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PRICE DISCOVERY UNDER 100% RENEWABLE ELECTRICITY SUPPLY

ISSUES DISCUSSION PAPER

MARKET DEVELOPMENT ADVISORY GROUP

Note: This paper has been prepared by the Market Development Advisory Group for the purpose of advising the Electricity Authority. Content should not be interpreted as representing the views or policy of the Electricity Authority.

Preliminary

Acknowledgements

This paper was prepared by the Market Development Advisory Group (MDAG). The current members of the MDAG are:

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MDAG's role

The Market Development Advisory Group (MDAG)[1] was established by the Electricity Authority (Authority) in October 2017. The MDAG provides independent advice to the Authority on the development of the Electricity Industry Participation Code 2010 (the Code) and market facilitation measures. The MDAG focuses its advice on matters relating to the evolution of the 'machinery' of the electricity market. Specifically, under its terms of reference the MDAG can advise on:

a) initiatives to promote efficient pricing in markets and for monopoly services

b) initiatives to promote efficient management of capacity and energy risks

c) any other policy matters that the Authority considers appropriate.

MDAG proposal

In June 2021, the MDAG proposed to the Authority that it undertake a project to understand how price discovery would work in the New Zealand wholesale electricity market (including spot and hedge markets[2]) under a 100% renewable electricity system.[3]

The objective of the project would be to develop sound recommendations on what changes should be made to the wholesale electricity market assuming 100% renewable supply to ensure economically efficient price signals (from short to long term) to meet the statutory objective of promoting competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.

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1 www.ea.govt.nz. 2017. *Charter, Terms of Reference And Operating Procedures*. Available at: https://www.ea.govt.nz/development/advisory-technical-groups/mdag/charter-and-terms-of-reference/.

2 Hedge markets include over-the-counter hedges, exchange-traded futures, and financial transmission rights.

3 The MDAG's project proposal and proposed scope are available here: MDAG 100% renewables project — Electricity Authority (ea.govt.nz).

The proposed project would consider short-, medium-, and long-term price discovery and would consider:

(a) how the spot market will promote efficient operation on a daily and inter-seasonal basis when a high proportion of generation has low or zero marginal cost of operation (ie, short-run marginal cost (SRMC))[4]

(b) how water will be priced, without thermal plant in the market

(c) how the wholesale market will enable efficient investment when supply is dominated by low-SRMC generation

(d) how to ensure efficient pricing in extended periods of scarcity such as dry years.

The proposed project would have three stages:

(a) **Issues discovery**: understanding the way in which the electricity system is likely to behave with 100% renewable supply and identifying the key issues that may need to be addressed from a market design perspective.

(b) **Option identification and analysis**: identifying and analysing options to address the problems established in (a).

(c) **Recommendations and proposal**: reporting with recommendations to the Authority's Board.

The MDAG's proposal noted that the project was complementary to the New Zealand battery project and the Future Security and Resilience (FSR) project being undertaken by the Authority and the system operator.

Authority approval of proposal

The Authority approved the MDAG's project proposal in July 2021.[5] The Authority agreed with the MDAG's view on the importance of determining early whether the current wholesale market model is robust under a 100% renewable generation future.

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4 Note that running costs can differ from the short run marginal costs at times. In particular, when supply is scarce the SRMC will include any scarcity rents. See p72 of MDAG's review of the high standard of trading conduct provisions (https://www.ea.govt.nz/assets/dms-assets/26/26404High-Standard-of-Trading-conduct-MDAG-discussion-paper-on-pivotal.pdf) for more information.

5 The Authority's letter to the MDAG approving the project is available here: MDAG 100% renewables project — Electricity Authority (ea.govt.nz).

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1 Foreword

Importance of renewable electricity to reducing emissions to address climate change

1.1 The imperatives of climate change require us to urgently reduce emissions of greenhouse gases, both long-lived and biogenic methane.

1.2 While electricity generation in our country may be a very small part of the problem[6], it has the potential to play a significant role in reducing our long-lived greenhouse gases. Put simply, we have the opportunity to convert much of our industry and transport to run on renewable electricity instead of coal, oil, diesel and gas[7].

1.3 Transpower estimates that electrification of transport and process heating, together with baseload growth, will increase electricity demand by 68% over the next 30 years. Add to this the need for new electricity generation and storage to help cover 'dry years', peak demand and intermittency. Further add the possibility of 'green' energy exports. It sums to a 'ramp' of sustained investment in new renewable electricity out to 2050 (and probably beyond).

1.4 This is entirely doable. Much of the technology is already available – indeed, pushed by exponential world-wide demand, the possibilities in renewable electricity are likely to only keep growing. Even better, the cost of energy from many renewable sources is already a lot cheaper[8] than power from non-renewables, and we can expect ongoing innovation to keep driving costs down.

1.5 While it is obviously not possible to predict the profile of new generation investment over 30 years, some broad themes are emerging:

(a) The country's generation portfolio is likely to become progressively more diverse and dispersed, with solar, wind and batteries becoming much larger contributors from a wider spread of locations – inside and outside distribution networks;

(b) Electricity supply to and from distributed sources – like electric vehicles and roof-top solar – is likely to become significant in our overall system;

(c) Intermittency is likely to increase substantially, so back-up supply will have to become more agile; and

(d) Importantly, flexible demand-side response will become a lot more valuable, particularly in managing peaks and short-term scarcity.

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6 Electricity generation (using coal, oil, diesel and geothermal) accounts for only circa 5% of gross greenhouse gas (GHG) emissions.

7 Energy for transport, manufacturing, and electricity production accounts for circa 40% of gross GHG emissions. Energy, industry and building together account for circa 77% of gross long-lived GHG emissions.

8 Excluding the cost of back-up support when the wind or sun are not available.

Need to ensure readiness

1.6 The way we configure and run our electricity system needs to not simply accommodate these changes – it needs to efficiently enable them. Across the sector, various projects are in-train to this end – for example:

(a) Transpower has issued "Whakamana i Te Mauri Hiko: Empowering Our Energy Future", which sets the stage with a range of supply and demand scenarios and related implications;

(b) The first phase of "Net Zero Grid Pathways: Phase One to 2035" is well underway – Transpower's planning process for future grid investments to meet the needs of a decarbonised future;

(c) The first report in the Authority's "Future Security and Resilience" project was released in mid-November 2021, reviewing in particular the integration of distributed energy resources, balancing of increased renewables and provision of ancillary services in a 100% renewable electricity system;

(d) MBIE's "NZ Battery Project" is evaluating the technical, environmental and commercial feasibility of pumped hydro and other potential energy storage projects as possible alternatives for addressing the 'dry year problem'; and

(e) A panoply of wholesale market participants, distribution companies and new investors are actively exploring a range of new renewable generation options, including solar, wind, 'green' hydrogen, biofuels and storage in a variety of sizes and locations, some grid connected, others not.

1.7 The Authority has also recently published an energy transition roadmap that sets out how the Authority intends to support an efficient transition to a low-emissions energy system.[9] MDAG's consideration of price discovery under 100% renewables is one of six 'transformational' workstreams in the Authority's roadmap[10] and is the key workstream addressing spot market operation and adequacy as New Zealand transitions towards 100% renewables.

Our approach – open-minded and rigorous

1.8 In short, our task is to look at whether our wholesale electricity market design is set up to efficiently enable the expected electrification 'ramp'.

1.9 Our project plan has three stages: (i) issues discovery, (ii) options identification and analysis; and (iii) recommendations. This report covers issues discovery.

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9 The Authority's roadmap is available here: https://www.ea.govt.nz/development/why-we-work-on-developing-the-electricity-market/roadmap-transition-to-low-emissions-energy-system/.

10 The Authority considers that these transformational workstreams have the potential to have a significant, once-in-a-generation impact on aspects of the core market design: paragraph 4.5, Energy transition roadmap, Electricity Authority 2021 (https://www.ea.govt.nz/assets/dms-assets/29/Authority-cover-paper-for-roadmap.pdf).

1.10 Our approach has been to put aside our 'priors' on how the market is likely to behave. Coming to it with an open mind, we have set out to build a more empirical and evidence-based framework, without seeking to favour or disfavour any particular outcomes.

1.11 The process to date has revealed that a market without thermal generation would appear to behave in ways that are not as many of us may have expected. Some of the outcomes seem counter-intuitive – such as how hydro storage should be valued without thermal generation; how hydro generators have less control over their reservoir levels (as they become a function mainly of weather, levels of new generation investment and demand); how it becomes efficient for more energy to be spilled (as capacity becomes a stronger driver); and how demand-side response becomes extremely valuable and incentives become stronger to grow its potential.

1.12 The process has also revealed that New Zealand will face some challenges that are different to other countries. For example, our hydro generation base means that system inertia[11] will be less of a problem than in many other countries. The hydro base can also provide a much needed source of flexibility if managed well. On the other hand, hydro generation has its own unique challenges in dry years.

1.13 This process is genuinely a journey of discovery in which we need to remain open to revisiting our intuitions if robust analysis points us in a direction different to that which we may have assumed.

Highly interactive and open

1.14 MDAG is taking a highly interactive approach. In this phase of the project alone, we have discussed:

(a) Initial appraisals of the issues with a wide range of consultants, including Concept Consulting, Sapere Research Group (Sapere), Whiteboard Energy, Easter Bay Consulting, Baringa Partners, Market Reform, and Broad Solutions with Energy Exemplar;

(b) Initial appraisals of the issues with individual stakeholders in 16 bilateral sessions;

(c) Our initial simulation model work with individual stakeholders in eight sessions; and

(d) Particular issues in more depth with a range of expert advisers and peer reviewers, including Concept Consulting with John Culy, Sapere, Whiteboard Energy, Easter Bay Consulting, Dr Grant Read, Energylink, Optimeering AS (Norway) and IPAG.

1.15 Along the way, we have encouraged interested parties to contact us directly to further discuss issues and share insights and analysis.

1.16 This open, highly interactive approach is extremely valuable for our process and, we perceive, for the market as a whole.

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[11] See paragraph 7.22(a) for more information.

1.17 We look forward to your continuing commitment in helping MDAG to assess the issues, evaluate the options and distil well thought-out recommendations – better readying our wholesale market for the challenges and opportunities in decarbonising our economy

Tony Baldwin
Chair,
Market Development Advisory Group

Why was the wholesale electricity market established?

This Issues Paper asks three basic questions: how is New Zealand's electricity system expected to change in physical and economic terms with 100% renewable electricity; will we still need a wholesale electricity market with no thermal generation; and, if so, what issues will need to be addressed in light of the expected physical and economic changes?

Before addressing those questions, let's recall why our wholesale electricity market was established in the first place.

Households and businesses must have access to reliable electricity at prices that are socially acceptable. To achieve this goal, it is vital that investments in new capacity are made at the right time, in the right quantities, in the right locations, using the right technology at the right cost – for the long-term benefit of consumers. This is the "Goldilocks zone" for electricity supply. The costs of missing it can be high:

- If we build new stations too soon or too big or in the wrong place or not using the right technology, we waste capital. We lose the opportunity to use the capital on things that society values more highly;
- If we build power infrastructure when it is not required, we impose harm on the environment that should not have occurred (which can be considerable); and
- If we build new stations too late or too small or not of the right type, we increase the risk of electricity shortages or black-outs, which, if sustained, can cause serious impacts on consumer welfare, losses of revenue for business and loss of reputation for our economy, not to mention asymmetric political fall-out. Delayed investment can also lead to reduced competition and higher prices for consumers.

For much of the last century[12], decisions on what, when and where to build new capacity were made by a small group of government people. Wholesale prices were averaged and decided on a political basis by the Minister of Electricity bearing little resemblance to supply and demand. Price trends played no significant role in signalling a shortage or the cost and timing of new supply. Misallocation of capital was not a serious concern, and harm to the environment could be overridden by public works or special legislation.

This approach built the backbone of our current electricity system, but it also missed the "Goldilocks zone" by a wide mark. Billions of dollars in public funds could have been saved and put to uses of greater value to society, considerable harm to the environment could have been avoided, and security of supply should have been a lot better.[13]

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12 Authority for the content of this paragraph is in Culy (1992), at 3.3, 3.4, and 4.1.

13 Culy (1992) at 3.3 and 3.4. Restrictions on electricity consumption due to shortages in supply were frequent between 1945 and the early 1960s. Before the formation of ECNZ, the security standard was around 1-in-10 years. This increased to 1-in-20 under ECNZ (1987-92), and then increased to 1-in-60 (1992-99, following the Prime Ministerial Review into the 1992 Electricity Shortage). By contrast, following the break-up of ECNZ in 1999, the effective standard is estimated to have increased to 1-in-100 – www.energylink.co.nz/news/blog/1992-shortage-revisited.

In the mid-1990s[14], the government decided that this troika of goals – security of supply, efficient use of capital and minimising environmental harm – could be better achieved by:

- Enabling a diversity[15] of parties to add capacity to meet security of supply and growing demand, which recognised that a handful of near-monopoly decision-makers simply can't see or deploy the full range of optimal solutions[16];
- Making wholesale prices, rather than government forecasts, the primary mechanism for signalling changes in supply and demand;
- Making wholesale prices reflect the cost of producing an extra unit of electricity in a given timeframe, rather than averaging prices on a political basis. (A key BERL study in 1994[17] found that average pricing would result in near double the level of demand – so a massive increase in the capital required for power stations and a lot more harm to the environment – which would have been avoided if wholesale buyers faced the full cost of producing an extra unit of electricity);
- Creating a process of effective competition among suppliers to put sustained downward pressure on costs and prices, particularly by promoting continuous improvement and innovation;
- Making information on the operation of the electricity system fully transparent, opening up the "black box" approach of the previous decades; and
- Allowing private capital to fund new power stations, freeing up taxpayer funds for higher value uses.

In short, a well-functioning wholesale electricity market was seen as a core requirement to enable these outcomes. Put simply, the wholesale market was put in place to enable a diversity of parties to sell and buy electricity using the national grid. (This is expanded on from paragraph 6.3 of the paper below).

This is not to say that our market has perfectly delivered on all of those elements. When the transition began in the mid-1990s, it was anticipated that achieving a well-functioning wholesale electricity market would involve a process of continuous improvement.

With the shift to 100% renewable supply underway, now is the time to revisit the wholesale market design to ensure it will meet the challenges and opportunities of electrifying a much larger part of our New Zealand economy using renewable sources of supply.

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14 Following several years of lead-up work which included a policy review (Treasury, 1985), analysis by NZIER (Bollard, 1987), a task force (1987-89), a paper by NZIER (Culy, 1992), Prime Ministerial Review Committee (1992), two development groups (WEM in 1991-2 and WEMDG in 1993-94), an officials committee (OCEP, 1992-98), and substantial body of competing reports by a range of consultants.

15 Diversity is a process – people and firms continuously adapting resources with an ever-evolving array of ideas and strategies to meet changing risks and opportunities. Put another way, "adapting to a complex changeable world is best achieved by a multiplicity of experiments from many different players" (Tim Harford, Economist).

16 As Culy observed in the prelude to the formation of a wholesale market: "Decentralised investment decision-making, involving a wider range of investment options, which, to satisfy funding organisations, requires rigorous project appraisal, risk analysis, risk management and cost control. This is likely to lead to a preference for more flexible, smaller scale, less capital intensive and shorter lead time projects" – Culy (1992) at 5.1 (p.22).

17 1997, "The State of the New Zealand Environment, 1997", Ministry for the Environment, section 3 at page 24. See also 1994. Wholesale Electricity Reforms (2): Economic Impacts of Electricity Pricing Options. Paper submitted to the Cabinet Strategy Committee on 28 October 1994 (CSC/94/148).

2 What you need to know to make a submission

What this discussion paper is about

2.1 This paper describes the key issues with the current wholesale electricity market design that the MDAG believes should be explored to enable a shift to 100% renewable electricity supply. The purpose of this paper is to consult with interested parties on the key issues identified by the MDAG.

2.2 Options to address the key issues will be considered in the next stage of the project, and we will separately consult on those in due course.

How to make a submission

2.3 Our preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix B. Submissions in electronic form should be emailed to MDAG@ea.govt.nz with "Price Discovery under 100% Renewable Electricity Supply – Issues Discussion Paper" in the subject line.

2.4 If you cannot send your submission electronically, post one hard copy to either of the addresses below, or fax it to 04 460 8879.

Postal address	Physical address
Submissions Electricity Authority PO Box 10041 Wellington 6143	Submissions Electricity Authority Level 7, Harbour Tower 2 Hunter Street Wellington

2.5 Please note the MDAG wants to publish all submissions it receives. If you consider that we should not publish any part of your submission, then:

(a) indicate which part should not be published

(b) explain why you consider we should not publish that part

(c) provide a version of your submission that we can publish (if we agree not to publish your full submission).

2.6 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

2.7 However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. We would normally consult with you before releasing any material that you said should not be published.

When to make a submission

2.8 Please deliver your submissions by 5pm on Wednesday 16 March 2022.

2.9 We will acknowledge receipt of all submissions electronically. Please contact us at MDAG@ea.govt.nz or 04 471 8628 if you don't receive electronic acknowledgement of your submission within two business days.

3 Executive summary

3.1 The Electricity Authority (Authority) has asked the Market Development Advisory Group (MDAG) for advice on what changes should be made to the wholesale electricity market to ensure it is effective[18] with 100% renewable electricity (100%RE) supply.

3.2 This first stage of the project has involved trying to understand, at an empirical and objective level, the opportunities and challenges for the electricity *system* with 100% renewable supply. From this framework, we have then sought to identify the key issues to be addressed from a *market design* perspective.

3.3 Options to address key issues will be considered in the next stage of the project, and we will consult on those in due course. At this stage, we would urge stakeholders to not presuppose the measures or changes that should be put in place. It is important to first establish robust and clear insights into the nature and scope of the issues to be addressed, which is the purpose of this paper. In short, to land on effective options, we need to be clear about the root issues. Quite a lot about the way the system and market are likely to behave with 100% renewable supply is unfamiliar or perhaps even somewhat counter-intuitive.

100%RE system will be different to what we know today

3.4 The next sections briefly describe the likely effects of a shift to 100%RE on the *electricity system*. These observations are based on market simulations for 2035 and 2050 assuming there is 100%RE supply (see from paragraph 5.2 for more detail). The simulation results are not precise forecasts but rather are intended to explore possible outcomes under 100%RE supply.

Investment levels will need to lift markedly

3.5 To achieve 100%RE supply a great deal of new generation and storage (e.g. batteries) will be required to meet projected demand growth and replace fossil-fuelled stations. The simulation results show an average investment requirement equivalent to 400-500 MW of new supply or demand response capability every year until 2050. The projected pace of development is much faster than experienced in living memory. As a comparison, net supply growth averaged around 60 MW/year between 1990 and 2020.

3.6 There would clearly need to be a big step up in development effort. Having said that, most new supply is expected to come from solar and wind generation and these technologies are very scalable, can be developed rapidly and have low technical entry barriers. This pipeline is likely to make the availability of new investment in renewables more akin to seeing additional "fuel" within shorter supply horizons than is currently the case.[19] This in turn feeds

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18 In this context, effectiveness refers to promoting competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers as per the Authority's statutory objective.

19 This is not suggesting a future where rapid build of new generation will mitigate temporary supply shocks such as dry years. Rather, the point is that there will need to be a closer linkage between new investment 'fuel' to match demand growth in a 100%RE system, otherwise hydro storage trajectories will (on average) drift downwards.

into how parties think about pricing their supply and demand-side resources into the wholesale market.

System likely to operate in a different way

3.7 Under 100%RE a much greater proportion of total supply will come from sources with short-term intermittency such as wind and solar. In the simulation reference case,[20] their share of annual average supply rises from 6% in 2020 to 31% in 2035 and 47% in 2050.

3.8 The hydro generation base is expected to become much more important as a shock absorber, smoothing out many of the short-term fluctuations between intermittent renewable sources and varying demand. Currently, the hydro generation base shares this role with fossil-fuelled stations, and intermittent wind and solar generation only accounts for 6% of total supply.

3.9 One consequence of these changes is that the optimal[21] level of storage for hydro lakes is expected to be higher on average than is currently the case. Without fossil-fuelled stations that can be run hard to ease pressure on storage lakes in dry periods, it will be prudent to enter each winter with higher operating storage than currently. Otherwise there would be undue risk of forced demand curtailment being required which has a high cost.

3.10 Another key change resulting from fossil-fuelled station retirements is that storage trajectories in major reservoirs will largely trace out the effect of weather and be less subject to short-term management. Put simply, if hydro generators raise their offer prices for generating from stored water, it will not make the wind blow harder or the sun brighter, whereas at present it may incentivise increased thermal operation.

3.11 Hydro storage levels will also be more sensitive to the rates of new investment and demand growth. This is because unexpected surges/reductions in demand growth are currently absorbed initially by more/less thermal operation, until new investment catches up. By contrast, in a 100%RE system such impacts would be reflected directly into the storage reservoir levels.

3.12 Finally a consequence of maintaining hydro storage at higher levels on average will be an increase in the level of renewable energy spill – which could be water, wind, solar or geothermal. Tolerating an increased level of spill would be a major shift from the predominant mindset in the sector today, even though such spill may be economically efficient as it is less expensive than the alternatives. The shift in mindset is really one of degree. The sector is used to spilling thermal generation capacity when supply is abundant.[22] In future it would likely switch to spilling some renewable capacity when supply is abundant.

3.13 Having said that, the system would benefit from additional energy storage capability if this has a lower cost than the alternatives, such as building more renewables and accepting spill

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20 A range of cases were simulated. See from paragraph 5.2 - 5.78 for more information on the simulations. The core elements of the reference case are based on the demonstration case in the Climate Change Commission report released in mid-2021.

21 Optimal in the sense of minimising system costs.

22 Another analogy of economically efficient “spill” occurs in our transmission and distribution network capacities.

at times. If additional energy storage can be obtained at reasonable cost, that would allow surplus energy to be captured for use at a later time.

System conditions will fluctuate more often – leading to higher spot price volatility

3.14 The simulation modelling indicates physical system conditions will fluctuate more frequently than today, reflecting the increased share of supply from weather-driven wind and solar generation, albeit buffered to some extent by the hydro base, more flexibility on the demand side, and batteries. These system fluctuations in turn mean that spot price volatility is likely to increase significantly compared to historical experience. In particular, there is likely to be a marked shift toward greater short-term volatility.

3.15 Having made these observations, it appears unlikely that New Zealand will experience spot prices that oscillate directly between zero and the value of lost load, which is sometimes posited as a potential outcome in some other countries. In particular, New Zealand's storage capacity in the major reservoirs and the approach to valuing water in them appears sufficient to avoid those outcomes.[23]

3.16 The factors that most change the expected degree of volatility in New Zealand are the offer behaviour of hydro generators and level of demand-side flexibility, as described in paragraph 5.71.

Security of supply requirements can be satisfied

3.17 The reference case shows that it is possible for a 100%RE system to satisfy both energy and capacity requirements. In the reference case, the flexibility provided by fossil-fuelled stations would be replaced by a different mode of operating the existing storage lakes, additional demand-side flexibility and a small level of generation from peakers running on renewable fuels such as bio-diesel or hydrogen. The reference case is just one scenario, but it indicates that security can be maintained in a 100%RE system if the right settings are in place.

Shifting to 100%RE is technically challenging but achievable

3.18 In short, our overall conclusion at a *system* level is that shifting to 100%RE appears technically challenging but is achievable if the right settings are in place. Market simulation modelling undertaken for MDAG shows that 100%RE is feasible based on the existing renewable generation base and plausible assumptions about the development of new renewable generation, demand-side flexibility and batteries. Furthermore, there are reasonable grounds to believe that average wholesale electricity prices under 100%RE could be similar in real terms to past levels if the transition is well managed.

3.19 Our findings in relation to the dynamics of the system are set out in paragraphs 5.3 to 5.78 below. The accompanying simulation assumptions and results slide pack [24] provides more detail about the simulations we have run.

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23 Other factors are also relevant. See from paragraph 5.60 for more information.

24 Available here: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/100%-renewable-electricity-supply/consutations.

1. Do you agree with the broad conclusions that emerge from the simulations in relation to spot price levels and volatility, in particular:
    a. significantly more spot price volatility is likely with a 100%RE system, especially shorter-term weather-driven volatility?
    b. New Zealand's sizeable hydro generation base is likely to moderate the growth in volatility to some extent, making extreme oscillations between zero and shortage spot prices relatively unlikely?
2. If you disagree, what is your view and the reasoning for it?

New Zealand will still need a wholesale electricity market with 100%RE

3.20 The wholesale market was established to enable a diversity of parties to sell and buy electricity using the national grid. At its core, the wholesale electricity market functions as a platform for processing information and coordinating actions among many electricity suppliers and consumers.

3.21 While the shift to 100%RE supply will cause many changes, the need for information sharing and coordination will remain. Indeed, the greater number and diversity of participants and resources will likely increase the requirements in some areas, especially for real-time decisions.

3.22 Based on this, we think a wholesale market providing price signals will continue to be the preferred mechanism for integrating information from multiple sources and coordinating actions among consumers and suppliers.

3. Do you agree that in a 100%RE system there will be many diverse and disaggregated resources to coordinate, and that a wholesale market will be the preferred mechanism to coordinate plans and actions among all the resource owners? If you disagree, what is your view and the reasoning for it?

What are the issues that may have design implications for the wholesale electricity market with 100%RE?

3.23 The next sections briefly describe a range of *issues* that arise from these likely system changes that may have design implications for the *wholesale electricity market* in a shift to 100%RE.

3.24 As noted earlier, *'options to address key issues'* will be considered in the next stage of the project, and we will consult on those in due course. Proposals and recommendations will not come until the third stage of project, later in 2022. Our focus now is to understand the nature and scope of the issues to be addressed.

3.25 In some areas, we think the key issues are relatively clear (e.g. for real-time coordination), and we have identified specific matters for further proposed work. In other cases, the key issues are broader (e.g. for demand-side flexibility) and our proposed areas of work are similarly broad. Finally, we recognise the Authority already has work underway on some issues (e.g. on ancillary services via the Future Reliability and Security project). We will take account of the Authority's existing initiatives as we develop the work programme for the next phase of this project.

Real-time coordination will get more challenging and make an effective spot market even more important

3.26 In a system with 100%RE, real-time coordination will become much more challenging. This is because many of the new supply sources will not be readily controllable because they are governed by weather conditions. In addition, the system will move from being balanced in real time by relatively 'few big' resources to much more reliance on 'many and small' resources – such as batteries, flexible demand-side parties and smaller scale generation. Indeed, Transpower has estimated there will be 3.9 million distributed energy resources across the system by 2035.[25,26]

3.27 The electricity spot market is the primary tool for coordinating resources in the lead up to, and during, real time. While the spot market already has many features needed to support real-time coordination in the 100%RE world, a range of aspects should be reviewed to ensure they are fit for the future.

Key issues for real-time coordination with 100%RE

3.28 Our findings in relation to real-time coordination are set out in paragraphs 7.3 – 7.14 below. We think the key issues in relation to real-time coordination are:

(a) Will forward scheduling processes be effective in a future environment where short-term system conditions change more rapidly (e.g. will there be a need to adopt more

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25 Transpower New Zealand (2020), *Whakamana i Te Mauri Hiko – Empowering our Energy Future* [Link], page 61.

26 As a helpful metaphor, the current market serves as the conductor of a medium sized brass band; by contrast, in an all-renewables market, it will conduct a large symphony orchestra.

frequent cycles of schedules, different publication timeframes, new information content such as confidence intervals)?

(b) Will demand forecasting processes be effective with an increasing prevalence of electric vehicles, and behind the meter storage devices?

(c) Will the range of resources subject to dispatch by the system operator be appropriate?

(d) Will there be an efficient mechanism to allocate dispatch rights when the volume of generation seeking to run at a zero price exceeds demand?

(e) Will there be a need for new mechanisms (such as a short-term commitment market) to coordinate resources that require a lead time to get ready, such as batteries which need to be charged, or production processes which need to be modified on the demand side?

(f) Will downstream parties such as aggregators be able to interact efficiently with the spot market (for example via adopting new mechanisms beyond the coming 'dispatch notification' product being introduced with real-time pricing)?

4. Do you agree that these are the key issues in relation to real-time coordination? If you disagree, what is your view and the reasoning for it?

Ancillary services will require a close focus

3.29 While the spot market is the primary mechanism for balancing supply and demand in real-time, ancillary services are also vital. The shift to 100%RE will likely affect the types and quantities of ancillary services needed to maintain secure supply.

3.30 An important step forward to understand future needs was the launch in 2021 of the 'Future Security and Resilience' (FSR) project by the Electricity Authority working with Transpower as system operator.[27] This workstream is examining how to ensure the electricity system remains stable, secure and resilient as it evolves in the coming decades. Transpower has recently delivered its first report identifying nine areas of challenge and opportunity[28]. This will be followed by a prioritised roadmap for investigating, monitoring and addressing these issues due in the first half of 2022.

27 See https://www.ea.govt.nz/about-us/media-and-publications/media-releases/2021/authority-project-to-explore-long-term-resilience-and-security-of-electricity-supply/.

28 See https://www.ea.govt.nz/assets/dms-assets/29/02-FSR-Phase-1-draft-report-Nov-2021-v2.1332512.1.pdf.

3.31 It will be important to ensure the ongoing results of the FSR project and this project are integrated, as the conclusions of one will likely affect the other. Likewise, we will ensure the analysis and findings from this project are available to the FSR team and system operator.

