarity existed around the government's climate change policies, are likely to have a better idea about the long-term viability of those investments, i.e., they may be unattractive; and
- in turn, this may clear the way for more new investments in *renewable* forms of generation, i.e., if the general expectation is that additional investment in non-renewable power is unlikely (and that existing plants may be decommissioned, e.g., Huntly), then this may result in more capital being committed.

Generators now have a clearer idea of what they are likely to be paying for transmission services.

There are also encouraging signs that the TPM saga is drawing to a close. The Authority is currently consulting on what could very well be the final iteration of the consultation process. A complete methodology – including indicative prices – has been produced and, barring any successful legal challenges, the new methodology will finally be implemented. As such, generators should now have a much clearer idea of what they are likely to be paying for transmission services if the new TPM 'goes live'.

This greater certainty already appears to have had positive effects on the investment environment. For example, Concept highlights that development interest in solar farms is surging and Transpower reports connection enquiries for generation have risen almost tenfold over the past two years.[93] There is also evidence that it may becoming easier for investors to obtain power purchase agreements (PPAs). In particular, Genesis signed PPAs with an independent supplier (Tilt Renewables before it was acquired by Mercury) and a competitor (Contact).[94]

We also understand that, collectively, industry participants (both existing and new) now have around $2 billion of investments either planned or under construction. But, of course, that investment will not happen overnight. It takes a long time to obtain resource consents, to build the plant and to arrange a network connection.

93 Concept Investment Environment Report, p.8.

94 *Op cit.*, pp.5-6.

The 'investment deficit' will take time to eliminate but, when it is, prices should realign with entry costs.

However, as that investment comes on-stream in the coming years, it is plausible – likely, even – that spot prices will realign with the LRMC of new entry, just as one would expect in a competitive market.

To be sure, absent the factors described in the previous section, this new investment might have happened sooner and prices might be lower today. But the important thing is that new investment *does appear to be happening*. In the meantime, prices may continue to be above LRMC. Yet, that does *not* mean there are enduring barriers to entry *or* that generators are exercising substantial market power. Moreover, any significant interventions might not only be unnecessary, but could even serve to disrupt any 'self-correction' currently underway.

5.3 Summary

Spot prices in the NZWM have exceeded LRMC in recent years and will continue to do so for some time. However, there appear to be good reasons why. Multiple factors may have diminished incentives to invest in new generation capacity. These include uncertainty surrounding the future of the Tiwai point smelter and government decarbonisation policies. These factors may have discouraged investors from committing capital, despite the ostensibly attractive returns on offer.

Much of that uncertainty has now diminished – but in some cases, only relatively recently. For example, the smelter's immediate future has been secured and there is much more clarity about the government's climate change policies. This has led to an enormous recent increase in connection requests, surging development interest in solar farms and around $2 billion of investments either planned or under construction. This may all serve to realign prices with entry costs.

However, this adjustment process may not be swift. It will take time for the 'investment deficit' that has built up during the recent period of extreme uncertainty to be erased. Obtaining resource consents, constructing plants and connecting to the grid all takes time – projects are multi-year endeavours. Even so, it would arguably be unnecessary and undesirable to intervene in a market that appears well on its way to addressing the 'gap' between prices and LRMC.