MDAG – Price Discovery with a 100% Renewables Wholesale Market

Literature Review of Price Discovery in 100% renewables.

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Contents

1 Purpose

The purpose of this literature review is to inform the issues stage of the Market Development Advisory Group's "Price discovery in the wholesale electricity market under 100% renewable electricity supply" workstream.

2 Approach to literature review

A 100% renewables wholesale market raises a range of questions about price formation, including:

1. How will short-term coordination and dispatch be affected (including security of supply)? Will existing ancillary services be affected, and will new ancillary products be required?
2. How will spot markets behave – level, volatility and uncertainty? Participant behaviour? Demand side flexibility?
3. How will contract markets (including retail) be affected?
4. How will investment be affected?

Our initial scan of the literature suggests that questions (1), (2) and (4) are the primary focus of studies that explicitly consider 100% (or, at least, very high) renewables.

However, in order to obtain useful insight for New Zealand, we have to be considerate of the market contexts in which the studies were conducted. The nature of observed or predicted impacts of 100% renewable generation (100%RE) on wholesale markets will depend on (amongst other things):

- How investment in renewable energy, and retirement of thermal is being driven – commercial decisions based on expected spot and contract market outcomes, or via government policies (e.g., feed-in-tariffs (FiTs), strategic reserve). Perhaps more than any other factor, the presence of FiTs, subsidies and other investment incentives is probably the most limiting factor in terms of providing insights for the New Zealand electricity market) in many of the international studies of spot price behaviour[1] and investment signalling. As noted by Joskow (2019), Lynch (2021) and Newbery (2018), both the cost structure and market implications of variable RES has led to a growing reliance of investment on the signals embedded in subsidies. We consider these limitations further below.
- Are prices subject to significant regulatory controls (e.g., price/offer caps caps)?
- How security of supply is incentivised and maintained – e.g., energy only market incentives or through capacity remuneration mechanisms. Jurisdictions with capacity remuneration mechanisms cloud the impacts of increasing intermittent renewable generation on security of supply, as – almost by definition – these mechanisms are often designed to directly achieve a certain level of supply security, and are typically paired with spot market caps well below the value of lost load (Joskow, 2019).
- Whether the market already has access to significant medium term renewable storage, or considers it in modelling for future scenarios?
- Whether the market under consideration is able to supplement supply via interconnectors with other markets (countries or states).

Unfortunately, there are likely to be few studies conducted in New Zealand's unique context of:

a) An island nation, with no ability to import electricity from, or export to, another market;

[1] As noted by Newbery *et al* (2018), renewable generation subsidies that are actually tied to dispatch

b) A significant renewable system presently (less than 20% thermal in an average year), dominated by storable, energy-limited but highly flexible hydro;
c) A relatively unfettered market design with an energy-only nodal and co-optimised reserve markets, and forward contract markets;
d) Dominance of vertical integration between generation and retail, and lightly regulated retail competition;
e) No government policies at present which support or subsidise investment in particular generating technology.

However, rather than ignore these studies in different contexts altogether, we have taken a mixed approach where topic areas (1) – (5) above are all considered, but to varying degrees of comprehensiveness. The degree is a matter of judgment and pragmatism, and areas with only a light touch can always be further investigated at the options stage should they arise as key issues in the wider MDAG analysis and consultation.

Finally, as well as using traditional academic search databases to source articles, we approached a number of authors who are active in particular areas where there appeared to be a scarcity of studies. These conversations reinforced our perceptions of limited studies (especially of relevance to New Zealand) but also provided very helpful insight into current directions of research that would be worthwhile MDAG staying apprised of during this project. Authors corresponded with were:

- Professor Paul Joskow at MIT;
- Professor Richard Green at Imperial College, London;
- Professor Paul Simshauser AM, Joel Gilmore, and Philip Wild at Griffiths
- Farhad Billimoria at Oxford University;

3 Outline of literature

The impacts of very high, or complete, renewable penetration on price discovery in wholesale markets have received considerable attention in the literature. These impacts span:

- The potential for greater real-time (weather-induced) variability on short-term coordination and dispatch processes (and thus pricing), as well as reduced inertia resulting from an increase in the penetration of non-synchronous machines;
- The impact on spot markets, both in terms of price level and volatility across short, medium and long timeframes;
- The role of contract markets in managing risk;
- With the exit of dispatchable thermal plant, how ancillary, spot and contract markets can provide the right incentives for the entry of flexible, renewable plant to manage the short, medium and long-term variations in demand and intermittent renewables.

As a general comment, the most significant component of the literature focuses on the combination of plant involved in a 100% renewables system i.e., what combination of storage, wind, solar, biomass, hydro, geothermal etc would result in the “optimal” system (see Zapata (2018), Weiss et al (2017)). As Zapata (2018) note in their assessment of the Colombian market, however, there is no single recipe for achieving 100% renewables, as the optimal makeup in any country or jurisdiction will depend on the natural endowment of resources that jurisdiction has, as well as the system that provides the starting point (e.g., the presence, or lack thereof, of significant flexible hydropower, which already provides significant short-term flexibility to respond to intermittent renewables). In this we would include the impacts of a high penetration of intermittent, non-synchronous generation system operation and stability.

Riesz *et al* (2016) noted that, "*most studies to date have focused on the technical ability of a system to supply reliable electricity; few have directly considered the market implications.*" This was probably an accurate picture in 2016, and since then the focus on wholesale market impacts has received greater focus. However, the vast majority of this focus has been on analysing and modelling the impact of intermittent renewables on spot prices (i.e., the "merit order" effect, as discussed below).

Fewer studies have focused on what the future, high-renewable, prospects are for wholesale market price discovery and design. It is here we also encounter the divergence of markets with capacity remuneration mechanisms, from energy-only[2] markets. At the issues stage, we are primarily interested in studies which consider how energy-only markets may fare under a very high renewables world.

Even fewer still studies have considered the implications of very high renewables for contract markets. This partly reflects the relatively small subset of liberalised markets which have liquid hedge markets, particularly between the supply side and demand side. For example, while a variety of contract forms – PPAs and CfDs - support the entry of intermittent renewables globally (often transacted between developers and government or corporates), most US states do not have retail competition. Second, in many jurisdictions, the availability of contract market data is far lower than spot market data, and is often insufficient to allow empirical analysis of competitor behaviour through time, or the way in which firms use different contract forms to manage risk (Rai and Nunn (2020)).

Finally, we note the interconnectedness of a number of studies. For example, studies of investment are hard to disentangle from assumptions, or insights, about pricing mechanisms, behaviour or contract support. Notwithstanding this, we proceed by starting at the long-term – investment, and then step through the markets and mechanisms that generate the revenue, and incentive the plant mix.