Key issues for ancillary services with 100%RE

3.32 Our findings in relation to ancillary services with 100%RE are set out in paragraph 7.15 – 7.37 below. We think future outputs from the FSR project will be important when considering the role and type of ancillary services (and how those services are provided) under 100%RE. We think the key issues include:

(a) Are there services that are currently provided freely as by-products that will become scarce under 100%RE?

(b) Will new ancillary services such as inertia, standby reserves on a longer time scale than current instantaneous reserves, ramping duties and reactive power be required?

(c) How can these new products be priced in a way that sends the correct operational and investment signals? Can or should they be integrated with the dispatch objective to allow automated dispatch and co-optimisation?

(d) How can decentralised distributed resources and new technology be sourced and used to provide current and new ancillary services?

5. Do you agree that these are the key issues in relation to ancillary services with 100%RE? If you disagree, what is your view and the reasoning for it?

Importance of accurate spot price signals to demand-side, contracting and investment incentives

3.33 As noted above, under 100%RE supply we are likely to see higher prices more frequently, properly reflecting real changes in the value of supply and demand. Signalling these high prices to buyers and sellers is critical for an efficient spot market. It provides signals to foster innovation and diversity of solutions and encourages market participants to seek out the options that best meet their needs. We know for sure that we cannot see all the innovations in renewable energy that are likely to emerge in the coming years, and so there is high value in a policy framework that fosters and enables this diversity to feed into our electricity system.

3.34 Under the current wholesale market design, participants bear the risks of their decisions in relation to risk management, contracting and investment in new generation. This encourages participants to be very disciplined in capital expenditure, avoiding premature investments or projects that are not cost-effective. Without question, investment efficiency represents the largest single impact the electricity industry has on the New Zealand economy.[29] Looking ahead, the investment efficiency prize will grow simply because the annual investment volumes will increase. For this reason, it makes sense to maintain the philosophy of seeking to ensure that suppliers bear investment risk and face robust competitive pressures.

3.35 However, there is a question about whether demand-side participation, effective forward contracting and investment in new supply in the current design might weaken due to the increased spot price volatility associated with 100%RE. If that occurred, there could be under-investment and unreliable supply. We have looked closely at this issue. The analysis indicates that increased price volatility per se is not the primary concern, as long as participants can enter into forward contracts to effectively mitigate their investment risks.

3.36 It would be a problem if parties' economic incentives to contract were to weaken. This could arise if purchasers have a lack confidence in contract prices (see from paragraph 3.54 on the importance of ensuring competitive outcomes), or if there is artificial suppression of spot prices during periods of genuine scarcity. Arguably there is heightened risk of the latter outcome in a world where spot prices are more volatile – even if the volatility is simply a true reflection of weather-driven variation in system conditions. Similarly, it is important that the types of products needed to manage risk in a 100%RE will be available to market participants. New sources of liquidity in these contracts will likely be required to support the transition. Likewise, it will be important to ensure that consumers (and aggregators) can harness demand-side flexibility. Strengthening the contract market and harnessing demand-side flexibility are discussed further from paragraphs 3.47 and 3.44 respectively.

3.37 Returning to the risk of artificial spot price suppression, there are two basic pathways to address the associated risk of under-investment:

(a) Maintain and strengthen the 'energy-only' design – i.e. wholesale buyers and sellers continue to decide how best to manage supply risks in response to 'energy-only' price signals – but strengthen certain features of the market's design; or

(b) Move to a 'capacity mechanism' design (which comes in a variety of forms) – i.e. make it mandatory for wholesale purchasers to have the level of forward contracts or generation judged by a central agency to be sufficient to cover their projected demand for some years ahead.

3.38 For an 'energy-only' approach to work, it relies on the following preconditions being in place:

(a) Prices that reflect real supply and demand conditions, including very high prices in times of scarcity;

(b) Confidence among wholesale buyers and sellers that the high prices make sense, (which means confidence in the structure and rules of the market, including the sufficiency of competition);

29 This is because investment that is too late will cause shortages which impose extremely high costs on consumers. Investment which is premature or in the wrong technology also causes costs, in this case because the supply-side of the industry is very capital intensive, so the cost of poor investments can be significant.

(c) Availability of 'tools' for wholesale buyers and sellers to manage their exposure to those spot price risks;

(d) General public and political acceptance that volatility and high prices (in times of scarcity) in the wholesale market are, in fact, in the best long-term interest of consumers, and that measures to 'soften the landing for unhedged participants' can trigger a vicious circle of undermined investment incentives and higher future prices; and

(e) Confidence among consumers/politicians that investment will be timely and competitive.

3.39 Fulfilling (d) and (e) above is highly influenced by whether (a) to (c) are satisfied.

3.40 Higher prices with more frequency in an energy-only regime will likely require both a change of mind-set and measures to strengthen delivery of the criteria outlined above. Likewise, it is critical that consumers have confidence that competition is disciplining prices, as noted further below in paragraphs 3.54 to 3.60.

3.41 Both the energy-only and the capacity market pathways have challenges, and both have risks. We will explore these in some detail in the next stage (options analysis) of this project. Neither are necessarily straightforward – if an energy-only approach is perceived to be hard, it does not follow that a capacity mechanism approach is any easier.

Key issues and measures for price signalling with 100%RE

3.42 Our findings in relation to price signalling are set out in paragraphs 7.38 to 7.88 below. We think that the key issues in this regard are:

(a) Whether higher prices (occurring with greater frequency) signalling genuine scarcity of supply will be accepted in the wider political economy of the market; and

(b) Whether the five elements set out in paragraph 3.38 above are required for an energy-only pricing regime to work; and

(c) Whether you agree that fulfilling (d) and (e) in paragraph 3.38 above is highly influenced by whether (a) to (c) are satisfied.

3.43 In this case, we also suggest that the measures below should be taken forward into the next stage of the process (options identification and analysis) in relation to spot price signalling with 100%RE:

Measures to increase confidence in spot prices during genuine scarcity events

(a) Reduce scope for spot price suppression during genuine scarcity events, for example via:

(i) Increase awareness of the necessity of high spot prices when supply is genuinely tight, and the adverse consequences of artificially suppressing prices in those events, with information programmes for market participants, consumers, media, policy makers etc.

(ii) Strengthen the stress testing regime to ensure market participants are consciously aware of the risks of their hedging choices

(iii) Strengthen processes for reviewing high price events to ensure they are examined in a robust and timely manner

(iv) Strengthen the process for determining UTS claims to include an explicit requirement to consider effects of any decisions on future investment incentives.

Explore backstop measures

(b) Explore measures that would introduce compulsory contracting obligations on purchasers to forward contract for their firm demand, and ensure suppliers do not sell contracts that exceed their firm output, which may include measures such as:

(i) A conditional forward contracting obligation if projected demand exceeds supply (say) three years into the future (similar to the retailer reliability obligation in Australia)

(ii) A reserve energy/capacity scheme with standing costs for reserve plant recovered from beneficiaries (i.e. parties that do not have forward cover for firm demand)

(iii) Introducing a firm capacity/energy market or similar mechanism.

6. Do you agree that these are the key issues in relation to price signalling with 100%RE as summarised in paragraph 3.42 above? If you disagree, what is your view and the reasoning for it?
7. Do you agree that the preconditions in paragraph 3.38 would need to be in place for an energy-only market design to be effective? If you disagree what is your view and the reasoning for it?
8. Do you agree that we should take forward to the next stage of the process (options identification and analysis) the measures referred to in paragraph 3.43 above? If you disagree, what is your view and the reasoning for it?

Greater role for demand-side flexibility from electricity users will be critical

3.44 The simulation modelling indicates there will be a growing prize if electricity users can (directly or indirectly) provide more demand-side flexibility (DSF). The benefits include reduced costs for consumers, increased competitive pressure and more confidence in market prices. An increase in participation of electricity users (the 'demand side') in the wholesale market has been a goal since market establishment, but remains a work-in-progress.

3.45 Technology changes are expected to make it easier for electricity users to participate in the wholesale market, either directly or (more likely) via agents such as a retailers. However, it remains unclear whether the benefits of DSF will be realised. Improving the potential for demand-side participation is already on the radar, but the potential rewards indicate it warrants even more effort.

Key issues for demand-side flexibility with 100%RE

3.46 Our findings in relation to DSF are set out in paragraphs 7.90 - 7.103 below. We believe that harnessing DSF is a major prize (gross benefits estimated at $120 to $170 million per year),[30] but it is unclear whether the full potential will be realised. We think the key issues in relation to DSF are:

(a) What are the wholesale market features necessary to fully realise the benefits of DSF under 100%RE?

(b) Are the wholesale market features identified in (a) likely to be present as the shift to 100%RE occurs?

(c) What are the actions needed to put the necessary features in place, to the extent that the wholesale market features in (b) are unlikely to develop naturally?

9. Do you agree that these are the key issues in relation to demand-side flexibility with 100%RE? If you disagree, what is your view and the reasoning for it?

Contracts market will have to do more 'heavy lifting'

3.47 We have endeavoured to assess how generation and retail investors may react to increased spot price volatility and the consequential greater variability in financial returns. Overall, the results suggest that increased volatility per se should not pose unmanageable risks for investors or purchasers *provided they can enter into suitable forward contracts*. This involves both access to the products themselves and having confidence in the pricing of those contracts. A further critical point for the latter is that participants will need reasonable information on the *level* and *shape* of forward price distributions. This is described further from paragraph 7.45 below.

3.48 Over the last 10 years, the contracts market and risk management practices have evolved considerably. Looking forward to a 100%RE market, there will need to be continued adaptation by market participants with an increased need for hedge products to manage the

30 This is the gross benefit and does not include the cost of foregone usage or any capital cost to enable flexibility. See paragraph 7.90 for more information. The estimate appears to be broadly comparable with a cost benefit study by Sapere, which estimated the economic surplus of distributed energy resources over 30 years at $6.9 billion in present value terms, or roughly $230m per year.

increased volatility. Put simply, the contracts market will have to do a lot more "heavy lifting". Questions arise as to whether the required range of products, information and liquidity will emerge in a timely manner.

Key issues for contracts market with 100%RE

3.49 Our findings in relation to the contract market are set out in paragraphs 7.104 - 7.124 below. In addition to reducing scope for artificial price suppression (paragraph 3.43(a) above), we think the key issues in relation to the contracts market are:

(a) What are the contract market features necessary to ensure participants will have reasonable access to the risk management products needed under 100%RE?

(b) Are the contract market features identified in (a) likely to be present as the shift to 100%RE occurs?

(c) What are the actions needed to put the necessary features in place, to the extent that the contract market features in (b) are unlikely to develop naturally, for example by building on existing regulatory tools or developing others?

10. Do you agree that these are the key issues in relation to contracts markets with 100%RE? If you disagree, what is your view and the reasoning for it?

Will the transition to 100%RE be orderly?

3.50 Some questions have been raised as to whether investment adequacy concerns could arise in the transition to 100%RE. In particular, whether large fossil-fuelled units might retire before replacement resources are available (referred to below as "premature retirement"). This risk seems low for baseload thermal[31] but is more of a concern for plant providing insurance services, i.e. generation to supply extreme demand peaks and/or when other generation is not available such as in dry years.

3.51 The most obvious potential cause would be an expectation (or reality) that spot prices will be held below their true value when conditions are tight. This, in turn, affects the price that potential buyers of contracts are willing to pay for the insurance provided by these units. While that concern is not new (and also applies in the 100%RE end-state) there are some factors which may elevate the concern in the transition.

3.52 First, potential buyers of contracts may believe the insurance units will not retire even if the owners cannot earn sufficient revenue. This view would presumably rest on a belief that government intervention would block a retirement decision. Such action might occur if the

31 In essence this is because a baseload supply deficit will be very visible – there will be a certainty of non-supply. By contrast inadequate insurance plant only becomes visible when the plant is called upon which is relatively rare.

government of the day thought security would fall below the level society was willing to pay for, or because the government itself preferred an even higher level of security. If insurance plant owners did not have the ability to credibly plan for plant retirement, that could make it very difficult to obtain adequate contract revenue in the transition. Second, various frictions may also hinder contracting[32] and raise the likelihood that mutually beneficial deals will be missed, leading to possible premature retirements.

Key issues for transition to 100%RE

3.53 Our findings in relation to the transition issues are set out in paragraphs 7.125 - 7.138 below. We think the key issues relating to the transition are whether:

Strengthen market process for retirement

(a) We should rely on contracting incentives (with spot prices allowed to reach high levels to properly signal scarcity) to avoid premature retirement of large fossil-fuelled thermal plant, and (in addition) improve participants' information and contracting incentives, for example by:

(i) Ensuring that participants have sound information about the system consequences of potential lumpy decisions - for example by strengthening the annual security assessment reports prepared by the system operator to include more information on different thermal plant retirement options, or effects of possible major energy storage projects such as pumped hydro;

(ii) Ensuring that any retirement of major thermal plant is telegraphed in advance – for example codification of the process for the retirement of plant above a certain size could be beneficial. Such a process could seek to ensure that plant owners and other participants have sufficient time to work through the options, while also making clear that final decisions on whether to retain plant will rest with owners;

(iii) Adopting measures to reduce the likelihood of artificial spot price suppression as set out in paragraph 3.37(a);

or

Explore a backstop mechanism to facilitate orderly transition

(b) We should explore options that would allow the retirement schedule for large fossil-fuelled units to be centrally determined, to reduce the risk of premature retirement, for example by adopting a strategic reserve mechanism as set out in paragraph 3.43(b)(ii); and

(c) If so, how to manage the risks of such a mechanism impacting on contracting and investment dynamics during and after the transition.

32 See from paragraph 7.132.

11. Do you agree that these are the key issues in relation to transition to 100%RE? If you disagree, what is your view and the reasoning for it?

12. Are there any other 'lumpy' issues that warrant specific consideration in the transition to 100%RE?

Competition will be vital

3.54 Competition will be vital to ensure a successful shift to 100%RE. Without effective competition, consumers and policy makers will not have confidence in electricity spot or contract prices. Without that confidence, investors are unlikely to commit the sums needed to underpin the shift to 100%RE. Competition also has a critical role to play in spurring innovation and finding the best solutions to drive down costs over time.

3.55 In some areas of the market the shift to 100%RE may strengthen competition. For example, batteries may increase competition in the provision of very short-term flexibility services and some ancillary services.

3.56 On the other hand, the shift to 100%RE may reduce competition in some areas. Our preliminary analysis suggests the areas of greatest concern will be flexibility services for weekly and beyond where batteries are unlikely to be economic, and therefore market concentration is likely to increase. That is because fossil-fuelled thermal plant is currently important in that area, but will cease operation under 100%RE. Furthermore, most of the relevant hydro storage capacity resides in a handful of reservoirs.

3.57 This increased concentration may hinder competition in both the spot and contracts markets, especially for products to firm intermittent supply and provide seasonal flexibility. Having said that, incumbent operators' ability to raise prices for flexibility services/products may be constrained by actual or threatened new entry by wind and solar (possibly backed by batteries).

3.58 Finally, competition is often reduced when the system is under stress, and yet those are the times when it can be most important to have confidence in prices and the market rules that govern their formation.

3.59 At this stage there is insufficient information to form any definitive views about competition. However, we think it is a critical issue and it should be considered further.

Key issues for wholesale market competition with 100%RE

3.60 Our findings in relation to competition are set out in paragraphs 7.139 - 7.144 below. We think the key issues in relation to competition are:

(a) What (if any) areas of the wholesale electricity market are likely to experience increased supplier concentration and cause inadequate competition in the shift to 100%RE?

(b) For any areas in (a) what is the timeframe over which changes are likely to occur?

(c) What are the options for addressing competition concerns identified in (a)?

> 13. Do you agree that we should analyse how competition in the wholesale market is likely to be affected by a shift to 100%RE, in particular, in competition for seasonal flexibility services? If you disagree, what is your view and the reasoning for it?

Have we missed any key areas of opportunity or challenge?

3.61 The preceding sections describe the major opportunities or challenges for the wholesale electricity market in the shift to 100%RE that we have identified.

3.62 Before moving to the next stage of this project, MDAG is seeking feedback on whether any major issues have been overlooked.

> 14. What other key areas of opportunity or challenge (if any) will arise in the wholesale electricity market with 100%RE that are likely to have a significant impact in relation to achieving the statutory objective of the Authority, which is to "promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers"[33]?

New Zealand's situation is unique and we will need our own solutions

3.63 Finally, although there is much that New Zealand can learn from international experience, we have come to realise that our physical characteristics and lack of any grid interconnection to other countries mean the challenges and opportunities we face are unique in many areas.[34]

[33] Section 15, which feeds into Section 32 (on the content of the Code), of the Electricity Industry Act 2010.

[34] Indirect linkages to other markets could occur via other means, such as the production and sale of green hydrogen.

For example, inertia on the system is likely to be a less pressing concern in New Zealand because the hydro generation will endure in the transition to 100%RE. Likewise, our sizeable hydro generation base means there is an existing buffer to help integrate additional intermittent renewable generation.

3.64 As New Zealand moves forward on its decarbonisation journey, it will be important to monitor international developments but also to think deeply about the particular features of our system and the opportunities and challenges they present.

Papers accompanying this Issues Paper

This Issues Paper has been informed by several background papers commissioned by MDAG, which we are publishing with the Issues Paper as a package. These accompanying papers explore some of the key issues, and explain the simulation assumptions and results, in more detail.

The eight accompanying papers are:

- a **review of international literature** on the transition to 100%RE by Dr Stephen Batstone
- a paper by Dr Stephen Batstone considering the potential impediments to **demand-side flexibility** playing its full role in price discovery and system security under 100%RE
- a paper by Dr Stephen Batstone that assesses participants' current and expected **risk management capability** in the transition to, and operation within, 100%RE
- a paper by Dr Grant Read on **water values** under 100%RE
- presentation slides by Concept Consulting and John Culy setting out the **assumptions and results of simulations** of the wholesale market in the transition to, and operation under, 100%RE
- two papers by Sapere Research Group: one on the **implications for contract markets** of transition toward a 100% renewable market; the other on the **retirement of fossil fuel powered plant**
- Annex 3 of the MDAG's discussion paper on the high standard of trading conduct provisions (released in February 2020), which outlines the **fundamentals of efficiency in electricity prices**, including the relationship between short-run (SRMC) and long-run marginal cost (LRMC) pricing.

4 Core questions this project addresses

4.1 Our brief boils down to answering the following core questions:

(a) How is New Zealand's *electricity system* expected to change in physical and economic terms with 100% renewable electricity (100%RE)?

(b) Will New Zealand still need a wholesale *electricity market* with 100%RE?

(c) If so, what issues will need to be addressed in light of the expected physical and economic changes with 100%RE?

4.2 We are keen to get stakeholder feedback on the issues we have identified, to see if we have missed or over-rated the importance of any issues.

4.3 This will help in the next stage of the project when we move on to options for both addressing the challenges and maximising opportunities. As noted by one international expert "wholesale electricity markets do not design themselves".[35] We need to pro-actively identify which aspects of the current design will be effective under 100%RE, and which will likely need to be updated.

[35] Professor Paul Joskow (2006), see https://economics.mit.edu/files/1185, p13.

5 How is New Zealand's electricity system expected to change with 100%RE?

Some directional trends can be predicted with high confidence

5.1 We can predict some trends with a high degree of confidence:

(a) Generation from fossil-fuelled power stations will trend downwards and these stations will eventually retire. These stations currently provide a mix of baseload (i.e. near constant running) and flexible supply (i.e. ramping up or down to offset fluctuations in hydro or wind generation or demand). Some may be able to switch to renewable fuels.

(b) Electricity demand is expected to rise substantially as the wider economy decarbonises and electricity replaces fossil fuels.[36] The growth is likely to come especially from a rising number of electric vehicles and replacement of coal/natural gas with electricity for process heat in some industries.

(c) A lot of new renewable generation will need to be built to satisfy demand growth and offset thermal station retirements. Most of the new renewable supply is expected to come from wind and solar generation because these technologies have seen big performance and cost improvements, and more are expected. By contrast, hydro and geothermal stations (which currently account for most of New Zealand's renewable generation) are mature technologies with stable costs and there are fewer untapped development options available, especially for hydro generation. The growth in wind and solar generation will mean that a much greater proportion of supply will come from so-called variable renewable energy (VRE) sources.[37]

(d) Batteries are another field where technology is expected to have a profound effect. This is already apparent with reduced costs and improved performance accelerating the uptake of electric vehicles. Batteries are also expected to become widespread in other parts of the electricity system. Many households are likely to have their own battery to store surplus solar power generated in the middle of the day for later use. Similarly, larger scale batteries are likely to be deployed to help smooth out power flows on distribution networks or the national grid.

(e) The system is expected to become much more disaggregated and diverse. Technology is the key driver for this change. Solar and wind generation are more scalable than traditional generation types, allowing a wider array of parties to become developers and operators. Furthermore, an increasing number of households and businesses will have their own rooftop solar panels and/or battery with an ability to act as a power consumer or supply source depending on conditions.

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36 Most forecasters project very substantial demand growth. However, rising energy efficiency is countering this trend, and some larger electricity users may reduce demand as they scale back operations in New Zealand.

37 We use the VRE term in this paper to refer to electricity sources that vary in output in the short term (minutes, days, weeks), such as wind and solar. In New Zealand, they are also referred to as intermittent sources. Hydro generation also varies but much of the variation is over longer periods (months or years) because when it has associated storage it allows some smoothing of short-term fluctuations.

(f) Finally, information systems and data management will become increasingly useful in coordinating market systems, such as demand response in the electricity market

Quantitative simulations used to understand potential scale of change

5.2 The previous section described key directional trends under 100%RE in qualitative terms. To better understand the potential scale and pace of those changes, a series of market simulations has been compiled.[38]

Simulation results are not precise forecasts

5.3 The simulations model the entire system and consider both investment and operational dynamics. This makes them computationally intensive, and it is not practical to model every single year. Instead, the simulations focus on the years 2035 and 2050. The year 2035 was chosen to reflect the system soon after a transition to 100%RE has occurred but noting that many other sectors of the economy will be at earlier stages in the decarbonisation journey.[39] The 2050 date reflects the system once much greater decarbonisation of the wider economy has occurred and electricity demand has consequently grown further.

Simulations focus on physical resource changes and spot price volatility

5.4 The market simulations focus on the variability in physical supply and demand under 100%RE, and the consequent impact on spot price volatility. To a large extent, physical variability and price volatility are opposite sides of the same coin.[40] For example, more rapid/extreme oscillations in the balance of supply and demand will typically cause greater price volatility. Similarly, more price volatility will typically indicate a system that is flexing more in physical terms. We are interested in both physical (supply/demand variability) and economic effects (price volatility) as both may create challenges or opportunities.

5.5 Figure 1 shows the main factors incorporated in the simulation model. The factors on the left-hand side are random and are mostly driven by weather (86 ‘weather years’ with varying hydro, wind and solar levels). These are derived from historical data. One factor not included in the analysis is the potential impact of climate change on wind, rainfall etc. This has been omitted because there is insufficient information available at present to model the likely effects of climate change on wind, rainfall etc. However, these are important issues and we suggest further work be done on them in the future (outside of this project given its timeframe).

5.6 The model also includes variations in customer demand and outages for major plant. Another factor tested is the level of system margin (i.e. the overall balance between generation/batteries and demand) which is assumed to randomly oscillate around a roughly balanced level. In addition, the simulation model includes some non-random factors termed

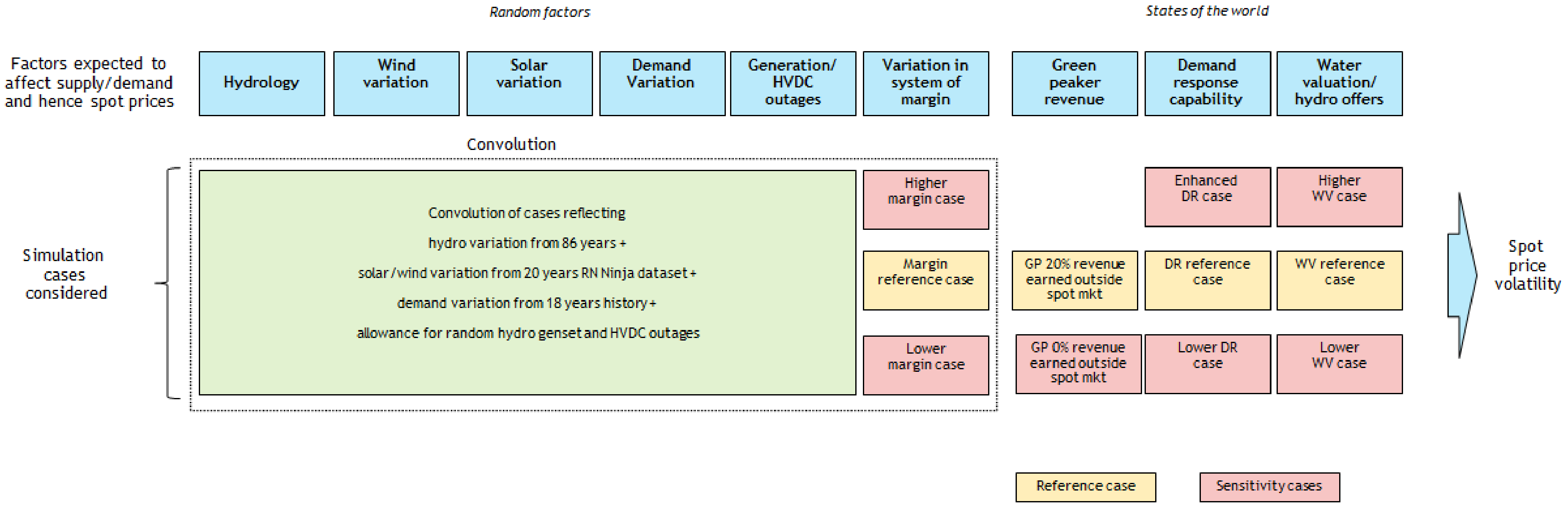
38 The simulations focus on supply and demand in each island. They do not account for power flows.

39 Results for 2035 can also be interpreted as roughly equivalent to those expected in 2030 if the Tiwai aluminium smelter remains in operation past its scheduled closure in 2024, i.e. an earlier point on the decarbonisation pathway if the smelter demand continues.

40 As we discuss later, there is also a behavioural factor to consider.

‘states of the world’ (right-hand side of the figure). These are used to test the sensitivity of results to various factors such as the level of DSF on the system. It is important to note that the sensitivity cases focus on the issues that are expected to have the greatest effect on spot price volatility, because that is a key issue to explore for this project.

Figure 1: Factors that affect supply/demand balance and influence spot prices in simulation modelling



Overview of simulation results

5.7 The full simulation results are set out in the accompanying paper "Simulation Assumptions and Results"[41]. The following sections provide a summary of key assumptions and results for the reference case. This case assumes that fossil-fuelled generation is not available due to a policy instrument outside of the electricity market itself (such as a ban on the use of fossil-fuels in power stations). In other respects, it is 'business as usual' in the sense that it assumes the Tiwai aluminium smelter exits as scheduled, that new supply decisions are based on market signals, and that there are no material external interventions.

5.8 It is important to emphasise the reference case should not be regarded as a precise forecast of the future. Rather it represents a set of outcomes that could be expected based on the given input assumptions, which are considered to be reasonably plausible. The simulation also includes some alternative cases to explore how outcomes vary with different assumptions (see discussion in later sections).

5.9 What we are looking to understand is not so much the specific results but rather orders of magnitude, rates of change and, importantly, how much the outcomes vary with a change in key assumptions. Our diagnosis of potential issues for market design can then be informed by evidence that is more robust than simply intuition and preconceptions.

5.10 Below we summarise the key assumptions and outcomes from our reference case.

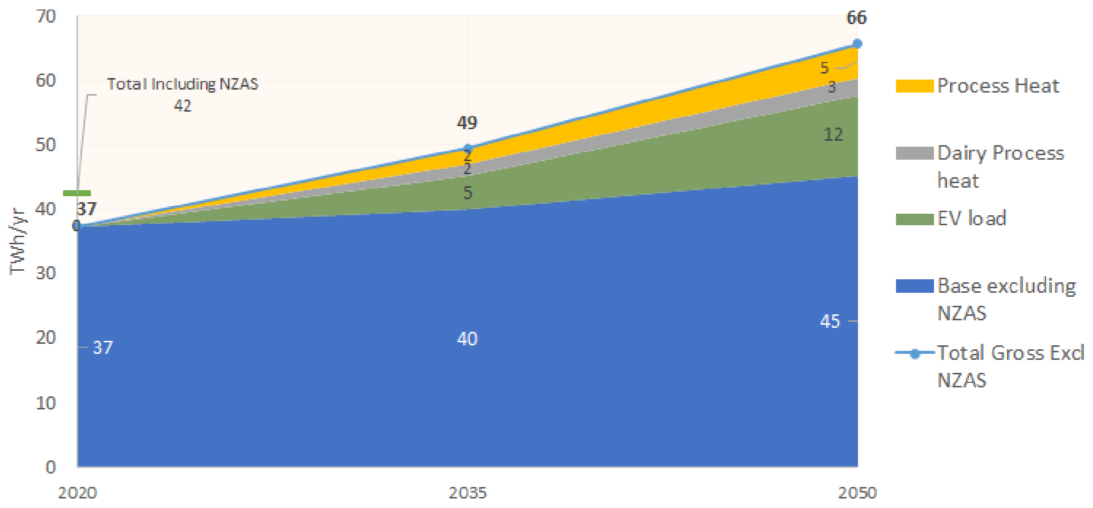
New Zealanders will use a lot more electricity by 2035 and 2050

5.11 Electricity demand in the reference case is based on the Climate Change Commission's demonstration path to net zero by 2050. Significant demand growth is expected from rising numbers of electric vehicles, a progressive conversion of process heating demand from fossil fuels to electricity, and a rising population. These factors are partly offset by the projected closure of the New Zealand Aluminium Smelter (NZAS) facilities at Tiwai Point and greater energy efficiency (insulation, better appliances etc). Total electricity demand (net of Tiwai) is assumed to grow by around 30% by 2035, and a further 30% by 2050 as shown in Figure 2.[42]

41 Available here: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/100%-renewable-electricity-supply/consutations.

42 The simulation results for the 2020 year (used for calibration purposes) include demand for the Tiwai smelter.

Figure 2: Electricity demand in reference case (TWh/year)[43]



A great deal of new generation will be added to the system – especially wind and solar

5.12 A lot of new generation, batteries and demand response resources will be needed to satisfy demand growth and offset the retirement of fossil-fuel stations (on the order of 400-500 MW per year on average until 2050). Solar and wind capacity is assumed to be unconstrained in volume terms, and the simulation model 'builds' this plant if prices reach a level that makes it revenue adequate. Geothermal is built in limited volumes due to resource constraints.

