Price discovery in a renewables-based electricity system

FINAL RECOMMENDATIONS PAPER

MARKET DEVELOPMENT ADVISORY GROUP

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Acknowledgements

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Stakeholder input and external experts

Our project has benefited greatly from the input of stakeholder submissions (in writing and in person) and from external experts in New Zealand and overseas. We would like to thank all stakeholders and experts for their engagement and input into this project.

Report aims to be self-contained

This Recommendations paper builds on work in our earlier Issues and Options papers. However, this third report is written on the assumption that readers may not have read, or have only limited recall of, our previous papers. Seeking to be relatively self-contained, this final report therefore sets out the 'back-story' and building-blocks from the first and second reports before setting our conclusions and recommendations. For ease of reference, key parts of our earlier work are hyperlinked in the body of this report.

ELECTRICITY AUTHORITY
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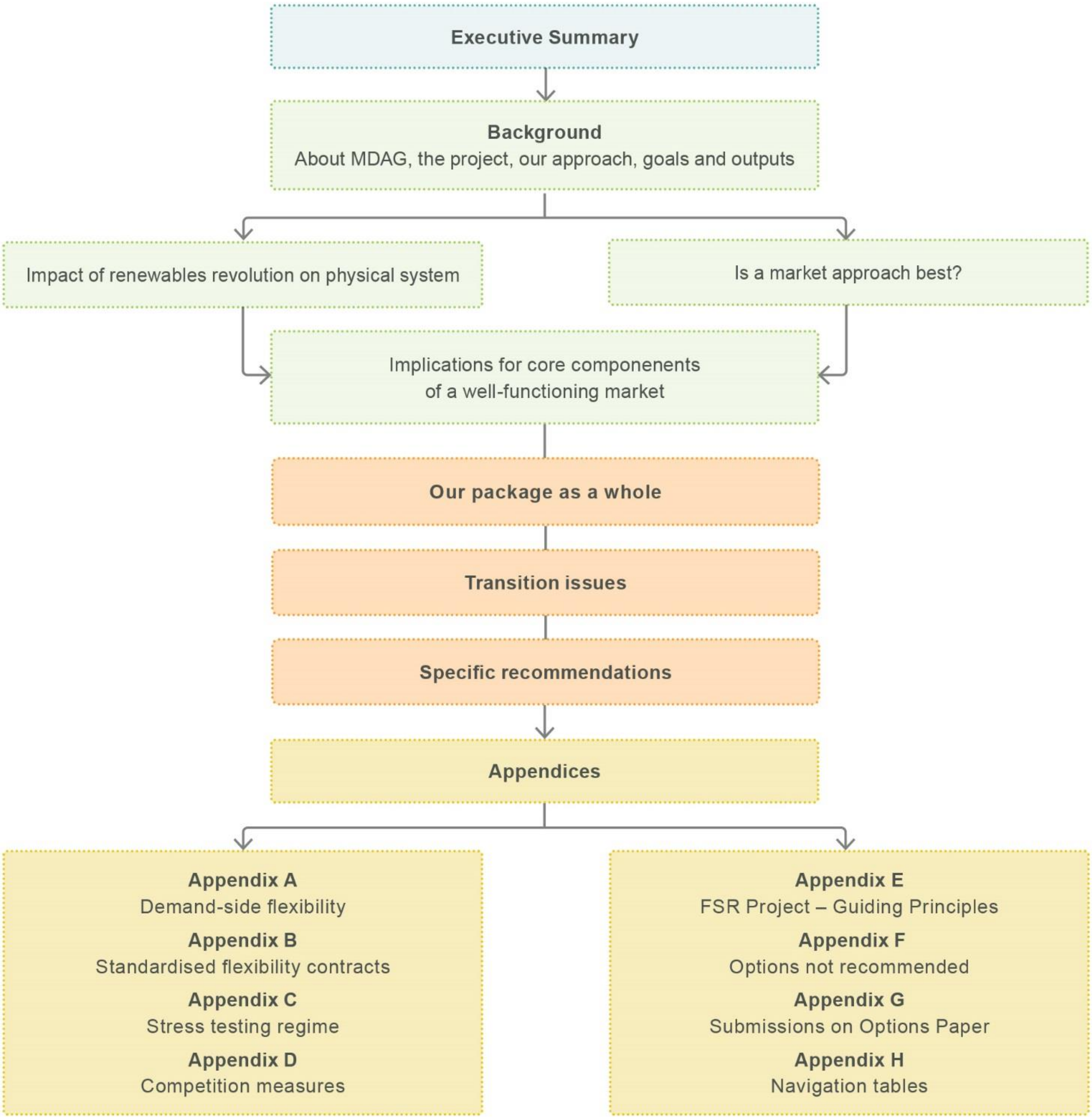
Structure of this paper



SUMMARY OF MARKET DEVELOPMENT ADVISORY GROUP FINAL RECOMMENDATIONS PAPER

A wholesale market remains the best way to ensure New Zealand's electricity is clean, reliable and available at the lowest possible cost…

1 OVERARCHING GOAL

Generate and deliver clean, reliable electricity to meet demand at lowest possible cost to consumers

2 Effective wholesale electricity market

3

Key pillars of a well-functioning wholesale electricity market

1. Our goal is to generate and deliver clean, reliable electricity at lowest possible cost to consumers.
2. A wholesale electricity market remains the best tool for discovering the lowest cost sources of supply to match demand in real time and future periods.
3. An effective wholesale market requires four key pillars to be in place.

…but pressures associated with electrification and decarbonisation of the economy are challenging the existing wholesale market design…

4 PHYSICAL CHANGES		5 IMPLICATIONS FOR WHOLESALE MARKET DESIGN
Huge increase in demand (50%+ by 2050)	→	Contract market must provide clearer and more timely signals about investment needs
Supply base much more weather-dependent	→	Participants need better tools to manage risks associated with increased spot price volatility
Bigger, more complex system to coordinate	→	Spot prices must provide clearer signals to coordinate system in real time
Thermal closures may reduce competition	→	Proactive measures needed to safeguard competition – especially for flexible supply
Technology enables demand side flexibility	→	Market rules must make it easy for consumers to reap benefits of providing demand side flexibility
Transmission grid no longer the sole market 'space'	→	Need to 'connect' widely dispersed energy devices on networks to wholesale market
Innovations in electricity industry happening faster	→	Market rules must enable innovation – in technology, systems, business processes and services to customer
Higher price volatility/ transition challenges	→	Market needs to maintain public/political confidence – underpins the dynamic that delivers reliability

4. Electrification and decarbonisation of the economy are unleashing new physical forces – such as the need to rapidly expand the electricity supply base, and to swiftly integrate new participants and technologies into the electricity system.
5. Existing wholesale market design is struggling to respond to some of these forces because it wasn't built with new electricity system in mind.

…the wholesale market design needs beefing up in key areas so it can fully support New Zealand's electrification and decarbonisation ambitions

6 PACKAGE OF 31 MEASURES* FOR IMPLEMENTATION OVER FOUR YEARS

* These measures are not a 'buffet' to choose from. They form an integrated package to be implemented as a sustained and coordinated programme of action over the coming four years. A few are 'backup' to be used if earlier actions are not sufficiently effective. All measures contribute to all four pillars.

7 **TRANCHE 1** (Action in 2024)
- 5 measures to improve price signals
- 6 measures to improve risk management tools
- 2 measures to strengthen competition
- 2 measures to lift public confidence

Examples:
- Improve short-term wind/solar/ demand forecasts
- Strengthen stress testing regime
- Publish seasonal outlook reports

8 **TRANCHE 2** (Action in 2025+)
- 6 measures to improve price signals
- 3 measures to lift public confidence

Examples:
- Raise consumer awareness of DSF benefits
- Enhance market monitoring
- Improve information on investment pipeline

9 **TRANCHE 3** (Action in 2026+)
- 4 measures to improve price signals
- 1 measure to improve risk management tools
- 1 measure to strengthen competition
- 1 measure to lift public confidence

Examples:
- Introduce 'ahead' market (contingent measure)
- Enact virtual disaggregation (contingent measure)

6. A package of measures is needed to beef up the wholesale market.
7. Tranche 1 covers 15 immediate measures to address pressing issues. Some are partially underway but should be expanded or accelerated.
8. Tranche 2 covers 9 measures to be actioned as soon as practical.
9. Tranche 3 covers 7 measures that are all (except for 1) contingent on earlier work or 'backstops' if earlier measures are not sufficient.

Getting the work done will require commitment and resourcing by the Electricity Authority and the industry

Contents

1. Executive summary[1]

Preparing for a renewables-based electricity system

1.1 New Zealand's electricity system is on the brink of a massive transformation. Demand is set to grow by 50% or more as New Zealanders increasingly switch from fossil fuels to electricity for their transportation and heating needs. A massive expansion of new renewable generation will be needed to meet the growing demand and replace less efficient fossil-fuelled generation. And technology advances are making it easier for new players (including households) to provide generation, energy storage or demand response services.

1.2 As part of its future-focused work, in June 2021 the Electricity Authority asked MDAG to investigate and report on changes needed to New Zealand's wholesale electricity market to facilitate the shift to a renewables-based electricity system. **This report sets out our findings and final package of recommendations for the Authority**.

1.3 Our investigation has been very thorough. We interacted extensively with New Zealand stakeholders and many overseas experts in undertaking the project. Our initial findings were set out in an Issues Paper released in early 2022, and this was followed by an Options Paper released in late 2022. We held briefing sessions for stakeholders on both documents and received written submissions from many parties. Our work has benefited greatly from the thoughtful submissions and support received from stakeholders, and we would like to thank them for their engagement.

Our project in the wider electricity picture

1.4 While the wholesale market is a central piece of the overall electricity picture, the success of New Zealand's electricity system in a renewables-based world also depends on several other key factors:

(a) Resource consenting processes for generation, energy storage and network infrastructure must enable the timely and efficient build of new infrastructure, otherwise supply may not keep up with rapidly growing electricity demand.

(b) Carbon pricing rules need to be clear and predictable, as they are the primary tool to drive decarbonisation decisions within the electricity sector and across the wider economy.

(c) Fuel sector arrangements have a critical influence on electricity generation costs and reliability. It is vital that the policy frameworks for both fossil and green fuels recognise the critical role these fuels play in the electricity sector.

(d) Network investment rules need to support the timely development of the national grid and distribution networks, while also safeguarding the interests of the consumers who ultimately pay for those investments.

(e) Retail market competition must be effective to ensure consumers fully benefit from the opportunities available in the future electricity system.

Clean, reliable, and least cost power

1.5 Our electricity system should produce reliable power at the lowest possible cost for the long-term benefit of consumers, as well as meeting society's environmental objectives. This is the energy trilemma – reliability, lowest cost and sustainability.

1 For brevity, sources for quotations and documents cited in this summary are not shown. See main body of paper for information on sources.

1.6 Environmental objectives are defined outside the electricity sector, via laws such as those covering consenting arrangements and the Emissions Trading Scheme. The goal for electricity sector arrangements is to provide power at the lowest possible cost while maintaining reliable supply to consumers and meeting environmental goals. This goal has guided the development of all of the recommendations in this report.

Do we still need a wholesale electricity market?

1.7 Before considering possible changes to the wholesale electricity market, we asked whether a market is needed at all. After all, our wholesale market was designed 30 years ago for a system that was strongly influenced by fossil fuel generation. Perhaps it is time to consider alternatives with more centralized decision-making.

1.8 After careful consideration of the options, including experiences in other countries, our conclusion is that a wholesale market is the best approach for the future. This assessment is based on three key factors:

(a) Harnessing innovation will be critical to meeting New Zealand's electrification goals. A well-structured wholesale market is the best platform to spur and deploy such innovation.

(b) Changes in technology make it technically feasible for new types of players (including households) to provide generation, energy storage and demand response services. It would be very hard (if not impossible) for these new players to participate commercially in the future system without a wholesale market platform.

(c) Competition is the most reliable way to put downward pressure on costs and prices – because suppliers with the best solutions win more customers (and vice versa). A wholesale market remains the best platform to enable competition.