4 Investment

The primary motivation for electricity reforms around the world was dynamic efficiency – ensuring the right investment (generation, storage, demand side response) occurred at the right time and place. 100% renewable markets will differ from mixed thermal markets - higher proportions of capital cost relative to operating cost, and significant short and medium term uncertainty about fuel availability, to name two. While the majority of renewables investment is expected to be intermittent, Joskow (2019) summarises the more difficult part of the investment problem succinctly, as needing to also incentivise investment in:

> "…*highly flexible generating capacity and/or storage, demand side responses…*with *relatively low capital costs, low start-up costs, and the ability to respond rapidly to dispatch instructions. There are a number of dimensions of flexibility. There is a need for*

[2] We acknowledge the comments of a range of authors that "energy-only" is an unhelpful term. Markets like New Zealand, the Australian National Electricity Market (NEM), or Norway (for example), which would be classified as "energy only" in the orthodox vernacular, all have reserve markets which reward plant for making firm capacity available to the market, and supply must match a demand determined by a security of supply constraint. While this does not fit the most commonly conceived version of a capacity market, it is still a market design option which forms a price which rewards a firm availability commitment.

generation that can increase or decrease production very quickly to respond to the very short-term fluctuations in the output of solar and wind facilities both to supply energy to balance variable demand and to stabilize what would otherwise appear as unwanted fluctuations in frequency and voltage. Similarly, there is a need for generation (or storage) that can ramp up quickly to contribute to the large but variable ramp over three or four hours at the end of the day as the sun goes down and before demand declines later in the evening. But as we drive the system toward 100% renewables fossil-fuelled dispatchable generation will be increasingly limited. Wholesale markets will need to adapt by creating new product categories to enable system operators to schedule, dispatch, and pay for generating capacity that meets these response needs efficiently."[3]

We cover the potential dimensions of adaptation in system operations and spot markets below, but it is important to recognise that the long-term incentives required for the set of investments that are required to support 100% renewables markets are critically dependent on the signals that arise from ancillary, spot, and contract markets – as Hogan (2013) observes, the long-term is a succession of short-term markets. Reisz (2016) also observes that scarcity price limits also strongly affect investment in the market. The higher the scarcity price (or market cap, in those jurisdictions that have them) "*the more revenue a new entrant can expect to make during periods of market scarcity. Thus, the attractiveness of investment in new capacity is directly affected by the [Market Price Cap], in combination with market expectations of how often extreme prices are likely to occur*." We cover scarcity prices further below.

Numerous studies outline the challenges facing investment in high renewables studies. As outlined below, Simshauser (2018) considers the difficulties in obtaining sufficient certainty in revenue to obtain finance for the high levels of capital cost required for renewables investments, tying this challenge to the lack of long-term hedge contracts in the Australian NEM. But the majority of international studies tie investment challenges to the "missing money" problem (driven principally by offer or price caps)[4] in *retaining* sufficient flexible thermal plant, and that the "merit order" effect[5] observed as supressing wholesale prices in many markets with increasing intermittent renewable generation, exacerbates this issue (e.g., Frew *et al* (2016), Lynch *et al* (2021), Newbery *et al* (2018)). This interplay between missing money, the merit order effect and variable renewables is discussed further in Section 6 below, but, in short, the merit order effect on average prices "*will make it more difficult for generators to recover all their costs because they will run less often and receive a lower average price when they do run*." (Frew *et al* (2016)). The lower utilisation and average price only further increases the challenge to achieve revenue sufficiency in those few remaining periods when last resort plant are in fact needed, and have the opportunity to charge scarcity rents, especially if market price or offer caps are in place which would limit the scarcity rents available to flexible plant.

Two helpful contributions in respect of energy-only markets come from Simshauser (2020) and Simshauser (2021). Both papers empirically analyse the investment attractiveness of a gas peaker in the Australian NEM energy only market in the presence of intermittent renewables. In the case of South Australia, the penetration of intermittent renewables, as modelled by Simshauser, is over

[3] P39

[4] The "missing money" problem is primarily attributed to the presence of price caps, which mean that "prices do not fully reflect scarcity in tight market conditions, reducing profitability and leading to underinvestment in capacity over the longer haul." (Newbery *et al* (2018)). We discuss the missing money problem further in Section 6.2 below, where we consider the role of scarcity pricing.

[5] The merit order effect is considered further in Section 5 below

50%. While the financial sustainability of a gas peaker may seem moot when considering a 100% renewable market, we should not be distracted by the fuel type; a very high renewable system will almost certainly benefit from investment in some form of flexible, dispatchable plant (Frew (2016)) – even with the retention of hydro. In all likelihood, this plant will have a high fuel cost (e.g., biofuels), and hence Simshauser's consideration is relevant.

Simshauser shows that, while the earnings stability in such a market would make financing an Open-Cycle Gas Turbine plant (OCGT) very challenging as a merchant proposition (even in the presence of a liquid market for baseload and cap hedge products), but when integrated with merchant intermittent renewable plant (in this case, wind), the entry costs of the OCGT are met. Simshauser (2021) finds a similar result for an OCGT in the Queensland price region, when vertically integrated with an electricity retailer. Simshauser's modelling is based on actual prices observed in both NEM regions, and comprehensive financial and dispatch models, and leads him to conclude that an energy-only market can support peaking investment even when intermittent generation exceeds 50%. However, the work does not directly address the question of whether his results change as the proportion of renewables increases further.

That said, separating the average price (and therefore revenue inadequacy) impact of renewables from the incentives that are driving investment in intermittent renewables (and thus possibly leading to an unintended oversupply) is extremely challenging from an empirical perspective.

Studies of investment trends in energy only, 100% renewable markets that explicitly consider price discovery, are rare, and none that we are aware of allowing for a significant pre-existing component of hydro with storage. There are, though, numerous scenario-based models of whether and how transitions to 100% renewables may occur, using cost-minimising energy planning models that simulate investment decisions based on a set of scenario assumptions, and including hydro storage (Zapata (2018), Barbosa *et al* (2017) considering different aspects of South American systems[6]). This includes a wide range of scenario modelling undertaken for the New Zealand future electricity system[7]. Similar studies have been conducted internationally which do plot successful paths to 100% renewables (e.g., Hrncic *et al* (2021)), but they are highly country specific and do not explicitly consider the underlying energy market dynamics, including price signals. Rather, they assume that the markets will convey the signals consistent with their cost-minimising investment paths.

An exception is Weiss *et al* (2017), which conducted a simulation (investment and market operation) of a 100% renewable energy-only market based around the Israeli power system[8]. The decisions of six generation companies were modelled both at a short term (hourly resolution) and long term (annual resolution). Generation options made available to the companies included biomass, biogas and batteries as the dispatchable generation. No contract markets or demand response was

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[6] Both Zapata (2018) and Barbosa *et al* (2017) highlighted the valuable role of hydro – in some cases almost eliminating the need for battery storage – to manage wind and solar fluctuations. De Souza *et al* focused on the impact of regional interconnection and major industrial consumption flexibility as a way to manage intermittency, finding that both reduced total system cost. The ability to extrapolate Zapata's results to the New Zealand situation were unfortunately clouded by the assumed presence of a capacity market in all four scenarios considered..