5.13 The other available generation option is fast-start peaker stations fuelled by a renewable source, such as bio-diesel or hydrogen (referred to as 'green peakers'). The assumed fuel cost for these units is based on existing technologies rather than requiring any breakthroughs. However, they are expensive to operate (fuel cost of $45/GJ real) and only provide last-resort cover. Except for geothermal, all of the above technologies are relatively scalable and have standardised performance characteristics.

5.14 No changes are assumed in the hydro generation base – including no development of hydro pumped storage. The performance characteristics of hydro options are very project specific, being affected by MW and storage size, conversion efficiency and location etc. There is currently insufficient information available to model such projects, but they could be added in future if information becomes available.

5.15 In the meantime, the key point to note is that if additional hydro (or other energy storage) capacity is developed, that would tend to 'relax' the system relative to the reference case. That would reduce the projected levels of physical variability between supply and demand, and associated spot price volatility.

[43] Note that the chart shows simulation results for 2035 and 2050. No results are calculated for intermediate years and the actual path between the years may not be smooth and linear. The same comment applies to subsequent charts.

5.16 Figure 3 shows the projected growth in the generation base in the reference case. Key points to note are:

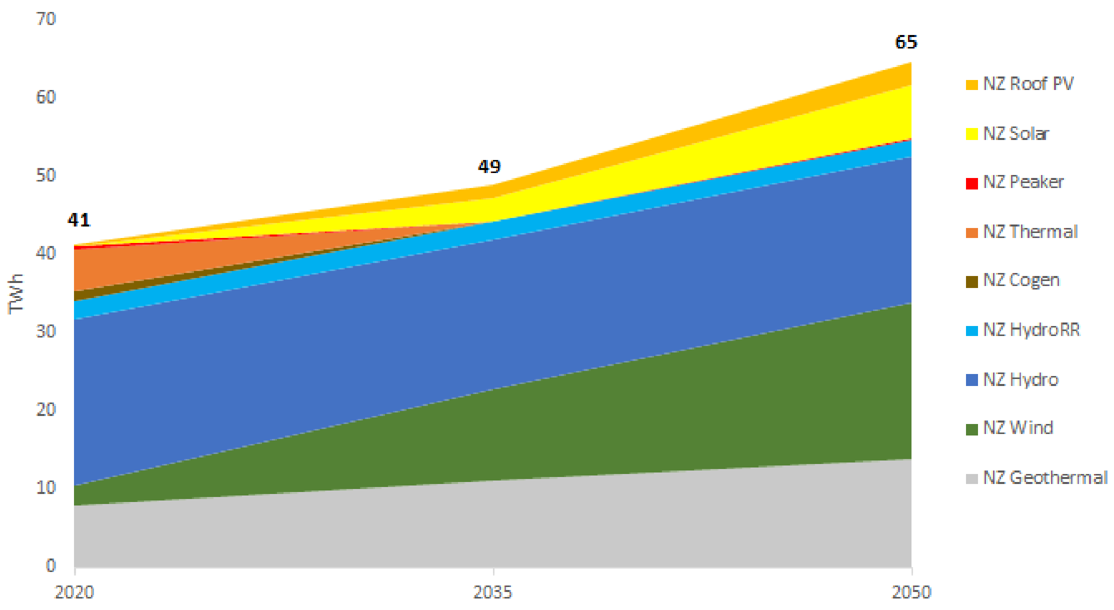
(a) all fossil-fuelled thermal plant is retired by 2035

(b) the share of total energy supply from sources with short-term intermittency (wind and solar) increases from 6% in 2020 to 31% in 2035 and 47% in 2050

(c) the share of total energy generated from flexible hydro (on average) declines from around 50% in 2020 to 40% in 2035 and 30% in 2050

(d) the growth in supply will need to be faster between 2035 and 2050 than the preceding 15 years. This reflects the assumed acceleration in electrification after 2035 and the closure of the Tiwai smelter before 2035.

Figure 3: Generation sources in reference case (TWh/year)



5.17 We consider these assumptions to be reasonably plausible. The projected demand growth is very similar to the 'Demonstration case' in the Climate Change Commission's 2021 report.[44] The supply mix assumptions are also similar, except the reference case eliminates all fossil fuelled generation and supplies around 1% of demand from bio-fuelled peaker generation. By comparison, the Climate Change Commission has around 1.5% supply from fossil-fuelled generation and no bio-fuelled peaker generation. Later in the paper we outline the impact of alternative scenarios for some key assumptions.

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44 See https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf (section 7.4).

New sources of flexibility will be needed on the power system

Batteries and demand-side flexibility are likely to grow

5.18 The rising share of VRE generation with its short-term intermittency will increase the need for offsetting flexibility from other resources. International experience indicates that some of this is likely to come from so-called smart charging of electric vehicles to avoid peak demand periods and using batteries in combination with rooftop solar panels to alter network power demand.

5.19 Another potential growth area is demand that can modulate in response to market conditions. Data centres are a possible option that have started being developed in New Zealand. For example, Contact Energy signed an agreement in August 2021 to supply up to 10MW of electricity to a data centre being developed near Clyde. Southern Green Hydrogen is another example of a potential electricity use which could flex in response to conditions.[45] Demand flexibility technology will be implemented to increase or reduce the data centre's operations depending on New Zealand's electricity needs, weather, and hydro generation water flows.[46]

5.20 As shown in Figure 4 the reference case includes significant levels of both demand shifting enabled by batteries, and demand which curtails in response to prices. In combination, these rise from around 8% of peak demand in 2020 to around 25% by 2050.[47] Compared to today this is a very substantial increase. However, technology to enable DSF is improving rapidly, particularly in the areas of batteries and control of devices via the internet. There is also considerable research underway to increase flexibility in certain energy-intensive industries. For example, Enpot technology has been retrofitted to an aluminium smelter in Germany and allows demand variation of around -13% to +20%. The developers have further work underway and consider +/- 25% to be achievable.[48]

5.21 More generally, the DSF assumptions in the reference case appear reasonable compared to other longer-term forecasts.[49] For example, our reference case appears to assume less load shifting than Transpower has included in its Whakamana i Te Mauri Hiko report released in 2020.[50]

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45 See https://www.southerngreenhydrogen.co.nz/about.

46 https://contact.co.nz/aboutus/media-centre/2021/08/30/contact-energy-to-supply-flexible-renewable-electricity.

47 The '2020 system' in the simulation modelling includes 500 MW of demand that is assumed to respond to high spot prices (at various tranches above $700/MWh). It is inherently difficult to know the true figure because it includes demand that would respond to events which have not occurred in the historical record (noting the simulations include a wider range of weather extremes than observed in the 2000-2020 period). Rather than direct observation, this quantity has been estimated based on the calibration process outlined in paragraphs 5.52 to 5.55. Having said that, the level of flexible demand assumed for 2020 does not affect the results for 2035 and 2050, but it is relevant for considering the level of change required in the DSF space.

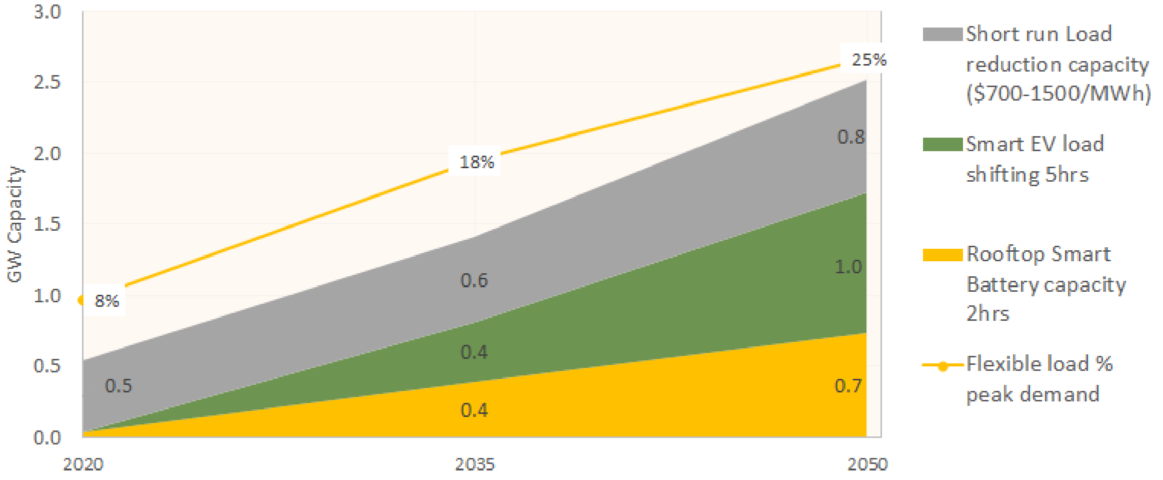
48 See https://energiapotior.com/case-study.

49 See "Whakamana i Te Mauri Hiko – Empowering our Energy Future" (see footnote 25 for link) and National Grid Future Energy Scenarios 2021 (Future Energy Scenarios 2021 | National Grid ESO).

50 Transpower's Accelerated Electrification scenario assumes energy demand growth of 55% by 2050 (net of the Tiwai smelter), which is the same as our reference case. Transpower also assumes that peak demand will grow by 28% by 2050 (half the rate of energy demand). Our reference case includes peak demand growth of 44% (80% of the rate of energy demand). The large difference in peak demand growth suggests that our load shifting assumptions are more conservative than Transpower, although it is possible that some of the difference is because the comparisons are not entirely 'apples with apples'.

5.22 Having made these observations, the level of future DSF is an area where there is uncertainty and later in this paper we outline the impact of alternative demand response cases.

Figure 4: Flexible demand sources in reference case (GW)



5.23 Figure 5 and Figure 6 show the simulated demand curtailment levels for the reference case, expressed as a percentage of total monthly demand.[51] The results indicate how much DSF providers in the reference case would be called upon to *curtail* (rather than shift) their power usage. Key observations are:

(a) There is a clear seasonal pattern to the triggering of DSF response, with curtailments being concentrated in the winter. This reflects the system being tighter at that time due to higher demand and reduced solar generation. When this is combined with low wind and/or hydro generation, this triggers a need for demand response. However, curtailment events can also occur at other times (as shown by the events in November and December).

(b) Average levels of demand curtailment (shown by blue lines) are relatively low in both 2035 and 2050.

(c) There is clear growth in curtailment events between 2035 and 2050 as the system becomes more sensitive to periods of reduced supply from intermittent sources.

(d) By 2050 demand curtailment in the more extreme weather years is reaching appreciable levels. For example, in the worst weather year of the simulation runs, the curtailment equates to 2.5% of total demand for July.

51 To obtain periods of equal length the charts show results for 4-week periods rather than calendar months.

Figure 5: Average demand curtailment volumes (reference case 2035)

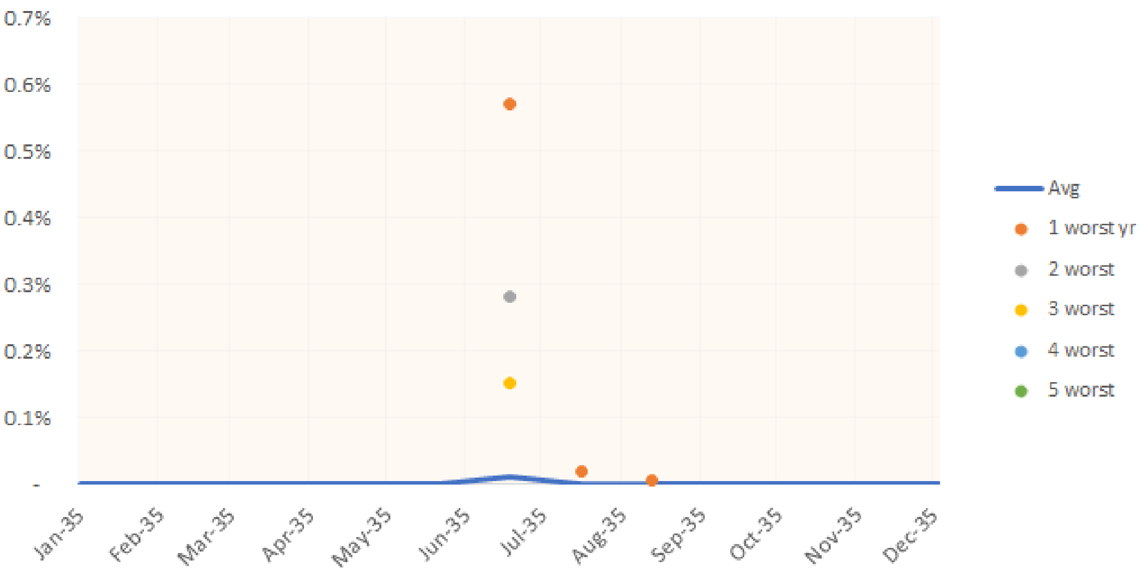
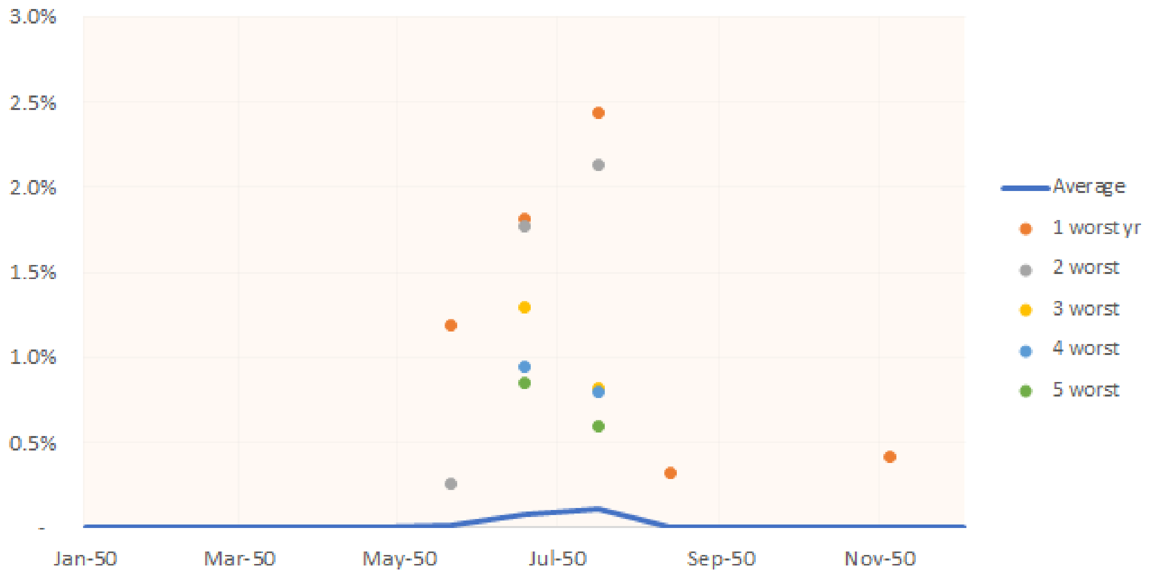


Figure 6: Average demand curtailment volumes (reference case 2050)



Bio-fuelled green peakers

5.24 Another source of flexibility included in the reference case is green peaker capacity. As noted earlier, these are open-cycle combustion turbines and are assumed to have fuel available at $45/GJ (real). Possible fuel sources include bio-diesel, biogas, or ammonia or hydrogen derived from renewable sources. This type of fast-start plant is suitable for providing network support services and the simulation assumes that 20% of the fixed costs are recovered outside the wholesale market. An alternative sensitivity case is also considered where 100% of costs are recovered in the wholesale market (see paragraph 5.70).[52]

5.25 In the reference case simulation, around 700 MW of green peakers were on the system in 2035 and around 900 MW in 2050. The simulation indicated this plant would operate mainly to provide last resort type back-up during weeks when solar/wind is very low, but it would also provide some limited dry year back-up.

5.26 We consider these assumptions to be reasonably plausible given that the technology is well understood and does not rely on any breakthroughs. Furthermore, there is currently around 500 MW of combustion turbine capacity on the system which appears to be capable of conversion to operate on bio-fuel.

5.27 The principal uncertainty relates to the cost of the fuel feedstock, and the consequent impact on operating costs. The assumed fuel cost of $45/GJ (real) seems reasonable based on:

(a) Pulp logs are a potential feedstock for production of biodiesel and should be available at scale. Based on the long-term average price of export logs, the equivalent fuel cost is $45/GJ. Domestic pulp log prices are cheaper and would imply a fuel cost of around $25/GJ, but it is not clear whether they would be available at scale as a feedstock. It is also possible that some biodiesel could be imported.

(b) Research by EECA/BECA indicates 5-13 PJ/year of biogas and biomethane could be available in future. The lower end of the cost range was $35/GJ and is below the estimate assumed for biodiesel.

(c) A $45/GJ cost for biofuel implies a carbon abatement cost of $320-$700/tCO2e. This range compares to the Climate Change Commission's estimated carbon value in 2050 of around $250/t.

Flexible component of hydro generation base likely to operate in different way

5.28 The flexible part of the hydro generation base[53] is likely to play a different role in a 100%RE system. As noted above, flexible hydro currently provides around 50% of total generation on average. Looking ahead, it is projected to decline but remain significant, accounting for around 30% of supply by 2050 in the reference case.

5.29 In relative terms, this flexible hydro is expected to become more important as a shock absorber, smoothing out shorter-term fluctuations between intermittent renewable sources and varying demand. Currently, flexible hydro shares this role with fossil-fuelled stations, and there is less need to balance wind and solar as they only account for 6% of total supply.

5.30 Another consequence of the above changes is that the optimal level of storage for hydro lakes is expected to be higher on average than is currently the case. Put simply, without fossil-fuelled stations that can be turned on at moderate cost to ease pressure on storage

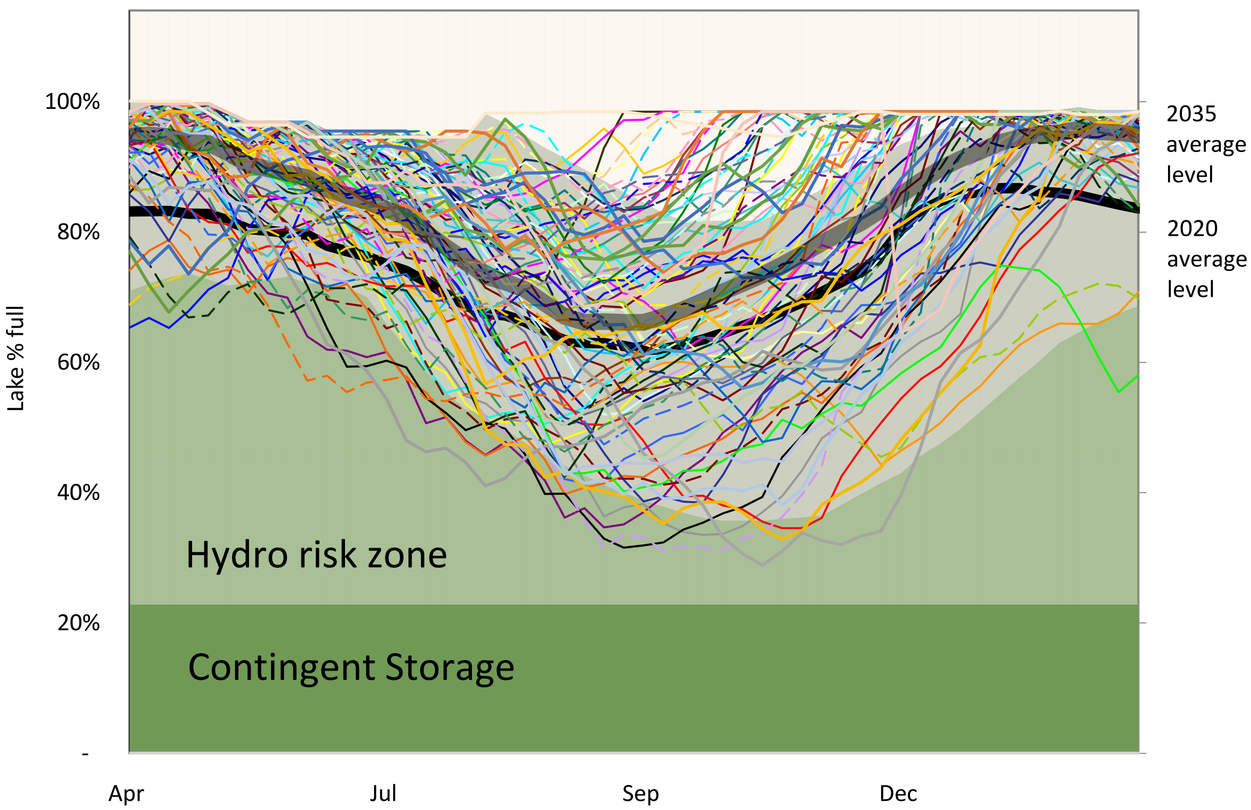
52 Another possibility is that the plant earns a premium to expected spot prices due to the insurance nature of the services being provided, and/or earns some ancillary service revenue.

53 The part that has storage and can control when stored water is used, as opposed to the run-of-river component.

lakes in dry periods, it will be prudent to enter each winter with higher levels of storage than is currently the case. The alternative would be to incur much greater risk of demand curtailment being required which has a very high cost.

5.31 Figure 7 illustrates the effect of such a change. It shows the simulated storage trajectories for the reference case in 2035 across the 86 weather years. The average over all the weather years is shown by the thick grey line. The thinner black line shows the typical trajectory based on the current system. The key difference is that the average storage level in the January–April period is appreciably higher, to reduce the risk of demand curtailment (and its costs) being required in the winter period when demand is higher. But storage is also higher at the end of winter to guard against a late dry spell. Because lakes are at a higher level on average, a larger number of storage trajectories hit the full level. This means that there is more spill as shown later in Figure 8.

Figure 7: Simulated hydro storage trajectories 2035 reference case (starting April)



5.32 Another key change resulting from fossil-fuelled station retirements is that storage trajectories in the major reservoirs will be subject to much less human 'management'. Whereas hydro storage trajectories (in aggregate) can currently be made less/more steep by turning thermal plant on/off, that lever will largely disappear under 100%RE. The only resources that could be activated quickly in the future will be demand response and green peakers, both of which have much higher costs than fossil-fuelled stations and therefore would be used much less. This means the storage trajectories will largely 'trace out' the effect of weather and demand fluctuations on the residual demand for flexible hydro generation.

5.33 Put another way, if hydro generators' raise offer prices for generating from stored water, it will not make the wind blow harder or the sun shine more brightly, whereas at present it will likely incentivise increased thermal operation. In the 100%RE world, changing the offer prices for stored water will not alter thermal generation (other than green peakers).

5.34 Instead, a hydro generator that raises its offer price may cause storage controlled by a competitor to be drawn down faster, and/or it may alter the level of flexible demand, and/or the timing of future generation investments. This latter effect is not immediately obvious but arises because new investment in a 100%RE system with growing demand is akin to fuel, albeit with a slower delivery time. In this context, it is important to keep in mind that the future pipeline of new solar and wind generation projects is likely to have a lot more volume and delivery times could shorten, especially for solar. For example, in Australia some solar projects have been generating within a year of being given the green light.[54]

5.35 The preceding point is not suggesting a future where rapid build of new generation will mitigate temporary supply shocks such as dry years. Rather, it is making the point that if new investment 'fuel' is not added to match demand growth in a 100%RE system, then hydro storage trajectories will (on average) drift downwards. Furthermore, this drift will occur more rapidly than has been the case in the past. This is because use of hydro storage is the principal shock absorber between changes in demand and VRE supply. Again, this contrasts with the current system where unexpected surges/reductions in demand are typically absorbed at first by more/less utilisation of existing thermal plant, until new investment rebalances the system.

Variation in renewable spill expected to become a more important source of flexibility

5.36 In the current system, hydro spill is rare and typically associated with extreme flood conditions, when there is no available capacity to capture or utilise water flows. Hydro operators can seek to reduce the future likelihood of spilling their water by keeping their storage reservoirs below levels where spill is likely should a major inflow event occur. They can currently do this because if it is unexpectedly dry, there is fossil-fuelled thermal generation which can fire up if needed to avert electricity shortages.

5.37 As shown above in Figure 7 the trade-off between avoiding shortage and spill is expected to change in 100%RE. It will become more economic to maintain hydro reservoir storage at higher levels on average, and as a consequence there will be an increase in the level of spill. It is important to note that spill in this context does not only refer to water. It includes wind or solar generation that is not fully utilised, and/or geothermal which is throttled back (noting that it faces a carbon charge for greenhouse gases in the station emissions). Wind and geothermal are likely to have higher variable costs than hydro, and therefore spill before hydro. Hydro generators will vary in their characteristics, though, with some having less

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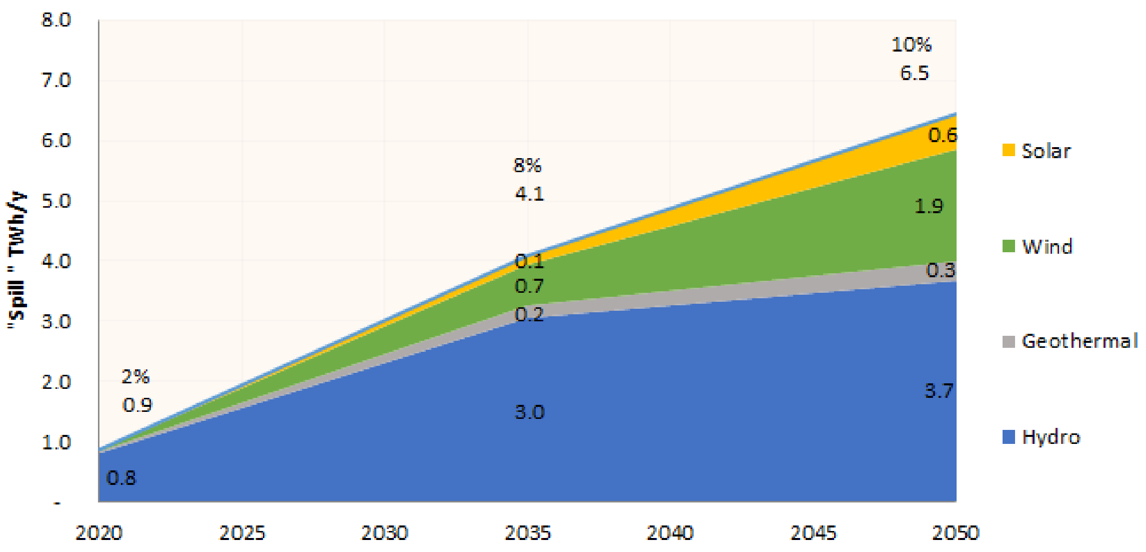
54 The Glenrowan West Solar Farm (in Victoria) project started in mid-January 2020 and started generating in December 2020 (https://www.glenrowanwestsolarfarm.com.au/). Construction of the Merriden Solar Farm (Western Australia) started in mid-2019 and it started generating in mid-2020 (https://reneweconomy.com.au/west-australias-first-100mw-solar-farm-starts-sending-power-to-the-grid-30918/).

operational flexibility to spill due to resource consent or health and safety (e.g. flood risk) issues.

5.38 Figure 8 shows projected average levels of spill in the reference case. These rise from 2% of total generation in 2020 to 8% in 2035 and 10% in 2050.

Figure 8: Wind/solar/water spill in mid-hydro offer scenario (TWh/year)



5.39 The projected levels of spill are much higher than in the current system. At one level, this increase may be viewed as wasteful because it is energy that is not utilised. However, this cost needs to be weighed against the alternatives. The spill could be reduced by building less intermittent generation, but that would trigger other costs such as higher use of green peakers or more demand curtailment. The simulation with the reference case assumptions indicates the option with the lowest overall cost includes some increased spill (along with green peakers and more DSF).

5.40 Clearly, tolerating an increased level of spill would be a major shift from the predominant mindset in the electricity generation sector today. But the shift is really one of degree. The sector is used to “spilling” thermal generation capacity when supply is abundant. In future it would switch to spilling some renewable capacity when supply is abundant.

5.41 Of course, it seems less obviously economic to spill renewable than thermal generation output because the latter has a running cost which is saved when plant is idle. However, that does not change the underlying need to make a trade-off between the cost of overbuild (and spill) and the cost of non-supply. That trade-off is evident in the network side of the sector which also has assets with zero (or very low) running costs. On most days, there is ‘network capacity spill’ in the form of transmission or distribution capability that is not fully utilised, but that is generally seen as sensible to avoid high costs of non-supply.[55]

55 Other factors are also relevant such as economies of scale and investment lumpiness. But even if the other factors did not apply, it would be cheaper to tolerate some network capacity spill on most days.