Market approach enables competition

"The market is a way of discovering the lowest cost price. When I was power planning engineer, there was one decision-maker about the future of our power system. Now we've got thousands of decision-makers and if someone finds an innovation, they're in there like a robber's dog – and that's fantastic"

Dr Keith Turner
Transpower Chairman

1.9 Our preference for retaining a wholesale electricity market reflects an assessment of practical rather than philosophical considerations – just as households might prefer those cats that are best at catching mice, irrespective of whether they are black or white. This preference for a market approach appears to be shared by many leading international experts and regulators. For example, we understand the European Union Agency for the Cooperation of Energy Regulators has been leaning towards this model.

Current wholesale electricity market design needs to be beefed up

1.10 However, electricity market design is not static. Before outlining the upgrades required for our market, it is useful to briefly describe the four pillars of a well-functioning wholesale electricity market:

(a) **Accurate (efficient) prices** – prices must accurately signal the value of an additional unit of electricity in the short, medium and longer term at different locations, including allowing for high prices to signal scarcity when required. In effect, these marginal prices become targets that market participants are competing to beat.

(b) **Tools and incentives to manage risk** – market participants must have access to tools to efficiently manage their risks. These tools can be physical options (e.g. an ability to increase supply or reduce demand) or financial arrangements where parties contract with others who can manage the underlying risk at a lower cost on their behalf.

(c) **Sufficient competition** – there must be sufficient competition among market participants such that no party has the means and incentive to exercise significant market power.

(d) **Public and political confidence** – there is a particular need for:

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

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

(iii) confidence among consumers and politicians that investment will be timely and competitive; and

(iv) confidence in the rule maker and rule making process to create an efficient platform for processing information and coordinating actions among many electricity suppliers and consumers.

Impact of renewable transformation on existing wholesale market design

1.11 Those four pillars are foundations of our existing wholesale market design – however, they need to be significantly strengthened to meet the physical changes and challenges associated with the shift to a renewables-based system. These physical changes and associated challenges are summarised in Figure 1.

Figure 1: Physical system changes and challenges for wholesale market design

Huge increase in demand (50%+ by 2050)	→	Contract market must provide clearer and more timely signals about investment needs
Supply base much more weather-dependent	→	Participants need better tools to manage risks associated with increased spot price volatility
Bigger, more complex system to coordinate	→	Spot prices must provide clearer signals to coordinate system in real time
Thermal closures may reduce competition	→	Proactive measures needed to safeguard competition – especially for flexible supply
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1.12 First, massive investment is needed to meet rising power demand. We estimate that $27-$37 billion of new investment in new demand-side flexibility (DSF), batteries and generation will be needed by 2050. There is a big payoff from making the right investments at the right time and place. This is where the contract market has a critical role to play. It needs strengthening to send clearer investment signals. In particular, it must provide more granular signals about the benefits of investment in flexibility – on both the demand- and supply-side of the system.

1.13 Second, our system will be more sensitive to the weather. This is a natural consequence of relying more heavily on solar and wind generation. Spot prices will become more volatile (with both low and high prices more common). We should not try and mask the effect of weather on spot prices, but we do need to make sure participants have access to the necessary tools to manage and mitigate increased spot price volatility. Political and public acceptance of increased spot price volatility is also fundamental for wholesale market participants to properly manage their risks.

1.14 Third, there will be a big increase in the number of active participants on the system, as many more parties (and devices) connect to the system as suppliers, storage providers or flexible users. We liken this change to moving from a string quartet to a full orchestra. A conductor is needed to coordinate this orchestra, and the most practical solution is the spot market. But the spot market will need to work harder than before to provide the signals required to coordinate actions across the entire grid.

1.15 Fourth, we will rely much more on the hydro generation system for flexibility as existing fossil-fuelled generation winds down. This increased reliance on flexible hydro generation may significantly weaken competition in some key areas of the wholesale market. We need to guard against that outcome and have measures at hand to address that risk if it appears to be crystallising.

1.16 Fifth, technology changes in metering, sensors and data processing are making it much easier for consumers (or their devices) to actively vary their demand. It is imperative that the wholesale market design facilitates full engagement by consumers who want to reap the rewards from active demand response.

1.17 Sixth, the wholesale electricity market ‘boundary’ has traditionally matched the geographical footprint of the transmission grid, with limited reach into distribution networks. However, with increasing numbers of active participants and devices being located within distribution networks, new wholesale market tools/processes will be needed to enable tighter optimisation across the nation’s electricity networks – irrespective of their classification as transmission or distribution assets.

1.18 Seventh, innovation in technology and business models is expected to accelerate as the world embarks on a quest to electrify much of its energy demand. It is vital to ensure that New Zealand’s wholesale market arrangements remain open to technical and commercial innovations where these provide benefits to consumers.

1.19 Finally, these physical changes to the system are already happening. Spot price volatility has stepped up and the renewables transition is underway. New Zealand needs to work at pace to strengthen the wholesale market so it can deliver clean, reliable power at least cost to consumers, and maintain public and political confidence.

We need WEM 2.0

New Zealand’s current wholesale electricity market (WEM) was designed in the mid-1990s and can be thought as ‘version 1.0’.

A step change is required to adapt the market’s design to meet the challenges of a high-renewables world.

Our recommendations set out the blueprint to deliver ‘version 2.0’ – an updated design to deliver reliable, renewable electricity at lowest cost for the long-term benefit of consumers into the future.

Recommended package of measures

1.20 We are recommending an integrated package of 31 actions to update the design of the wholesale electricity market. Each measure is described in more detail in Chapter 9.

1.21 Our recommended package is both sizeable and demanding in its timeline – but this simply reflects the volume and pace of work required to equip the wholesale market so it can do its job well in delivering a renewables-based system.

1.22 At a practical level, we recommend the package should be implemented in three tranches:

(a) Tranche 1 comprises measures that are required urgently – to address issues already arising, to support a smooth transition, or to lay the foundation for later work;

(b) Tranche 2 comprises measures that are also important, but which can be prioritised behind those in Tranche 1 based on current information; and

(c) Tranche 3 comprises measures that are recommended, but implementation can come after Tranche 2.

1.23 Some of the recommended measures are *contingent* on the effectiveness of prior actions. In particular, we are recommending a progressive set of measures to safeguard competition in the provision of flexible supply contracts (see Appendix D for a full description).

1.24 In the sections following, we briefly describe each recommended measure. All recommended measures contribute to all four pillars of the wholesale market (accurate prices, tools to manage risks, competition and public confidence). For the purposes of grouping, however, each measure is sorted by the pillar to which it contributes with more emphasis.

Accurate price signals – spot and contract markets

Why it matters

1.25 Accurate price signals act as the musical conductor for the electricity market. With a much greater range of players and more physical resources to coordinate, it is even more important for price signals to be accurate and clear. Upgrades are required to information inputs for price discovery processes, in both the spot and contract markets. Improvements are also required in the pricing processes themselves. To this end, we recommend the following actions to strengthen accurate price signals.

Tranche 1 as it relates to accurate prices

1.26 There are five accurate pricing measures for urgent implementation in Tranche 1:

(a) **Short-term forecasts** *(Recommendation 1)* -- Improve short-term forecasts of wind, solar, and demand. This will provide better information for decision-makers leading into real-time. Accuracy in these forecasts is critical to help participants make good decisions about things like when to charge/discharge batteries, utilise flexible generation or undertake demand response. Making good decisions in these areas will help to minimise system costs and maintain reliable supply. The Authority is already working to improve the accuracy of solar and wind generation forecasts – the work should continue and be accelerated if possible.

(b) **Hedge market transparency** *(Recommendation 2)* – Improve transparency of hedge market activity (especially non-baseload contracts). Where practical, enhanced disclosure should include information on contract offers and bids, as well as executed contracts. This measure is urgent because it addresses challenges that are already emerging in the transition to a renewables-based system. Making that information more transparent will help potential buyers and providers of those products with their risk management and investment decisions. The Authority is already working on this measure – it should continue and be accelerated if possible.

(c) **Demand-side flexibility (DSF) activity monitoring** *(Recommendation 3)* – Monitor provision and uptake of DSF-rewarding activity (including tariffs) and publish a DSF scorecard. Empirical evidence of trends over time in development and consumer uptake of DSF tariffs is critical and to date is largely absent. As detailed in Appendix A, this action combines with a range of other measures to deliver an integrated strategy for DSF.

(d) **Pricing to optimise distribution investment** *(Recommendation 4)* – Authority and Commerce Commission to work together to do more to cause more widespread and sooner use of efficient pricing signals for flexibility on distribution networks. If possible, use (or *enable* use of) the Part 4 regime for this purpose. Progress towards pricing structures that signal distribution network needs has been slow and so pricing signals to consumers considering DSF investment are likely to understate its potential to lower network costs.

(e) **Price-driven secure distribution dispatch** *(Recommendation 5)* – Establish a significant multi-year project to develop an efficient form of security constrained economic dispatch (SCED) on distribution networks for the purpose of 'integrating' into the wholesale market widely dispersed DSF and other distributed sources of 'supply'. As a market design exercise, this should be led by the Authority and overseen by a small, enabling group that brings in expert perspectives that span wholesale market design, distribution, transmission, and system operation.

Tranche 2 as it relates to accurate prices

1.27 There are six accurate pricing measures for implementation in Tranche 2:

(a) **Scarcity pricing parameters** *(Recommendation 16)* – Update the security standard and associated settings for the spot market to ensure they properly reflect the value of reliability to consumers. These have not been updated for many years. In addition, consider indexing shortage values (like Australia) and undertake further updates where required. If the parameters are set too low, the system will be less reliable than consumers want (and vice versa).

(b) **Information on development pipeline** *(Recommendation 17)* – Collate and publish comprehensive and regular updates on the demand trends and outlook, project development pipeline, and projected energy/capacity margins. Participants need better information about the supply and demand outlook to make high quality contracting and investment decisions. Transpower's connection enquiry dashboard has significantly improved the visibility of generation and load projects (and so this recommendation is not so urgent as to be put in Tranche 1). However, there are still some significant information gaps.

(c) **Sunset profiling** *(Recommendation 18)* – Change the Code to require use of half-hourly metering data rather than default demand profiles if smart meters are in place. Default profiles are still used for ~40% of users even though 90% of connections have half-hourly metering capability. Continued use of default profiles seriously diminishes incentives to offer and use DSF-rewarding tariffs.

(d) **Network capacity in DSF dispatch** *(Recommendation 19)* – Make Code changes to amend the Default Distributor Agreement (DDA) to require coordination protocols in relation to distribution system limits. This is an interim measure pending development of an efficient form of price-driven secure distribution dispatch *(Recommendation 5)*.

(e) **Consumer awareness of DSF** *(Recommendation 20)* – Increase consumer awareness of the opportunities and benefits from providing DSF to the wholesale market, which is low. The Energy Efficiency and Conservation Authority (EECA), tariff comparison providers and the Authority all have roles to play.

(f) **Market-making for flexibility products** *(Recommendation 24)* – This action is *contingent* on assessing whether previous measures are sufficiently effective, as explained further in Appendix D.

Tranche 3 as it relates to accurate prices

1.28 There are four accurate pricing measures for implementation in Tranche 3. These are all *contingent*:

(a) **Undesirable Trading Situation (UTS) over-ride** *(Recommendation 26)* – Remove the UTS over-ride of trading conduct provisions, *subject to* the trading conduct provisions continuing to perform satisfactorily. Participants' reliance on spot price signals is likely to be compromised if they believe there is significant chance that prices could be revised after the time they apply, particularly for 'last resort' supply when spot prices are high but accurate.

(b) **Ahead market** *(Recommendation 27)* – Investigate and put in place an ahead market *if on review* in 2027 it becomes apparent that adding an ahead market would likely yield significant net benefits. This would be a major change and needs to be considered carefully before any implementation steps are taken.

(c) **Market making for longer-dated futures** *(Recommendation 28)* – Enhance price discovery by requiring market making for longer dated futures. A longer forward curve would help parties facing investment and/or retirement decisions. Putting this measure in place is contingent on *first assessing* whether previous actions have been sufficiently effective.

(d) **Negative offers/prices** *(Recommendation 29)* – Investigate negative offers/prices in the wholesale market as a tool to manage temporary periods of oversupply, *if on review* in 2027 it becomes apparent that the current spot market process could be significantly improved (with benefits greater than costs) by allowing negative offers/prices.