[7] See e.g., BusinessNZ (2019) "New Zealand Energy Scenarios", Climate Change Commission (2021) "Ināia tonu nei: a low emissions future for Aotearoa", NZ Productivity Commission (2018) "Low emissions economy". Mason, Page and Williamson, (2010, 2013), Ferris and Philpott (2020), Reeve and Stevenson (2021) as referenced in the bibliography.

[8] The study did not consider how the 100% system was arrived at; the first year in the simulation was a static optimisation of a set of plant made available to it.

modelled. They found that the energy-only market based on marginal pricing provided sufficient incentives to ensure continuous investment in a balance of technologies as demand continued to grow, albeit with 5.75 hours per annum of lost load in 2050, even with VoLL scarcity pricing[9].

In Weiss *et al*'s optimal plant mix in 2050, dispatchable generation made up only 30% of generation fleet (including 17% of short-term batteries), much lower than would be experienced by New Zealand in the near future, but may be more representative of the more distant future.

Weiss *et al* conclude: "*Therefore, attracting enough flexible resources to the market, that is, different types of storages and demand-side resources, and ensuring appropriate competition among them will play a vital role in the efficient functioning of the 100% RES markets.*" (p272-3)

Kraan *et al* (2019) provide an agent-based model of investment, comparing energy-only markets to capacity markets. Their agent-based model has highly simplistic assumptions (i.e., it has no spot market or dispatch model, and only models investment decisions by agents assuming a scarcity rent "curve", albeit on a daily resolution).   It concludes that an energy only market with "realistic" assumptions about agent (investor) behaviour will not achieve a reliable, affordable and renewable system. However, we note that the primary "realistic" assumption about agent investment behaviour is that there is a 7-year gap between the time that an investment decision is made to when it is completed. We do not believe this is at all realistic in a renewable world, where investors are likely to have development options, and the time to execute these options (presuming the developers will have a range of options identified) can be much shorter than 7 years. Further, and more importantly, the model only allows for an 8GWh storage asset to be chosen by the agents, in a system with a fixed "daily" demand (one time period) of 15GW; implying that at most, the model could store two days' worth of demand[10]. This is a vastly different investment landscape to the New Zealand system.

5 Dispatch and Ancillary Service requirements

There are many studies of the impact of variable renewables on short-term dispatch and ancillary service markets (Transpower (2021), Simshauser (2017), Sysflex (2019), Kroposki *et al* (2017)). We do not present the full spectrum of technical issues associated with high renewables, and refer the reader to Transpower (2021) for a full discussion of the New Zealand context and supporting papers and analysis. The ancillary service impacts of very high renewables that attract our attention are those which may have price formation implications. These effects include:

i. The increase in asynchronous renewable generation (solar, wind) (which are not physically coupled to the system frequency) at the expense of thermal plant (which is) is a **net loss of inertia to the system**. Inertia is the first response to a drop in system frequency. Historically, inertia has been provided in such abundance through large rotating turbines that it has never had to be "procured" or priced. Simshauser (2017) argues that inertia is a "missing market" in the Australian NEM, due to the fact that it is moving from abundance to potential scarcity. The increasing pressure on Australia and New Zealand systems' existing 6 second reserve, resulting from less inertia, may motivate the need for a "Very Fast Instantaneous Reserve"[11] (<1 second) market, which batteries could supply response to. Transpower (2021) identify that a reduction in inertia resulting from the retirement of

[9] The price level was not made explicit in the study
[10] In a separate study, Kraan (2018) present what we believe is the same model with the explicit assumption that there is no seasonal storage available to the model.
[11] Transpower, 2021, *Price discovery under a 100% renewable electricity supply*, Presentation to MDAG

thermal, and increases in inverter-based generation like solar, may present a challenge for the New Zealand system if the proportion of synchronous generation falls below 50%. Transpower's decarbonisation scenario suggests this may not be a challenge until much closer to 2050.

ii. The increased challenge associated with **short-term forecasting error for wind**, which may require flexibility on a time scale longer than frequency reserves (Frew *et al*, 2016). Presumably the same challenges arise with solar. In a simulation of the Texas electricity market, which has a similar design to New Zealand, Frew *et al* included a scenario with an additional reserve product ("Flex Up") designed to "[hold] back or [bring] online additional eligible generating capacity to meet an hourly reserve requirement for the expected forecast error (uncertainty)." While the direct revenues associated with reserves was relatively low for all plant types considered, the energy revenues were around 13% higher, due to the co-optimisation of energy and reserves, which saw the reserve price influence energy prices.

iii. The **rapid system ramping required** due to the confluence of declining solar production and increasing demand at the end of the daytime period (Joskow (2019), Simshauser (2017)). Like for inertia, Simshauser argues that "ramping duties" also constitutes a missing market in a high renewables world.

iv. Transpower (2021) identify "**system strength**" as an important aspect of the New Zealand market today. System strength is "*a measure of the power system's ability to maintain voltage waveform and recover stably following a fault or disturbance*". There is some uncertainty about how various inverter based generation technologies will collectively behave, and, as Transpower notes, is likely to have localised manifestations with "*greater potential for problems where multiple [inverter based resources] are connected in proximity.*" We include voltage management issues here due to the ongoing discussion in the literature about the potential for reactive power pricing, which may form part of a solution (see, e.g., Chattopadhyay, Chakrabarti and Read, 2002).

In respect of (ii) and (iii), Transpower (2021) suggests that "*present operational practices will carry enough reserve to mitigate low penetration level of wind and solar PV, however this will be monitored closely. This challenge will occur in the mid-term as the penetration level of wind and solar PV generation increases.*"

In respect of reserves, Hogan (2013) argues that system operators should consider procuring reserves beyond the minimum amount currently typified by standard practice. By procuring only the minimum amount through reserves markets, the implication is that additional reserves are not worth anything; however, procuring anything less than the minimum amount implies the system operator would contemplate involuntary pre-contingent load shedding. This jarring transition is challenging from an economic perspective, and Hogan argues that "*System reliability would be improved if more operating reserves than the minimum were available in terms of response to increase generation or quickly decrease load. Over the next few minutes or parts of an hour, events may arise that deplete operating reserves and bring the system below the minimum contingency requirement, in which case the operator will have to impose involuntary load curtailments to restore the minimum contingency protection*." Hogan's proposed "Operating Reserve Demand Curve", which has been implemented in a number of US jurisdictions, approximates a downward-sloping demand curve for reserves based on the probability of those reserves being required due to unforeseen circumstances. Co-optimisation of energy and reserves would therefore include the reserve effect in energy prices, providing both an additional scarcity signal during times of tight margins.