Impact of more energy storage capacity

5.42 New Zealand is unusual by world standards because it will not retire most of its flexible generation base with a shift to 100%RE. A sizeable component will remain in the form of hydro generation backed by storage. As discussed earlier, that source of flexibility is expected to play an important shock absorber role for the system under 100%RE.

5.43 Having said that, the growing spill in the reference case also signals that the system would benefit from additional energy storage capability if it is available at reasonable cost. The specific benefits of additional energy storage include:

(a) Capturing energy that would otherwise be spilled so it can be utilised later.

(b) Reducing the amount of new generation or demand response that would otherwise be required because some demand can be met by the stored energy from (a) instead.

5.44 In this context, we note that the Government has established the NZ Battery Project to investigate the technical, environmental, and commercial feasibility of pumped hydro and other potential energy storage projects.[56] An observer from the NZ Battery Project has been participating in MDAG's workstream on 100%RE.

Effect of physical changes to system on spot price volatility

5.45 The preceding sections outlined the main *physical* changes to the system in the simulation reference case. Those physical changes would be expected to affect *spot price volatility*. This is an important issue because all electricity consumers and suppliers are affected by spot price volatility, either directly or via the risk management practices they adopt to manage volatility. For example, if a big step-up in spot price volatility was likely, it would be important to consider how that affects the risks and opportunities faced by consumers, retailers, and investors in new generation or batteries.

5.46 Keep in mind that spot price volatility which reflects underlying economic conditions is not a flaw; on the contrary, it is signalling real changes in the cost of supply to meet changing levels of demand.

56 See www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery/.

Volatility

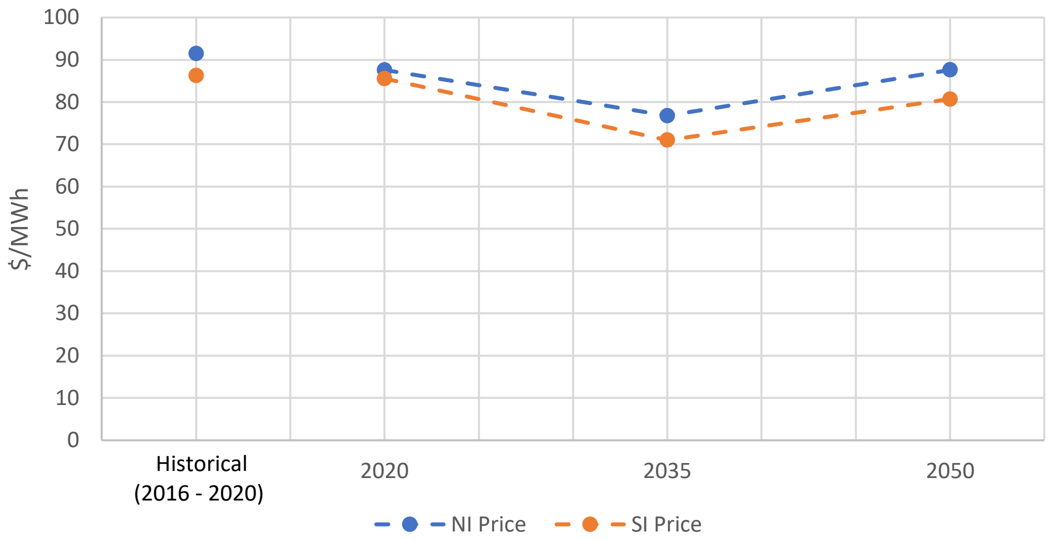
Volatility is an inherent feature of our wholesale electricity market. It is caused by several factors, including relatively inelastic demand; our long, stringy transmission network; highly changeable weather; large variations in hydro inflows; and big step-changes in the cost of fuel (from run-of-river hydros to valuable storage and expensive gas, coal, and diesel).

A key purpose of the wholesale market when it was put in place in the late 1990s was to make this inherent volatility transparent – to signal it clearly in wholesale prices, without smearing or camouflage, as it is this information that drives risk management by wholesale buyers and sellers, which then feeds into longer-term contracts and drives innovation and investment for the long-term benefit of consumers. In New Zealand, this was a foundational idea for market design that came out of the inquiry into the 1992 electricity shortage chaired by Rt Hon Sir Ronald Davidson.[57]

Average level of prices in reference case

5.47 While is it not the primary focus of the analysis, it is useful to briefly describe the projected *average* price levels in the reference case for the North Island (Haywards) and South Island (Benmore).

Figure 9: Projected average levels of prices in reference case



5.48 In the reference case, the projected average price levels in 2035 and 2050 are quite similar to recent historical average levels in real terms. Indeed, they decline slightly in the period between 2020 and 2035.

5.49 The key drivers for the relatively flat (or slightly declining and then rising) outlook are the assumptions that capital costs continue to gradually decline for wind (-1% per annum to 2035 and -0.5% to 2050) and solar (-3.5% per annum until 2035 and -0.9% to 2050), but that this

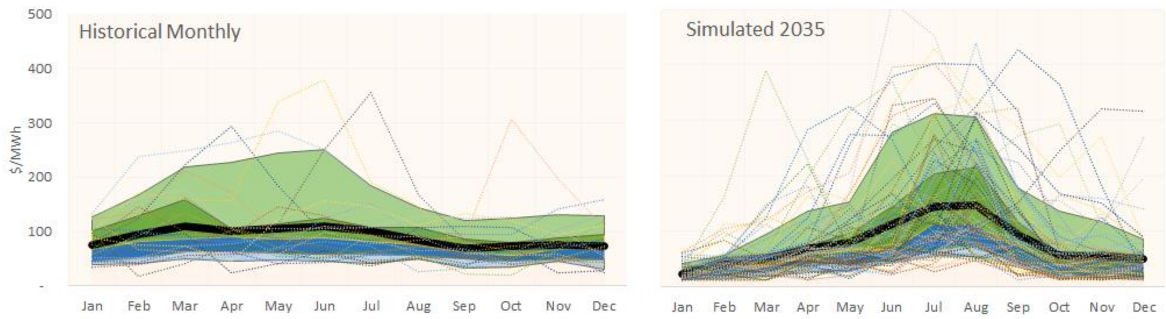
57 See Electricity Shortage Review Committee, The Electricity Shortage 1992 (December 1992).

offset by falling capture rates[58] as intermittent renewables rise as a share of total generation. Having made these observations, it is important to note that this project is not seeking to predict the average level of future prices. Furthermore, had it been a key focus, a range of additional sensitivity cases would need to be explored.

How spot price volatility is measured

5.50 Rather than average prices, the simulation modelling is focussed on exploring price volatility. The main yardstick used to compare spot price volatility is the so-called 'volatility ratio'. This is defined as the standard deviation of spot prices divided by the mean of spot prices.

Figure 10: Seasonal price variation (monthly average prices)[59]



5.51 As shown in Figure 10, a more pronounced seasonal variation in spot prices is expected with 100%RE. Some of the variation is predictable, as indicated by comparing the mean monthly prices (heavy black lines). This is sometimes referred to as 'cyclic variation'. And some of the increased variation is unpredictable as shown by the wider spread of percentile areas.

5.52 The method used to calculate volatility ratios focuses on the variation in spot prices which cannot be readily predicted and seeks to filter out the more predictable seasonal component of price variation.[60,61]

5.53 Turning to volatility ratio results, these are shown in Figure 11 for the reference case.[62] The dots at the left-hand portion of the chart show the ratios computed from historical data for

58 The proportion of the time weighted average spot price captured by a generation plant.

59 Note that the historical data includes only 20 sets of observations, whereas the simulated results include 86 sets of observations.

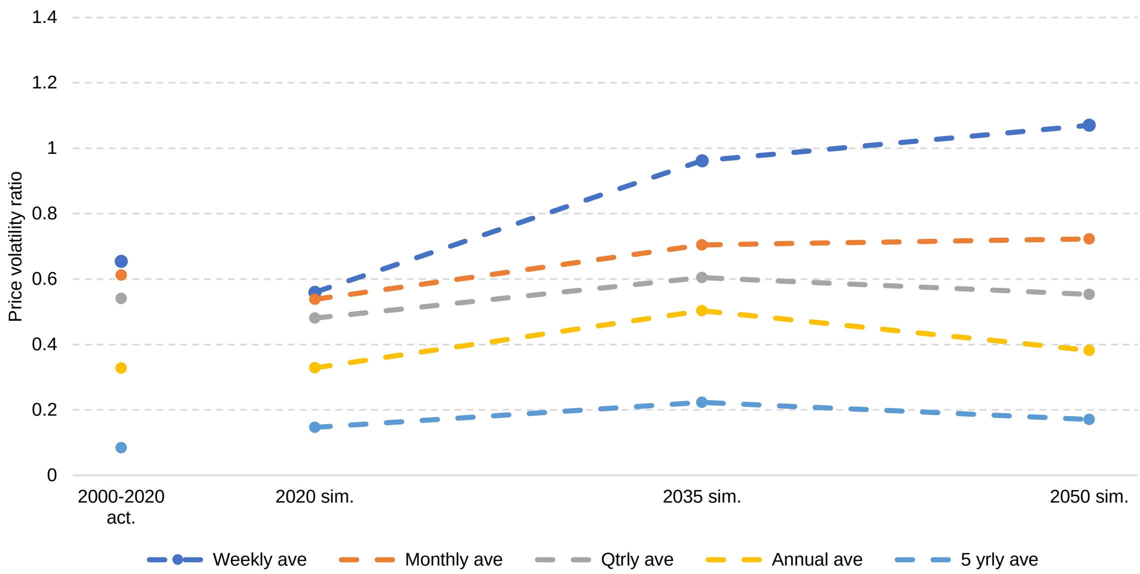
60 The annual measure is the standard deviation of the annual average spot price for each of the 86 simulation years, divided by the mean annual spot price over all simulations. A similar approach is used to calculate volatility ratios for quarterly, monthly and weekly average spot prices, which implicitly account for the predictable component of within-year seasonal price variability. For the quarterly measure, the standard deviation of average prices in the first quarter of the year is calculated and divided by the mean of all first quarter values. The same process is followed for the other quarters, and the quarterly volatility ratio is the mean of the ratios for the four quarterly measures.

61 Although the model computes hourly spot prices within each week, there is less confidence about the within-week structure of prices as these are particularly sensitive to assumptions about battery use and EV charging patterns. Furthermore, within week price volatility seems less likely to emerge as a dominant concern because the scalability, falling cost and fast discharge/recharge time of batteries mean they can moderate peak demand growth and readily cap within week volatility. Transpower's base case scenario in Whakamana i Te Mauri Hiko seems to be based on a similar view. It projects peak demand to grow by 40% by 2050, whereas energy demand is projected to grow by 68%. See footnote 25.

62 See paragraph 5.10 for more information on assumptions and the basis for them.

2000-2020.[63] For example, the upper dot indicates that the standard deviation of average weekly spot prices was 0.75 of the mean of all weekly average spot prices (after adjusting for the predictable seasonal component as noted above).

Figure 11: Volatility ratios – reference case



5.54 Note that the historical data includes volatility effects arising from factors other than weather and demand variability, such as shocks to thermal fuel supplies. On the other hand, the historical data does not incorporate the full range of weather variability assumed in the model because it only reflects 21 years of weather data.

5.55 The dashed lines show the price volatility ratios computed from the simulation model. The points labelled '2020 sim' show simulation results based on the system prevailing in 2020 (i.e. not 100%RE). These results reflect the 86 simulated weather/demand years etc but not other factors such as thermal fuel price volatility. The historical and 2020 simulated results are broadly comparable, and this provides some reassurance that the underlying structure of the simulation model is reasonable.

Spot price volatility is expected to increase, especially shorter-term volatility

5.56 Turning to the simulations for the system with 100%RE, Figure 11 shows results for 2035 and 2050. Although the chart shows volatility ratios as lines between the years, it is important to emphasise that simulations have only been performed for the years shown (i.e. 2020, 2035, 2050) as it is computationally impractical to simulate all years. Hence, nothing should be inferred about the volatility ratios between the years shown.

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63 Historical data was adjusted for inflation. Prices are at the Haywards node.

5.57 The principal way to interpret the chart is to compare the 2020 sim results (not the actual results) with simulation results for 2035 and 2050. This ensures a comparison that is more apples with apples in nature.[64] Key observations from this comparison are:

(a) Between 2020 and 2035 there is an across-the-board rise in volatility ratios.

(b) Between 2035 and 2050 some ratios continue to increase while others flatten or even decline.

(c) In absolute terms, volatility ratios for shorter duration periods tend to increase more than those for longer periods. For example, the volatility in weekly average prices almost doubles between 2020 and 2050, whereas the volatility in annual average prices increases by around 15% over the same period.

5.58 Overall, the simulation results in the reference case indicate both a lift in volatility ratios (especially between 2020 and 2035), and a shift toward greater short-term volatility. The intuition behind these trends is that the overall system will become more reliant on resources that are subject to short-term weather variability. While longer-term weather effects (such as 'dry years') remain important, the shorter-term weather 'noise' gets larger over time, driving up volatility ratios at the shorter end of the spectrum.

5.59 The levelling off (or decline) in some longer duration volatility ratios between 2035 and 2050 is because the new investment becomes increasingly driven by capacity (rather than energy) requirements. Indeed, the large volume of VRE resource needed to meet peak capacity requirements in 2050 provides more buffer to address dry years, but they remain a key risk. In very simple terms, the reference case suggests that as New Zealand transitions to 100%RE, the security challenge will evolve from being a dry year problem and become a dry, calm, and cloudy problem.

Volatility outcomes will be affected by hydro generation offer behaviour

5.60 As discussed earlier, simulation results should not be interpreted as specific forecasts. Rather, they have been used to see how outcomes vary under different input assumptions and explore the possible range of future outcomes. The simulations indicate that one of the key factors affecting price volatility is how hydro generators will value stored water in a 100%RE system.

5.61 As discussed in a paper by Dr Grant Read,[65] the general theory for determining water values is long-established and is the same whether applied in a centrally managed system or a perfectly competitive market. Fundamentally, the general theory provides that water values should be driven by the expected marginal water value of holding water for future use. Moving to 100% renewable supply will not change that theory, but it will significantly alter the environment in which the theory is applied.

64 It is impossible to make the comparison entirely 'apples with apples' due to the multiple factors included in the model, and the fact that results reflect the combined influence of all the various factors.

65 One of the accompanying papers available here: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/100%-renewable-electricity-supply/consutations.

5.62 Dr Read did not seek to predict future outcomes in quantitative terms and notes these will depend on empirical factors. However, he makes a number of qualitative observations which included:

(a) Much of what is commonly described as electricity price "volatility" is actually predictable "cyclic variation" (typically diurnal and seasonal) which optimal storage management will arbitrage away as much as possible, implying a distinct cyclic water value pattern within the random "noise" caused by weather etc.

(b) The loss of thermal system "storage", and the need to hold hydro storage at higher levels to manage random influences, will reduce the effective capacity available to arbitrage between low- and high-priced periods, implying higher intra-day and inter-seasonal price/water value differentials.

(c) For a 100%RE system which is in equilibrium, water values will be determined by the costs implied by various forms of demand-side management, the prices of (renewable) thermal fuel, spill probabilities, and (indirectly) new investment costs.

(d) Ultimately, marginal generation expansion costs will continue to limit prices and water values.

5.63 In some jurisdictions, concerns have been raised that spot prices might exhibit ‘bang-bang’ or bi-modal outcomes, where they oscillate between zero and the Value of Lost Load (VoLL). This raises the question of whether such outcomes might arise in New Zealand. For that to be likely, it would be necessary to believe that the system under 100%RE will cycle between surplus (spill) and shortage (demand curtailment) with very little time in between these states. Furthermore, for that cycling to persist, it would be necessary to believe that there are no self-correcting forces that reduce the likelihood of such cycles in future.

5.64 These pre-conditions appear unlikely to hold in New Zealand because:

(a) New Zealand has an appreciable volume of hydro storage capacity in the power system. As shown in Figure 7 simulated hydro storage trajectories under 100%RE spend a considerable amount of time in the state between full and empty and it takes many months to move from one state to the other. Accordingly, water values for the major hydro reservoirs are unlikely to exhibit bang-bang outcomes.

(b) Water management in the major hydro reservoirs is likely to strongly influence the level and structure of spot prices for the system because they will be the principal resource with inter-season flexibility on the system (although see next section for discussion of relationship between offer prices and water values).

(c) The system is expected to have a considerable volume of new resource with short-term flexibility in the form of storage batteries and load (such as EVs) which can be shifted a few hours on a day. Furthermore, batteries are relatively inexpensive and scalable and could expand as opportunities arise. Accordingly, provided there is effective short-term coordination (see later section on real-time coordination from paragraph 7.3), the water values in the major reservoirs are likely to anchor spot prices much of the time.

(d) Finally, New Zealand has some self-correcting forces not present in all systems. Probably the most important is that generators rely exclusively on the wholesale market for revenues (either directly or via contracts which insulate end-users from short-term spot price volatility). In contrast, systems where new entry is underpinned by feed-in tariffs or other mechanisms outside the wholesale market can exhibit increased price volatility. In essence, the bottom end of the price distribution is reduced (with negative prices in some cases) because some suppliers are driven to generate to obtain external revenue sources. Meanwhile, this accelerates the retirement of high-merit order plant which in turn causes higher prices when the system is tight. This is often called the "merit-order" effect and does not apply in New Zealand.

Merit-order effect

The reduction in wholesale prices is typically referred to as the "merit-order" effect (see e.g. Lynch et al. (2021)[66], Newbery et al. (2018)[67], Simshauser (2018)[68]), which sees generation from high marginal cost thermal plant offset by very low short run marginal cost SRMC renewables. Many of these studies are of jurisdictions where renewable investment is supported by incentives outside the spot market (e.g. feed-in-tariffs).

The impetus to build renewable plant is therefore driven less by expected spot prices, and more by the degree of subsidy, than would occur in New Zealand. Joskow (2019)[69] 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 generalise the resulting price series to jurisdictions where this incongruence does not exist.

Furthermore, VRE in many jurisdictions is driving out all (or most) of the controllable plant on the system. While VRE entry will accompany the exit of thermal in New Zealand, it will not result in the exit of hydro, which provides significant firming support to the market. As noted by Evans (2017)[70], the opportunity cost (or "delay option" value) of hydro storage will continue to be a core part of a very high renewable system. We are not aware of any merit-order analysis in markets that have experienced a significant increase in intermittent renewables, while retaining a substantial degree of medium-term renewable storage, such as hydro.

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. This begs the question inferred by Joskow (2019)[71], noted above, as to whether the timing of renewable investment, and its coordination with thermal exit, would have been different without the support. Newbery (2018)[72] 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.

5.65 In summary, while significantly more price volatility than in the past is to be expected, bang-bang outcomes appear improbable.[73]

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66 Lynch, M., Longoria, G., Curtis, J., 2021, *Future market design options for electricity markets with high RES-E: Lessons from the Irish Single Electricity Market*, Working Paper no. 702, Economic and Social Research Institute.

67 Newbery, D., Pollitt, M., Ritz, R., Strielkowski, W., 2018, *Market design for a high-renewables European electricity system*, Renewable and Sustainable Energy Reviews, vol. 91, p695-707.

68 Simshauser, P., 2018, *On intermittent renewable generation and the stability of Australia's National Electricity Market*, Energy Economics, vol. 72, May 2018, p1-19.

69 Joskow, P., 2019, *Challenges for Wholesale Electricity Markets for Intermittent Renewable Generation at Scale*, Working Paper CEEPR WP 2019-001, MIT Center for Energy and Environmental Policy Research.

70 Evans, L., 2017, *The electricity spot market: Is it future proof?*, The Electricity Journal vol. 30, 2017, p25-29.

71 See footnote 70.

72 See footnote 68.

73 This assumes within-day and within-week coordination is effective with batteries, smaller headponds within river chains etc. See paragraphs 7.1 to 7.14 for further discussion of this issue.

5.66 One issue touched on above is the relationship between water values and offer prices. As noted earlier hydro offers are unlikely to materially affect dispatch decisions when storage levels in major reservoirs are in the 'intermediate zone' with low likelihood of shortage or spill in the immediate future. To reflect the uncertainties about hydro offer behaviour, three different approaches were simulated. In essence, they are:

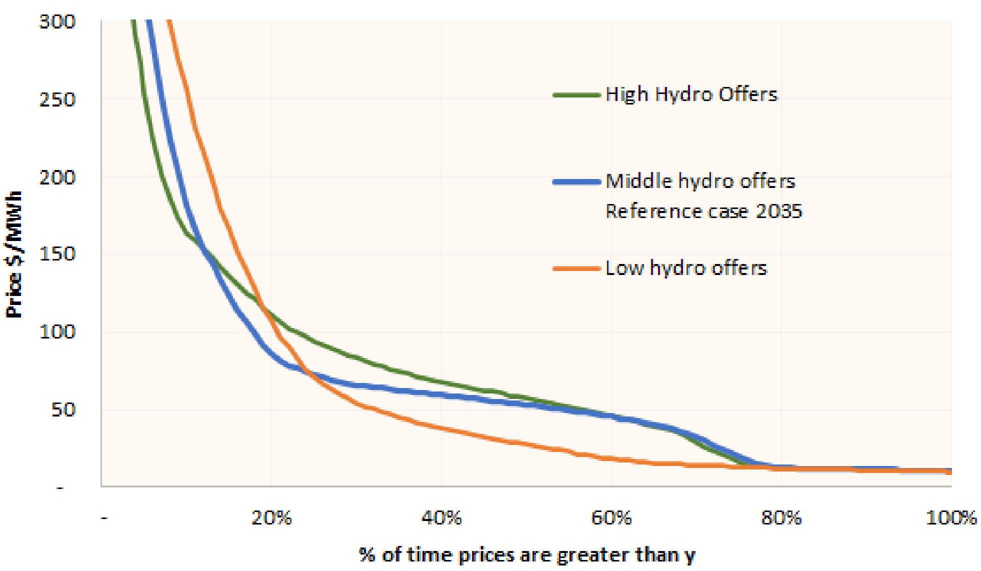
(a) Lower case – offers are $5/MWh in the spill zone, then rise exponentially up to the green peaker cost.

(b) Middle case – offers compete with wind running costs of around $12/MWh in the spill zone, then rise quickly towards a level to reflect new entry-based costs, then are relatively flat before rising steeply towards the green peaker cost.

(c) Higher case – offers have a minimum of $12/MWh in the spill zone, and then rise to the green peaker cost.

5.67 In all cases the offer prices in the spill zone reflect the variable cost or carbon cost saving that can be achieved when wind/solar or geothermal are dispatched off.[74] Figure 12 shows the duration curves for weekly average prices implied by the different approaches.

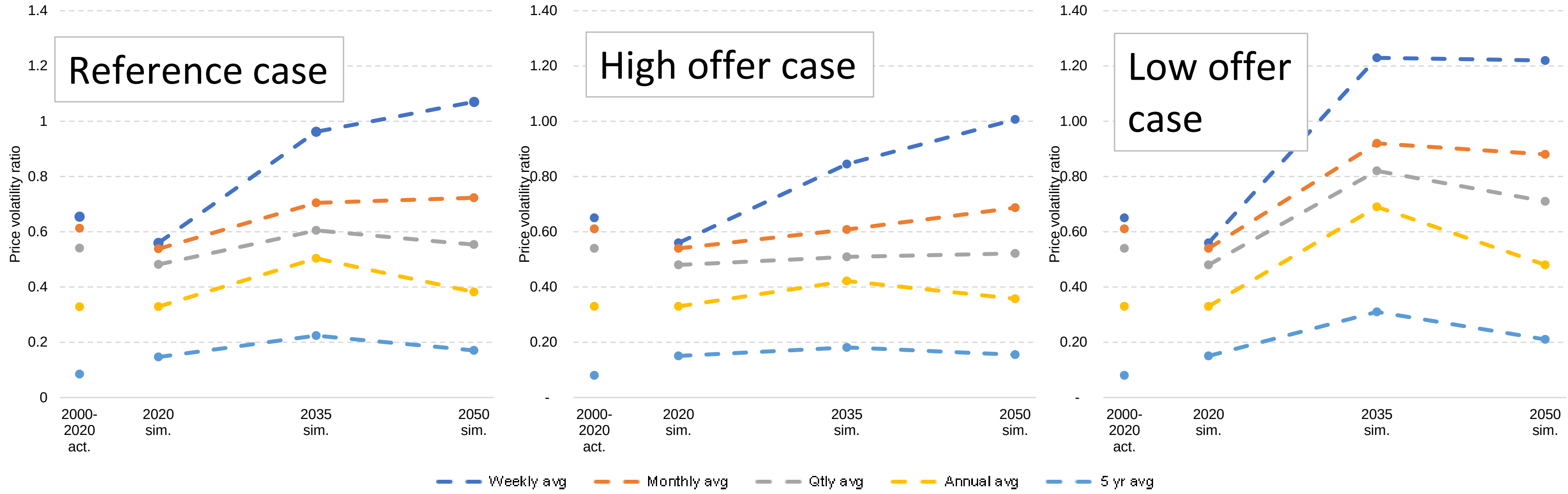
Figure 12: Hydro offer sensitivity cases – implied price duration curves (2035)



5.68 The effect of the different hydro offer cases on volatility ratios is shown in Figure 13.

74 See accompanying paper on Simulation Assumptions and Results for more information (available here: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/100%-renewable-electricity-supply/consutations).

Figure 13: Volatility ratios – effect of different hydro offer behaviours



5.69 Key observations are:

(a) ”2020 sim” results are comparable to “2000-2020 actual” results.

(b) In all cases, volatility increases appreciably relative to 2020 – but especially for the low offer case.

(c) The largest modelled increase is from 2020 to 2035 as the system moves to a 100% renewable state. There is little difference from 2035 to 2050 in all scenarios, with some predicting a small increase and some a small decrease.

Other sensitivity cases

5.70 A range of other sensitivity cases were examined in addition to hydro generator offer behaviour to examine the effect on volatility outcomes. The cases included:[75]

(a) Demand-side flexibility – the lower case assumes smart charging applies to 35% of electric vehicles and that price responsive demand is 30% lower than the reference case. The higher case assumes an additional 400 MW of flexible demand, and that 100% of electric vehicles adopt smart charging.

(b) System margin – the short-supply case assumes the system margin is below the equilibrium level by around 400MW (approximately 1.5 years of grid investment requirement) with the shortfall spread between solar, wind and green peakers. The long-supply case has a corresponding surplus of 400 MW. The long supply (fixed pkr) case assumes that extra supply is from sources other than green peakers.

(c) Green peakers – this alternative case assumes these units require 100% of capital and standing costs to be recovered from spot revenues. This compares to the reference case assumption of 80%, which reflects an expectation that such plant will likely be able to earn some revenue from network support services and/or premia for providing insurance products.

5.71 Figure 14 shows the summary results for the reference and sensitivity cases. Key observations are:

(a) Hydro generator offer behaviour is the variable that generally has the greatest impact on projected volatility outcomes, especially for 2035.

(b) The sensitivity of results to green peaker costs and DSF is higher in 2050 than 2035. This likely reflects the system becoming more sensitive over time to short-term capacity constraints as the share of intermittent renewable generation increases.

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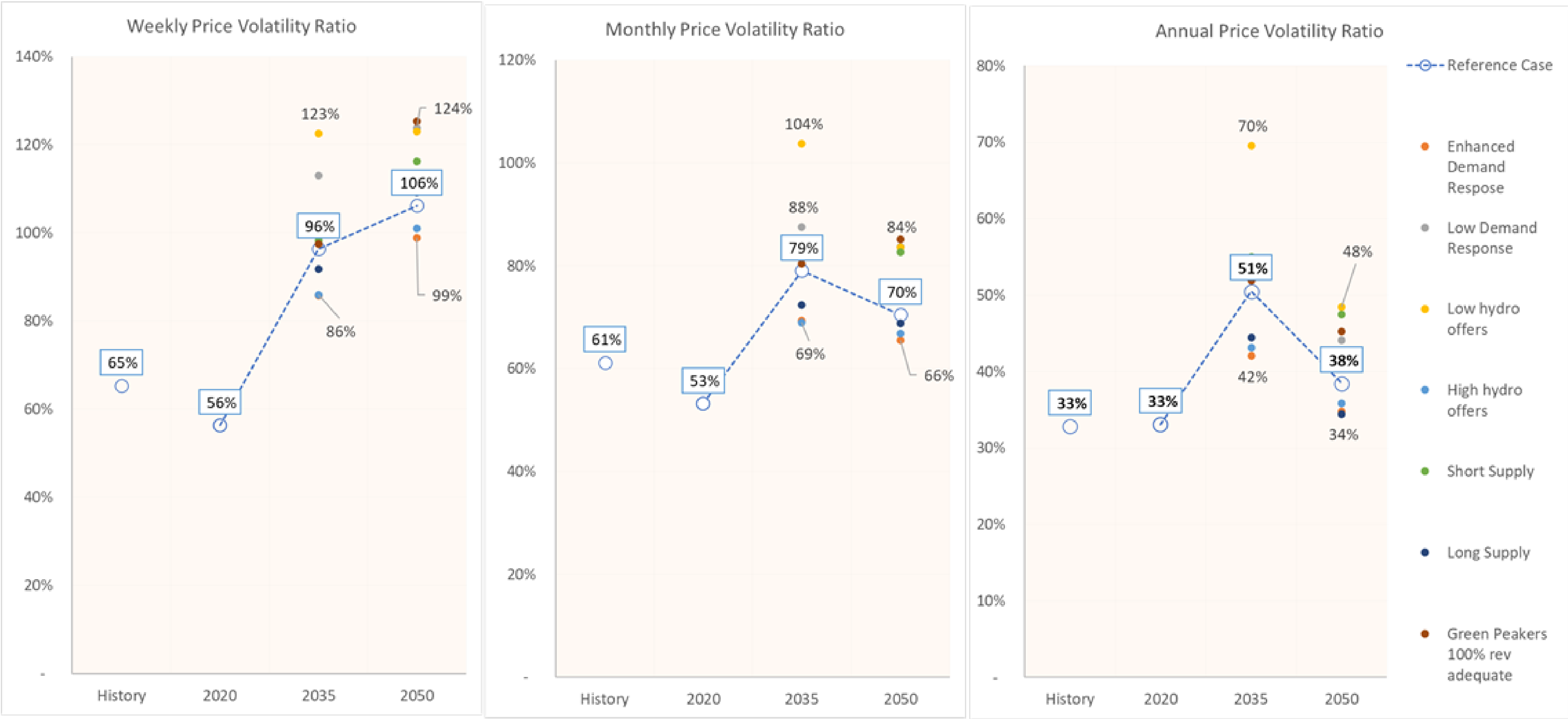
75 See accompanying paper on Simulation Assumptions and Results for more information (available here: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/100%-renewable-electricity-supply/consutations).