Tools to manage risks

What we mean by 'tools' and why they matter

1.29 Market participants need access to tools to efficiently manage their risks. These tools can be physical options (e.g. an ability to increase supply or reduce demand) or financial arrangements where parties contract with others who can manage the underlying risk at a lower cost on their behalf. Effective risk management of spot price volatility also includes demand-side flexibility (DSF). More intermittent supply will make increased DSF particularly valuable.

1.30 The contract market plays two vital roles. First, it provides products that wholesale buyers and suppliers can use to manage their exposure to spot price risks. The contract market's second critical function is to provide signals to guide longer term decisions – especially investment in generation, storage and demand-side capability.

1.31 We are moving into a world where the electricity system will be much more sensitive to weather effects and participants will need better tools to manage the resulting spot price volatility and associated risks.

1.32 To this end, the contract market must be strengthened so it can do more of the heavy lifting in future. In particular, the market for 'flexibility contracts' needs to develop significantly (see side-box for description of flexibility contracts).

1.33 This finding is based on a range of qualitative and quantitative work, which is set out in our Options Paper. For example, we looked at whether the availability and liquidity of hedge products – especially flexibility contracts – will be sufficient to allow parties to workably manage risk in a renewables-based system.

1.34 Another critical conclusion is that consumers can play a much greater role as a source of flexibility to the system – by shifting their demand in time, or by altering their total demand depending on system conditions. This will bring benefits for consumers (lower bills) and for the system (more resilience). We recommend a range of measures to activate the demand-side market, as explained further in Appendix A.

What is a flexibility contract?

A flexibility contract (or product) is the term we use to describe a hedge contract that provides the buyer with protection against high spot prices at specific times – such as when intermittent supply is low and/or demand is especially high. This type of contract is expected to become increasingly important in future because it can be used to 'firm' the output of intermittent supply sources, such as wind or solar, that are expected to account for the lion's share of new supply.

We also called this a 'shaped product' in the Issues and Options Papers, because it contrasted with baseload or 'flat' contracts that have the same price mitigation effect in every half hour period.

1.35 Third, we recommend new tools be introduced or explored to reflect the system's changing physical characteristics.

Tranche 1 as it relates to tools

1.36 There are six measures for urgent implementation relating to 'tools' in Tranche 1:

(a) **New reserve product** *(Recommendation 6)* – Develop a new reserve product to cover sudden supply reductions from intermittent sources. This new product should harness the full range of potential resource providers including batteries and demand-side flexibility, be co-optimised with the wider spot market and conform to causer-pays principles. We understand the Authority is working on the design of a new ancillary service product – this work should continue as a priority issue.

(b) **Stress testing** *(Recommendation 7)* – Change the Code to enhance the stress test as recommended in the 'blueprint' set out in Appendix C. Our proposed changes reflect the existing core philosophy that participants must decide their own risk appetite and preferred risk management strategies. The aim of the change is to reinforce participants' incentives to actively manage their exposure to spot price risk, which (in aggregate) underpins the provision of adequate physical resources to ensure reliable supply.

(c) **New flexibility products (standardised)** *(Recommendation 8)* – By a co-design process with the industry, develop one or more standardised flexible supply contracts using the framework set out in Appendix B as a base. Forward price discovery, and hedging for flexible supply and DSF products, are critical market functions in a renewables-based world, and both are impeded by the lack of any standardised flexibility product(s). Flexibility contracts are expected to become the market's 'secret sauce', enabling a range of wholesale market processes to function effectively.

(d) **Contract process disclosure rules** *(Recommendation 9)* – Develop rules requiring disclosure of process steps by parties negotiating over-the-counter (OTC) contracts.

(e) **DSF interface systems and protocols** *(Recommendation 10)* – Develop a range of new standards and protocols[2] to enable efficient interface among the chain of participants in the DSF market.[3]

(f) **FSR Project as it relates to demand-side flexibility (DSF)** *(Recommendation 11)* – Future Security and Resilience (FSR) project to bring forward the priority of improving visibility of DSF for the System Operator and remove Code barriers to DSF offering ancillary services. As explained elsewhere, the DSF 'market' will be vital in a renewables system to ensure lowest cost reliable supply for consumers. How this measure fits into our recommended approach to DSF overall is explained more fully in Appendix A.

Tranche 3 as it relates to tools

1.37 There are no measures relating to 'tools' in Tranche 2 but there is one *contingent* action in Tranche 3 – namely, **'Last resort' demand-side flexibility (DSF) scheme** *(Recommendation 29)*, which calls for a procurement process for 'last resort' DSF.

Ensuring adequate competition

Why it matters

1.38 Competition is fundamental to finding and supplying the least cost way of reliably meeting the next increment of demand. As the Commerce Commission explained: "Competitive behaviour is a dynamic process – one that emerges from the rivalry of market participants". It is a process the puts downward pressure on costs and prices, particularly by promoting continuous improvement and innovation. In the words of the High Court: "The practical context is the existence of sufficient rivalry between firms (sellers) to push prices close to efficient costs".

2 This includes System Operator visibility of DSF activity, communications protocols and standard market contract templates.

3 This includes DSF provider (consumer), retailer / flex-trader, distribution, transmission, and System Operator.

1.39 Adequate competition can be difficult to achieve in electricity markets. However, as Michael Hogan observes:

> "Ensuring competition is a non-negotiable prerequisite for the market in general, much less for proper energy price formation"

Measures for competition in general

1.40 Pursuing the competition goal has permeated all of our work. We believe competition needs to be 'designed into' market arrangements – not treated as an add-on. That thinking underlines many of the recommendations we have already described. For example:

(a) *Recommendations 3-5, 8, 10-11, 18-20 and 30* will promote greater demand-side flexibility, strengthening competitive disciplines in the spot and contract markets.

(b) *Recommendation 2* will improve information about hedge contract terms and prices and promote competition in the contract market. Improved information on the supply and demand development pipeline under *Recommendation 17* will help competition in new investment and related hedging decisions.

(c) Similarly, *Recommendation 9* will make it harder for any supplier to limit competition via process obstacles or unreasonable non-price terms by increasing transparency of behaviour by parties seeking to agree OTC contracts (rather than mandating contracting terms/practices).

Risk of less competition in flexible supply

1.41 While ensuring adequacy of competition has been a broad motivation, we have given special consideration to one particular area of the wholesale market. Analysis in the Issues Paper and the Options Paper highlighted the potential for a thinning of competition in the provision of flexibility contracts covering periods of a week or longer. This is because a sizeable slice of this flexibility comes from fossil-fuelled generation, and this is expected to progressively shrink.

1.42 New sources of flexibility are likely to emerge over time – such as flexible demand sources, pumped hydro storage, or biofueled thermal operation. Nonetheless, a significant thinning of competition in the provision of longer duration flexibility products is possible because much of the existing physical capacity to back such products is held by parties with the major flexible hydro schemes. Analysis in the Options Paper showed that larger generators with substantial flexible hydro bases may well have greater means and incentive to exercise market power in the supply of flexibility products as thermal generation declines.

1.43 A thinning of competition for flexibility products could tear at the fabric of the broader market. That is because flexibility products provide a critical bridge to integrate intermittent supply into products suitable for retail consumers. Put simply, weaker competition for flexibility products could also undermine competition in the retail and new investment markets.

1.44 Although our analysis cannot be determinative because of uncertainties about the future, it highlights a risk that we think cannot be ignored. Our view is that the risk of declining competition for longer-duration flexibility contracts must be proactively managed – rather than adopting a 'wait and see' approach.

Measures for competition in flexible supply

1.45 As noted earlier, we are recommending a progressive chain of actions for competition in flexible supply where implementation of the next action in the chain depends on whether the previous actions are sufficiently effective in practice. It is, in essence, a three-step ladder, with progression between the steps determined by assessing a dashboard of competition indicators.

Tranche 1 measures for competition

1.46 There are two measures in Tranche 1 as it relates to competition in flexible supply. As explained below, *Recommendation 8* (standardised flexibility products), which is described under 'Tools to manage risk' above, is also a key element on the first rung of the step ladder.

(a) **Competition dashboard** *(Recommendation 12)* – Authority to develop dashboard of competition indicators for flexibility segment of the wholesale market. Indicators could include: (i) the availability and pricing of standardised flexibility products, (ii) availability and pricing of non-standardised flexibility products – such as 'sleeves' or other firming contracts, (iii) the extent to which independent generators and retailers are able to access flexibility products of reasonable terms from the market, and (iv) the extent of actual or planned entry or exit by providers of flexibility – such as biofueled generators or demand response providers.

(b) **Virtual disaggregation – high level outline** *(Recommendation 13)* – Develop a high level outline of 'virtual disaggregation' *(Recommendation 31)*, to 'put in the drawer' ready for use if other measures are not effective. If a structural solution is ultimately required to address competition problems in flexibility services, it should be put in place with the least possible delay. That means some initial scoping work in Tranche 1 as a precautionary step, even if it turns out structural options were not ultimately needed.

(c) **New flexibility products (standardised)** *(Recommendation 8)* – As recommended under 'Tools to manage risks' above, by a co-design process with the industry, develop one or more standardised flexible supply contracts using the framework set out in Appendix B as a base. Forward price discovery and hedging for flexible supply (including demand-side flexibility) are foundational for the wider market in a high-renewables world, and both are impeded by the lack of any standardised flexibility product(s). Flexibility contracts will become the market's 'secret sauce' enabling a range of core wholesale market processes to function effectively.

1.47 Some parties might regard it as premature to consider backstop options. We think a 'wait and see' approach would be unwise for a number of reasons. First, it will take time to design backstop options and put them in place. Waiting for a problem to fully emerge before starting that work could mean that an extended harm occurs before a solution is in place. Second, it could lead to hasty and sub-optimal solutions being implemented if a problem emerges. Third, confidence in competition is a foundational 'must have' element for an electricity market. If that confidence is not present, parties will be unlikely to invest at the pace needed to provide reliable and affordable power and there is a continual risk of government intervention.

Tranche 2 measures for competition

1.48 One of the measures in Tranche 2 – **Market making for flexibility products** *(Recommendation 24)* – is grouped under 'accurate price signals' (above). While this reflects its primary emphasis, it is also a key action on our step ladder to safeguard competition in flexible supply. As explained above, this measure is *contingent* on assessing whether previous measures are sufficiently effective. See Appendix D for more information.

Tranche 3 measures for competition

1.49 There is one measure in Tranche 3 as it relates to competition in flexible supply – namely **virtual disaggregation** of parties with undue market power in the supply of flexibility service *(Recommendation 31)*, using the outline developed in Tranche 1 under *Recommendation 13.*

1.50 Based on a range of analysis and advice (set out in paragraph 10.10 of our Options Paper and distilled in Appendix D below), our recommended approach is to first try the menu of conduct measures in Tranches 1 and 2, but then, if they are not sufficiently effective, implement virtual disaggregation. In this context, virtual disaggregation refers to the splitting of the flexible supply capability of the relevant participant(s) into two components:

(a) a portion that would be required to be offered by a defined process and on approved terms – effectively creating one or more additional sources for the supply of longer duration flexibility products; and

(b) the balance of the relevant participant's supply capability, which would remain available to them to use as they think fit.

1.51 If such a backstop measure is needed, it will likely be due to very high concentration of control of flexibility resources in the hands of very few parties, with little or no prospect that new entry or other market processes will alter that market structure in an acceptable timeframe. Put simply, it is possible that supplier concentration for longer-duration flexibility could be so great that market-making arrangements (and other tools in Tranche 2) are insufficient to address the underlying structural market power. In that case, it would be necessary to consider structural solutions to reduce that market power at its source.

1.52 This is described more fully in Appendix D.

Public understanding and confidence

Why it matters

1.53 Public and government confidence in our electricity system is foundational in enabling it to deliver reliable and clean supply at least cost for consumers. Electricity systems are quite complicated and any government's understanding of the fine detail of how they work is always likely to be relatively thin. So what matters is trust in the surrounding institutional arrangements – a sense that there are processes and expertise in place that the public and government can trust to provide the required assurance it all works the way it is supposed to, and strong guidance on how to fix problems if they emerge.