6 Studies of spot price behaviour under high renewables

There are numerous studies of an observed price-suppression effect of increasing low marginal cost renewable generation in a variety of jurisdictions in Europe, North America, Australia and Japan (Halttunen et al, 2020). This reduction in wholesale prices is typically referred to as the "merit-order" effect (see e.g. Lynch *et al* (2021), Newbery *et al* (2018), Simshauser (2017)), which sees generation from high marginal cost thermal plant offset by very low SRMC renewables, thus lowering wholesale prices and challenging the revenue adequacy of thermal plant with higher variable costs. However, care is required in extrapolating the degree to which prices are reduced to the New Zealand context, for the following reasons:

- A large proportion of these studies are of jurisdictions where renewable investment is supported by investment or generation incentives (e.g., feed-in-tariffs). This results in the drive to build renewable plant being less driven by expected spot prices, and more by the degree of subsidy, than would occur in New Zealand[12]. Joskow (2019) argues the incongruence of subsidised entry of renewables and market-driven exit of thermal, with the latter relying on volatile energy and ancillary market revenues, means that the market simply cannot be in any sort of equilibrium, which raises questions about the ability to generalize the resulting price series to jurisdictions where this incongruence does not exist.
- In the majority of these studies, the (often incentivised) entry of very low SRMC[13] renewables is leading to the exit of the only plant in the system that provided firming support and thus non-zero price formation (i.e., thermal). While the entry of intermittent renewables will also cause the exit of thermal in New Zealand, it will not result in the exit of hydro, which provides significant firming support to the market (albeit medium-term only due to limited storage). In their analysis of the merit order effect in 37 international jurisdictions, Halttunen *et al* (2020) analysed wholesale prices in Norway (4% intermittent renewable penetration) and Austria (15% intermittent renewable penetration), two hydro-dominated jurisdictions (albeit interconnected with other systems), and found evidence of a small merit-order effect, concluding that load and "time" (potentially a proxy for storage) had substantially greater predictive effect on price variation.

With the majority of studies, it is difficult to disentangle the degree of price suppression observed due to the fact that renewable investment was being incentivised through government policies, rather than expectations of wholesale revenues, and the fact that in those markets with capacity remuneration mechanisms (and, in all likelihood offer caps), rents earned during periods of scarcity are less important (or less significant in overall revenue terms) . This begs the question inferred by Joskow (2019), noted above, as to whether the timing of renewable investment, and its coordination with thermal exit, would have been different without the support. Simshauser (2021a) goes further and ties the merit order effect directly to the inefficient[14] delay of thermal exit. Newbery *et al*

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[12] Also, a number of feed-in-tariffs are coupled with priority dispatch often resulting in negative prices (Newbery, Pollitt, Ritz, & Strielkowski, 2018).

[13] The literature frequently refers to "zero-SRMC" plant, usually in reference to wind and solar. In New Zealand, it has been recognised for some time that wind plant has variable operating and maintenance costs which should be allowed for in its offer to the market, and potentially curtailed if prices fall below that. Solar may genuinely have zero-SRMC

[14] Simshauser's definition of efficiency here is driven by the expectation that thermal would exit when wholesale prices could no longer financially sustain operation of the plant.

(2018) also observes that in the early days of subsidised renewable increase, the merit-order impact on prices was not foreseen and many of the European energy companies continued to invest in base-load fossil fuel power plants in anticipation of high wholesale prices.

6.1 The importance of opportunity cost pricing

As outlined below, Reisz *et al* (2016) analysed a 100% renewable future making a simplifying assumption that prices in that world (in the Australian context) would either be zero or the market price cap. This reflects an impression found occasionally in the literature that renewables are zero-SRMC; this is often a critical part of the assumptions about price distributions that are forecast for high renewables.

The notion of opportunity cost pricing is embedded in the New Zealand market, principally (but not exclusively, as discussed shortly) because of the presence of large hydro reservoirs. However, the relevance of opportunity cost to pricing in electricity markets poorly canvassed in the literature we reviewed on pricing. Read (2018) provides a comprehensive treatment in the New Zealand context that, in reality, offering based on opportunity cost is the correct way for any plant whose fuel sources are limited by some storage (reservoir, stockpile) capacity - thermal and (obviously) storable hydro included. Demand-side bids will invariably have an opportunity cost component to them. Evans (2017), echoing Read, reinforced Weiss *et al*'s observation by concluding that battery owners should apply opportunity cost pricing to their market behaviour, and that this is consistent with the intended operation of New Zealand's spot market design.

We do not review the literature on opportunity cost pricing here, but refer the reader to Read (2018) for an excellent discussion.

6.2 The importance of Scarcity Pricing

Similarly, scarcity pricing and scarcity rents are critical to market efficiency. The implication of many papers is that, ignoring the presence of significant medium-term storage priced on opportunity cost, the merit order effect sees renewable investment and thermal disinvestment but without a commensurately higher occurrence of scarcity prices that would presumably result lower capacity margins. These scarcity prices would otherwise offset the merit-order effect of increased very low SRMC generation, and exit of thermal, on the average price.

Joskow (2008) points out, scarcity pricing is not a departure from the basic principle of short run marginal cost pricing. Rather, changes in price (moving along the demand curve) when capacity constraints are binding reflect represent consumers' short run marginal opportunity cost of having more or less generating capacity.[15]

This raises the question of the extent of "true" scarcity pricing in many jurisdictions observing the merit-order effect. Hogan (2013) and Joskow (2019) reinforce the primary importance of scarcity pricing to the efficiency of energy-only markets, with Hogan (2021) arguing that the predominance of very low SRMC plant does not at all undermine the basic principles of an energy-only market as long as effective scarcity pricing is in place.

That said, Murphy *et al* (2018) simulated a system in the Australian NEM with a low $1,000/MWh price cap in scarcity situations and increasing renewables and found that even renewable (intermittent and firm) penetrations of 70% resulted in all generators (across thermal and renewable fuel types) being revenue adequate. However, this included a 25% minimum dispatch constraint on

[15]Joskow, Paul L. 2008, "Capacity Payments in Imperfectly Competitive Electricity Markets," Utilities Policy, 16: 159-170.

non-VRE plant (coal, gas, utility hydro, pumped hydro, biomass generators as well as batteries) to ensure system stability which likely added to revenues.

The reality in many jurisdictions, however, is the existence of the "missing money" problem (identified by many authors e.g., Newbery (2016), Joskow (2019), Cramton *et al* (2013)) that typically results from energy market price caps well below scarcity value set either by demand-side bids or administratively through the value of lost load (VoLL). This missing money problem has, amongst other things, led to the introduction of capacity remuneration mechanisms in a number of liberalised markets; and the merit order effect has simply shifted revenue reliance for firming plant progressively towards the capacity market (Joskow (2019), Lynch (2021)).

However, New Zealand's approach to scarcity pricing is closer to Hogan's ideal and will move closer again with the introduction of real-time pricing[16]. Shorter dispatch and pricing periods, such as that heralded by the RTP project, featured as part of Lynch (2021) prescription to deal with the impact of VRE in the Irish market. Again, the characteristics of the New Zealand market design means that international studies of the merit order effect and very high renewables are less comparable to New Zealand, and that the New Zealand market may be more resilient to increasing amounts of VRE.