Figure 14: Sensitivity case results – volatility ratios



5.72 Finally, it is important to note the charts show the effect of single sensitivity cases. It is possible that multiple 'downside' (or 'upside') cases could coincide and have compounding effects on volatility.

Comparison of volatility results with other electricity systems

5.73 The preceding analysis compares projected future volatility for New Zealand with 'current'[76] ratios. Another reference point is to compare New Zealand ratios with historical data for overseas markets (acknowledging these are not 100%RE). This provides a perspective on how the projected results for New Zealand compare with the realm of international experience.

5.74 Figure 15 compares the New Zealand simulation results for 2050 with historical results for Australia and Texas.[77] These two overseas markets were used because they have similar market designs to New Zealand (so-called energy-only markets) and because data going back a decade or more was available. Having said that, each system has its own unique features (demand patterns, fuel types and costs etc), so they should not be interpreted as being completely comparable.

5.75 In addition to volatility measures shown previously, Figure 15 shows within-week volatility measures. The first is 'full hourly' being the standard deviation of all hourly prices calculated over the entire dataset, divided by the mean price for all hours. The second calculates the hourly volatility measure for each year, and then averages that over the number of years in the dataset.

5.76 Some health warnings should be noted about the within-week volatility results. There is less confidence about these because the simulation model was calibrated using volatility measures for annual, monthly and weekly prices as the reference points. As shown in the chart, the simulated within-week volatility for the 2020 system is lower than the actual levels observed in 2000-2021 (although the past will include some factors not relevant in a 100%RE system such as fossil-fuel shortages and large thermal plant outages). In addition, the model assumes perfect foresight within each week in relation to the operation of batteries, management of intermediate storage in river chains etc. By themselves, these factors imply that within-week volatility will be under-estimated in the simulation modelling.

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76 Current includes ratios observed since 2000, and simulated ratios based on 86 years of weather data applied to the 2020 system.

77 The Australian data was also examined in two blocks from 2000-2010 and 2010-2020 to see whether volatility increased in the second decade as more renewable supply was added. In fact, it was lower in the latter decade in each of the three Australian regions.

5.77 On the other hand, as noted earlier, within-week volatility seems less likely to emerge as a dominant concern in the future because the scalability, falling cost and fast discharge/recharge time of batteries mean they should be able to cap within week volatility. Transpower's base scenario in Whakamana i Te Mauri Hiko seems to be based on a similar view.[78]

5.78 With these caveats in mind, the following observations are made based on Figure 15:

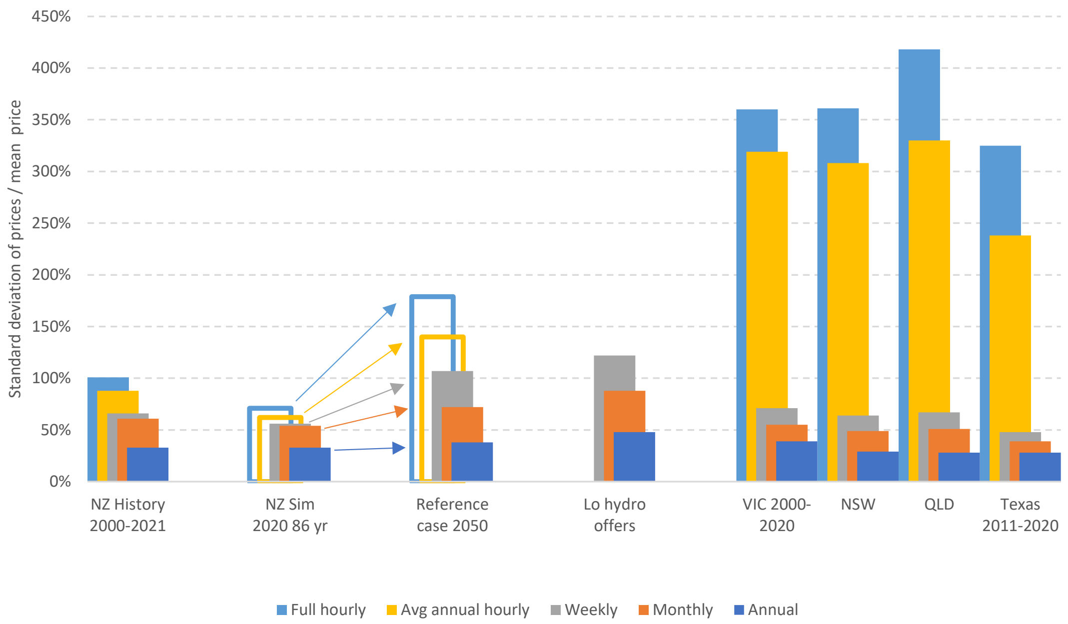
(a) Spot price volatility is expected to increase under 100%RE as compared to levels in the past, and measures for shorter periods (e.g. weekly) are expected to rise faster than for longer periods (such as annual measures) as the system becomes more sensitive to transitory weather effects.

(b) The historical 'structure' of price volatility differs between New Zealand and Australia and Texas. The latter two systems have had much more hourly volatility than New Zealand, but less weekly and monthly volatility and similar levels of annual price volatility.

(c) Looking ahead, New Zealand's volatility at the hourly end of the spectrum is likely to move closer to that experienced in Australia and Texas. However, to achieve parity with those levels, actual results for New Zealand would need to be roughly double the level indicated in the simulations. While there may be some under-estimation of within-week volatility, there is no information to suggest the error would be large enough to result in New Zealand's hourly volatility exceeding that observed in Australia and Texas.

78 The report states the base case scenario sees an approximately 68 per cent annual increase in gross electricity demand by 2050, but with peak demand growing at a much lower 40 per cent. To a large extent, this is because the scenario includes wide deployment of batteries, coupled with DSF and smart charging of vehicles. (Whakamana i Te Mauri Hiko, page 61, see footnote 25). As a point of comparison, in our reference case, peak demand is assumed to grow at 80% of the rate of energy demand by 2050.

Figure 15: Comparison with results for other electricity systems



Comparison with Nordic experience

We asked an energy market practitioner (Dr Gavin Bell) based in Norway to provide high level comments our analysis from a Nordic perspective. He commented as follows:

> *I agree broadly with the simulation conclusions. This matches expectations and what we are seeing in the markets in the Nordics – substantially more hourly, weekly, monthly, quarterly volatility, and the shorter the time frame, the more volatility increases.*
>
> *I would have thought actually you would get a larger increase in monthly and quarterly than the simulations indicate. What we have seen here is that we get periods of high or low wind that tend to last a while (weeks or months) and can be correlated over large geographic areas, impacting overall price levels.*
>
> *The other aspect that perhaps could be looked at is how short-term volatility varies – for example, a moving average of weekly volatility, or hourly volatility – experience here again shows periods with very little hourly volatility, say, followed by periods with very high volatility. That dynamic is important to raise as an issue*
>
> *Also, one other impact from thermal retirements is that the seasonal and yearly volatility driven by thermal price volatility disappears – this can account for some of the flatness in volatility the simulations exhibit over these longer time frames. This also should be raised – that the retirement of fossil may also contribute to volatility reduction over some timeframes.*

1. Do you agree with the broad conclusions that emerge from the simulations in relation to spot price levels and volatility, in particular:
    a. significantly more spot price volatility is likely with a 100%RE system, especially shorter-term weather-driven volatility
    b. New Zealand’s sizeable hydro generation base is likely to moderate the growth in volatility to some extent, making extreme oscillations between zero and shortage spot prices relatively unlikely?

2. If you disagree, what is your view and the reasoning for it?

6 Will New Zealand still need a wholesale electricity market with 100%RE?

6.1 Before considering any changes to the wholesale electricity market, it is useful to ask whether a wholesale market will be needed at all. To address this, the following sections describe the functions performed by the wholesale market and consider whether they would still be needed with 100%RE.

What do we mean by wholesale market?

6.2 The wholesale electricity market includes the spot market for electricity, markets for ancillary services, and the hedge market for electricity (including the market for financial transmission rights (FTRs)). Figure 16 describes the components of the wholesale market.

Figure 16: The wholesale market[79]

Source: Electricity Authority.

79 Electricity Authority, Electricity in New Zealand (September 2018), Figure 13. The figure shows hedges that are bought and sold through the wholesale market. In addition, some participants have generation and retail operations. Vertical integration is a form of 'internal' hedging.

Wholesale market provides a mechanism for processing information and coordinating actions for the long-term benefit of consumers

6.3 Put simply, the wholesale market was established to enable a diversity of parties to sell and buy electricity using the national grid. It is the 'hub' for the 'spokes' of diversity and competition. At its core, the wholesale electricity market functions as a platform for processing information and coordinating actions among many electricity suppliers and consumers. These functions occur across three broad timeframes:

(a) Real-time operation – electricity supply must be continuously matched to demand across each day and at every location of the grid, otherwise the system becomes unstable and blackouts will occur. In addition, it is important to supply power from the cheapest available sources at each moment in time, as this reduces overall costs to society. The spot market includes an auction mechanism to ensure the lowest priced offers are selected to generate, taking in account grid and other security limits. The spot market also provides price signals and dispatch instructions to ensure orderly real-time operation.

(b) Intra-year – generators with access to finite stored fuel and demand response (DR) providers with time-limited responses need to decide when to use their flexibility. Price signals from the contract market and forward schedules of the spot market are a key information source for such decisions. The prices provide signals about the expected value from using resources at different times. These signals assist parties to optimise the timing of their power usage and to manage fuel inventories, which together help to minimise overall system costs.

(c) Investment decisions – it is important to build the right mix of supply, and at the right time. Getting the decisions wrong will result in wasteful investment and/or poor reliability. Both of these impose costs on society. The wholesale market provides signals on the value to consumers of different supply options (e.g. batteries versus baseload generation). This information assists parties to make decisions about the timing and type of new investments.

6.4 Joskow (2019)[80] noted that high renewables markets need:

> "…*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 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*

80 See footnote 70.

adapt by creating new product categories to enable system operators to schedule, dispatch, and pay for generating capacity that meets these response needs efficiently."

Effect of 100%RE on information flows and coordination needs

6.5 As shown in Table 1, while the shift to 100%RE supply will cause many changes, the need for information sharing and coordination will remain. Indeed, the greater number and diversity of participants and resources will likely increase the requirements in some areas, especially for real-time decisions. As one international expert observed:

> *"moving to a greater reliance on distributed resources (many and small) and demand participators (many and small) leads inexorably to a greater need to have real-time spot prices that send the right price signals. The central control of distributed resources would not be feasible, and prices must provide the needed incentives."*[81]

6.6 Based on this, we think a wholesale market with price signals will continue to be the preferred mechanism for integrating information from multiple sources and coordinating actions among consumers and suppliers. Indeed, the need will increase particularly as we see more modular and more dispersed and disaggregated renewable electricity supply solutions (this is discussed further from paragraph 7.3).

Table 1: Effect of 100%RE on information flows and coordination needs

	Likely changes with 100%RE supply	**Implication for wholesale market functions**
Real-time info flows & coordination	Greater range and number of resources/parties to coordinate. For example, Transpower estimated there will be 3.9 million distributed energy resources across the system by 2035.[82] Increased proportion of supply from resources that are not centrally dispatched – e.g. rooftop solar, household batteries, smart chargers for EVs. Increased need to allocate dispatch rights among suppliers in periods when there is surplus supply.	Significant increase in information flows and complexity of flows (frequency, types of data, direction etc). Significantly greater coordination requirement.
Intra-year info flows & coordination	Management of energy storage sources (hydro reservoirs, DSF, any other new forms of storage) will be important.	Coordination requirement remains but changes to coordination of multiple energy storage sources, green peakers, and DSF. Value from utilising DSF expected to increase significantly, with gross benefit of

81 Hogan, William W. "*Market Design Practices: Which Ones Are Best? [In My View]*." IEEE Power and Energy 17.1 (2019).

82 See footnote 25.

		potentially $120-$170 million per year (see paragraph 7.90).
Investment info flows & coordination	Greater number of potential participants – some 'lumpy' decisions in transition and then likely to be a progression of modest increments on a relatively frequent basis.	Higher importance because investment requirement is greater – expected to total $27-37 billion by 2050 for generation and batteries. In addition, renewable investments are almost entirely upfront capital with little operating cost. This makes any premature investment in generation sources more costly. On the other hand, demand is expected to grow more quickly over the next 30 years, so early generation investment should get corrected relatively quickly. Finally, new supply investment will become the 'fuel' for the 100%RE system (see paragraph 5.35) – and without timely investment consumers will suffer from poor reliability.

3. Do you agree that in a 100%RE system there will be many diverse and disaggregated resources to coordinate, and that a wholesale market will be the preferred mechanism to coordinate plans and actions among all the resource owners? If you disagree, what is your view and the reasoning for it?

7 What issues need to be addressed in light of the expected physical and economic changes with 100%RE?

Focus on root issues

7.1 This section draws on the qualitative and quantitative analysis of the system with 100%RE to identify priorities for future work on the wholesale market, i.e. the areas where opportunities may not be realised or where challenges may arise.

7.2 As noted earlier, options to address key issues will be considered in the next stage of the project, and we will consult on those in due course. At this stage, we would urge stakeholders to not presuppose the measures or changes that should be put in place. It is important to first establish robust and clear insights into the nature and scope of the issues to be addressed, which is the purpose of this paper. In short, to land on effective options, we need to be clear about the root issues.

Real-time coordination will get more challenging and make an effective spot market even more important

7.3 Basic physical laws require that electricity supply and demand must be continuously matched in real time at every location of the grid, otherwise the system becomes unstable and blackouts will occur.

7.4 Under current arrangements, demand is allowed (with rare exceptions) to 'roam' freely up and down, and the level of supply is controlled to perfectly match with demand at each point on the grid. The spot market is the primary mechanism used to achieve this balance.[83] In addition, it ensures that demand is met from the cheapest mix of offered supply at each moment in time, to minimise overall costs to society.[84]

7.5 The spot market is essentially a rolling series of auctions in which generators make offers to supply electricity. Non-binding offers go into the auction schedules prepared before real time that show projected demand, offered sources of supply, and resultant spot prices. Suppliers can progressively update their indicative offers in the lead up to real time in response to evolving conditions, for example by lifting offered supply quantities if predicted prices are high or vice versa.

7.6 Suppliers must submit binding offers into the final auction schedule. This schedule is used to determine the 'dispatch' instructions issued by the system operator to generators whose output can be controlled. The great majority of supply is currently from dispatchable sources, and generators must obey dispatch instructions unless they have a bona fide excuse. Generators that are dispatched receive the market-clearing price (or their offer price via a so-

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83 Strictly speaking, this is the spot market for active energy, but we stick to the shorthand version in this paper. As we discuss in a later section, ancillary services are also very important for ensuring real-time reliable supply.

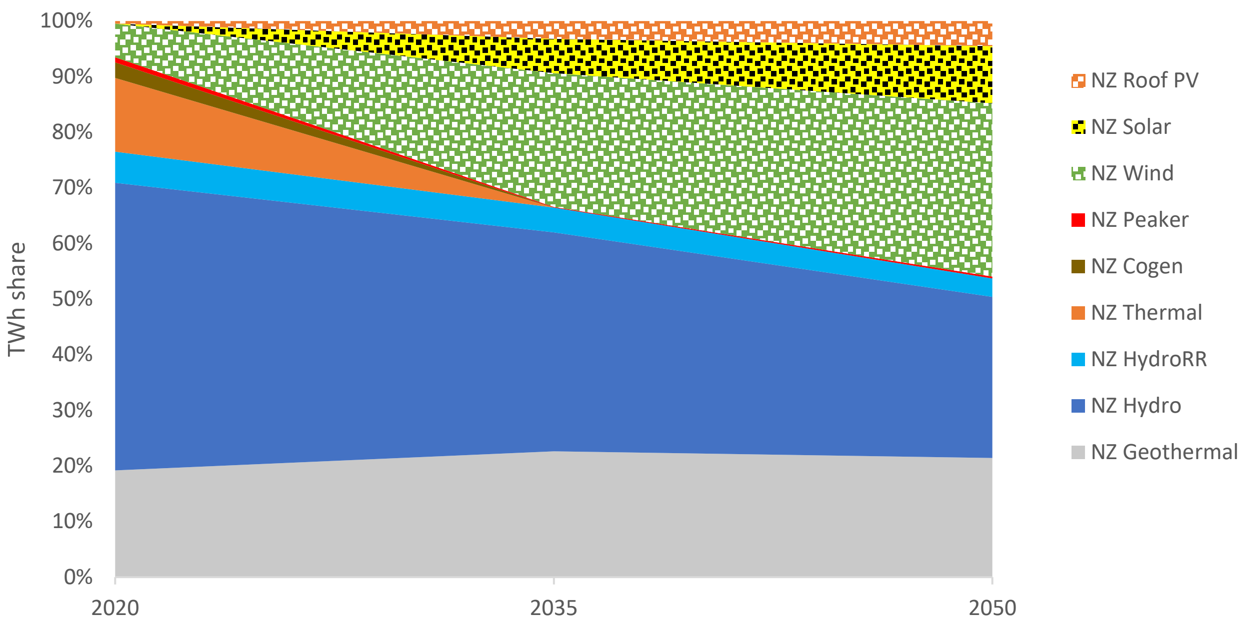
84 This occurs provided competition is sufficient to drive offer prices towards costs.

called constrained on payment if they are not cleared but are forced to run for system security reasons).

7.7 Looking ahead, a growing proportion of grid-supplied power will come from intermittent sources such as solar and wind generation. In the reference case, these increase from 6% of supply in 2020 to 47% by 2050. While these resources may be dispatched downward (by spilling some energy) they will often not be dispatchable upwards. In addition, a rising number of customers are expected to install rooftop solar panels or other distributed generation, and this is unlikely to be dispatchable. Together, these two factors suggest a shrinking proportion of the total generation base will be easily and directly controlled via central dispatch.

7.8 On the other hand, an increasing number of batteries (including those within electric vehicles) will introduce a new mechanism to help with balancing in real time. Indeed, batteries will be especially useful because they can act as controllable demand or supply, and switch between the roles very quickly. Some electricity users may also become more willing to flex their demand up or down in response to spot prices. As noted earlier, the reference case in the simulation assumed that flexible demand (in part enabled by batteries) would increase from 8% in 2020 to 25% of peak demand by 2050.

Figure 17: Projected supply mix (non-dispatchable are shaded)



7.9 In parallel with these physical changes, the system (generation, batteries, and demand response) is expected to become more disaggregated, with ownership and control spread among a much wider range of parties such as households and businesses with solar panels and/or storage devices and/or electric vehicles.

7.10 In essence, the system is expected to move from being balanced in real time by relatively 'few big' resources to much more reliance on 'many and small' resources.[85] As noted in the previous section, this change will make the spot market even more important as the primary real-time balancing mechanism.

7.11 New Zealand's spot market design already has many of the key building blocks needed to support real-time coordination in the 100%RE world. In particular, it has locational marginal pricing which is symmetrical for demand and supply sources.[86] In addition, from late 2022 the method of calculating spot prices is scheduled to change so that it reflects dispatch in real time, creating better alignment between financial incentives and physical conditions. There will also be a low-cost mechanism for distributed energy resources (such as DSF) to participate in the price-setting process.

7.12 Having said that, the combination of more intermittent supply and increasing disaggregation will create new challenges. For example, the system will be much more reliant on batteries doing the right thing at the right time. This means battery owners (or their agents) will need to have the right information to plan ahead (i.e. get their battery ready so it can discharge or charge later when required), and that they will be able react in real time as needed.

7.13 Some of the mechanisms to facilitate participation by distributed resources will be downstream of the spot market, such as the arrangements that apply between retailers/aggregators and battery owners not offering directly into the spot market. Those types of issues are discussed later in the section on DSF providers.

Key issues for real-time coordination with 100%RE

7.14 We think the key issues in relation to real-time coordination are:

(a) Will forward scheduling processes be effective in a future environment where short-term system conditions change more rapidly (e.g. will there be a need to adopt more frequent cycles of schedules, different publication timeframes, new information content such as confidence intervals)?

(b) Will demand forecasting processes be effective with an increasing prevalence of electric vehicles, and behind the meter storage devices?

(c) Will the range of resources subject to dispatch by the system operator be appropriate?

(d) Will there be an efficient mechanism to allocate dispatch rights when the volume of generation seeking to run at a zero price exceeds demand?

(e) Will there be a need for new mechanisms (such as a short-term commitment market) to coordinate resources that require a lead time to get ready, such as batteries which

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85 To be clear, some big resources will remain (such as major hydro stations) but they will contribute a smaller proportion of total controllable supply.

86 Some markets have different locational signals for demand (e.g. zonal) and supply (e.g. nodal). Newbery et al. (2018, see footnote 67) argues that locational pricing is a key element to an efficient transition to high renewables.

need to be charged, or production processes which need to be modified on the demand side?

(f) Will downstream parties such as aggregators be able to interact efficiently with the spot market (for example via adopting new mechanisms beyond the coming 'dispatch notification' product being introduced with real-time pricing)?

4. Do you agree that these are the key issues in relation to real-time coordination? If you disagree, what is your view and the reasoning for it?

Ancillary services will require a close focus

7.15 While the spot market is the primary mechanism for balancing supply and demand in real time, ancillary services are also vital. In particular, much of the fine tuning on the supply-side is achieved via the provision of so-called frequency keeping services. These are resource providers that automatically vary their output to maintain the frequency within acceptable limits. The other key service is instantaneous reserve. This refers to resources which can restore balance very quickly in the event of a failure by a large generator or transmission circuit (so-called contingent risks). At present, resources can be spinning generators, or demand which can be cut very quickly (such as hot water heating).

7.16 An important aspect of current arrangements is the co-optimisation of procurement of energy, frequency keeping and instantaneous reserves. This means the auction processes in the spot market identify the lowest overall cost of procurement for the services, recognising the potential inter-linkages and ability of some providers to supply multiple services simultaneously. This is important because it helps to reduce overall costs to consumers.

7.17 The shift to 100%RE will likely affect the types and quantities of ancillary services needed to maintain secure supply. For example, retirement of all New Zealand's large thermal units would make an HVDC pole failure the only large contingent risk on the system. In that case, it could make sense to cover more risk with extended reserves[87] and less with instantaneous reserves. It is also possible that completely new ancillary services will be required as the system becomes increasingly reliant on intermittent sources of supply.

7.18 Review of international literature shows that it is highly desirable to undertake detailed system analysis to identify how a shift to 100%RE will affect ancillary service requirements well before it occurs. In particular, the analysis should seek to identify any services that could become scarce during the shift to 100%RE.

7.19 A detailed analysis of how the system will operate under 100%RE is very important because maintaining secure real-time operation requires multiple conditions to be satisfied. At present,

87 See How extended reserve works — Electricity Authority (ea.govt.nz) for a description of extended reserves.

some services could be provided for 'free' because they are a by-product of energy generation sold into the spot market. However, as the technology mix on the system changes some services may no longer be provided freely as by-products. If they become scarce, they will need to be paid for as separate service. For example, in some systems there has been a need to introduce a payment for provision of inertia service. This is a by-product of thermal generation but is not provided by solar generation.

7.20 As one international expert observed,[88] it is very important to get an early view on services that may become scarce. If the analysis is not undertaken sufficiently in advance, regulators and system operators can end up playing 'whack-a-mole'. This can lead to a patchwork of ancillary service products being introduced, raising costs as there is little or no scope for co-optimisation or integration of future service demands into investment plans.

7.21 Another key lesson has been the importance of understanding the economic trade-offs when weighing possible changes. System operators are well-placed to undertake the necessary technical analysis, but it is also important to understand the economic benefits and costs. Consumers are an important party in this context, but most will lack the necessary technical resource or understanding to engage in depth. Regulatory bodies therefore need to ensure that market design and enhancement processes integrate both technical and economic analysis as far as practical.

7.22 International experience suggests that some new ancillary services that may need to be procured under 100%RE, and could assist in price formation that rewards flexible resources, include:

(a) **Inertia**. The increase in VRE generation (solar, wind) (which are not physically coupled to the system frequency) at the expense of thermal plant (which is) will cause a net loss of inertia to the system. Inertia is the first response to a drop in system frequency, before even 6-second reserve. Historically, inertia has been provided in such abundance through large rotating turbines that it has never had to be "procured" or priced. Simshauser (2018)[89] therefore argues that inertia is a "missing market" in the Australian NEM. The increasing pressure on 6-second reserve, resulting from less inertia, may motivate the need for a "Very Fast Instantaneous Reserve" (<1 second) market, which batteries could provide.

(b) **Flexibility on a longer time scale than frequency reserves**. 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).[90] 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

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88 Based on discussion with Hamish Fraser of Easter Bay Consultants Ltd.

89 See footnote 68.**Error! Bookmark not defined.**

90 Frew, B., Milligan, M., Brinkman, G., Bloom, A., Clark, K., Denholm, P., 2016, *Revenue Sufficiency and Reliability in a Zero Marginal Cost Future*, Presentation to 15th International Workshop on Large-Scale Integration of Wind Power into Power Systems, November 2016.

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.

(c) **Ramping duties**. 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)[91], Simshauser (2018)[92]) can cause ramping issues.[93] Like for inertia, Simshauser argues that "ramping duties" also constitutes a missing market in a high renewables world.

7.23 However, New Zealand's system and likely future trajectory is different to many international jurisdictions, not least due to the sizeable hydro base. Consequently, some issues encountered overseas may not arise here. Whether or not, or for how long, New Zealand's current hydro plant can meet these changing requirements necessitates a technical study tailored to our system context.

7.24 An important step forward in this area was the launch in 2021 of the 'Future Security and Resilience' (FSR) project by the Authority.[94] This workstream is examining how to ensure the electricity system remains stable, secure and resilient as it evolves in the coming decades. A secure and resilient power system is important to all electricity consumers, to all participants in the electricity system, and to all New Zealanders more broadly.

7.25 The initial focus of the FSR workstream is on maintaining security, stability and resilience of the power system in, and close to, real time rather than the power system's ability to maintain a balance of demand and supply over periods of longer than a few days.

7.26 The first phase of this project has seen Transpower as the system operator deliver a draft report on future security and resilience challenges and opportunities[95]. This will be followed by a prioritised roadmap for investigating, monitoring and addressing these challenges and opportunities, which is due in the first half of 2022. The final phase of the work will be the multi-year delivery of a programme of studies and solutions to address the challenges and opportunities identified.

7.27 As it stands, Transpower's initial analysis of ancillary service requirements was based on their "Mobilise to Decarbonise" scenario from Whakamana i Te Mauri Hiko[96], which retained a small amount of gas generation out to 2050. Hence it was not an analysis of a 100%RE scenario per se. However, we expect that it identified many of the ancillary service issues that would arise under a 100%RE scenario. In any case, we understand that future phases of the FSR work will consider a range of scenarios, including 100%RE.

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91 See footnote 69.

92 See footnote 68.

93 Likewise solar eclipses. The eclipse in 2015 is reported to have caused a rapid swing of up to 40GW in Europe!

94 See https://www.ea.govt.nz/about-us/media-and-publications/media-releases/2021/authority-project-to-explore-long-term-resilience-and-security-of-electricity-supply/.

95 See https://www.ea.govt.nz/assets/dms-assets/29/02-FSR-Phase-1-draft-report-Nov-2021-v2.1332512.1.pdf.

96 See footnote 25.

7.28 Transpower's draft report identified the following opportunities and challenges:

(a) Leveraging distributed energy resources (DER) to build and operate the future grid, as they may help to shape the daily load curve in a way that reduces transmission, distribution and generation costs;

(b) Leveraging new technology (such as batteries) to enhance existing ancillary services, and potentially provide new services such as inertia or very fast instantaneous reserves;

(c) The need to monitor and manage the visibility and observability of the performance of DER, and its impact on the power system;

(d) Meeting the increasing challenge of balancing variable and intermittent renewable generation;

(e) Managing the impact of reducing system inertia, driven by an increase in inverter-based resources (IBR) like solar, and reduction in synchronous generation (thermal power stations), on frequency management in a system that already experiences low inertia;

(f) Again, as a result of the increase in IBR generation, operating with low system strength (another characteristic of New Zealand's system) and managing the impacts on voltage management;

(g) Accommodating future changes within technical requirements (in the Code, technical standards and grid and distribution operating processes and procedures) in a rapidly changing technology environment, to ensure the system can get the maximum benefit from new technology whilst complying with obligations for those technologies;

(h) Coordination of increased connections as the system decentralises (with the relative increase in DER connections compared to traditional grid-scale generation) to avoid operational issues.