1.54 Achieving public and political confidence is highly influenced by whether there is sufficient competition and whether tools for managing spot risk are properly available, which support efficient new investment and, in turn, adequacy of supply. In this regard, the other measures recommended in this paper are fundamental for delivering public and political confidence in the wholesale market. The measures outlined below are focused on improving public information and understanding, working in conjunction with those other measures.

1.55 Public information is also essential. It must be neutral, clear, timely and relevant for consumers, so it can improve the public understanding of what to expect from our electricity system (about both quality and price) and opportunities for consumers to get better value.

Tranche 1 as it relates to public confidence

1.56 There are two measures relating to public confidence in Tranche 1:

(a) **Governance of FSR project** *(Recommendation 14)* – Incorporate into the terms of reference for the FSR Common Quality Technical Group (CQTG) the tasks of helping to (i) identify and address key economic and technical trade-offs, (ii) oversee that application of the guiding principles, (iii) examine issues where Transpower (or the Authority) may be perceived as having potential conflicts of interest, and (iv) support periodic stakeholder engagement. Recommended guiding principles are set out in Appendix E. We also recommend adding to the CQTG a person with strong experience in economic and technical trade-offs.

(b) **Seasonal outlook report** *(Recommendation 15)* – The Authority to publish quarterly briefings on current and expected market conditions (akin in concept to the quarterly reports published on the primary sector) with a view to regularly calibrating public and political expectations in relation to the wholesale electricity market. We recommend that the Authority draw on various experts to prepare a model seasonal outlook briefing following a process that tests the model with a sample of the target audience (opinion-makers in policy and public circles), iterating to find a template that achieves the intended communication goals.

Tranche 2 as it relates to public confidence

1.57 There are three measures relating to public confidence in Tranche 2, which should be put in place following Tranche 1. None of the measures in Tranche 2 are contingent on any other actions – they have been spaced simply to make implementation digestible:

(a) **Monitoring and enforcement of Code** *(Recommendation 21)* – Authority to increase resourcing for its monitoring activity, as well as making its monitoring function more independent from its rule-making function by establishing a monitoring and enforcement 'unit' within the Authority.

(b) **Information programme for opinion-makers** *(Recommendation 22)* – Strengthen structured information programme for wider stakeholders on how the market works.

(c) **International experts** *(Recommendation 23)* – Improve international linkages via hosting visiting experts, initiating secondments, hosting a conference or similar measures. We can learn much (both 'dos' and 'don'ts') from experiences in other countries.

Tranche 3 as it relates to public confidence

1.58 There is one measure relating to public confidence in Tranche 3, which should be put in place following Tranche 2 – namely, a **periodic 'warrant of fitness' for the regulatory agency** *(Recommendation 25).* It is not contingent on any other actions. Every five years, carry out a review involving external experts of whether the Authority is delivering the outcomes expected under the regulatory framework. Given that governments' understanding of how the electricity market works in any detail is always likely to be relatively thin, it is crucial that governments have confidence that the institutional arrangements for an independent regulator overseeing the electricity market are sound.

Demand-side flexibility (DSF)

1.59 DSF is where consumers shift their demand in time or alter their total demand. As the renewables world unfolds, it has the potential to play a significant role in our system, as both a risk management tool and a source of flexible 'supply' competing with some forms of generation. Efficient DSF will deliver benefits for both consumers (lower bills) and for the system as a whole (more resilience).

1.60 Our three-tranche package contains a combination of measures that tie together to 'activate' DSF in the wholesale market. Given the importance of this field, we explain our rationale and recommendations in relation to DSF in some depth in Appendix A.

1.61 Keep in mind that our approach to DSF is derived from, and fits within, the common framework we are applying to all other aspects of the wholesale electricity market.

Navigating the transition

1.62 The industry is understandably focused on issues that feel quite 'pointy' in the near-term, for example potential concerns about reliability for winter 2024 and what to do about forward wholesale prices that seem stuck at high levels well above the cost of new generation.

Keep a clear eye on longer term objectives

1.63 We think some of these pointy issues are manifestations of (or at least related to) an accelerated transition to a renewables-based system. As a broad observation, we think it important to ensure that responses to these current issues take account of the broader goal of moving to a renewables-based system. Likewise, we would urge policy makers and stakeholders to avoid ad hoc or temporary measures to address symptoms. Experience elsewhere shows that such measures can delay the transition by increasing investor uncertainty, and/or extending the dependence on fossil-fuelled plant.

Will the transition from fossil-fuelled generation be orderly?

1.64 A core concern in the transition is whether there will be a smooth displacement of fossil-fuelled generation with new renewable sources, or whether the shift will become disorderly. In our view, there are three distinct risks to consider.

Risks relating to operational coordination

1.65 There are already some signs that operational coordination is becoming more challenging – especially in relation to commitment of slower-start thermal plant. To address this issue, the Authority implemented a set of measures to improve information and coordination for winter 2023. These appear to have been beneficial and were recently extended into 2024. We believe some measures in this package – *Recommendation 1* (short-term forecasts), *Recommendation 6* (new reserve product) and *Recommendation 16* (scarcity pricing parameters) – will also be beneficial in this context, and we propose that they be accorded a high priority. We think alternatives such as warming contracts (as discussed in Option A10 in our Library of Options) which address symptoms rather than underlying causes, should not be pursued.

Risk of premature closure of existing fossil-fuelled thermal plant

1.66 Fossil-fuelled thermal plant owners face a declining revenue outlook as renewables account for a rising share of total supply. It is inevitable that some plant will close – but the question is whether *premature* closures might occur. Based on current information, we think the answer is likely to be ‘no’. The fundamental reason is that New Zealand (unlike some other countries) does not subsidise new renewables. This means that thermal plant operators should be able to earn sufficient revenue from the wholesale market to cover a plant’s costs if it is economic to retain that plant.

1.67 Of course, thermal operators will likely want some degree of certainty about forward revenues via contracting. Historical experience suggests that the process of negotiating such contracts can be noisy as respective parties manoeuvre to strike the best possible deal from their perspective. Nonetheless such contracts have been concluded in the past and we see no reason that should not continue. Having made these observations, some of the proposed measures in this paper should help to reduce the likelihood of premature thermal retirement – for example, *Recommendation 6* (new reserve product) and *Recommendation 7* (stress testing). We think these measures should be treated as high priorities.

Risk of delayed investment in additional flexibility resources

1.68 It is likely that investment in additional flexible resources will be needed at some point – such as bio-fuelled generation. In principle, such investment ought to be forthcoming if it is genuinely required because of the contracting and investment incentives generated within the wholesale market. However, a range of measures in this package should further reduce the risk of any delay for efficient investment. These include *Recommendation 6* (new reserve product), *Recommendation 7* (stress testing) and *Recommendation 8* (new standardised flexibility products).

1.69 Finally, investors considering the development of new flexibility solutions are likely to be quite sensitive to fuel sector and emissions policy settings. The Authority should ensure that agencies in charge of fuel and emission policy have a thorough understanding of the implications in the electricity sector of any measures that would extend or magnify policy uncertainty.

Getting the work done

The future is arriving faster than expected

1.70 When our work began in mid-2021, a renewables-based system seemed to be many years into the future. However, as noted above, the transition to a renewables-based system is well underway. The future is arriving faster than expected, and so time is of the essence to put in place the measures required to strengthen the wholesale electricity market.

Recommendations are a package and require quality and timely implementation

1.71 It may be tempting to view our package of recommendations as a kind of 'regulatory buffet' from which interested parties can pick and choose what to put on their plate. But that kind of approach would not work.

1.72 The recommended measures form an integrated package to be implemented as a sustained and coordinated programme of action over the coming four years.

1.73 If our wholesale electricity market over the last 20 years has been 'version 1.0', our recommendations are designed to accelerate the arrival of 'version 2.0', fit for purpose to deliver reliable electricity at lowest cost for the long-term benefit of consumers in a high-renewables world.

1.74 In Chapter 9, we set out clear guidance on the priority, sequencing and key parameters for the implementation process for each recommended measure. For four of the Tranche 1 measures we have gone further and set out more specific guidance:

(a) For developing standardised flexibility products *(Recommendation 8)*, we have developed an initial framework as a platform for further work in an industry co-design process (Appendix B);

(b) For enhanced stress testing *(Recommendation 7)* we have developed a 'blueprint' to enable early implementation (Appendix C);

(c) For the high level of outline of virtual disaggregation *(Recommendation 13)*, we have set out a framework of the key design elements to be considered (Appendix D under "Virtual disaggregation is preferred backstop tool"); and

(d) For FSR project governance *(Recommendation 12)*, we have developed a 'blueprint' for the Guiding Principles to enable early implementation (Appendix E).

How to undertake the work

1.75 Many of the actions recommended in this paper are 'bread and butter' regulatory measures. They should fit well with the typical approaches used by the Authority when considering possible amendments to the Code – i.e. analytical work (possibly including an advisory group or targeted stakeholder engagement) followed by formal consultation and then decision-making on the final form of any amendments.

1.76 However, some of the recommendations are market acceleration or facilitation measures rather than regulatory instruments. For example, work on standardised flexibility contracts or certain measures to quicken the development of demand-side response.

1.77 For these actions, we believe the Authority should (at least initially) undertake a facilitation and sponsorship role. This means more of the onus would be placed on stakeholders to co-design solutions, working with a framework established (and monitored) by the Authority. The Authority (and its predecessors) have successfully used market facilitation approaches in the past, especially for issues that were relatively complex and in an early stage of development.

1.78 We think the Telecommunication Carriers Forum's (TCF) process for developing codes covering non-price elements for competitive access to the 'monopoly' local telecom wires in 2006/07 may also be a useful point of reference. Success in the TCF multilateral process relied (among other things) on wide participation of market participants, a rigorous analytical framework, and a shared commitment to a disciplined process in which all participants understood that a co-designed common-good solution would better than the regulated alternative.

1.79 There may also be a case for using a hybrid approach in some cases with market facilitation followed (if necessary) by regulation. This would allow issues to be initially explored in a less formal (and hopefully more collaborative) environment, followed by Code development to address outstanding issues.

Resources for wholesale market development work

1.80 This report is recommending a sizeable package of measures to strengthen the wholesale market. Furthermore, we think fast progress is needed on many of measures because the transition is well underway. If our recommendations are accepted by the Authority, there will be a need to make a step-change in the rate of development of electricity sector arrangements.

1.81 As discussed above, most of that development work would fall to the Authority to undertake or lead. It is possible that the Authority may be able to free up some resources by reprioritising existing activities. However, reprioritisation alone is unlikely to free up the level of resources needed to undertake the proposed work. It is therefore imperative that the resourcing for the Authority be reviewed to enable implementation of the workplan with urgency. It is also imperative that the Authority give serious consideration to a co-design process for certain measures to enable it to tap into the resources and expertise of the wider industry.

2. About MDAG and this project

MDAG's role in general

2.1 The Market Development Advisory Group (MDAG)[4] was established by the Electricity Authority (Authority) in October 2017. MDAG provides independent advice to the Authority on the development of the Electricity Industry Participation Code 2010 (the Code) and market facilitation measures. MDAG focuses its advice on matters relating to the evolution of the 'machinery' of the electricity market. Specifically, under its terms of reference 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; and

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

Origins of this project

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

2.3 The proposed objective was 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.

2.4 The Authority approved MDAG's project proposal in July 2021.

Relevance of 100% renewable supply

2.5 The assumption of 100% renewable supply reflected the previous government's objective of achieving 100% renewable electricity generation by 2030. This was subsequently recalibrated by the previous government as an aspiration, with the Climate Change Commission projecting renewables to reach a 96.5% share by 2030.

2.6 To be clear, our analysis and proposals do not depend on reaching 100% renewable electricity, or even 96%. This is because the market conditions that make our recommended measures necessary are likely to come into play in advance of reaching such a high level of renewables.

2.7 As outlined in this paper, we are seeing evidence that the conditions of the transition have already started to emerge, some years in advance of expectations when this project started.

2.8 To avoid any confusion, our recommendations are for a 'renewables-based' system or a 'high-renewables world'.

Our project in the wider electricity picture

2.9 We are focused on the wholesale electricity market. This includes the spot, contracts and ancillary services markets. They currently map on to the physical flow of electricity from generators into the national transmission grid and out to consumers and retailers connected to the grid.