6.3 Studies of spot price behaviour in 100% renewables

A relatively simple study of pricing in Australia's energy-only NEM market under 100% renewables was conducted by Reisz *et al* (2016). Reisz's study was focused primarily on the level of the market price cap (MCP) that would be required to maintain the target reliability level in the NEM (0.002% unserved energy). On the assumption that all variable renewables would offer at zero, Reisz calculated that the MCP would have to increase from its then-current level of $13,500/MWh to between $60,000-$80,000/MWh during scarcity periods in order to create average prices commensurate with the volume-weighted market LRMC of between $111/MWh and $133/MWh necessary to fund a 100% renewable market[17].

There were significant limitations to this study – firstly, despite storage being considered as part of the 100% renewable mix, no consideration was given to the extent to which this would change the price distribution from its assumed binary ([0, MCP]) nature. Second, we are unsure if any consideration was given to whether an individual investor would achieve their LRMC if the price distribution implied by Reisz's modelling was achieved on a generation-weighted basis (e.g., solar). Despite this, though, Reisz's study was an intelligent commentary on the interconnectedness of administered scarcity pricing, reliability targets, contracts, demand side participation and investment.

A later study by Rai and Nunn (2020) reassessed the expectation of greater instances of very low and very high prices in the Australian context. Their analysis of actual market outcomes only partially supported Reisz's hypothesis. While spot volatility had risen, prices had not become more extreme

[16] See https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/

[17] The costs of a 100% renewable power system were sourced from detailed modelling conducted by the Australian Energy Market Operator. Their analysis quantifies the cost of a 100% renewable power system that meets the NEM reliability standard of 0.002% USE over the long term, and includes the cost of sufficient firm generation to complement the large capacities of wind and photovoltaics that are deployed on the basis of their low costs. This modelling finds that to cover the capital and operating costs of generation, storage and network connections for a 100% renewable power system in the NEM would cost in the range of $111/MWh (2030, low cost scenario) to $133/ MWh (2050, high cost scenario). These are volume weighted average costs.

in any of the NEM's four regions – the volatility was caused by an increased incidence of prices in the AUD100-500/MWh range. The authors provide four potential reasons for these outcomes:

(i) Greater investment in storage and interconnectors, which dampen intra-regional volatility;
(ii) Increased contract cover[18];
(iii) More price-responsive demand[19], and/or
(iv) The emergence of ancillary service streams, resulting in additional pool payments to generators.

The authors are quick to note that these are results for discussion, and they expect that evidence is still emerging.

The most relevant study to the New Zealand situation is a dispatch-based simulation model of the New Zealand market (Gholami, Poletti, & Staffell, 2021), which investigated a variety of high-renewable scenarios ranging between 84% and 99% penetration in 2035. The scenarios are constructed primarily by the authors to reflect different mixes of wind and solar, but any investment required to "complete" the system to a pre-defined system capacity level[20] at the 2035 demand was constructed using the Electricity Authority's Generation Expansion Model (which primarily added a combination of peakers and demand-side response, but also geothermal in one scenario).

Due to limitations of input data, this study of 2035 subjected (via simulation) the various renewable makeups to two historical years of solar, wind and inflow data (2004 and 2006) matched to a scaled load profile for both years. Usefully, however, the two simulation years chosen represented wet and dry hydro years. Market prices were simulated using a market solver which assumed SRMC offering by all market generation, except for hydro which was offered in at a simulated water value, calculated using an approach similar to Tipping and Read (2010)[21].

Approximately 500MW of demand-side response was included at an offer price of $999/MWh, and a system VoLL price of $3,000/MWh. Battery storage was not modelled.

All increased renewable scenarios saw a positive number of "outage hours" (compared to zero in the baseline), peaking at 218 hours in the scenario with the highest levels of both solar and wind investment. Intriguingly, the outage hours in this scenario were more than four times *higher* in the wet year than the dry year. Once these hours were accounted for at the assumed VoLL price of $3,000/MWh, average prices displayed no clear merit-order effect, and scenarios with high solar saw prices rise well above the baseline figure, at least in the wet year. The solar-dominant scenarios left

[18] Through discussions with market participants the authors estimate that "*contract cover in South Australia and other parts of the NEM increased between 2017 and 2018, from around 80% to 90%*". The authors infer this is a semi-permanent increase, attributing it to the high price events arising from the closure of a power station, and changes to the Retailer Reliability Obligation.
[19] The author's do not actually provide evidence that there has been "more" demand response; simply noting that there is ~400MW of wholesale-offered DR today, and the introduction of AEMC's wholesale DR mechanism should increase this further.
[20] A peak system capacity: peak demand ratio of 1.22, as the system has today.
[21] We note that the approach of Tipping et al was to estimate water values based on an econometric model of observed reservoir management and price behaviour. The relationship between reservoir levels and water value will have some significant embedded component related to the market context at the time, including regulatory frameworks and fuel mix. Using this approach, based on observed history, to estimate future reservoir management behaviour in a 100% renewable world, is questionable.

the system exposed to high peak demand in winter (when the solar resource is lowest), whereas wind-dominant scenarios had more reliable winter generation.

The authors conclude that, despite the lack of evidence of price-suppression in these scenarios, average price levels “are still below LRMC of new generation for the high renewables scenarios”. However, LRMC figures to justify this assertion are not quoted.

In order to achieve even higher renewable penetrations, the authors constructed two additional high wind scenarios with 300MW and 600MW of geothermal added respectively – effectively creating a renewable overbuild world. Hours at VoLL pricing reduced significantly, as did the average wholesale price in both years simulated. Prices were reported to be $0/MWh in 40%-60% of hours; with little in the way of scarcity prices, average annual price levels fell below $30/MWh.

We have a number of observations about the Gholami *et al* study:

- The reliance on two simulated years (essentially for meteorological conditions, but also demand profile) is very limiting. The authors note that both years had higher wind capacity factors than usual.
- Average prices were supported by a varying number of hours at a “scarcity” level of $3,000/MWh in all scenarios. In some respects, for involuntary curtailment, $3,000/MWh is relatively low compared to today’s administrative scarcity prices in New Zealand ($10,000/MWh), and in today’s market a small amount of generation capacity (~200MW) is routinely offered at price levels higher than $3,000/MWh[22]. The model also did not allow for voluntary demand response. The authors speculate that the introduction of batteries into the model would make many of the scarcity hours disappear, thus collapsing prices. However, we note that this depends heavily on how the battery owners offer during peak periods, as they would presumably price based on opportunity cost, and occasionally earn scarcity rents (if they were charged); indeed, they would need to do so in order to recover the high level of investment cost.
- As outlined above, the assertion that prices do not support investment in new generating capacity is unsupported, and needs to recognise that contract market prices (including retail) is what drives investment. The higher volatility world envisaged by the Gholami study would plausibly result in higher contract risk premiums that could support investment (see below).