(i) Loss of control due to cyber security issues that come with a system that makes greater use of smarter technology, and greater levels of data management and automatic controls at a user level;

(j) Growing skills and capability of the workforce as technology changes to ensure high quality service provision and adaptability to challenges that arise.

7.29 Transpower has proposed timeframes and a prioritisation of the investigations associated with each of the ten challenges and opportunities above. This is shown in Figure 18.

Figure 18: FSR dashboard[97]

Opportunities & challenges	Timeframe	Priority
Leveraging DER to build and operate the future grid	3-7 years	Medium
Leveraging new technology to enhance ancillary services	Enduring	Low
Visibility and observability of DER	3-7 years	Medium
Balancing renewable generation	3-7 years	Low
Managing reducing system inertia	7-10 years +	Low
Operating with low system strength	3-7 years	Medium
Accommodating future changes within technical requirements	0-3 years	High
Coordination of increased connections	0-3 years	High
Loss of control due to cyber security	Enduring	Medium
Growing skills & capabilities of the workforce	Enduring	High

7.30 Another recent development was the review of the forced power cuts on 9 August 2021 carried out by Hon Pete Hodgson. One of the findings was a recommendation that a longer-period reserve product be considered for the wholesale market.

7.31 It will be important to ensure the ongoing results of the FSR project and other related work are integrated into this project, as they will likely affect the conclusions from this project. Insofar as the investigations point to the design of new ancillary service or wider market products which reward particular services, or change the demand for existing ancillary service products, this will be critical to understanding how operating, risk management and investment incentives will arise under 100% renewable markets.

7.32 Likewise, we will ensure the analysis and findings from this project are available to the FSR team and system operator. In particular, we think it will be desirable to ensure that as far as practical, the current integration between the spot and ancillary services markets is maintained.

7.33 As the number of ancillary service and short-term coordination products grow, co-optimisation across these products, and with the energy market, will help ensure that dispatch of available resources is optimised in a "whole of market" manner, and pricing efficiently incentivises the development of flexible resources which support the dispatch objective.

7.34 While the above discussion highlights the potential emergence of new ancillary service requirements, there is strong potential for new technology (e.g., batteries) and distributed energy resources (DER) to provide ancillary service products.

7.35 Reeve et al. (2021)[98] provide a commentary on the ability for DER to access ancillary service markets. In fact, the authors argue that service performance of DER should improve, noting that:

97 See footnote 95, p9.

98 Reeve, D., Stevenson T., and Comendant, C. (2021), *Cost-benefit analysis of distributed energy resources in New Zealand*, Report for Electricity Authority, Sapere Research Group, September 2021, p9-12.

(a) Smart grid communication and control should enable a continuous demand response to an under-frequency event, which is in contrast to the current binary response of interruptible load afforded by relay technology that trips load at a pre-defined frequency;

(b) It is technically feasible for currently installed DER to meet the technical requirements for frequency keeping, but current system operation policies do not permit access below a certain size;

(c) The power electronics in some DER systems can operate so quickly that they could provide a very quick response to any changes in frequency. This is technically ultrafast reserve but could be designed to simulate inertia. Therefore, some DER can assist with the potential inertia problem that is likely to arise in a 100% renewable world.

7.36 Further, the recent draft decision to amend Part 13 of the Code will allow battery storage systems (or, more generally, energy storage systems) to participate in the instantaneous reserves market. The Code change was motivated initially by the prospect of grid-scale battery installations. The Authority is further exploring the potential for smaller-scale distributed resources to provide services to ancillary markets in the FSR workstream discussed above.

Key issues for ancillary services with 100%RE

7.37 We think future outputs from the FSR project will be an important input when considering the role and type of ancillary services (and how those services are provided) under 100%RE. We think the key issues include:

(a) Are there services that are currently provided freely as by-products that will become scarce under 100%RE?

(b) Will new ancillary services such as inertia, standby reserves on a longer time scale than current instantaneous reserves, ramping duties and reactive power be required?

(c) How can these new products be priced in a way that sends the correct operational and investment signals? Can or should they be integrated with the dispatch objective to allow automated dispatch and co-optimisation?

(d) How can decentralised distributed resources and new technology be sourced and used to provide current and new ancillary services?

5. Do you agree that these are they key issues in relation to ancillary services with 100%RE? If you disagree, what is your view and the reasoning for it?

Importance of accurate prices to demand-side, contracting and investment incentives

7.38 Consumers will be harmed if investment in generation and batteries does not keep up with power demand. As noted above, moving to 100%RE will require a lot of new investment. Indeed, generation and batteries together are expected to require annual investment of around $700 million to $900 million[99] on average until 2050.

7.39 Participants' willingness to commit the necessary capital at the right times will be strongly influenced by signals in the wholesale electricity market.[100] If the signals are not clear, investors may be deterred or defer decisions, leading to a supply gap and unreliable supply. Conversely, if signals are distorted or too strong, investment could occur in more expensive options or be premature – both of which would raise costs for society.

Allocating project risk to investors would retain cost discipline on new developments

7.40 A core aspect of current wholesale market arrangements is that suppliers bear the risks associated with their generation investment decisions. Consumers may choose to share those risks via longer-term contracts, but suppliers cannot unilaterally transfer investment risks to consumers. This framework encourages suppliers to focus their attention on those projects which are most cost-effective. The framework also disciplines the timing of investment commitment decisions, as suppliers must weigh the risks of being too early (insufficient revenue and lower returns) against being too late (missing out to a competitor's project).

7.41 Maintaining discipline on investment decisions is important because capital expenditure is the single largest component of industry costs. In a day to day sense this benefit is invisible because we can't see the costly projects which have not been built. Nonetheless, there is little doubt the benefit is significant. As noted in the foreword to this paper:

(a) If we build new stations too soon or too big or in the wrong place or not using the right technology, we waste capital. We lose the opportunity to use the capital on things that society values more highly (prior to creation of the wholesale market, it was common for projects to have big cost overruns, or to be delayed. A Treasury study in 1985 estimated that building power stations in the wrong order or too early imposed economic costs of $2.3 – $3.0 billion on New Zealanders).[101]

(b) If we build new stations too late or too small or not of the right type, we increase the risk of electricity shortages or black-outs, which, if sustained, can cause serious losses

99 This includes investment to meet demand growth, plant retirements, and stay-in-business capital.

100 Networks will also require investment but this paper does not consider those issues as they are largely outside the wholesale market and are regulated by the Commerce Commission under Part IV of the Commerce Act. However, we note that the Commerce Commission will be completing a review of the underlying regulatory rules and processes for electricity lines companies by the end of 2023.

101 New Zealand Treasury, Review of Electricity Planning and Electricity Generation Costs, 1985, paragraph 6.

of revenue for business[102] and loss of reputation for our economy, not to mention asymmetric political fall-out.

7.42 In technical terms, this is referred to as 'dynamic efficiency'. Without question, it represents that largest impact that the electricity industry has on the New Zealand economy and it underpins the statutory objective for the wholesale market.[103]

7.43 Looking ahead under 100%RE, the 'size of the prize' from maintaining investment discipline will increase. This is because annual investment flows must grow to keep up with demand, and costs for renewables and batteries are by nature almost entirely capital -related with zero or very low operating costs once they are built.

7.44 The current wholesale market's approach of making suppliers bear project risk has been effective at disciplining investment costs, and there is a good case for retaining this approach.[104] However, it is important to consider whether investment incentives could weaken in the shift to 100%RE, with the consequent risk for reliability.

Will greater price volatility create undue financial risk for investors or purchasers?

7.45 Let's first consider how generation investors may react to increased spot price volatility and the consequential greater variability in financial returns.

7.46 To get a sense of the impact, the simulations included an analysis of generic wind and solar generation projects to compare the variability in expected financial returns in 2020 with 2035 and 2050. A common notional hedging approach was assumed to apply over time in which developers sell only quarterly baseload products – i.e. no shaped products are assumed. In each year, developers are assumed to hedge to the level that minimises the downside variability in their gross revenues.

7.47 This hedging approach was chosen to provide a common yardstick for gauging the impact of moving to 100%RE. It is clearly not intended to represent the probable or best strategy for project developers to adopt. In practice, developers would likely apply more sophisticated hedge strategies, and there would probably also be variation among developers to reflect specific projects, circumstances and risk appetites. Nonetheless, using this simple strategy provides a yardstick to see how the cashflow variability is changing over time.

7.48 To illustrate the approach, Figure 19 shows the modelled distribution of cashflows for a notional wind project in 2020 under different levels of hedging.[105] For example, if zero hedging

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102 It is estimated that the 1992 crisis sliced 0.6 per cent off gross domestic product. Treasury and the Reserve Bank estimated (at the time) that the 2001 crisis could shave $225 million off the economy — assuming target savings of 10 per cent were met — reducing GDP by about 0.2 per cent - www.nzherald.co.nz/nz/how-we-learned-the-lessons-from-1992/NLFVIOGURGV7GAL3XCHNWBX4ZM/.

103 See https://www.ea.govt.nz/assets/dms-assets/9/9494statutoryobjective.pdf.

104 For example, see Figure 14 in Electricity Price Review Issues Paper, 2018 and the chart on page 4 of the Authority's submission on the Climate Change Commission's draft advice (https://www.ea.govt.nz/assets/dms-assets/28/Electricity-Authority-submission-on-the-Climate-Change-Commissions-draft-advice-March-2021.pdf).

105 The windfarm output level in this example includes an extra 3% site specific random factor based on a location in the upper North Island.

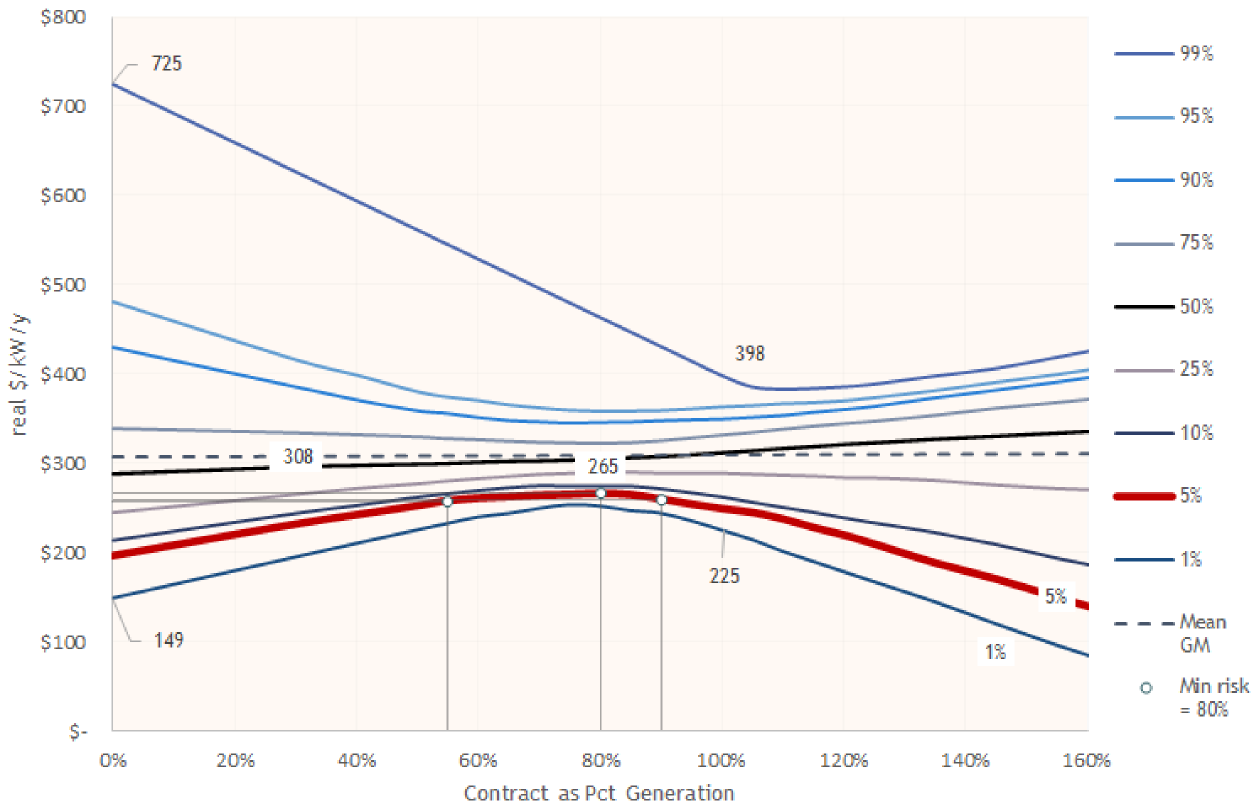
occurs the revenue will be directly related to spot price variation and is expected to lie between around 149 and 725 $/kW/year. As the level of hedging goes up, the project is less exposed to low spot prices because more volume is sold at the contract price instead.[106] However, selling hedges will also expose the project developer to being a net buyer in the spot market when wind output is below the contract volume. Furthermore, a developer's risk from being over-hedged will be magnified if there is positive correlation between low wind output and high prices. If the developer sells 100% of average output, the expected revenue will be between 225 and 398 $/kw/year. This is narrower than selling no hedges but is still a wide range.

7.49 Repeating the analysis for different hedge levels produces the bowtie chart which shows the range of revenue distributions (depicted as percentiles) for each hedge level. For example, the 5% line indicates at each point on the line there is a 5% likelihood of revenue being lower than the given level (in $/kW/year) for that hedge ratio.

7.50 If the developer desired to (say) minimise its downside risk on a 1-in-20 year basis, it would hedge to around 80% of expected output. That is because an 80% hedge level minimises the difference between the mean revenue line and the 5% line. At 70% hedge the developer would expect the 'revenue at risk' to be $308-$265 = $43 /kW/year. This equates to 14% of mean expected revenue in this example. This percentage figure is the summary ratio used to gauge how cashflow risk would change under 100% RE.

106 Hedges are assumed to be sold at a price equivalent to the mean spot price for the relevant generation project (after accounting for any spill). While a hedge contract discount or premium may apply in practice, it would likely affect expected returns in a systematic way and not materially alter financial return variability.

Figure 19: Illustrative wind project revenue distribution with different hedge levels



7.51 Figure 20 shows the results of repeating the bowtie chart analysis for wind and solar projects for various years in the reference and hydro offer sensitivity cases. The bars show the estimates percentage of mean revenue that is at risk on a 1-in-20 year basis. Key observations include:

(a) Using only baseload products, the revenue variability in 2035 is higher than for 2020, but the increase is relatively modest except for the low hydro offers case (where revenue variability at the 5% probability level increases from 14% to 20% of annual revenues).

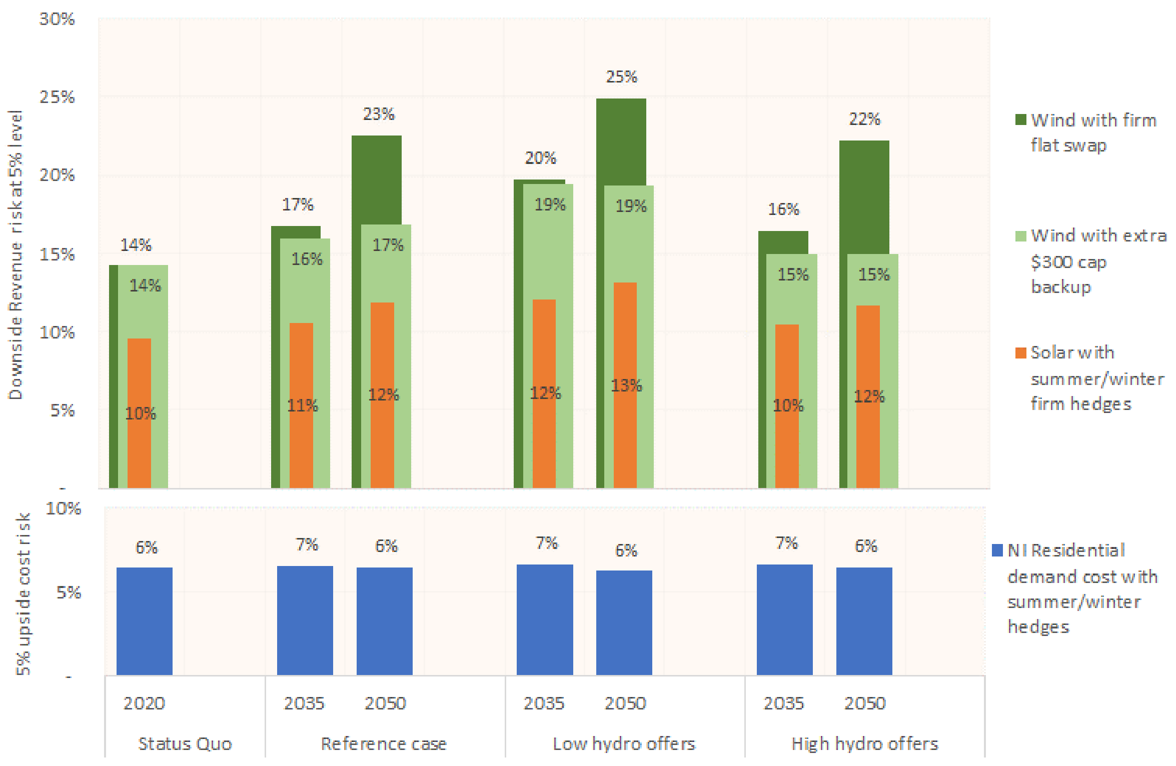
(b) Using only baseload products, revenue variability in 2050 is appreciably higher in 2050 than 2020, especially for wind generation. This is because wind projects are expected to account for a large slice of supply by 2050 and there is a significant negative correlation between wind output levels and spot prices.

(c) If project developers can utilise 'shape' products to cap exposure to high prices when their output is low, they can appreciably reduce their revenue variability. For example, if a wind developer purchased a cap product and sold a baseload product, it could achieve revenue variability would be less than 20% in the all simulation cases shown. Even for wind in the low hydro offer case (the technology/hydro offer combination with the greatest amount of volatility) the strategy is estimated to result in around 19% of revenue at risk (i.e. around 79% of annual revenue would not be at risk in 19 years out of 20). This compares to a revenue at risk of around 25% if it sold baseload products. In addition, the level of hedge sales that minimises cashflow at risk will be higher if developers can access shape products. For example, the level in 2050 increases to around 85% of mean output if the developer can purchase caps, compared to around 60% with no caps.

7.52 The above analysis highlights the importance for developers to be able to access shape products. Participants with access to generation which is flexible should have a natural hedge enabling them to become sellers of such products, for example, owners of green peakers or flexible hydro generation. In addition, there may other parties willing to offer products which reduce exposure to weather-related risks. For example, one global re-insurance company reportedly offers products for wind developers to reduce their revenue risks associated with high or low wind output.[107] While potential sources of shaped hedges or similar insurance products exist, it is not clear whether such products would be available in practice. This issue is discussed further from paragraph 7.107.

7.53 Finally, investment decisions require developers to form views on revenue over a project's entire lifetime, which will typically be 25 years or longer for wind and solar projects. Given the long-term nature of these commitments, investment decisions are likely to be influenced more by risks that affect lifetime revenues than by weather-driven annual (or within year) volatility. For example, technology changes will typically have a bigger impact on project economics decisions than annual volatility.

Figure 20: Projected cashflows at risk for wind and solar generation projects and purchasers



107 See www.swissre.com/dam/jcr:4cf88867-9e90-4f69-b0f4-250ea329b8bf/protection-against-resource-volatility.pdf.

7.54 Turning to the perspective of wholesale market purchasers, a similar analysis has been performed to see how cashflow variability would change for purchasers as spot price volatility increases. This analysis uses the shape of a North Island residential consumer as the load profile. This load has significant shape with winter peaks etc.

7.55 The lower portion of Figure 20 summarises the results of the analysis. In each case the level of purchases that minimises cashflow at risk is around 110% of expected demand. The analysis shows that moving to 100%RE is expected to have relatively little effect on cashflow variability. Indeed, the results for 2020, 2035 and 2050 are essentially within the margin of estimation error. At first sight it may seem counter-intuitive that cashflow variability is expected to increase somewhat for wind and solar developers but show little change for purchasers. However, this reflects an expected shift in the main causes of spot price volatility, with demand peaks playing a lesser role and wind/solar intermittency playing a bigger role. Hence we expect a modestly declining correlation between a purchaser's demand and the spot price.

7.56 Overall, the results suggest that increased volatility per se should not pose unmanageable risks for investors or purchasers provided they can enter into suitable forward contracts. This involves both access to the products themselves (volumes and types) and having confidence in the pricing of those contracts (an issue that is discussed further below).

7.57 A further critical point for the latter is that participants will need reasonable information on the *level* and *shape* of spot price distributions, in order to make informed decisions about the optimal level of contracting and the resulting risk they face. Risk exposures for buyers and sellers will be affected by both factors. The above analysis presumes that investors and purchasers know the level and shape of spot price distributions. Without information on expected shape of price distributions, it will be much harder for participants to be able to efficiently manage their risk.

7.58 In this context, it is important to note that the market price of baseload contracts only provides information about the expected level of prices and not the expected shape of the price distribution. Forward prices for other contract types (e.g. caps or options) would be needed to understand shape. Finally, the desire of participants to understand the shape of price distributions is not new. That desire exists today. However, looking ahead the issue is likely to increase in importance because the system itself is changing. That means the past will be a less reliable guide than it has been, and hence other ways to understand the possible distribution of outcomes will become more important. This issue is discussed further from paragraph 7.107.

Greater price volatility could increase the risk of a missing money problem

7.59 As we have already noted, the shift to 100%RE is expected to increase spot price volatility due to:

(a) More frequent periods of very low (possibly zero) prices when intermittent renewable generation is high relative to demand and storage lakes are already full.

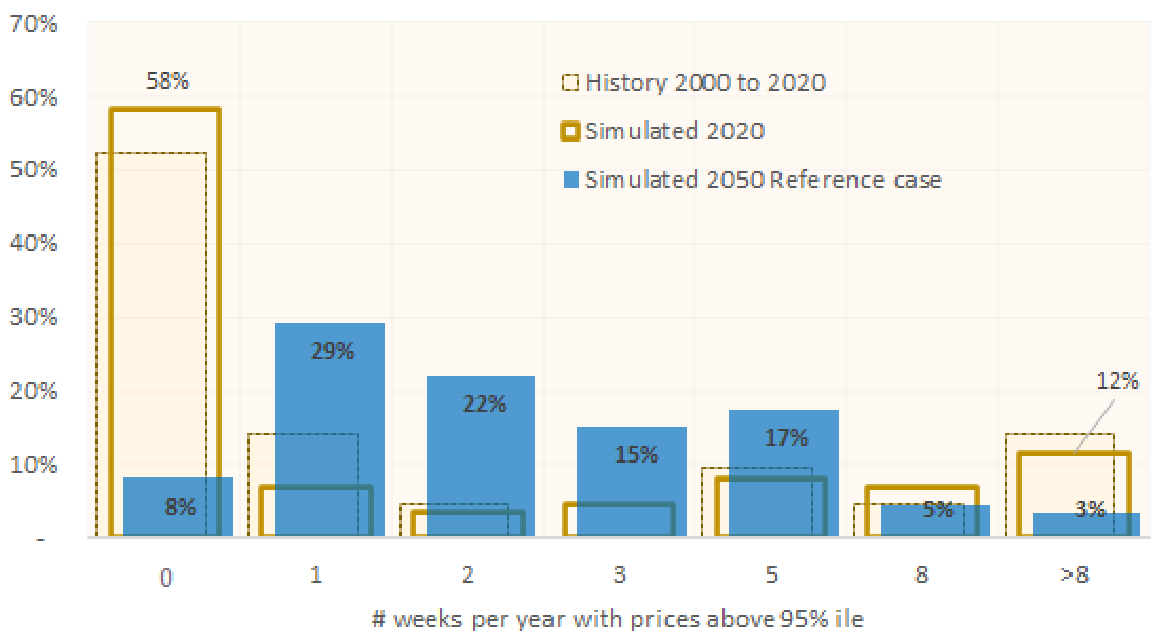
(b) Higher prices, or more frequent high prices, during occasional periods of tight supply, reflecting the loss of flexibility from fossil-fuelled plant and the need to rely instead on demand response or very expensive green peakers for last-resort cover.

7.60 In principle, a rise in spot price volatility should not undermine investment incentives because the impacts of (a) and (b) will cancel each other out.[108] However, this assumes the spot prices in (b) will be realised and that suppliers will account for this effect in their investment decisions. If suppression of such prices (whether real or anticipated) were to occur, a 'missing money' problem would likely emerge and lead to unreliable supply.

7.61 One possible trigger for such suppression is the rise in the proportion of time when very low spot prices will occur. This change may prompt a behavioural change by purchasers, and encourage them to take on more spot exposure. When an inevitable increase in spot prices occurred in a tight supply period, the higher overall level of unhedged demand could increase the pressure on regulators and politicians to intervene to artificially suppress high spot prices.

7.62 While this dynamic is quite plausible, the simulation modelling also identified a potential countervailing factor that may increase the propensity to hedge. Under 100%RE, there will likely be change in the nature and frequency of risk events. In relative terms, they are expected to become shorter and sharper, and occur when wind/solar output are low for a week or more (as well as dry years). Such calm/dark periods are expected to recur much more frequently than dry years.

Figure 21: Distribution of weeks per year with high prices



7.63 The recurrent nature of the risk may make purchasers more inclined to hedge (all other things being equal) because there will be a more recent 'lived experience' of a risk event. In contrast, if greater dry year risk had been the sole cause of increased future volatility, purchasers might

108 See, for example, Joskow, Competitive electricity markets and investment in new generating capacity, 2006.

be less inclined to hedge because many years could potentially elapse between major events and memories could fade.

7.64 Another factor which could increase the risk of artificial price suppression is the retirement of fossil-fuelled stations.[109] This will reduce the external benchmarks available for assessing the reasonableness of spot prices (and hydro offers). Spot prices will instead need to be assessed against the opportunity value of stored water (or other stored energy sources). These will be subject to more areas of judgment, such as the likelihood and relevant costs of future shortage. On the other hand, if significant levels of DSF can be unlocked, then a new benchmark would emerge which could be used for assessing spot price outcomes.

Historical concerns about missing money problems have not been borne out to date

7.65 It is also useful to consider the missing money issue in light of experience. Since the wholesale electricity market began in 1996 there have been periodic worries that a 'missing money' problem could emerge.[110] Indeed, the risk of wholesale buyers failing to adequately hedge against infrequent high prices was a particular focus in deciding whether to go with an energy-only market:

> *"The prime potential concern is that, for a variety of reasons related to the risk of government intervention, retail competition, etc, wholesale buyers may have inadequate incentives to purchase a firm supply contracts or security hedges from generators to cover the 'essential demands' of their customers, and that without firm supply contracts generators will not be able meet the full costs of investing in and maintaining adequate back up reserves and hence 'security of supply' will fall to unacceptable levels."*[111]

7.66 Among the concerns raised 25 years ago about an energy-only market, it was argued that wholesale buyers may be reluctant to enter firm contractual commitments in the wholesale market because they would perceive that, "should a crisis arise, the government would intervene to limit spot prices and to provide a 'fair share' of the power even if buyers don't have appropriate commercial contracts"[112].

7.67 Despite these concerns, investment capital has flowed fairly steadily into the generation sector, with many hundreds of millions of dollars committed in the last 25 years.

7.68 Some parties have expressed a view that current market oversight arrangements, especially the undesirable trading situation (UTS) provision have suppressed spot prices, and that this

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109 See later section from paragraph 7.125 for a discussion on transition issues.

110 For example see "Managing 'Dry-Year' Risk in a Fully Competitive Market: Issues and Options", Report for Officials Committee on Energy Policy, John Culy, NZIER, May 1995.

111 Ibid, p5.

112 Ibid p14 and 22. The Government of the day considered a range of options to mitigate the risk of market participants failing to adequate cover their risks, including a mandatory "security hedge" regime) which would have required retailers to be hedged to ~95% of expected demand), a prudential management scheme, compulsory contracting, pool price caps and administered capacity pricing. Weighing the pros, cons of each option relative to the nature and degree of the risk, it was agreed that a "security hedge" regime was not required on the basis that "[t]he transition to a fully competitive market was likely to be gradual, which made it possible to allow the electricity pool, in conjunction with market participants, to develop appropriately flexible rules to deal with the potential concerns if they emerge as the level of competition in the market increases over time through new entry or further disaggregation".

will occur more often with 100%RE. There have been 18 claims alleging a UTS event since 2003.[113] The Authority/Electricity Commission has upheld only three of those claims[114] and reset spot prices downwards in each instance. Although this information is not definitive, it does by itself suggest that regulatory resetting of prices has not had any major direct suppressive effect on spot prices.

7.69 Another concern that has been raised is that the existence of the UTS provision could induce self-imposed suppression of generation offers below efficient levels in some situations. We are not aware of any evidence to support or refute this theory, but would be interested in whether submitters have any information that they can share.

7.70 Another relevant historical benchmark is the spot revenue attributable to peaking/support plant. This type of insurance plant is the more sensitive to any suppression of high spot prices because it operates mainly when supply is tight. An earlier high-level study based on spot price data for 2010 to 2018 concluded that "no thermal plant type seems to be quite recovering its costs, but that is not surprising, in a market where LRMC is declining, and only limited entry [has been] occurring. Most plant types seem to be very nearly recovering costs, though." The sole exception was the diesel-fired plant at Whirinaki which was significantly under-recovering its full capital cost, but the study also noted that this plant was "not constructed in response to market signals".[115]

7.71 In short, past experience suggests that a degree of caution is warranted in predicting the emergence of a missing money problem.