4 See www.ea.govt.nz/about-us/our-people/our-advisory-and-technical-groups/mdag/.

2.10 While the wholesale electricity market is a central piece of the overall electricity picture, the success of our electricity system in a renewables world also depends on several other key elements:

(a) Resource consenting processes for generation, energy storage and network infrastructure must enable the timely and efficient build of new infrastructure, otherwise supply may not keep up with rapidly growing electricity demand. We recognise there are challenges in this area, as highlighted by reports from Sapere for the New Zealand Infrastructure Commission[5] and by Concept Consulting for the Electricity Authority.[6]

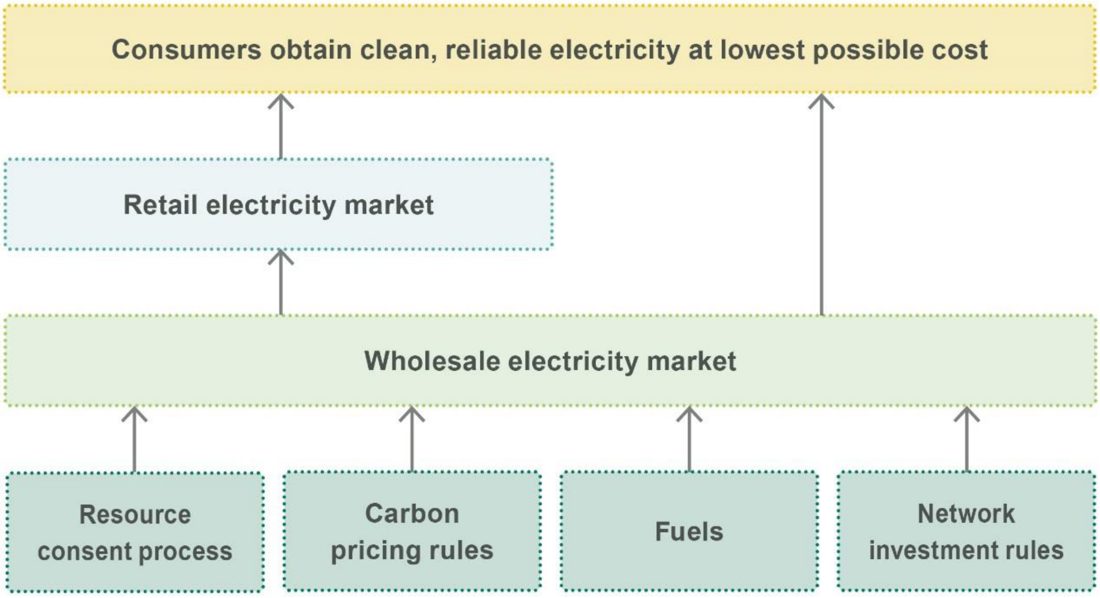
(b) Carbon pricing rules need to be clear and predictable, as they are the primary tool to drive decarbonisation decisions within the electricity sector and across the wider economy.

(c) Fuel sector arrangements have important implications for electricity generation costs and reliability. While fossil-fuelled generation has been trending sharply downward in recent years, it is expected to remain a critical source of back-up supply for some time to come. New green fuel sources are expected to emerge for use within back-up power generation, such as biofuels, ammonia or hydrogen. It is critical that the policy frameworks for both fossil and green fuels recognise the critical role these fuels play in the electricity sector.

(d) Network investment rules need to support the timely development of the national grid and distribution networks, while also safeguarding the interests of the customers who pay for those assets. A particular challenge in this area is that it typically takes longer to build new network infrastructure than it does to develop new demand or sources of supply. This raises the question of how to ensure that network capacity does not become a bottleneck for decarbonisation efforts.

(e) Retail market competition must be effective to ensure end-use consumers fully benefit from the opportunities available in the future electricity system.

Figure 2: Key elements of the electricity policy landscape



5 See media.umbraco.io/te-waihanga-30-year-strategy/z50ht3nz/infrastructure-consenting-for-climate-targets.pdf.

6 See www.ea.govt.nz/documents/2156/Information-paper-Generation-Investment-Survey-2022-Concept-Consulting-.pdf.

2.11 While this report is silent on matters outside the wholesale electricity market, that does not mean those matters are unimportant. On the contrary, they also deserve close attention as the benefits for consumers outlined in this report will not be realised unless those other areas are also performing well and enabling the outcomes sought in the electricity sector.

2.12 In relation to distribution networks, the traditional view is that they are separate from the wholesale electricity market. But this is not so in a high-renewables world with a myriad of renewable resources (electric vehicle batteries, small to large demand-side response sources, and a variety of solar and wind supply) likely to be widely dispersed across many distribution networks, all of which will need to be properly priced and coordinated with the wholesale market. Pricing and system coordination on distribution networks are therefore critical to a well-functioning wholesale market in a renewables world, which we address in Appendix A.

Policy goal

2.13 The wholesale electricity market is defined and governed by rules[7] made under the Electricity Industry Act 2010 and overseen by the Authority. The Authority's statutory objective has three main limbs – competition, reliability, and efficient operation – all for the long-term benefit of electricity consumers.[8]

2.14 The essence of achieving the statutory objective is to *reliably* meet electricity demand from *least cost* sources, in the short, medium and longer terms.[9] This is especially important in the context of bringing a large quantity of new renewable supply into the system over the coming decades.

Purpose of this report

2.15 This paper is the third and final instalment in a suite of papers by MDAG on its review of how the wholesale electricity market design needs to be strengthened to enable the shift to a renewables-based system:

(a) **Stage 1:** Our first (issues) paper of 2 February 2022 sets out our analysis of the problem. In the process of preparing our Issues Paper, we gained the benefit of extensive bilateral consultations with stakeholders. In the formal submissions process, we received 29 submissions, all of which were helpful.

(b) **Stage 2:** Our second (options) paper of 6 December 2022 sets out our analysis of the options to address the issues identified in our Issues Paper. This work also involved extensive bilateral consultations with stakeholders. In the formal submissions process, we received 33 submissions, all of which were helpful.

(c) **Stage 3:** This **third and final paper** sets out our recommendations to the Authority. It seeks to tell the story as a whole, drawing on the two previous papers as well as accompanying analyses, submissions and consultations.

7 Electricity Industry Participation Code 2010.

8 See sections 15 and 32 of the above Act. Note that in relation to industry participants' dealings with domestic consumers and small business consumers, there is also a statutory goal of protecting those consumers' interests. The statutory objective has been considered by the High Court in *Manawa Energy v Electricity Authority* [NZHC 1444] at 69-71.

9 "Electricity markets are designed to provide reliable electricity at least cost to consumers" – Peter Cramton, Electricity market design, Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612.

Key tasks for stage 3

2.16 In a nutshell, our task in stage 3 has been to:

(a) evaluate whether the analysis and conclusions in our Options Paper remain robust in the light of submissions and any new evidence, and to update our work accordingly;

(b) 'blueprint' or 'proof of concept' four proposed measures to enable early progress by the Authority;

(c) undertake targeted consultation on those 'blueprints' or 'proofs of concept'; and

(d) set out in a final report (in a clear, relatively self-contained form) our recommended package of measures with guidance on their implementation.

Rigorous and interactive approach

2.17 We have approached this project as a whole with an open mind, seeking to build an empirical and evidenced-based framework and sharing what we learn with the industry, policy makers and wider stakeholders, without seeking to favour or disfavour any particular outcomes.

2.18 This has genuinely been a journey of discovery in which we have remained open to revisiting our intuitions if robust analysis pointed us in a direction different to that which we may have assumed.

2.19 To this end, we have undertaken a range of high-quality qualitative and quantitative analysis, which we have published over the course of this project, as set out below.

2.20 Particularly in stages 1 and 2, we greatly benefited from speaking at some length with regulators in a range of overseas markets and other international experts (see paragraph 1.17 of our Options Paper). Along the way, we also conferred with various other related policy and industry projects in progress and shared our key findings with stakeholders on a bilateral basis. We have also encouraged interested parties to contact us directly to further discuss issues and share insights and analysis.

2.21 This open and interactive approach has been extremely valuable for our process and, we perceive, for the market as a whole.

Our published papers

2.22 For ease of reference, we set out below a full list of the papers we have published over the course of this project. Each reference is hyperlinked to its online source. Where practical, this report also includes hyperlinked cross-references to various sections of this supporting work.

Stage 1 – Issues

(a) MDAG: Issues paper;

(b) Dr Stephen Batstone: Literature Review of Price Discovery in 100% renewables;

(c) Dr Stephen Batstone: Demand-side flexibility in the New Zealand wholesale electricity market under 100% renewables;

(d) Dr Stephen Batstone : Wholesale risk management practice trends in the NZ electricity market, and prospects for a high renewables future;

(e) Dr Grant Read: Opportunity Costing in the NZEM Implications of Decarbonisation;

(f) Concept Consulting and John Culy: Price discovery with 100% renewable electricity supply – a slide pack setting out simulation (modelling) assumptions and results;

(g) Sapere Research Group: Implications for contract markets of transition toward a 100% renewable market;

(h) Sapere Research Group: Retirement of fossil fuel powered plant; and

(i) MDAG: Efficient pricing benchmark – Annex 3 of MDAG's High Standard of Trading Conduct Discussion Paper (published 25 February 2020).

Stage 2 – Options

(a) MDAG: Options paper;

(b) MDAG: Library of options – a paper by MDAG describing the options reviewed by MDAG;

(c) MDAG secretariat: Summary of submissions – a paper which provides an analysis of submissions on MDAG's Issues Paper;

(d) MDAG secretariat: Taxonomy of issues paper submissions – a spreadsheet setting out key points from submissions on MDAG's Issues Paper;

(e) Concept Consulting and John Culy: Competition analysis – a slide pack setting out further analysis of how a renewables-based system could impact on competition in the wholesale electricity market;

(f) Dr Stephen Batstone: Enhancing wholesale market demand-side flexibility: Framework for Option Development – a paper setting out the framework applied by MDAG in considering options to enable more efficient use of DSF;

(g) Dr Stephen Batstone: DSF case studies – a slide pack illustrating the potential integration of forward wholesale price information and DSF options into the evaluation of real-world demand-side investment decisions;

(h) Dr Stephen Batstone: Overview of Australian Wholesale Demand Response Mechanism (WDRM) – a slide pack examining in more detail the option of a 'nega-watt' scheme; and

(i) MDAG secretariat: Options paper brief overview – a slide pack setting out a brief distillation of our Options Paper.

Stage 3 – Recommendations

(a) MDAG: Final Recommendations Paper (this report).

Interaction with related projects

2.23 During the period of this project, the future of the electricity system has been considered by a range of government and private sector processes. The process of improving our system's regulatory settings certainly benefits from an open exchange of information and a robust competition of ideas among interested parties. To this end, MDAG has taken a very open and cooperative approach to sharing our work with other initiatives.

2.24 Other projects we have interacted with include:

(a) **Boston Consulting Group (BCG) 'The Future is Electric' Report**[10] – commissioned by several participants across the electricity sector[11] to advise on how the electricity sector could evolve to best contribute to the country's decarbonisation objectives;

(b) **Future Security and Resilience (FSR) project**[12] – an initiative by the Electricity Authority, in conjunction with Transpower as the System Operator, focused on how to ensure that the electricity system remains secure and resilient in the coming decades as we transition to a high level of renewable supply;

(c) **Flex Forum** – a cross industry group formed to identify a set of actions to integrate distributed energy resources (DER) into the New Zealand electricity system and markets. In 2022, Flex Forum released a Flexibility Plan[13] which describes these actions;

(d) **Winter 'peak' issue** – this initiative by the Electricity Authority in 2022 focused on ensuring that mechanisms were in place to ensure that sufficient capacity is available in the system to cover short periods of extremely high demand, typically in cold winter evenings. Our Options Paper discussed this issue as it is highly relevant to the transition to a more renewable system; and

(e) **Other government initiatives** – which include the NZ Energy Strategy,[14] the NZ Battery Project,[15] and the Gas Transition Plan,[16] all three projects run by MBIE.[17]

2.25 In Table 20 of our Options Paper, we set out a summary comparison of our project's preferred options relative to the Authority's Wholesale Market Review and BCG's 'The Future is Electric' report.