Finally, while not incorporating medium term storage (like hydro), Mallapragada *et al* (2021) models increasing renewables for the energy-only market in Texas (ERCOT). While not modelling 100% renewables per se, the authors applied two scenarios of total carbon dioxide emissions limits: 5g, or 1g CO_2 per kWh of electricity[23]. The authors modelled a variety of technology scenarios (as subsets of the two emissions scenarios), including different battery technologies (lithium Ion and redox flow), thermal storage, demand flexibility and response, synthetic fuels including hydrogen at different price points and dispatchable renewable generation.

The resulting system mix was dominated by wind and solar in all scenarios modelled. All scenarios had varying amounts of lithium-ion batteries and CCGT with carbon capture and storage, depending on the other technologies made available to it.

[22] See e.g., https://www.emi.ea.govt.nz/Wholesale/Reports/W_OS_C?Band5=3000&RegionType=NZ&_si=tg|offers,v|3
[23] For reference, emissions in New Zealand today are around 110g/kWh

In the 10 scenarios[24] for which price distributions were produced, none looked anywhere near the binary outcome between zero and scarcity[25] some commentators assume. In six of the scenarios, prices below USD5/MWh persisted for 60% of the time (similar to Gholami *et al* for the New Zealand context), with four (all in the 1g emission limit) seeing <USD5 prices occur ~80% of the time. Above this, prices rose somewhat smoothly, with prices greater than USD1,000/MWh observed in less than 1% of periods in all scenarios.

Mallapragada *et al's* modelling showed the value of longer-duration storage for price volatility – it was the additional of thermal storage and hydrogen that produced the "smoothest" transitions from low to high prices in the distributions.

7 Demand side participation

It is well recognised in the international literature that increasing demand-side responsiveness solves a number of imperfections with electricity market design (Cramton *et al* (2013), Fraser (2001), Hunt (2002)). Our purpose here is not to consider the spectrum of these imperfections, or review the vast literature on enabling demand-side participation, but focus on literature that illustrates how demand side participation could impact price discovery in a 100% renewable market.

Above we raised the importance of scarcity pricing in energy only markets, and the prospect that the level (frequency, price) of scarcity pricing may become more important in a 100% renewable world. Hogan (2013) connects lack of scarcity prices to a lack of "*incentives to participate in demand bidding or make the investments needed for active load management*"[26]. However, as noted by Reisz *et al* (2016) the level and frequency of scarcity prices are challenging politically. Further, from an equity perspective, scarcity results in non-price rationing (Simshauser, 2018) where shortfalls in generation relative to demand are managed through involuntary curtailment that does not discriminate between customers (other than the priority order for load shedding). However, in the theoretical ideal of significant demand side participation, each participating customer could indicate the price at which they were willing to remove load from the system, reflecting their individual value of (grid) reliability. This also has the benefit of reducing volatility (Reisz *et al* (2016)) and improving price formation, as, presumably, there would be a spectrum of valuations at which different customers would reduce consumption, providing a smoothness to the demand curve that may replicate (or improve on) the shape that thermal currently provides to the system. Lynch *et al* (2019) notes that this logic also applies to very low prices, which might trigger an increase in consumption (e.g., from new industrial processes) and thus raise prices at the lower end of the distribution.

Joskow (2019) suggests that a key challenge for highly renewable systems is better integration of the demand side with spot wholesale market pricing through the introduction of real time pricing and related demand control mechanisms, to help manage the short, medium and long term needs of a 100% renewable system. He argues, however, in order for demand-side flexibility to work, efficient scarcity pricing has to be paired with reforms of retail pricing. He believes flat retail rates will

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[24] five scenarios for the 5g emissions limit, and five scenarios for the 1g limit. The five technology sub-scenarios iteratively added to the base case (i) redox flow batteries, (ii) redox flow plus thermal storage, (iii) redox flow plus a hydrogen production process at a sale price of $2/kg, and (iv) redox flow plus hydrogen production @ $10/kg.

[25] In Mallapragada's study, VoLL was assumed to be $50,000/MWh.

[26] We note that Hogan has also been a critic of FERC's approaches to compensating customers for reducing demand. See Hogan (2010) *Demand Response Pricing in Organized Wholesale Markets*.

prevent the significant potential arising from battery storage, interruptible and shiftable heating/cooling (not to mention EV charging).

Joskow does not here consider the possibility where a third party could leverage the flexibility for their own wholesale market exposure, and share the benefit with the customer as a fixed payment, leaving the retail price flat. The end customer does not need to "see" the wholesale price, they just have to be incentivised to provide the flexibility to someone else. That said, he later forecasts the increase in "*more stable partially hedged retail price structures….in return for rights to partially control*" their load. This highlights that it doesn't require the customer to be exposed to the price, it just has to be a tradeoff between price stability and control.

Joskow cites the work of Imelda *et al* (2018), based on the Hawaii system, which shows that dynamic retail pricing yields a 2.4%-4.6% reduction in power expenditures in a fossil-fuel environment, but an 8.5%-24.3% improvement in a system heavily dependent on renewable generation. Joskow concludes:

> "*This makes intuitive sense. In a system where the short run marginal cost of generation fluctuates a lot from hour to hour and day to day, the welfare cost of flat per KWh rates is much higher than in a system where the short run marginal cost of production does not vary very much. This is the case because with flat retail prices the average gap between retail price and marginal generation cost is much larger in a system with widely time-varying short run marginal costs than in a system where short run marginal costs do not vary very much. In their analysis, Imelda et. al. (2018) find that the* ***demand-side responses induced by variable prices reflecting intermittency and associated variations in spot prices and short run marginal costs significantly reduces the costs of meeting a 100% renewables goal****. Of course, the benefits depend heavily on the assumptions about consumers' demand elasticities and more generally, their attention to and responsiveness to variable pricing*."[27]

Joskow also concludes that there is an inherent danger in demand response "trials", as they do not flush out whether consumers are willing to invest in the equipment to properly participate in demand-side responsiveness; neither do the retailers and flexibility traders have the incentives to properly establish systems, and allow the forces of competition to refine the products.

8 Contract markets

Contract markets are critical to managing risk exposure in the short-term market, as well as providing long-term incentives for plant entry. As Hogan (2013) notes, the design of the short-term market, the nature of volatility and risk in the medium term, and the ability to signal the type of investment required in the long term are all connected through forward markets. Reisz *et al* (2016) also hints at this connection between short term price volatility and contracting, indicating the advantage of energy-only markets (compared with capacity markets) is effectively involving the retailer – as the agent for aggregate customers' load profiles - in determining the "optimal" level of firm capacity in the market, via contracting. However, we note that where these retail contracts are held within a vertically integrated generator-retailer, the signals they provide for investment in flexible generation will not be transparent externally.

Again, there is a significant literature dating back to the 1990s on the role of hedge contract markets in electricity markets (see e.g., Gedra (1992), Allaz and Vila (1993), Klemperer and Meyer (1989),

[27] Page 48

Green (1993)), but there has been relatively little consideration of how increasing variable renewables will impact hedge markets. There is no study we are aware of that considers how contract markets would work in a fully renewable system.