Low tolerance of high spot prices in genuine scarcity events is a key risk to investment adequacy rather than increased price volatility per se

7.72 While the shift to 100%RE will cause increased price volatility, this is unlikely of itself to undermine forward contracting or investment incentives. Instead, the more significant issue is whether higher prices (occurring with greater frequency) that signal genuine scarcity of supply will be accepted in the wider political economy of the market.

7.73 As noted in paragraphs 7.59 to 7.71 above, the long-standing concern that the government would intervene to limit spot prices and adversely impact on new investment has not been borne out by evidence. However, an almost reflex question raised by many interested parties is whether the levels and frequency of high prices with 100%RE might increase political-economy pressure to a degree that makes it more likely that future governments or regulators would intervene (directly or indirectly) to restrain high prices.

7.74 As noted earlier, actual price suppression (or the perceived risk of it) would seriously weaken incentives to buy firm supply contracts or security hedges, which could, in turn, undermine future investment.

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113 Details of UTS claims and decisions are available here: https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/.

114 The three UTS claims upheld were for the period 3-27 December 2019, 26 March 2011, and 24 April 2004.

115 See EGR Consulting Ltd, Economic Perspective on the New Zealand Electricity Market, 2018, pp 54-55.

7.75 Keep in mind that efficiency of new investment remains a pivotal policy objective – that is to:

> *"create a commercial market framework within which individual parties, bearing their own financial risks, can make their own decisions so as to get new investment in either efficiency, or supply, at the lowest overall cost, not too late to risk shortages, nor too early or too much to cause oversupply"*[116]

7.76 Given the long and large pipeline of new investment projected for the coming 15 to 30 years, achieving this dynamic efficiency prize is particularly important. Spot price suppression (or the market perceiving it is likely) is therefore a key issue.

Pathways to address risk of under-investment due to artificial spot price suppression

7.77 In broad terms there are two basic pathways to address the risk of under-investment due to artificial price suppression:

(a) Maintain and strengthen the 'energy only' design – i.e. wholesale buyers and sellers decide how best to manage supply risks in response to 'energy-only' price signals –but strengthen certain features of the market's design.

(b) Move to a 'capacity mechanism' design (which come in a variety of forms) – i.e. make it mandatory for wholesale purchasers to have sufficient forward contracts or generation to cover their projected demand for some years ahead, and/or make it mandatory for generators to offer certain contract profiles relative to their generation capacity[117].

7.78 An energy-only path facilitates innovation and choice because risk-management decisions are decentralised. This allows market participants to seek out the options that best meet their unique needs and fosters diversity.[118] However, the approach relies on the following critical ingredients:

(a) Prices that reflect real supply and demand conditions, including very high prices in times of scarcity.

(b) Confidence among wholesale buyers and sellers that the high prices make sense, (which means confidence in the structure and rules of the market, including sufficiency of competition).

(c) Availability of 'tools' for wholesale buyers and sellers to manage their exposure those spot price risks.

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116 "Managing 'Dry-Year' Risk in a Fully Competitive Market: Issues and Option", Report for Officials Committee on Energy Policy, John Culy, NZIER, May 1995, p8.

117 Strictly speaking, a contract offer requirement could also form part of an energy-only design. The main objective of such requirements is to address competition concerns.

118 As noted earlier, diversity is a process – people and firms continuously adapting resources with an ever-evolving array of ideas and strategies to meet changing risks and opportunities. Put another way, "adapting to a complex changeable world is best achieved by a multiplicity of experiments from many different players" (Tim Harford, Economist).

(d) General public and political acceptance that volatility and high prices (in times of scarcity) in the wholesale market are, in fact, in the best long-term interest of consumers, and that measures to 'soften the landing for unhedged participants' can trigger a vicious circle of undermined investment incentives and higher future prices; and

(e) Confidence among consumers/politicians that investment will be timely and competitive.

7.79 Fulfilling (d) and (e) above is highly influenced by whether (a) to (c) are satisfied.

7.80 Higher prices with more frequency in an energy-only regime will likely require both a change of mind-set and measures to strengthen delivery of the criteria outlined above. Likewise, it is critical that consumers have confidence that competition is disciplining prices, as noted further below.

7.81 Both the energy-only and the capacity market pathways have challenges, and both have risks. We will explore these in some detail in the next stage (options analysis) of this project. Neither are necessarily straightforward – if an energy-only approach is perceived to be hard, it does not follow that a capacity mechanisms approach is any easier.

7.82 Capacity mechanisms seek to sidestep the incentive issues by compelling wholesale purchasers to obtain forward cover via contracts, generation and/or firm DSF capability.[119] This approach can also involve requiring suppliers to offer contracts covering a certain profile of their firm capacity.

7.83 The architecture of even apparently simple or 'limited' capacity mechanisms tends to be more involved than is often assumed. Among other things market participants' forward positions need to be closely monitored and mandates need to be enforced by a central agency. Capacity mechanisms are necessarily prescriptive because a central agent must set binding standards for how demand and supply will be measured and monitored – for example determining what constitutes firm DSF capability, solar and wind output, etc. The combination of mandates and centrally determined prescription means that there is, unavoidably, less scope for innovation and choice and this in turn reduces scope for competition and tends to raise costs over time.

7.84 Overseas experience also needs to be taken into account:

(a) Most recently, Alberta and Singapore are jurisdictions with energy-only electricity markets that decided in principle to introduce capacity mechanisms. However, after more detailed study both later shelved those plans.[120] In September 2021, Australia

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119 Arguably the incentive issue still arises because there is a need to set financial penalties to deter non-compliance with capacity mechanism requirements, e.g. for non-delivery of energy as compared to contracted quantities. Recent experience in the United States suggests that penalties in a well-functioning capacity market need to be similar to spot prices in an energy-only market to achieve efficient outcomes, i.e. low penalties in times of abundance and penalties which reflect non-supply when curtailment occurs.

120 In 2017, Alberta decided to introduce a capacity market after some years of study. However, that path was abandoned in 2019 when authorities decided to stick with an energy-only citing cost concerns - see https://www.alberta.ca/release.cfm?xID=642387D0ECA3E-ED8E-6B02-885D35312EBBB3EE. In 2019, Singapore

announced that it would progress an 18-month study on the possible introduction of a mechanism "that specifically values capacity in the NEM".[121] We intend to find out more about these recent developments to more fully gauge their relevance to New Zealand; and

(b) The jurisdictions that have successfully operated capacity mechanisms for many years are all dominated by thermal generation and have capacity during peak demand periods as the central reliability concern. As a system with a large hydro base, New Zealand has to address both energy and capacity constraints. These twin requirements make the design of a 'capacity-like mechanism' much more challenging. The only hydro-dominated system with a capacity-like mechanism is Colombia, but that design was assessed by the World Bank as not operating adequately.[122]

7.85 It is also relevant that the transition to 100%RE in New Zealand will occur over 15 to 30 years, which gives us the opportunity to first test the effectiveness of strengthening an energy-only design. If this proves to be unsatisfactory, there should still be plenty of time to further explore and implement an alternative based on some form of mandatory forward contracting.

7.86 Having made these observations, it is important to be clear-eyed about the challenges associated with an energy-only design. We think it would need to be strengthened in a range of areas to be sustainable. Hence, we consider the following measures should be further explored.

7.87 We also think it might be prudent to scope out what would be required to implement more heavy-handed mechanisms if missing money concerns could not be addressed by the primary measures.

Key issues and measures for accurate price signals with 100%RE

7.88 We think that the key issues in relation to price signalling with 100%RE are:

(a) Whether higher prices (occurring with greater frequency) signalling genuine scarcity of supply will be accepted in the wider political economy of the market; and

(b) Whether the five elements set out in paragraph 7.78 above are required for an energy-only pricing regime to work; and

(c) Whether you agree that fulfilling (d) and I(e) in paragraph 7.78 above is highly influenced by whether (a) to (c) are satisfied.

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announced its intention to adopt a forward capacity market from 2022. After two years of implementation work that project was placed on hold until further notice, with the regulator stating a forward capacity market "may not provide competitive market outcomes and achieve the key objective of maximising economic efficiency" - see Info Paper - Update on FCM.pdf (ema.gov.sg).

121 See Energy National Cabinet Reform Committee | Ministers for the Department of Industry, Science, Energy and Resources.

122 Rudnick H. and Velásquez, C. (2019). *Learning from Developing Country Power Market Experiences The Case of Colombia*. World Bank Group Energy and Extractives Global Practice: 51-52. The study identified mixed results with the design and stated that "even though the Colombian regulator has set a mechanism that pursues security of supply, this has not operated adequately".

7.89 In this case, we also suggest that the measures below should be taken forward into the next stage of the process (options identification and analysis) in relation to spot price signalling with 100%RE:

Measures to increase confidence in spot prices during genuine scarcity

(a) Reduce scope for spot price suppression during genuine scarcity events, for example via:

  (i) Increase awareness of the necessity of high spot prices when supply is genuinely tight, and the adverse consequences of artificially suppressing prices in those events, with information programmes for market participants, consumers, media, policy makers etc.

  (ii) Strengthen the stress testing regime to ensure market participants are consciously aware of the risks of their hedging choices

  (iii) Strengthen processes for reviewing high price events to ensure they are examined in a robust and timely manner

  (iv) Strengthen the process for determining UTS claims to include an explicit requirement to consider effects of any decisions on future investment incentives.

Explore backstop measures

(b) Explore measures that would introduce compulsory contracting obligations on purchasers to forward contract for their firm demand, and ensure suppliers' do not sell contracts that exceed their firm output, that may include measures such as:

  (i) A conditional forward contracting obligation if projected demand exceeds supply (say) three years into the future (similar to the retailer reliability obligation in Australia)

  (ii) A reserve energy/capacity scheme with standing costs for reserve plant recovered from beneficiaries (i.e. parties that do not have forward cover for firm demand)

  (iii) Introducing a firm capacity/energy market or similar mechanism.

6. Do you agree that these are the key issues in relation to price signalling with 100%RE as summarised in paragraph 7.88 above? If you disagree, what is your view and the reasoning for it?
7. Do you agree that the preconditions in paragraph 7.78 would need to be in place for an energy-only market design to be effective? If you disagree what is your view and the reasoning for it?
8. Do you agree that we should take forward to the next stage of the process (options identification and analysis) the measures referred to in paragraph 7.89 above? If you disagree, what is your view and the reasoning for it?

Greater role for electricity users will be critical

7.90 The modelling described in Section 5 above highlights the growing prize from getting better DSF. The benefits include:

(a) Reduced system costs as DSF can – at least partly – fulfil the role of a peaking plant, potentially at lower cost to the system. For example, if an additional 5-6% of system load was responsive (as per the enhanced demand flexibility case) that would save around $120 to $170 million per year in generation system costs (i.e. excludes any additional savings from reduced network costs). This is a gross benefit and the net benefit would be lower because the costs for demand-side parties to be responsive (foregone usage and any capital costs) would need to be deducted. This estimate appears to be broadly comparable with a cost benefit study by Sapere, which estimated the economic surplus of distributed energy resources over 30 years at $6.9 billion in present value terms, or roughly $230m per year.[123] These estimates provide an indication of the size of the prize that could be available if additional DSF can be unlocked;

(b) Increased demand-side participation would lower price volatility, which is likely to help participants with their risk management decisions;

(c) More competitive pressure on wholesale prices/costs, especially during times of higher prices when generation is scarce, some customers may prefer to reduce demand rather than incur these prices; and

(d) More confidence in the quality of prices, especially when the system is tight and administrative scarcity pricing (and potentially non-price rationing) is possible. Here, if customers are able to reveal their true willingness to pay for electricity via bids into the wholesale market, the marginal price of electricity will reflect these customers'

123 Reeve, Stevenson, Comendant (2021), *Cost-benefit analysis of distributed energy resources in New Zealand*. Available here: https://www.ea.govt.nz/assets/dms-assets/28/Cost-benefit-analysis-of-distributed-energy-resources-in-New-Zealand-Sapere-Research-Group-final-13September.pdf.

valuation rather than an administered price. This should bolster the political sustainability of scarcity prices (Simshauser, 2018). This is discussed further in the section on the impact of greater price volatility on the missing money problem (starting paragraph 7.59).

7.91 These system benefits are reflected in the international literature. Joskow (2019)[124] cites the work of Imelda and Roberts (2018)[125], 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*."

7.92 Increased wholesale market participation from consumers was seen as important during the market design period in New Zealand (see Culy (1995)[126]) and internationally (see e.g. Cramton, Ockenfels and Stoft (2013)[127], Fraser (2001)[128], Hunt (2002)[129]). However, in New Zealand it remains a work in progress. A number of factors have slowed the widespread deployment of demand-side participation:

(a) Consumers' awareness and understanding of the possibilities for demand-side participation, and the various forms that could take.

(b) The incentives faced by consumers to manage their own consumption, particularly shifting consumption from one time period to another. With the prevalence of retail tariffs which are constant throughout the day, there is no financial incentive to shift consumption.

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124 See footnote 69.

125 Imelda, Fripp, M., Roberts, M., 2018, *Variable Pricing and the Cost of Renewable Energy,* Working Paper 24712, National Bureau of Economic Research, http://www.nber.org/papers/w24712.

126 Culy, John, *Managing 'Dry-Year' Risk in a Fully Competitive Market: Issues and Options*, Report for Officials Committee on Energy Policy, John Culy, NZIER, May 1995.

127 Cramton, P., Ockenfels, A. and Stoft, S., 2013. *How to negotiate ambitious global emissions abatement. A Statement of Key Principles and an Explanatory Note*, 2013-05_Cramton-Ockenfels-Stoft_How-to-Negotiate-Ambitious-Abatement.pdf.

128 Fraser, H., 2001, *The Importance of an Active Demand Side in the Electricity Industry*, The Electricity Journal, Nov 2001, p52-73.

129 Hunt, S., 2002. *Making Competition Work in Electricity*, John Wiley&Sons, Inc., New York, 2002.

(c) The degree to which customers have to – and want to -– actively manage DSF, including the trade off between the service they require (eg heating, cooling and more recently state of charge of their electric vehicle) and how much flexibility is used to manage their own consumption costs.

7.93 Ultimately, whether or not customers choose to provide flexibility in their consumption to the wholesale market will in large part be about the extent to which they are aware of their options to enable and provide flexibility, and whether or not the cost they incur in enabling participation (time, investment, hassle) is outweighed by the benefit they receive.

7.94 The factors above are still present, but the costs or impediments to participation have reduced. Technology – sensors, algorithms and communications – has evolved to a point where it can make these service trade offs for residential consumers by directly controlling appliances (including electric vehicles and batteries) and/or reacting to prices, while preserving the level of service the customer needs. In the case of a number of appliances (e.g., EV charging, heating/cooling, refrigeration) the technology that enables demand-side participation is increasingly embedded in the power electronics modules of these appliances, making it less necessary for customers to have to purchase, install or retrofit a “smart” device to enable flexibility.

7.95 Business models for providing this service to customers are yet to emerge in New Zealand. However, we expect that many consumers will likely be unaware that “smart” appliances exist and have this functionality built into them. There are also a wide range of competing smart communication systems which may not be inter-operable. This is a natural outcome of innovation, but may be a level of complexity which is hindering uptake.

7.96 For commercial and industrial customers, while smart heating, cooling, ventilation and electric vehicle charging infrastructure is available to them, the job of integrating flexibility in demand into more complex business processes is highly specific to their context. While these organisations are more likely to have dedicated energy management personnel, this integration may have considerable up-front costs, which, in the absence of any third-party contract for flexibility (such as a retailer or flexibility trader), will only be recouped through an uncertain and volatile stream of reductions in electricity consumption costs. The complexity and risk of investing in DSF may be a barrier to these organisations, whose primary focus is on the production of some good or service, not the energy market.

7.97 We also believe that the driving forces behind demand-side participation that shifts demand from one period to another (e.g., hot water, electric vehicle charging and battery storage) will be different to participation that curtails (or opportunistically increases) demand for a longer period of time (days or weeks). The modelling suggests that both are valuable to a 100%RE system. However, curtailment is likely to be harder to achieve, as it will result in a degradation to the service experienced by the customer – the temperature of their house, the amount they can use their vehicle, or the ability of the business to operate at full capacity. Shorter term demand shifting, on the other hand, should in most cases make no perceptible difference to the customer, as it is using thermal inertia or battery storage.

7.98 Most fundamentally, in so far as the vast majority of consumers are insulated from wholesale prices, they are unlikely to be motivated to purchase or enable smart appliances (including EV chargers and distributed batteries) in a way that benefits the wholesale market. To enable an increased use of DSF to manage wholesale market outcomes, a number of issues need to be addressed:

(a) Customers need to be aware that smart appliances exist, and are easy to implement, and that there are retail products that will reward them for enabling the flexibility in these appliances. Importantly, consumers will not need to 'trade' in the wholesale market to obtain benefits. Instead, such engagement can occur via an agent such as a retailer or other service provider.

(b) Customers presently have both a stable retail tariff, insulating them from wholesale prices *and* provide no control over their discretionary consumption to their retailer (which faces the wholesale price volatility on their behalf).[130] Ideally, customers could select from a range of contractual relationships with their electricity service providers that reflected (amongst other things) their appetite to directly engage in providing flexibility, to leave the use of their flexibility to someone else, or not to provide flexibility at all. These options would have a different relationship with their electricity service providers that could encompass scenarios such as:

  (i) a retail tariff that dynamically reflects wholesale market conditions, and make use of technology to manage their own consumption. In a 100%RE world, this may not necessarily be achieved with a time-of-use tariff structure that sees higher retail prices during load peaks, and may require tariffs that dynamically reflect wholesale market conditions; or

  (ii) a semi-stable tariff but one that provides some control of their available flexibility to the retailer, who in turn manages their wholesale market purchase profile with the aggregate flexibility provided to them by their customers; or

  (iii) a relationship with both their retailer and a 'flexibility trader' (requiring multiple trading relationships to be permitted), which has control of their discretionary consumption, in turn selling this flexibility to wholesale market participants or directly into various markets (e.g. spot market arbitrage, or ancillary services, or distribution network flexibility) with few barriers to entry; or

  (iv) a fixed tariff that provides no flexibility or control to the retailer.

7.99 All of the potential DSF outlined above could, under various tariff scenarios, respond to the wholesale price, but not necessarily set the wholesale price. There are a range of scenarios[131] where demand-side response could improve the efficiency of, and confidence in, the wholesale price setting process if they were to formally bid into the wholesale market. Historically, though, very few demand-side participants have been willing to submit bids to the wholesale market. Whether or not customers choose to provide flexibility in their consumption to the wholesale market in any of the ways outlined above will in large part be

130 The use of demand-side management by retailers is a potential wholesale risk management product which should be considered alongside the future needs for other hedging product, as discussed from paragraph 7.104 below.

131 The most obvious scenario is where the system is very close to needing demand curtailment – not only would DSF potential prevent involuntary curtailment, but, if it were bid into the market, it may actually set the wholesale price, thus sending an efficient signal reflecting the opportunity cost of energy at that point in time.

about whether the cost they incur in enabling participation (time, investment, hassle) is outweighed by the benefit they receive.

7.100 The Authority's proposed "dispatch notification" product, which forms part of the Real Time Pricing project, will allow DSF providers (and embedded generators) to formally bid their ability to respond into the wholesale market under a less onerous compliance regime. The Authority has been clear in their belief that a major driver of the dispatch notification product is the benefit of participation in the price-setting process.

7.101 However, even a lower compliance and simplified approach to bidding into the wholesale market requires a demand-side participant to contemplate bid quantities and price, and then monitor dispatch instructions and consider compliance. This is only likely to occur in DSF owners or agents/intermediaries who are of a sufficient scale to warrant dedicated resources to wholesale market participation. It is highly unlikely that residential DSF owners would contemplate direct participation.

7.102 Experience from other countries (e.g. Norway, Australia) suggest that increased demand-side participation may most likely be catalysed by an event (high retail prices, and/or significant uptake of a particular technology such as electric vehicles or batteries) that drives increased customer awareness and emergence of demand-side response tariffs and products that incentivise involvement.

Experience from Norway

Norway's electricity market has some similarities to New Zealand – e.g. large hydro resources and an energy only wholesale market. However, the vast majority of customers in Norway (including residential) are on tariffs linked to the spot price; few choose to take up fixed price contracts.

Due to a range of events – low inflows, low wind output, and high fuel and CO_2 (ETS) prices, combined with robust demand levels – electricity prices have hit very high levels: in the third quarter of 2021, Statistics Norway reported the average residential spot tariff was 76 krona per kWh, up from 9 krona per kWh in the same quarter in 2020.

This has seen rapidly increasing interest among consumers in ways to reduce and/or manage their demand. One significant opportunity for this is electric vehicle charging – Norway has one of the highest penetrations of electric vehicles in the world, with around 80% of all new car sales in Norway being EVs.

Products are quickly emerging – both from traditional and new retailers – that allow customers to specify how much control the retailer has over charging, as well as specifying the state of charge that must be reached at a critical time (e.g. 75% charged at 8am). For customers to enable this, they must have a smart charger.

We understand that similar products exist for stationary batteries, and smart water and space heating products and technology is likely to emerge very soon, spurred on by the strong interest (and drivers) for demand-side participation.

Smart consumption technology has very limited access to Norway's reserve markets, but there are a number of changes planned to these markets over the next 12-18 months.

Key issues for demand-side flexibility with 100%RE

7.103 We think the key issues in relation to DSF are:

(a) What are the wholesale market features necessary to fully realise the benefits of DSF under 100%RE?

(b) Are the wholesale market features identified in (a) likely to be present as the shift to 100%RE occurs?

(c) What are the actions needed to put the necessary features in place, to the extent that the wholesale market features in (b) are unlikely to develop naturally?

9. Do you agree that these are the key issues in relation to demand-side flexibility with 100% RE? If you disagree, what is your view and the reasoning for it?

Contracts market will have to do more 'heavy lifting'

7.104 The foregoing discussion highlights the importance of understanding how market participants (generators, storage owners, retailers and consumers) might adapt their risk management practices – including their demand for, and supply of hedge products - to an increasingly renewable world.

7.105 Our confidence that market participants will adapt practices to a higher volatility world can be supported by observing the degree of adaptation that has occurred historically. A study of wholesale market participants' views on risk management[132] revealed that risk management (risk models, policies, and use of hedge products) across market participants has evolved and improved substantially since the commencement of the market, and especially over the past ten years. This period has seen substantial change, including the emergence of over 30 new retailers, as well as the establishment of an electricity futures exchange and a financial transmission rights market.

7.106 While this evolution may have occurred slower than the original market designers expected, no evidence was identified that pointed to systemic exposure risk across the market; in fact, most of the observable data shows an increasing, and adapting use of hedge products[133].

7.107 That said, concerns were expressed by some market participants regarding the current liquidity and pricing of options and shape-related hedge products (e.g., peak and cap products)[134]. These products are particularly valuable to independent retailers who want to be able manage the wholesale risk associated with a residential profile, and:

132 Batstone, S (2021) "Wholesale risk management practice trends in the New Zealand electricity market, and prospects for a high renewables future", Working paper for MDAG, October 2021.

133 Ibid, section 3.4.

134 Ibid, section 6.1.2.

(a) while some of these products are listed on the ASX futures exchange, there are no market making agreements for them, and liquidity is low compared to market-made baseload products;

(b) those that are not listed on the ASX are traded in the over-the-counter (OTC) markets, where more tailoring is possible, but this is more difficult to monitor;

(c) some evidence emerged that, for some products, there is simply a material gap between what sellers and buyers believe the risk management value of the product is worth.

7.108 Some parties argued that existing options and peak products listed on the exchange should be subject to market-making requirements, and/or new options and profile-related products listed.

7.109 However, many noted the sheer cost of trading on the exchange (especially due to the quantum of initial margins, but also the timing of settlement cashflows through variation margins) which has recently become very high for participants[135]. There was also a perception that the demand for some products (e.g. caps) would not warrant the effort and cost of listing on the exchange. Trading in the OTC market is less costly and allows more customisation of the product, unlike the ASX which demands standardisation.

7.110 The cost of ASX trading also adds to the prudential burden borne by electricity purchasers, as the margins held on the ASX cannot be offset against the spot market prudential requirements. Given the importance of the ASX to electricity risk management in New Zealand, the cost of participation could become a significant barrier for some parties.

7.111 A number of market participants, including renewable generation developers, expressed concern about the cost of 'firming' intermittent renewables, and the lack of market depth for power purchase agreements (PPAs)[136]. Both buyers and sellers of PPAs for new wind and solar indicated that the lack of transparency makes it difficult to reconcile offered PPA prices to firm market products (e.g. Contract for Differences, CfDs, or futures). This is further compounded by the fact that the cost of firming is uncertain through time[137]. While, as outlined below, there are options for developers to firm up intermittent projects (e.g. co-location with batteries, or use of a combination of firm hedge products and accept some degree of wholesale risk), these are not without their own costs and concerns about liquidity. This is an important issue to resolve if we are to achieve a vibrantly competitive investment market.

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135 An expert reviewer noted that increases in margining requirements have been identified as the cause of reducing liquidity in the Nordic forward market.

136 Power Purchase Agreements. These contracts are often referred to being "non-firm", as the purchaser agrees to pay a fixed price for the output of the generation project – whatever that output is in each half hour. Hence the purchaser receives an uncertain degree of hedging value, especially in the short to medium term. We note that internationally PPAs may be confused with feed-in tariffs, where government policy ensures that developers of renewable generation receive a minimum price for their generation. Often government-backed PPAs are used to achieve this outcome, but that is not the context in which we refer to PPAs here, as current government policy does not include feed-in tariffs.

137 For example, the GWAP discount of a wind or solar farm will change as other projects come online, depending on their degree of output correlation.

7.112 Looking forward to a 100%RE market, the continued adaptation by market participants will likely result in changes in the demand and supply of different hedge products. We consider these include the following themes:

Changes in the demand for hedge products

(i) The increase in, and changing nature of, volatility will increase profile risk for retailers, although it is not clear to what degree. As discussed above, with the increasing penetration of wind and solar, the weather will play a stronger role in volatility, hence the correlation between a retailer's demand and the spot price may reduce. In any case, this uncertainty will likely see purchasers increase their demand for shape-related contracts like peak hedges and options (caps).

(ii) Similarly, products such as caps, when combined with baseload hedges, provide an alternative to PPAs for intermittent renewable developers when trying to provide a firmer hedge contract for their output (depending on the degree to which this satisfies banks' requirements for proof of firm revenue, in the context of the developer's financial capacity). This was illustrated in paragraph 7.52 above. This would also partially address market participants' concerns about how the cost of "firming" intermittent projects would be made explicit, and paid for. Equally, intermittent generation developers may choose to co-locate batteries onsite to firm up the overall output from the project, thus reducing their demand for additional shape products.

Changes in the supply of hedge product liquidity

(i) This raises the question of how this increase in demand, particularly for shape-related products, will be met. Today, as highlighted above, there are concerns about the low liquidity in these products.

(ii) Currently, flexible hydro and thermal owners are a key source of liquidity of firm hedge products (baseload and shape-related contracts). Presumably, as thermal is retired, it will be replaced in the market (on an energy basis) by intermittent renewable generation. As the simple illustrations provided in 7.45-7.58 above show, optimal levels of baseload contracts for intermittent generators is likely to be significantly less than 100%, whereas the baseload contract demand from independent retailers is likely to be close to or even over 100%.

(iii) It remains to be seen as to what extent the removal of liquidity provided by thermal will be replaced. At a high level, this could come from the remaining flexible hydro providers and new sources of liquidity, such as flexibility providers using combinations of distributed solar, batteries and DSF to back firm contracts. Further, there are a range of large companies that are not market participants who may have the financial capacity to provide contract liquidity into some parts of the market, such as what is seen in the corporate PPA market[138].

7.113 Surprisingly few international studies have considered in any depth how contract market outcomes will change under very high renewables. Various studies of electricity contract market outcomes have highlighted how the degree of volatility in the market will have an

138 Data on the vibrant corporate PPA market in Australia can be seen at https://www.energetics.com.au/insights/knowledge-centres/corporate-renewable-ppa-deal-tracker.

influence on the equilibrium price paid for hedge products, and potentially strategic behaviour by large electricity suppliers (e.g. Simshauser (2018)[139], Ritz (2016)[140], Peura and Bunn (2018)[141]).

7.114 Specifically in respect of PPAs for intermittent renewables, some Australian studies have queried how much supply of "non-firm" PPA contracts a very high renewables market can absorb (e.g. Simshauser 2018[142], 2019[143]) before the demand for firm products from retailers cannot be satisfied. These studies did not, however, consider how developers of wind and solar farms may use firm hedge products (e.g. a combination of baseload and cap contracts as illustrated in 7.51 above) as an alternative to non-firm PPAs, or self-provision of physical firming by co-locating with batteries or even potentially flexible demand.

7.115 Further, few of these theoretical studies have been tested against real world hedge market outcomes, and none of them have considered a 100%RE scenario where contract sellers (primarily generators) would have reduced discretion over their output due to the dominance of weather conditions.

7.116 Additional advice provided to the MDAG from Sapere Research Group[144] confirms the view that, as we transition to 100%RE, the increase in wholesale market volatility identified above will likely shift the demand for hedge products away from baseload products towards options (e.g., caps) and peak products. It is also likely to result in more tailored products developed and provided through the OTC market, as the changing nature of volatility and its impact on output revenue and purchase costs may make it difficult to determine a standardised product for exchange listing that is both durable and provides good risk management value for a broad set of market participants.