10 Published in 2022 – see www.bcg.com/publications/2022/climate-change-in-new-zealand.

11 Sector participants that commissioned this independent report include Contact Energy, Genesis Energy, Mercury, Meridian Energy, Vector, Unison Networks, Powerco, Wellington Electricity, and Orion. Manawa Energy, Lodestone Energy, Eastland, Nova Energy, Transpower, and Copenhagen Infrastructure Partners provided data but otherwise were not involved in the commissioning of this report.

12 See www.ea.govt.nz/projects/all/future-security-and-resilience.

13 See www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf.

14 See www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/new-zealand-energy-strategy/.

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

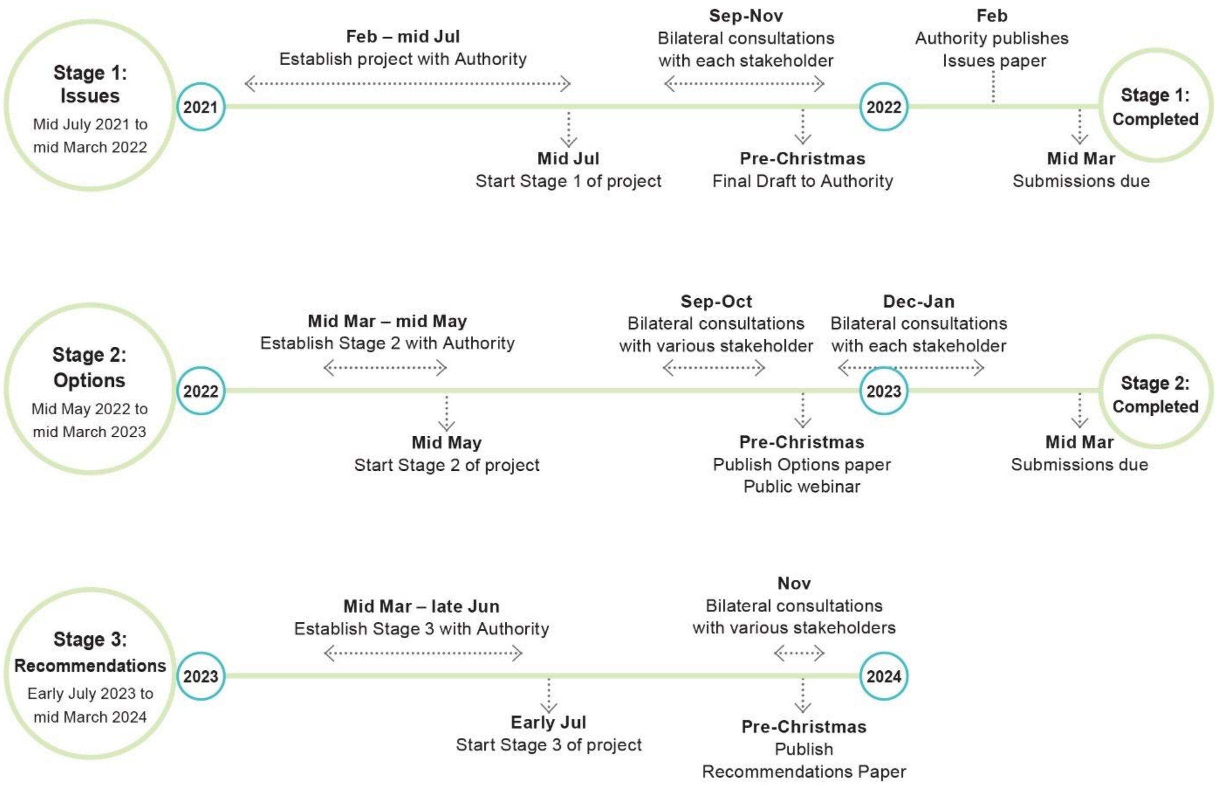
16 See www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/gas-transition-plan.

17 In addition, we considered the report in 2022 of New Zealand Council of Trade Unions, with the Workers First Union and '350 Aotearoa', arguing (among other things) that New Zealand's four largest generator-retailers have under-invested in renewable generation capacity, which has resulted in higher prices for consumers, higher carbon emissions and excessive dividends.

Recap on our timeline

2.26 A summary of our key milestones is set out in a timeline below.

Figure 3: Project timeline



2.27 For extraneous reasons, we were late to start stage 3 and so time to completion was more constrained than intended. Our opportunity for stakeholder consultations during this third stage was therefore less than we had planned.

3. Overall goal

3.1 Before we can assess the suitability of current arrangements and diagnose any weaknesses, we need to define the goals they are intended to achieve.

Clean, reliable, and least cost power

3.2 Our electricity system should produce power that is reliable at the lowest possible cost for the long-term benefit of consumers, as well as meeting society's environmental objectives. This is the energy trilemma – reliability, lowest cost and sustainability.

3.3 The environmental objectives are set outside the electricity sector in laws such as those covering consenting arrangements and the Emissions Trading Scheme. The task for electricity sector arrangements is to produce power at the lowest possible cost while maintaining reliable supply to consumers.

Costs need to be minimised in both short and longer run

3.4 In thinking about costs, it is useful to consider two timeframes:[18]

(a) In the short run, we want to deploy our *existing resources* in the lowest cost manner to meet demand. This is also called 'productive efficiency'.

(b) In the longer run, if existing resources are not sufficient to meet expected future demand, we want *new resources* to come into the system at the right time, in the right size and type, in the right location, and at the lowest cost of the competing alternatives. This is also called 'dynamic efficiency'. This will be especially important in the coming decade and beyond as large amounts of capital are deployed in new electricity investments. Alongside decarbonising our economy, it is the big prize we need to secure.

Reliability is very important but has a cost

3.5 Clearly, it is also vital that our electricity system meets society's expectations in relation to both reliability and security.[19] But how much security we want needs to be informed by how much we are willing to pay to ensure that we don't have to go without power.

3.6 Of course, electricity outages can become very unpalatable from a political viewpoint. For example, in 2016, Malcolm Turnbull as Prime Minister of Australia declared, in effect, that the political tolerance for blackouts is zero – "0.002% risk of outage is not good enough".[20]

3.7 However, we need to keep in mind that the infrastructure required to provide those last tiny fractions of percentages of absolute security can be *very* expensive. Most consumers prefer to tolerate some very low risk of outage rather than pay much higher power bills.[21] The ideal outcome is that consumers receive the level of reliability that reflects their willingness to pay.

18 Cramton (2017) referring to the twin goals of short-run and long-run efficiency.

19 By 'reliability', we mean having adequate generation and demand response to continuously meet consumers' demand for electricity. This covers all timeframes – within the half-hour, hour, day, week, season, year and beyond. By contrast, 'security' means tolerating a disturbance (such as loss of a major generator or transmission circuit) and still maintaining electricity supply to consumers. Security is a necessary, but not sufficient, condition for reliability.

20 Aurora podcast.

21 In some cases, consumers with very low risk tolerances are installing solar/batteries on their properties to provide security. This will become an increasingly feasible option for consumers as cost curves for these technologies come down. However, this option will not be available to all consumers due to cost implications, thus creating the potential for further inequities.

4. New Zealand's electricity system is being transformed

4.1 This section explains the key physical forces at work on both the demand and supply sides of the industry. It draws on modelling analysis from our Issues Paper to illustrate the magnitudes of the changes on the system.[22] This information provides a foundation to understand the challenges and opportunities presented by the changing system that are discussed in the following chapters.

Big ramp up in power demand

4.2 The future is never certain – but all forecasters agree that New Zealand's electricity demand will grow substantially with the electrification of transport and process heating, together with underlying growth. Add to this some new generation to replace coal, gas and other fossil fuel usage, and the need for extra electricity generation and storage to help cover 'dry years', peak demand and intermittency, and it sums to a 'ramp' of sustained investment in new renewable electricity out to 2050 (and probably beyond).

4.3 We projected total electricity demand will grow by around 33% in energy terms between 2020 and 2035, and by over 50% to 2050, as discussed in paragraph 5.11 of our Issues Paper. These projections may well be too low. They do not include any additional electricity demand for aviation or marine transport – both of which are now firmly on the radar.[23] Nor did it include any additional electricity demand for 'green' energy exports, such as hydrogen.[24]

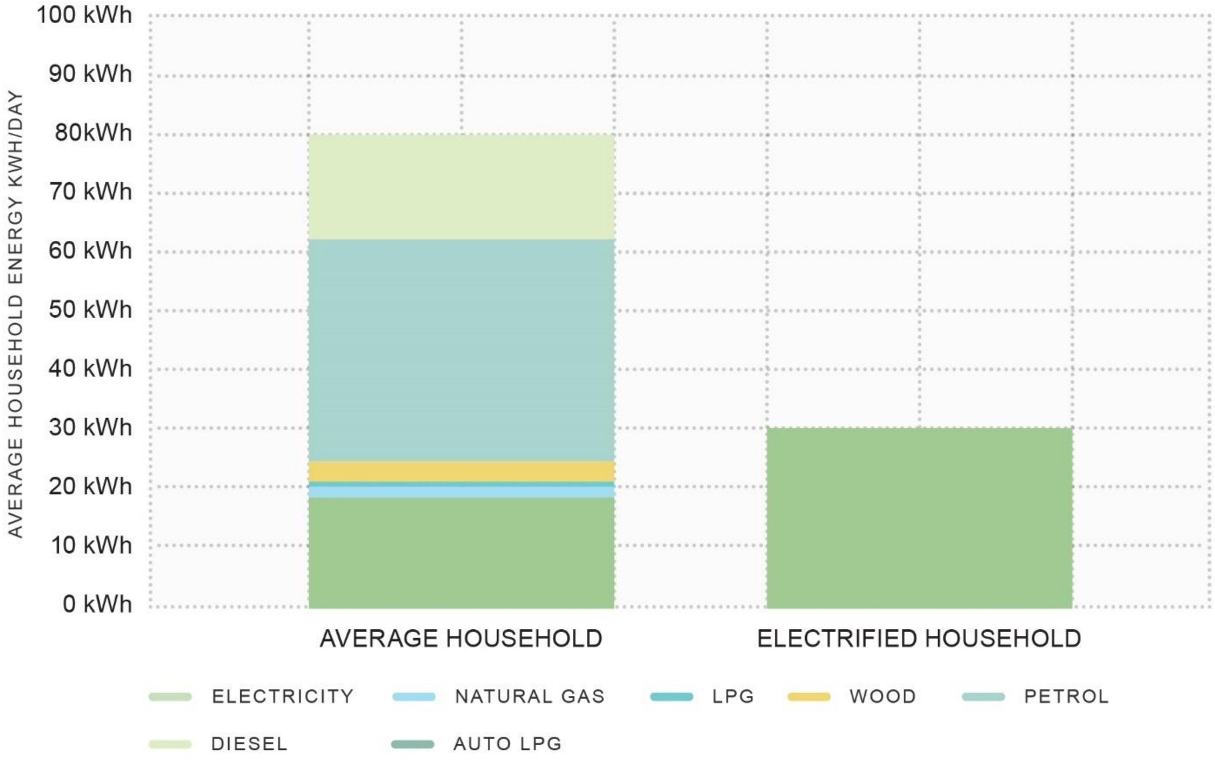
4.4 At the micro level, fully electrified households are projected to use around 50% more electricity than average households today as shown in Figure 4. This is because of the step up in power usage for transport and heating as they switch away from petrol and gas, etc.

22 The Issues Paper included a range of scenario cases for the future system under 100% renewable supply. While the scenarios differ in detail, the key trends are consistent across scenarios. The projections also broadly align with projections for systems with very high renewable supply from other sources such as Transpower and the Boston Consulting Group.

23 See p-airnz.com/cms/assets/PDFs/2023-air-nz-next-generation-aircraft-eoi.pdf and www.interislander.co.nz/interislander-2026/new-ferries/.

24 See www.meridianenergy.co.nz/news-and-events/meridian-selects-southerngreenhydrogen-partner.

Figure 4: NZ average household energy use, current vs electrified households[25]



So a big ramp in new generation investment is needed

4.5 A lot of new generation is needed to keep pace with rising demand and to replace baseload fossil-fuelled generation. The Issues Paper estimated that around 1,100 GWh/yr of new renewable generation capability will be required each year until 2050 to meet expected growth.