The majority of studies that do exist are theoretical or philosophical in nature, likely due to the difficulty of obtaining empirical evidence of contract market stability or outcomes in the face of increasing renewables (Simshauser (2018)). We summarise these here.

Strategic Contracting

A number of analyses extend the work of Allaz and Vila (1993) to allow for the volatility introduced to markets as a result of renewable generation. Allaz and Vila demonstrated that increasing contracts diminishes the market power incentives of large generators, since the marginal increase in revenue from holding back generation only applied to their spot profit, not their contract profit. Hence they established (along with Scott (1998) and other work at the time) that "fully contracted" generators would result in the perfectly competitive solution. However, there was no consideration of market power in the contract market, or the role of risk aversion in setting contract prices.

Early theoretical extensions of Allaz and Vila to account for market volatility included Bunn *et al* (1998), and Batstone (2002). The latter investigated the incentives for generators with market power to amplify renewable-induced volatility (in this case, hydro) in order to increase contract market profits (and at the sacrifice of spot profits). The author found that there was a stable equilibrium where the gains in the contract market more than offset lost profits in the spot market, although the degree to which this equilibrium was profitable depended on both the relative risk aversion between the sellers (generators) and buyers (retailers) of contracts, as well as the degree of responsive demand. As Batstone (2002) notes "*customers who exhibit optimally responsive electricity demands are less willing to pay to avoid spot price variance than those who have fixed loads and thus can't respond*", highlighting the link between volatility in price, demand side flexibility, and contract market outcomes.

The notion of strategic firms acting to amplify weather-induced volatility raises an interesting question about the extent to which "firm" generators in a 100% renewable world would have sufficient discretion over output, and market power, to conduct such strategies. There has been no empirical analysis of the New Zealand market that assesses whether Batstone's conclusions could be detected in actual market behaviour[28], or whether a 100% renewable system would afford firm generators (hydro) sufficient opportunity to amplify the effects of the weather.

More recently, Ritz (2016) looks at the effect of the introduction of renewables on strategic contracting, finding that introducing uncertain fuel into Allaz *et al* lessens contracting by incumbents. This offsets the merit-order effect on price, but the net effect depends on the utilisation of renewables: in low wind/sun states of the world, the net effect is to raise prices (compared to Allaz), if wind/sun is plentiful, the net effect is to lower prices more than the merit order effect alone. The authors did not consider whether these state-dependent effects on the overall price distribution affected spot market volatility overall and thus contract market premia. Further, no empirical analysis tested these theoretical results.

Peura and Bunn (2018) further developed the general findings of Ritz, finding that modest increases in renewable generation causes incumbents to increase hedging (to insulate against volatility),

[28] Bunn et al (1997) constructed a simulation model of destabilisation based on the UK electricity market at the time, and found that overall revenue gains of 11% were possible

reinforcing the merit-order effect. However, for higher intermittent renewable penetration, variability conversely causes power producers to behave less aggressively in forward trading for fear of unfavourable spot-market positions. The lower sales counteract the merit-order effect, and prices may then paradoxically increase with wind capacity despite its lower production cost. The authors use real-world wind and demand parameters from the UK and Danish markets to demonstrate these effects.

Finally, Hesamzadeh *et al* (2020) provide an interesting extension to Peura and Bunn. The authors sought to explain a significant change in the spot market offering behaviour of a large generator in the Australian NEM; specifically, that the way a power station was offered switched from one of withholding capacity to force prices up, to a period where they looked to supress price. A model of firm behaviour (assuming risk neutrality) elicits the result that, when large generators cannot observe each other's hedge position, there is no pure (equilibrium) strategy in contract decisions – it is an all-or-nothing decision. However, as the number of firms increase, and/or are symmetric, they show that the tendency is for full contract cover.

While this primary work is not related to renewable generation, the authors offer preliminary results from a model that incorporates wind power. The skewness of the wind power production function has the effect of pushing the hedging decisions towards zero hedge cover.

Ritz, and Peura and Bunn, raise the interesting question of whether, in the medium term, forward market reactions to renewables change the degree to which increasing variable renewables drive a merit order effect. Above, we have argued that the merit order effect may be different in New Zealand than other jurisdictions, due to the entry of renewables, <u>and</u> exit of thermal, being driven from the same market signals, as well as the continuing presence of significant hydro which offers in at its opportunity cost. However, the strength of the merit-order effect is just one factor in the European work highlighted above; the impact of uncertain output and market conditions on forward market behaviour (liquidity, price levels and volatility) are worthy of consideration in the NZ context.

That said, the analytical results provided above raise interesting questions about the relevance to a market such as New Zealand's where the majority of "contract cover" is provided via vertical integration.

Contract market liquidity

More generally, Newbery *et al* (2018) argues that renewable generation owners may face a higher transaction cost in terms of risk management. One component of this risk relates to the challenges intermittent renewables face when contracting output ahead of time, leaving a residual risk (positive or negative) in balancing markets. While New Zealand does not have a day-ahead market, intermittent generation owners using short-medium term baseload contracts (e.g., in the futures markets) will face a constant task in monitoring output and potentially adjusting hedge positions. Newbery acknowledges that securing a pure power purchase agreement (PPA) removes the price component of this risk, leaving a residual volume risk, which is likely to be sufficiently modest and uncorrelated with the stock market to not require a significantly higher return from equity investors.

Simshauser (2018) raises the potential impact of the nature of variable renewables contracts on general contract market liquidity. The basic thesis is that renewables are being secured using *non-firm* PPAs and/or CfDs (the latter underwritten by state governments, the risk of which is also highlighted by Newbery *et al* (2018)), while simultaneously driving out thermal plant which typically back *firm* CfDs and cap products. Simshauser concludes:

"*But as non-firm VRE instruments form a progressively larger share of the forward market via the ongoing exit of thermal plant, there must be some tipping point whereby a level of instability emerges in hedge markets via shortages of primary-issuance firm swaps and caps required by firms with retail exposures*."

Simply put, Simshauser is suggesting that a point is reached where there is insufficient plant left in the system to offer firm shaped products for retailers, especially those who are not part of a vertically integrated portfolio. While not highlighted by Simshauser, the potential for incumbents – renewable or otherwise – to reduce their contracting level in the face of uncertainty noted by Peura and Bunn potentially adds to the shortage. In the New Zealand context, though, it is unclear whether an equivalent tipping point for Tier 2 retailers will come into view given that a significant proportion of firm contracts are currently offered by hydro owners, who will still be present in the 100% system.