7.117 Using the transaction cost theory of Williamson (1971, 1973)[145], Sapere ultimately conclude that the increased transaction costs associated with market contracting in a more volatile world increase the likelihood that vertical integration will be preferred more as a risk management solution. This echoes Simshauser (2021)[146] who, again leaning on Williamson's transaction cost theory, 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. An earlier

139 See footnote 68.

140 Ritz, R., 2016, *How does renewables competition affect forward contracting in electricity markets?*, Economics Letters 146, p135-139.

141 Peura, H., Bunn, D., 2018, *Renewable Power and Electricity Prices: The Impact of Forward Markets*, Management Science, vol. 67, No. 8.

142 See footnote 68.

143 Simshauser, P., 2019, *On the Stability of Energy-Only Markets with Government-Initiated Contracts-for-Differences*, Energies 2019, vol. 12.

144 Available here: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/100%-renewable-electricity-supply/consutations.

145 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.

146 Simshauser, P., 2021, Vertical integration, peaking plant commitments and the role of credit quality in energy-only markets, Energy Economics 104 (2021).

paper by Simshauser (2020)[147] demonstrated empirically 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 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.[148]

7.118 Similarly, Sapere's advice highlighted that uncertainty about the spot price distribution may hamper good contract outcomes. Market participants' beliefs about volatility will change as we transition towards 100%RE, as the usefulness of historical prices gradually wanes. Elsewhere[149] we highlight how different expectations about the behaviour of prices in the current market is a potential factor driving a gap between the willingness to buy, and the willingness to sell particular hedge contracts – particularly those products that manage the *shape* of volatility (rather than just the price level). However, we cannot say conclusively whether increased future volatility will magnify this problem (as Sapere suggest), or create an additional impetus to contract, thus reduce the buy-sell gap.

7.119 While we accept that the need for tailoring suggests many shape-based products should be negotiated through the OTC market, the simplicity of the cap product makes it a potential candidate for exchange listing. The traded price of caps would provide the market with some information about the various participants' beliefs about volatility. However, the ASX has cautioned that the initial margin requirements for cap products could be significant. The ASX are investigating a superpeak product with their Australian users as a replacement for the current peak product[150].

7.120 If a sizeable portion of hedge market liquidity in a 100%RE world will be provided through OTC markets, it may be necessary to increase the monitoring and transparency of this market to ensure a reasonable degree of product liquidity is maintained as the market transitions to 100%RE.

7.121 We observe that some of the underlying themes and concerns expressed above were echoed in a 2006 report by the Electricity Commission's Hedge Market Development Group[151], and again in 2016 by the Authority's Wholesale Advisory Group's work on Hedge Market

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147 Simshauser, P., 2020, Merchant renewables and the valuation of peaking plant in energy-only markets, Energy Economics 91 (2020).

148 Simshauser is silent on whether the implied result of both analyses is that *increasing* intermittency results in a trend towards increasing vertical integration, although, as Sapere point out, this seems a natural conclusion. 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.

149 Transition discussion from paragraph 7.125 and Batstone, S (2021) "Wholesale risk management practice trends in the New Zealand electricity market, and prospects for a high renewables future", Working paper for MDAG, October 2021, p33.

150 A superpeak product would focus in on peak load periods (morning and evening peaks) rather than the broader daily coverage of the current peak product (7am-10pm). Note though that a 100%RE world may not see peak load periods as having the greatest exposure to peak purchase costs, as discussed earlier.

151 "Hedge Market Development – Issues and Options: Technical Paper", Electricity Commission, 18 July 2006.

Development[152]. Significant progress has been made on the hedge market since 2006, but it appears there are still improvements to be made, especially as we look forward to a more volatile market.

7.122 The majority of market participants in the Batstone (2021) study were confident that their risk management practices would continue to adapt and evolve as the market approached 100%RE[153], but views were divided on whether the liquidity and pricing of hedge products would be part of this improvement.

7.123 Given the importance of the contract market to providing incentives for generation, and allowing retailers to efficiently manage risk, the above analysis suggests it will be critical to ensure the availability of risk management products that participants require, as the transition to a higher volatility market takes place.

Key issues for contracts market with 100%RE

7.124 We think the key issues in relation to the contracts market are:

(a) What are the contract market features necessary to ensure participants will have reasonable access to the risk management products needed under 100%RE?

(b) Are the contract market features identified in (a) likely to be present as the shift to 100%RE occurs?

(c) What are the actions needed to put the necessary features in place, to the extent that the contract market features in (b) are unlikely to develop naturally, for example by building on existing regulatory tools or developing others?

10. Do you agree that these are the key issues in relation to contracts markets with 100%RE? If you disagree, what is your view and the reasoning for it?

[152] "Hedge Market Development", Recommendations Paper, Wholesale Advisory Group, 26 June 2015. We note that the paper contained a dissenting view from two members, part of which related to their concerns about the low liquidity of peakload futures.

[153] See Batstone, S (2021) "Wholesale risk management practice trends in the New Zealand electricity market, and prospects for a high renewables future", Working paper for MDAG, October 2021, p28.

Will the transition be orderly?

7.125 The previous section considered whether investment adequacy issues might arise once the system has achieved 100%RE supply. A distinct but related concern is whether investment adequacy concerns could arise in the transition to 100%RE due to 'lumpy' decisions.[154] In particular, whether large fossil-fuelled units might retire before replacement resources are available (referred to below as "premature retirement") and therefore cause a disorderly transition.

7.126 Putting the question another way, if the benefit to society (and consumers) of retaining some fossil-fuelled plant during the transition will exceed the cost, what if any factors exist that might block that outcome from occurring?

7.127 The most obvious potential cause would be any factors that artificially suppress spot prices (or an expectation that this will occur). This concern was discussed extensively in the previous section on general investment incentives in the *100%RE end state*. It will also affect retirement and fuel purchase decisions during the *transition*. Rather than repeat that earlier discussion, the balance of this section discusses whether there are any further factors related specifically to the transition to 100%RE which might lead to premature retirements.

7.128 Before proceeding, it is useful to distinguish the two categories of fossil-fuelled plant on the system that are expected to retire. The first is plant operating in (or near to) a baseload role. By definition such plant has relatively high expected utilisation, providing some revenue assurance and reducing the likelihood of premature closure. At present, such plant contributes about 5,000 GWh/year of generation, and this is expected to progressively decline as the system shifts towards 100%RE.[155]

7.129 The remaining fossil-fuelled plant provides a mix of insurance services covering short-term renewable intermittency (e.g. low wind generation), predictable seasonal variations in demand and renewable supply, and hydro firming including dry year cover. As noted in paragraph 7.70, insurance plant by its nature is more sensitive to any factors that suppress spot prices during period of scarce supply.

7.130 One specific factor has been suggested as elevating the risk of price suppression for such plant in the transition period. This is the concern that potential buyers of contracts may believe the insurance units will not be permitted to retire even if the owner wishes to do so. This view assumes that government intervention in some form will block a retirement decision if security would be impaired. Such action might occur if the government of the day thought security would fall below the level that society was willing to pay for, or because the government itself preferred an even higher level of security (e.g. to reduce in a transition to 100%RE).

7.131 If insurance plant owners were perceived to not have the ability to retire plant, that could make it very difficult to obtain adequate hedge contract cover in the transition. In effect, this

154 Lumpiness here refers to decisions which are binary in nature, and have a significant effect on market participants depending on which way the decision goes.

155 Some of this baseload plant may in turn become mid-merit insurance plant.

would be a type of price suppression because the contract prices realised by plant owners would be lower than the level required to justify plant retention.

7.132 Other concerns raised by stakeholders about the transition are not strictly about price suppression but more about the potential difficulty buyers and sellers might face in striking deals due to contracting frictions or associated issues.

7.133 The first concern relates to the relatively large size of the three Rankine units at Huntly and the fact that retention/retirement decisions must be for whole units. It has been suggested this may lead to a free-rider problem. For example, there could be a system demand for (say) two units to remain operable in the transition. However, individual market participants may think they can obtain the benefit of plant retention without forward contracting because other parties will collectively contract for (say) 1.5 units, forcing the owner to retain two whole units. If sufficient participants follow this strategy the units may not have sufficient contract cover and may be retired.[156]

7.134 Another concern is that information asymmetries may impede contracting. For example, some fossil-fuelled units are quite old and there is an increasing risk of unexpected failure. This risk is partly age-related (i.e. inherent) but will also be affected by plant owner's maintenance practices. Purchasers will be reluctant to bear risk that could be influenced by the owner's actions. On the other hand owners will likely be reluctant to bear the risk of age-related plant failure. Both parties will find it hard to agree the demarcation between these risks, making contract decisions more difficult. Another area where information asymmetry may arise is the treatment of fuel supply risk – especially for gas where information is both more limited and can be subject to more rapid change.

7.135 A further issue which may affect contracting dynamics is policy uncertainty. The demand for insurance plant and the cost of providing insurance services will be affected by a range of policy decisions that have yet to be made, such as carbon pricing, the extent of any restrictions on the use of specific fuels such as coal, the availability of any new major flexibility sources (such as a pumped hydro storage facility) underwritten or provided by the state. Policy uncertainty is not a new issue but is arguably heightened for the next few years as New Zealand and other countries reset policies to address climate change.

7.136 Participants may be able to manage some of the policy uncertainties via contractual terms (such as treatment of carbon price effects). However, it may be harder to address issues of a more general nature such as the effect of a major new flexibility source being added to the system. This may lead purchasers to prefer to contract for shorter periods (e.g. 1-2 years at a time), but it is unclear if this will align with the physical decisions required for insurance plant. For example, if some plant is coming to a point where major life-extension capital expenditure is required, owners may seek revenue certainty for periods that are longer than buyers are prepared to commit for.

7.137 While all of the above contracting frictions raise the likelihood of missed opportunities to conclude socially beneficial deals, there remains a question of whether and how quickly any such errors would be corrected. For example, if an owner did announce a plant retirement

156 Such plant would still be able to earn spot revenues, but owners may be unwilling to accept the uncertainties associated with spot revenues.

due to insufficient forward contracting, it seems unlikely that irreversible change to the plant would occur immediately. More likely, there would be a period of some months before such decision became completely irreversible. Indeed, that was the experience with the announced closure in 2015 of the Huntly Rankine units[157] which was later rescinded.[158]

Key issues for transition to 100%RE

7.138 We think the key issues in relation to transition are:

Strengthen market process for retirement

(a) Should we rely on contracting incentives (with spot prices allowed to reach high levels to properly signal scarcity) to avoid premature retirement of large fossil-fuelled thermal plant, and (in addition) improve participants' information and contracting incentives, for example by:

(i) Ensuring that participants have sound information about the system consequences of potential lumpy decisions - for example by strengthening the annual security assessment reports prepared by the system operator to include more information on different thermal plant retirement options, or effects of possible major energy storage projects such as pumped hydro;

(ii) Ensuring that any retirement of major thermal plant is telegraphed in advance – for example codification of the process for the retirement of plant above a certain size could be beneficial. Such a process could seek to ensure that plant owners and other participants have sufficient time to work through the options, while also making clear that final decisions on whether to retain plant will rest with owners;

(iii) Adopting measures to reduce the likelihood of artificial spot price suppression as set out in paragraph 7.89(a) above;

or

Explore a backstop mechanism to facilitate orderly transition

(b) Should we explore options that would allow the retirement schedule for large fossil-fuelled units to be centrally determined, to reduce the risk of premature retirement, for example by adopting a strategic reserve mechanism as set out in paragraph 7.89(b) above; and

(c) If so, how to manage the risks of such a mechanism impacting on contracting and investment dynamics during and after the transition.

157 See https://www.nzx.com/announcements/268005.

158 See https://www.nzx.com/announcements/281406.

11. Do you agree that these are the key issues in relation to the transition to 100%RE? If you disagree, what is your view and the reasoning for it?

12. Are there any other 'lumpy' issues that warrant specific consideration in the transition to 100%RE?

Competition will be vital

7.139 Competition will be vital to ensure a successful shift to 100%RE. Without effective competition consumers and policy makers will not have confidence in electricity spot or contract prices. And without that confidence, investors are unlikely to commit the sums needed to underpin the shift to 100%RE. Competition also has a critical role to play in spurring innovation and finding the best solutions to drive down costs over time. This will be particularly important in an environment where technology and business models are evolving rapidly.

7.140 The shift to 100%RE will affect competition in different parts of the wholesale market. Although many of the effects will depend on factors which cannot be predicted at this point (such as whether new market participants enter), some broad changes can be posited as fossil-fuelled thermal stations retire. All other things being equal, this will reduce the number of competitors in some segments. On the other hand, new sources of competitive tension are likely to enter, such as batteries.

7.141 Another important issue to bear in mind is that competition is often reduced when the system is under stress, and yet those are the times when it can be most important to have confidence in prices and the market rules that govern their formation.Table 2 sets out a summary of the various impacts using data from the reference case. As with all the simulation modelling, it should not be treated as a specific forecast but rather provides an indication of broad direction of change.

Table 2: Possible competition effects from shift to 100%RE (reference case)

Segment of wholesale market	Comment	Competition effect
Base energy services	Supplier concentration may decline as wind and solar generation have relatively low technical entry barriers/scale economies, and more customers have own generation. However, will depend in part on availability of hedging products required by developers.	↑?

Daily/within week flexibility services	Supplier concentration likely to rise as fossil-fuelled stations retire. May be offset by new resources/providers, especially batteries, DSF and green peakers.	↕?
Within year flexibility services	Supplier concentration likely to rise as fossil-fuelled stations retire. May be partially offset by entry of new resources/providers, especially DSF, green peakers, other flexibility sources. Entry threat also provides some discipline as it appears hard to lift spot prices (even selectively) without increasing risk of entry by solar, wind or batteries.	↓?
Ancillary services	Supplier market concentration likely to rise for some services as fossil-fuelled stations retire, but batteries appear well placed to compete in much of this space.	↕?
Risk management products	Supplier market concentration likely to rise as fossil-fuelled stations retire. For shorter term products (within week etc) batteries could provide some competitive pressure. However, the availability of within-year seasonal products is linked to the physical supply of within year flexibility noted above.	↓?

7.142 There is insufficient information available at this stage to form any definitive views about the competition implications of shifting to 100%RE. However, in directional terms, it does seem that market concentration could materially increase for provision of seasonal flexibility services. That is because fossil-fuelled thermal plant is currently important in that area, but will cease operation under 100%RE. Furthermore, most of the seasonal hydro storage capacity is held in a handful of reservoirs. That would affect competition in the spot market and in the contract market for relevant products. Having said that, incumbent operators' ability to raise prices for flexibility services may be constrained by actual or threatened new entry by wind and solar (possibly backed by batteries). More detailed analysis would be required to come to a clearer view on these issues.

7.143 Looking further ahead, if competition were to become inadequate in some key segments of the wholesale market, remedial options would need to be considered. A spectrum of options could be considered, ranging from strengthened market conduct provisions through to contract offer obligations, virtual disaggregation or structural measures.

Key issues for wholesale market competition with 100%RE

7.144 We think the key issues in relation to competition are:

(a) What (if any) areas of the wholesale electricity market are likely experience increased supplier concentration and cause inadequate competition in the shift to 100%RE?

(b) For any areas in (a) what is the timeframe over which changes are likely to occur?

(c) What are the options for addressing competition concerns identified in (a)?

13. Do you agree that we should analyse how competition in the wholesale market is likely to be affected by a shift to 100%RE, in particular, in competition for seasonal flexibility services? If you disagree, what is your view and the reasoning for it?

Have we missed any key areas of opportunity or challenge?

7.145 The preceding sections describe the major opportunities or challenges for the wholesale electricity market that we think will arise in the shift to 100%RE. Before moving to the next stage of this project, MDAG would like to know whether any major issues have been overlooked.

14. What other key areas of opportunity or challenge (if any) will arise in the wholesale electricity market with 100%RE that are likely to have a significant impact in relation to achieving the statutory objective of the Authority, which is to “promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers”?[159]

159 Section 15, which feeds into Section 32 (on the content of the Code), of the Electricity Industry Act 2010.

Appendix A Simulation case assumptions

A.1 The table below provides a summary of the main assumptions in the reference case. Key variations for alternative sensitivity cases are as set out in paragraph 5.70.

Table 3: Main assumptions for reference case

		Reference Demand Case			Increase GW/15yrs		Increase MW/yr	
Group	Units	2020	2035	2050	2020 to 2035	2035 to 2050	2020 to 2035	2035 to 2050
Thermal	GW	0.3	0.0	0.0	(0.3)	(0.0)		
Cogen	GW	0.3	0.0	0.0	(0.3)	-		
HydroRR	GW	0.6	0.6	0.6	-	-		
Hydro	GW	4.5	4.5	4.5	-	-		
Geo	GW	1.3	1.4	1.8	0.2	0.4	10	24
Wind	GW	1.3	3.5	6.2	2.2	2.7	150	181
Solar	GW	0.0	1.7	4.0	1.7	2.3	116	151
Rooftop PV	GW	0.4	1.3	2.4	0.9	1.1	63	76
Peaker (Gas - Green)	GW	0.6	0.7	0.9	0.1	0.2	7	13
Grid 5-12hr Battery	GW	0.1	0.2	0.9	0.1	0.8	3	50
Loadshift 5hr (EV charging)	GW	0.0	0.4	1.0	0.4	0.6	26	38
Distributed Battery (3hr) with solar	GW	0.1	0.4	0.7	0.3	0.3	19	23
Market Response (>$700/MWh)	GW	0.4	0.6	0.8	0.2	0.2	11	13
Elastic Flexible Load (>$300/MWh)	GW	0.0	0.0	0.0	-	-		
Total Capacity	GW	9.9	15.4	23.9	5.5	8.5	5.5	3.0
Shiftable load & Batteries	% pk	3%	12%	26%				
Price Elastic Load	% pk	6%	7%	8%				
Total non-hydro grid renewable	GW	2.6	6.7	12.0	4.1	5.3	276	356
Total non_hydro renewable	GW	2.9	8.0	14.5	5.1	6.5	339	432
Total Reserves	GW	1.3	2.3	4.3	1.0	2.1	66	138

		Reference Demand Case			Increase GW/15yrs	
Group	Units	2020	2035	2050	2020 to 2035	2035 to 2050
Thermal	TWh	0.3	0.0	0.0	(0.3)	0.0
Cogen	TWh	1.2	0.0	0.0	(1.2)	0.0
HydroRR	TWh	2.2	2.2	2.1	(0.1)	(0.0)
Hydro	TWh	19.8	19.2	18.7	(0.6)	(0.5)
Geothermal	TWh	10.0	11.0	13.8	1.1	2.8
Wind	TWh	4.4	11.7	20.1	7.4	8.4
Solar	TWh	0.0	3.0	6.7	3.0	3.7
Roof PV	TWh	0.4	1.6	2.9	1.1	1.4
Peaker	TWh	0.1	0.1	0.2	(0.1)	0.2
Total Generation	TWh	38.4	48.8	64.5	10.4	15.7
Demand	TWh	35.0	48.5	64.0	13.5	15.5
Max Flexible Load	TWh	0.0	0.0	0.0	-	0.0
Flexible Load not supplied	TWh	0.0	0.0	0.0	(0.0)	0.0
Total Market response/shortage	GWh	0.0	0.5	11.4	0.5	10.9
Total Spill	TWh	2.7	4.1	6.4	1.3	2.4
% Non Renewable	%	3%	0%	0%	(3%)	0%
Pct Intermittent	%	12%	33%	46%	21%	13%
% Wind	%	11%	24%	31%	13%	7%
% Solar	%	1%	9%	15%	8%	5%
Total Emmisons	mt	1.4	1.2	1.5	(0.2)	0.3
Thermal Emissions	mt	0.9	-	-		
Geothermal Emissions	mt	0.5	1.2	1.5	0.7	0.3

Group	Units	2020	2035	2050	Increase GW/15yrs 2020 to 2035	2035 to 2050	Increase MW/yr 2020 to 2035	2035 to 2050
Thermal	GW	0.3	0.0	0.0	(0.3)	(0.0)		
Cogen	GW	0.3	0.0	0.0	(0.3)	-		
HydroRR	GW	0.6	0.6	0.6	-	-		
Hydro	GW	4.5	4.5	4.5	-	-		
Geo	GW	1.3	1.4	1.8	0.2	0.3	10	23
Wind	GW	1.3	3.5	6.2	2.2	2.7	146	183
Solar	GW	0.0	1.3	3.1	1.3	1.8	90	118
Rooftop PV	GW	0.4	1.3	2.4	0.9	1.1	63	76
Peaker (Gas - Green)	GW	0.6	0.2	0.6	(0.4)	0.4	(26)	27
Grid 5-12hr Battery	GW	0.1	0.2	1.0	0.1	0.9	3	57
Loadshift 5hr (EV charging)	GW	0.0	0.6	1.4	0.6	0.8	38	54
Distributed Battery (3hr) with solar	GW	0.1	0.4	0.7	0.3	0.3	19	23
Market Response (>$700/MWh)	GW	0.4	1.0	1.4	0.6	0.4	37	27
Elastic Flexible Load (>$300/MWh)	GW	0.0	0.4	0.6	0.4	0.2		
Total Capacity	GW	9.9	15.0	23.8	5.1	8.8	5.1	3.7
Shiftable load & Batteries	% pk	3%	14%	31%				
Elastic Load	% pk	6%	17%	20%				
Total Non-hydro grid renewable	GW	2.6	6.3	11.1	3.7	4.9	246	324
Total non_hydro renewable	GW	2.9	7.5	13.5	4.6	6.0	309	400
Total Reserves	GW	1.3	2.3	5.2	1.1	2.8	72	187

Group	Units	2020	2035	2050	Increase GW/15yrs 2020 to 2035	2035 to 2050
Thermal	TWh	0.3	0.0	0.0	(0.3)	0.0
Cogen	TWh	1.2	0.0	0.0	(1.2)	0.0
HydroRR	TWh	2.2	2.2	2.2	(0.0)	(0.0)
Hydro	TWh	19.8	19.8	19.5	0.0	(0.3)
Geothermal	TWh	10.0	11.1	13.7	1.1	2.6
Wind	TWh	4.4	11.8	20.6	7.4	8.8
Solar	TWh	0.0	2.4	5.4	2.4	3.0
Roof PV	TWh	0.4	1.6	2.9	1.1	1.4
Peaker	TWh	0.1	0.0	0.1	(0.1)	0.1
Total Generation	TWh	38.4	48.8	64.3	10.5	15.5
Demand	TWh	35.0	49.4	65.3	14.5	15.9
Max Flexible Load	TWh	0.0	3.5	5.3	3.5	1.8
Flexible Load not supplied	TWh	0.0	0.9	1.4	0.9	0.5
Total Market response/shortage	GWh	0.0	1.7	9.1	1.7	7.4
Total Spill	TWh	2.7	3.1	4.6	0.3	1.5
% Non Renewable	%	3%	0%	0%	(3%)	0%
Pct Intermittent	%	12%	32%	45%	20%	13%
% Wind	%	11%	24%	32%	13%	8%
% Solar	%	1%	8%	13%	7%	5%
Total Emmisons	mt	1.4	1.2	1.5	(0.1)	0.3
Thermal Emissions	mt	0.9	-	-		
Geothermal Emissions	mt	0.5	1.2	1.5	0.7	0.3

Group	Units	Low Demand Response Case 2020	2035	2050	Increase GW/15yrs 2020 to 2035	2035 to 2050	Increase MW/yr 2020 to 2035	2035 to 2050
Thermal	GW	0.3	0.0	0.0	(0.3)	(0.0)		
Cogen	GW	0.3	0.0	0.0	(0.3)	-		
HydroRR	GW	0.6	0.6	0.6	-	-		
Hydro	GW	4.5	4.5	4.5	-	-		
Geo	GW	1.3	1.4	1.8	0.2	0.4	10	24
Wind	GW	1.3	3.7	6.4	2.4	2.7	160	181
Solar	GW	0.0	1.5	3.8	1.5	2.3	99	151
Rooftop PV	GW	0.4	1.3	2.4	0.9	1.1	63	76
Peaker (Gas - Green)	GW	0.6	0.3	0.9	(0.3)	0.6	(20)	40
Grid 5-12hr Battery	GW	0.1	0.3	1.3	0.2	1.0	13	67
Loadshift 5hr (EV charging)	GW	0.0	0.2	0.5	0.2	0.3	12	19
Distributed Battery (3hr) with solar	GW	0.1	0.2	0.4	0.1	0.2	6	11
Market Response (>$700/MWh)	GW	0.4	0.4	0.6	(0.0)	0.1	(1)	9
Elastic Flexible Load (>$300/MWh)	GW	0.0	0.0	0.0	-	-		
Total Capacity	GW	9.9	14.4	23.1	4.6	8.7	4.6	4.1
Shiftable load & Batteries	% pk	3%	9%	21%				
Elastic Load	% pk	6%	5%	5%				
Total Non-hydro grid renewable	GW	2.6	6.6	11.9	4.0	5.3	269	356
Total non_hydro renewable	GW	2.9	7.9	14.4	5.0	6.5	332	433
Total Reserves	GW	1.3	1.4	3.6	0.2	2.2	11	146

Group	Units	Low Demand Response Case 2020	2035	2050	Increase GW/15yrs 2020 to 2035	2035 to 2050
Thermal	TWh	0.3	0.0	0.0	(0.3)	0.0
Cogen	TWh	1.2	0.0	0.0	(1.2)	0.0
HydroRR	TWh	2.2	2.2	2.1	(0.1)	(0.0)
Hydro	TWh	19.8	19.2	18.7	(0.6)	(0.5)
Geothermal	TWh	10.0	11.0	13.8	1.0	2.8
Wind	TWh	4.4	12.2	20.5	7.9	8.3
Solar	TWh	0.0	2.6	6.3	2.6	3.7
Roof PV	TWh	0.4	1.6	2.9	1.1	1.4
Peaker	TWh	0.1	0.0	0.2	(0.1)	0.2
Total Generation	TWh	38.4	48.8	64.6	10.5	15.8
Demand	TWh	35.0	48.5	64.0	13.5	15.5
Max Flexible Load	TWh	0.0	0.0	0.0	-	0.0
Flexible Load not supplied	TWh	0.0	0.0	0.0	(0.0)	0.0
Total Market response/shortage	GWh	0.0	4.7	11.0	4.7	6.3
Total Spill	TWh	2.7	4.1	6.5	1.4	2.3
% Non Renewable	%	3%	0%	0%	(3%)	0%
Pct Intermittent	%	12%	34%	46%	21%	12%
% Wind	%	11%	25%	32%	14%	7%
% Solar	%	1%	9%	14%	7%	6%
Total Emmisons	mt	1.4	1.2	1.5	(0.2)	0.3
Thermal Emissions	mt	0.9	-	-		
Geothermal Emissions	mt	0.5	1.2	1.5	0.7	0.3

Appendix B Format for submissions

Submitter:	

	Question	Page references	Comment
1	Do you agree with the broad conclusions that emerge from the simulations in relation to spot price levels and volatility, in particular: (a) significantly more spot price volatility is likely with a 100%RE system, especially shorter-term weather-driven volatility? (b) New Zealand's sizeable hydro generation base is likely to moderate the growth in volatility to some extent, making extreme oscillations between zero and shortage spot prices relatively unlikely?	p18, p61	
2	If you disagree, what is your view and the reasoning for it?	p18, p61	
3	Do you agree that in a 100%RE system there will be many diverse and disaggregated resources to coordinate, and that a wholesale market will be the preferred mechanism to coordinate plans and actions among all the resource owners? If you disagree, what is your view and the reasoning for it?	p18, p65	
4	Do you agree that these are the key issues in relation to real-time coordination? If you disagree, what is your view and the reasoning for it?	p20, p69	
5	Do you agree that these are the key issues in relation to ancillary services with 100%RE? If you disagree, what is your view and the reasoning for it?	p21, p74	

	Question	Page references	Comment
6	Do you agree that these are the key issues in relation to price signalling with 100%RE as summarised in paragraph 3.42 above? If you disagree, what is your view and the reasoning for it?	p24, p88	
7	Do you agree that the preconditions in paragraph 3.38 would need to be in place for an energy-only market design to be effective? If you disagree what is your view and the reasoning for it?	p24, p88	
8	Do you agree that we should take forward to the next stage of the process (options identification and analysis) the measures referred to in paragraph 3.43 above? If you disagree, what is your view and the reasoning for it?	p24, p88	
9	Do you agree that these are the key issues in relation to demand-side flexibility with 100%RE? If you disagree, what is your view and the reasoning for it?	p25, p93	
10	Do you agree that these are the key issues in relation to contracts markets with 100%RE? If you disagree, what is your view and the reasoning for it?	p26, p98	
11	Do you agree that these are the key issues in relation to transition to 100%RE? If you disagree, what is your view and the reasoning for it?	p28, p102	
12	Are there any other 'lumpy' issues that warrant specific consideration in the transition to 100%RE?	p28, p102	
13	Do you agree that we should analyse how competition in the wholesale market is likely to be affected by a shift to 100%RE, in particular, in competition for seasonal flexibility services? If you disagree, what is your view and the reasoning for it?	p29, p104	

	Question	Page references	Comment
14	What other key areas of opportunity or challenge (if any) will arise in the wholesale electricity market with 100%RE that are likely to have a significant impact in relation to achieving the statutory objective of the Authority, which is to “promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers”?	p29, p104	