4.6 That will require a rate of renewable development that is almost 2.5 times the average rate achieved in the 30 years to 2020. Put another way that is roughly equivalent to building a Clyde hydro scheme *every two years*.

4.7 Development of new generation has already begun. In their 2022 Generation Investment Survey for the Electricity Authority, Concept Consulting noted that "generation development pace has lifted significantly compared to the previous decade" and that "based on recently developed/committed projects, gross new generation additions will average around 780 GWh per year between 2021 and 2025." But it will need to grow further and be sustained over many decades.

How much new generation is needed

Rising demand will mean we need to build around 1,100 GWh of new generation each year. That rate of renewable development is almost 2.5 times the average rate achieved in 1990-2020.

That is roughly equivalent to building a Clyde hydro scheme *every two years.*

New supply will be a lot more intermittent

4.8 In the modelling for our Issues Paper, we reported the results of modelling to explore the likely future generation supply mix. The results are summarised in Figure 5.

25 See Rewiring Aotearoa, Submission to Productivity Commission's "Fair chance for all" consultation, November 2022.

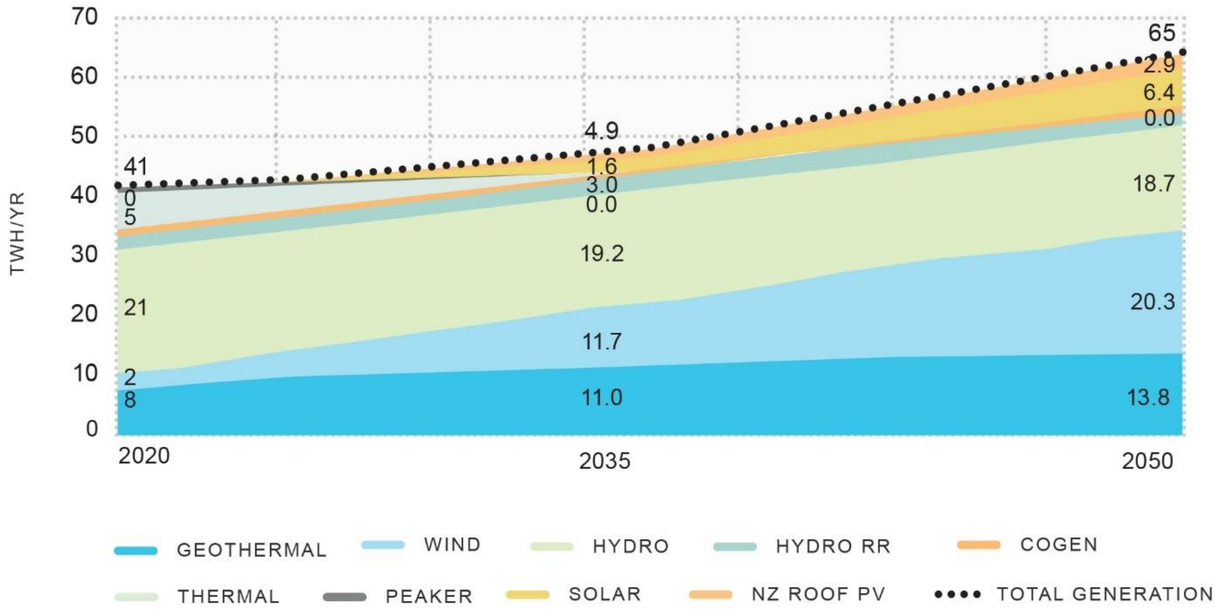
4.9 The analysis indicates that some further growth in geothermal is likely, but the lion's share of new generation is expected to come from solar and wind power. This is because of their cost effectiveness and relative resource abundance in New Zealand.

4.10 Thermal generation is projected to fall to very low levels, compared to around 18% of annual generation in the five years to 2021. In Figure 5, projected future thermal generation volumes are barely discernible (shown as 'thermal' and 'peaker'). However, thermal generation (or a close substitute) is expected to remain important as a source of firm capacity to back-up for occasional periods of low wind, solar and/or hydro generation – and complement other sources of flexibility (see later discussion from paragraph 4.33 onward).

4.11 In the Issues Paper analysis, the projections assumed that future thermal generation would move towards 'green peakers' – i.e. existing or new gas turbine plant that use biodiesel or another renewable liquid fuel as their energy source. It is possible that other emerging technologies (such as hydrogen or ammonia-based options) will perform this role of providing firm capacity to the system for durations where chemical batteries are unlikely to be economic.

4.12 A notable finding from the Issues Paper analysis is the predicted massive shift in the supply mix towards sources that have short-term intermittency, particularly solar and wind generation. As shown in Figure 5 these sources are likely to account for almost 50% of supply by 2050 compared to around 6% in 2020. That has important implications for spot price volatility as we discuss later in this report.

Figure 5: Projected demand growth and energy supply mix (reference case)



Our hydro generation system will become more important as buffer

4.13 A notable feature of the New Zealand system is its large hydro generation base. As shown in Figure 5 flexible hydro[26] currently provides around 50% of total generation in an average year. Its share of generation is projected to decline over time, but it will remain very significant in absolute terms, accounting for around 30% of supply by 2050 in the Issues Paper reference case.

4.14 The changing supply mix is expected to affect the way the hydro system is operated. Critically, it will become the primary 'buffer' filling in (or backing off) in the periods when solar and/or wind generation is low (or high).

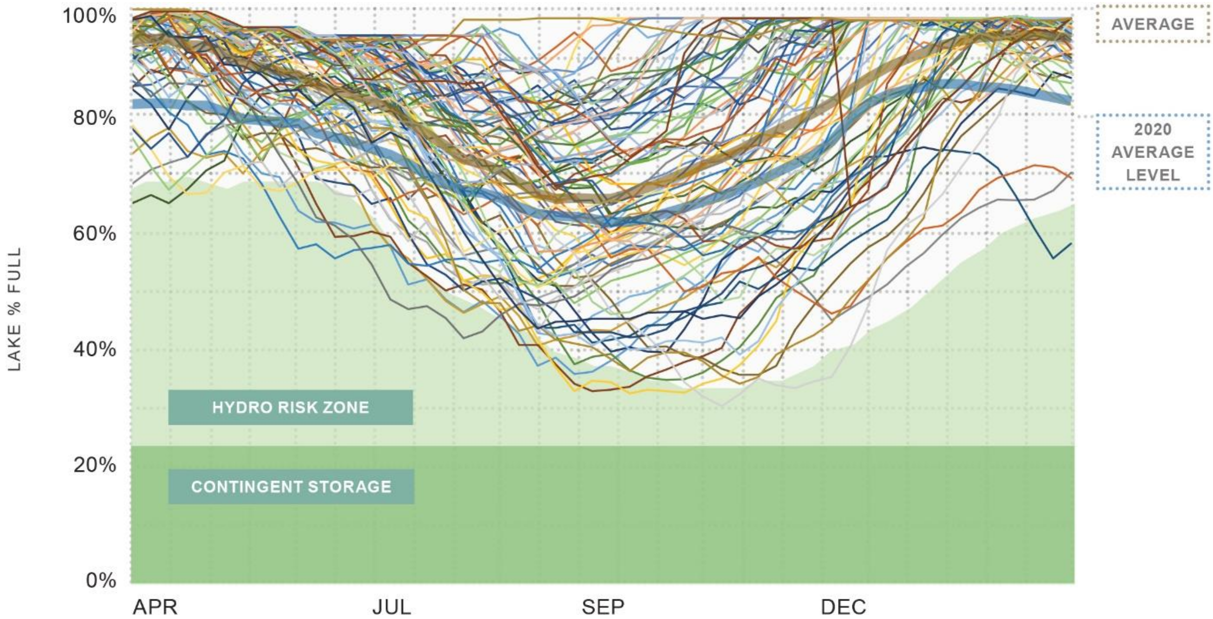
26 The portion of hydro generation that has storage and can control when stored water is used, as opposed to the run-of-river component.

4.15 Another key change will be how hydro storage lake levels are managed. Put simply, we will have much less ability to 'refill' the hydro lakes by turning on thermal generation, so it will be prudent to start each winter with higher levels of storage than has been the case in the past. The alternative would be to incur much greater risk of demand curtailment being required at some point in winter, which would have a high cost for consumers.

4.16 Figure 6 illustrates the effect of the system's changing dynamics on storage patterns. The 'spaghetti' lines show simulated storage trajectories for the reference case in 2035 across 86 historical 'weather years'. The lines for individual years trace out the level of storage that results from the pattern of weather (hydro, wind, solar) recorded in that year. The average over all the weather years is shown by the thicker brown line. The thicker blue line shows the average trajectory based on historical patterns under the current system.

4.17 A key difference for the future system 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. Storage is also higher on average at the end of winter to guard against a late dry spell.

Figure 6: Hydro storage trajectories – simulated 2035 and historical average



4.18 Another change that is expected is that hydro storage levels will in future be more sensitive to the rates of new investment and demand growth. This is because unexpected surges/reductions in demand versus supply growth are currently absorbed initially by more/less fossil-fuelled thermal operation, until new supply investment catches up. By contrast, in a renewables-based system such impacts would be reflected directly into the storage reservoir levels. Put another way, it will be even more important in future that new supply keeps pace with demand growth, because the buffer provided by fossil-fuelled thermal generation is expected to shrink.

Spill will be more frequent and that is OK

4.19 Spill refers to the phenomenon where so much renewable energy is coming into the system at times that some of it can't be used. In the current system, this mainly takes the form of hydro spill and is relatively rare. It is typically associated with extreme flood conditions, when there is no spare capacity to capture or utilise all of the available water flows. Hydro operators can reduce the likelihood of spill by running their reservoirs down before periods (e.g. spring) when higher inflows are expected. They have been able to do this fairly reliably in the past because if it became unexpectedly dry, there was generally some fossil-fuelled thermal generation that could fire up if needed.

4.20 However, as explained earlier, in a system with less fossil-fuelled generation it will make sense to target higher levels of hydro storage on average. As a consequence, there will be more frequent periods when some generation is spilled. This could be wind, solar, hydro or other forms of generation. As noted in paragraph 5.38 of our Issues Paper, we estimated that spill will rise from around 2% of total generation in 2020 to approximately 8% in 2035 and around 10% in 2050.

4.21 It is tempting to think that higher spill is a problem. However, it is really a consequence of the fact that electricity is very valuable to consumers. As a result, it is important to have a low likelihood of running out, even if that means there is sometimes too much supply. In system that is more weather-driven, those periods will increase in frequency, all other things being equal.

4.22 Of course, if there are cost-effective ways to reduce spill, such as creating additional energy storage or flexible demand that can ramp up at times of abundant supply, it would be great to utilise them. But the key point is that the costs of spill need to be traded off against the cost of the alternatives.

System more sensitive to shorter-duration weather effects

4.23 Our electricity system has always been sensitive to prolonged (but occasional) droughts – often called 'dry years'.

4.24 In the future the system will become more sensitive to shorter-duration weather events due to a rising share of supply from intermittent sources such as wind, solar and run-of-river hydro. As shown in Figure 5 these sources are likely to account for almost 50% of supply by 2050 compared to around 6% in 2020.

4.25 This trend will make the system more sensitive to 'dunkelflaute' periods, especially when they coincide with high winter demand.

Dry years and dunkelflaute

Dry years – extended periods (weeks or months) of low hydro inflows have historically been the main supply challenge to manage in New Zealand.

Dunkelflaute (German for 'dark doldrums') – short periods (days) of low wind/solar will increasingly become a new challenge to manage.

4.26 On the other hand, the exposure to dry year risk is likely to gradually reduce over time (but not disappear). In essence, this is because the level of spill is likely to become a new source of longer-duration flexibility for the system, with the total level of spill declining in dry years and vice versa.

Increased sensitivity to weather will cause more spot price volatility

4.27 The increasing share of supply from intermittent sources will lead to more frequent fluctuations in the short-term balance between supply and demand. This physical trend will cause an increase in short-term price volatility in the spot market, with more frequent periods of very low and very high spot prices.