While not in the context of variable renewables per se, Simshauser also raises the challenges with obtaining project finance for investment without a good availability of long-term contracts. He notes the NEM's tendency (as with New Zealand) for its forward market liquidity to only span 3 years, compared to the much longer horizons required by project finance. He ties the short span of forward markets to the lack of willingness of retailers to sign contracts beyond that – blaming (as others have, e.g., Newbery 2006) customer level uncertainty, demand uncertainty, and risks of being undercut by others resulting from excessive retail competition. Simshauser highlights declining contract terms for C&I customers as evidence for this effect; however, anecdotally we are aware that C&I contract terms may be increasing in NZ. That said, both Simshauser (2019) and Newbery (2018) are highly critical of the response to this shortage of contracts seen in both the UK and Australia, where governments have underwritten non-firm CfDs for plant entry. Simshauser offers no remedies to this shortage of long-term contracts, and the conclusion for New Zealand might be that the most likely parties to underwrite entrant renewables are incumbent vertically-integrated generator retailers.

Using the transaction cost theory of Williamson (1971, 1973)[29], Simshauser (2021) showed how the earnings volatility faced by merchant investors in volatile energy-only markets can be better overcome through vertical integration (between retail and peaking plant, in this case) than using baseload and cap hedge products. As mentioned previously, an earlier paper by Simshauser (2020) demonstrated how horizontal integration between peaking plant and intermittent renewables is again a lower cost form of achieving earnings stability, even with intermittent renewable penetrations reaching 50% (such as that seen in South Australia). The primary transaction cost[30] removed by vertical integration (compared with OTC or exchange-based hedging) in Simshauser's modelling is that of credit-worthiness: a combined portfolio of generation and retail enhances credit metrics which, ceteris paribus, produces lower debt transaction costs[31].

[29] See Williamson, O.E., 1971. The vertical integration of production: market failure considerations. Am. Econ. Rev. 61 (2), 112–123; Williamson, O.E., 1973. Organisational forms and internal efficiency. Am. Econ. Rev. 63 (2), 316–325.

[30] Simshauser refers to contract premia as an additional transaction cost that is reduced on integration. We are unsure of this; we would prefer to categorise the premium as part of the combination of counter-cyclical revenue streams (which, admittedly, results in the improvement of credit metrics).

[31] Simshauser's modelling for the 2005-2020 period in the Queensland region of the Australian NEM shows a standalone retailer consistently below investment grade (BBB), and the merchant gas plant primarily below investment grade but occasionally having years of BBB or BBB+. The integrated entity is almost exclusively BBB.

The empirical analyses by Simshauser (2020, 2021) was based heavily on modelled market outcomes in, and assumptions tailored to the Australian NEM. We have not explored whether Simshauser's results are replicable for New Zealand.

Simshauser is silent on whether the implied result of both analyses is that increasing intermittency results in a trend towards increasing vertical integration . Simshauser simply notes that in the two Australian markets modelled – both of which have significant intermittent renewables – the financial sustainability of (a) a retailer, and (b) a wind farm, is more assured when part of a vertical or horizontally (respectively) portfolio, due to the transaction costs of "on market" contracting between merchant organisations being eliminated by being part of a single firm. We intend exploring Simshauser's modelling further.

In summary, the literature hints at the impacts of increasing renewables on contract market outcomes through theoretical development and reasoning, falling frustratingly short of providing strong evidence. However, this is not a criticism, since the evidence may not yet be available, given the recency of renewables increases in many markets around the world. And theoretical developments should not be dismissed, but rather highlight where better evidence of contract market outcomes would be valuable.

9 Summary

Beyond technical optimisations, or cost-minimising energy system scenario models, there are few studies of price discovery in 100% (or even very high) renewables markets, and very few whose conclusions consider a system with significant medium term storage (in the form of hydro), and/or the absence of government support for investment in renewables.

Notwithstanding that, we have attempted to find studies which might have insights in respect of the kinds of issues that might arise in markets like New Zealand. First and foremost, many of the studies highlight that the right investment (i.e., dynamic efficiency) is critically dependent on the interplay of short-term (including ancillary service) market price discovery and contract market price discovery. Challenges in these markets will result in challenges for investment. More specific insights include:

- It is likely that **new market products, spanning reserves and short-term dispatch, may have to be developed**. The literature suggests priority areas will be inertia (<1second reserve products, to offset the lower proportion of synchronous generating plant), and products to help manage the short-term variability of wind and solar, including significant ramping. Whether or not, or for how long, NZ's current hydro plant can meet these changing technical requirements is the subject of the Electricity Authority's "Future Security and Resilience" project. But the establishment of market products will result in enhanced pricing which rewards flexibility, which will be critical to 100% renewable markets.
- There are concerns globally about the "merit order effect", supressing wholesale prices, induced by the increase in zero-SRMC renewables. The **primary concern is the exit of flexible thermal plant due to the well-known "missing money" problem, which appears to be exacerbated by the merit order effect.**. However, a number of prominent authors maintain that energy-only markets with strong scarcity pricing regimes should be revenue sufficient even in the face of increasing renewables. Hence it is unclear to what extent we should be concerned about the merit order effect (and its impact on any missing money problem in existence) in the New Zealand case,. Firstly, unlike most jurisdictions experiencing the merit order effect, New Zealand is not accelerating the uptake of renewables through subsidies; the entry of renewables should be better tied to thermal exit

and wholesale outcomes more generally. Secondly, the opportunity-cost pricing behaviour of medium term hydro storage may ameliorate the merit order effect; given hydro's dominance, we would expect to see a greater prevalence of mid-merit prices than in a purely intermittent renewable jurisdiction. Thirdly, New Zealand does not have explicit price caps or offer caps, which exacerbate the missing money problem internationally (and equally may exacerbate the merit order effect as thermal retires); however we have not investigated whether there are implied (behavioural) limitations on how generators offer during periods of scarcity due to perceptions of e.g., regulatory or political risk. New Zealand, through the implementation of real-time pricing in 2022, will move closer to an ideal scarcity pricing regime which also helps avoid missing money.

- The potentially enhanced role of scarcity pricing in a 100% renewables future increases the value that demand-side participation can bring, especially if it can **provide price-based elasticity to the demand curve based on revealed willingness to pay preferences of customers (rather than administratively determined VoLL estimates)**. This will also **reduce market volatility, and some studies suggest that it may decrease the overall cost of achieving 100% renewables**. However, impediments to demand-side participation remain, particularly **the prevalence of flat retail price structures which insulate customers from movements in wholesale prices**, although some degree of price stability could be retained if retailers organised the bulk of demand response on behalf of consumers, and shared the benefits with them.
- We have not found any studies of the impact 100% renewables will have on contract markets. That said, there are numerous theoretical studies of the role that volatility plays in electricity contract markets. These suggest that **increasing volatility may change the strategic behaviour of large participants in both contract and spot markets; and these changes are non-linear and dependent on the degree of intermittency and volatility induced by renewables**. Commentary and analysis of the Australian NEM proposes that an increase in merchant renewables investment, backed by "off market" non-firm PPAs or CfDs, and the commensurate exit of thermal plant which traditionally provided firm hedging instruments, **may lead to the destabilisation of hedge markets for Tier 2 retailers who are trying to obtain firm hedges for their purchase profile**. There has been no study of the potential for these effects to occur in New Zealand, where a significant proportion of firm contracts are backed today by large hydro companies, which will still be present in a 100% renewable world.

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