4.28 To better understand the magnitude of this change, we undertook simulation modelling for the Issues Paper. Figure 7 and Figure 8 show the results of that modelling (discussed in more detail in paragraphs 5.45-5.78 of our Issues Paper).

4.29 The key insights from the modelling analysis are that:

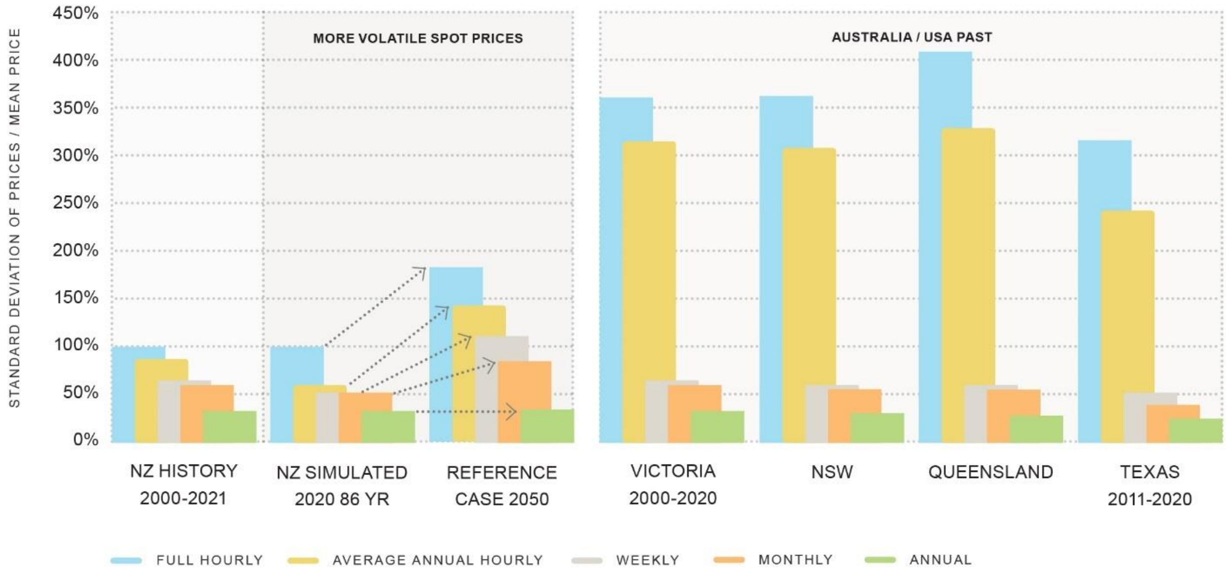
(a) Spot price volatility is expected to increase significantly over time, especially between 2020 and 2035 (with less pronounced shifts from 2035 to 2050).

(b) Volatility measures for shorter-duration periods (e.g. hours, days, weeks) increase more than for longer periods (months or years). While longer-term weather effects (such as 'dry years') remain, the shorter-term weather 'noise' gets larger over time, driving up volatility ratios at the shorter end of the spectrum.

(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 in the past. However, the available information suggests New Zealand's hourly volatility is unlikely to exceed that observed in Australia and Texas.

Figure 7: Estimated change in spot price volatility ratio

Figure 8: Comparison of NZ spot price volatility with other countries



4.30 A rise in spot price volatility will increase the challenges that retailers, wholesale buyers and generators have in managing their spot and contract market positions. To address such challenges, it could be tempting to look for ways to dampen spot price volatility at its apparent source, such as by capping or averaging spot prices.

4.31 However, we think that would be counter-productive because it would be 'shooting the messenger'. The underlying cause for increased spot volatility is a shift in supply towards physical resources with greater weather variability. Allowing spot prices to signal the effect of that change will create better incentives to invest in resources like batteries that can offset the physical variability. Conversely, muffling the spot price signals would weaken the incentives to make those desirable investments in demand response, batteries, etc.

4.32 Having made these observations, we think it is vital that market participants have better tools to predict and manage spot price volatility. We also want to make sure that spot market volatility is not magnified by any competition issues. We return to these matters in Appendix D.

Flexibility in supply and demand becomes the 'secret sauce'

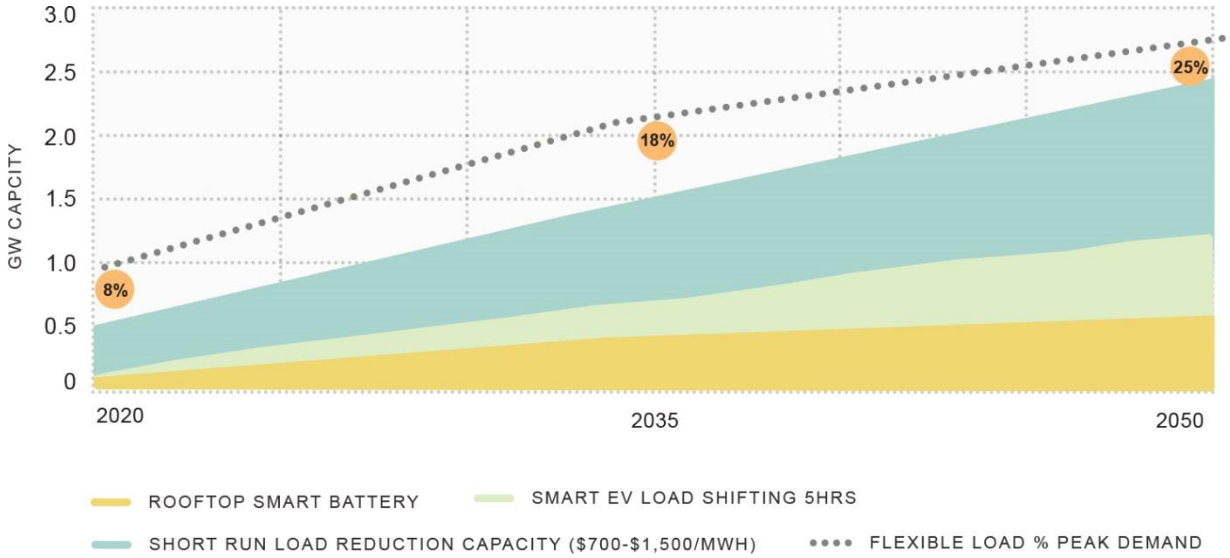
4.33 As discussed earlier New Zealand's hydro system is expected to be a vital source of flexibility as the system shifts towards renewable supply. However, we will also need other flexibility sources to help balance the system.

4.34 Some of the future flexibility is likely to come from new (or repurposed) flexible generation sources. For example, Genesis is reported to be looking at the feasibility of utilising biofuels within the Rankine units at the Huntly power station site. Another potential option is the use of so-called 'green peakers', which are fast-start turbines that run on a green fuel such as biodiesel. These could be new facilities, or existing turbines converted to run on green fuels.

4.35 Batteries (lithium ion and potentially other types) are also expected to make a big contribution to balancing the system. These have the key advantages of being very responsive and relatively scalable. Other forms of energy storage may also be utilised, such as pumped hydro, gravitational storage devices, or compressed air systems. All of these storage technologies provide ways to capture energy when it is abundant (e.g. spill) and save it for use at later times of greater need. However, they do not generate electricity, so they are not a total answer.

4.36 Finally, we expect demand-side flexibility (DSF) to become a very significant source of flexibility. This flexibility may be in the form of time-shifting of demand (with no change in aggregate usage) or altering the aggregate usage dependent upon system conditions. Electricity consumers who can alter their demand are likely to see much greater benefits from providing this flexibility to the system. As shown in Figure 9, the Issues Paper projected that flexible demand (as a percentage of total demand) would increase from 8% to 18% by 2035 and reach around 25% of total demand by 2050.

Figure 9: Demand-side flexibility (Issues Paper reference case)



4.37 At the household level, much of this rise is expected to come from smart charging of electric vehicles to avoid peak demand periods – a form of time-shifting. Likewise, increasing numbers of homes are likely to have batteries in combination with rooftop solar panels, and could alter their network power demand to avoid peak periods.

4.38 Similarly, businesses are also likely to see greater benefits from altering demand in response to system conditions. For example, cool stores may shift their usage to avoid peak demand periods and some customers may be able to reduce demand for longer periods.

4.39 Consumers who are willing and able to flex their demand should be able to make significant savings. In the Issues Paper we estimated that very flexible consumers could save 30% of the average wholesale energy cost by 2035 and over 45% by 2050.[27]

4.40 Substantial work will be needed to unlock the full potential of DSF. Key actions include providing much clearer signals about the expected future 'shape' of spot prices (see box), making it easier for consumers to capture benefits from providing DSF, and reducing the barriers that impede DSF uptake. Further information on recommended actions is set out in Chapter 9.

What we mean by 'shape' of spot prices

Spot prices vary each half-hour. We use 'shape' as a shorthand to refer to how spot prices vary. Price shape will affect how much a flexible consumer can save from utilising DSF.

For example, a consumer with flat usage across the year will pay the time weighted average spot price.* By contrast, a consumer that can shift usage away from high priced periods will pay less than the time-weighted average – with the level of savings determined by the shape of spot prices and their pattern of usage.

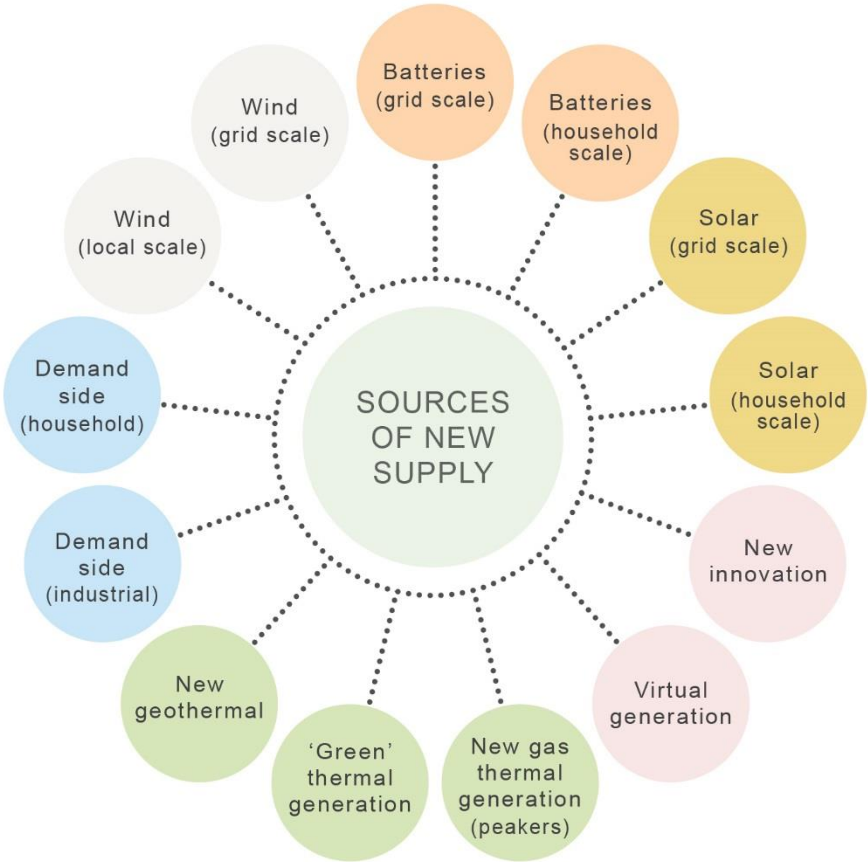
*This assumes the consumer purchases directly from the spot market – similar points hold for retailers purchasing on behalf of consumers with different demand profiles

27 See slide 55 of our Issues Paper modelling.

System becoming more diverse with many new players

4.41 For over 100 years, our electricity system (like that of other countries) has been heavily centralised. Most electricity was produced by a handful of generators and consumers had little active role in balancing the system. The future electricity system will have many more participants and types of participants as shown in Figure 10. For example, Transpower estimates there will be 3.9 million distributed energy resources across the system by 2035.[28]

Figure 10: Future electricity system and potential participants



4.42 At the transmission level, New Zealand's grid has been developed to handle changes in the direction of power flows due to fluctuations in renewable generation. This feature is different from many other national grids. But with the growth of batteries and generation located within homes and businesses, the network as a whole (grid and distribution lines) will become bi-directional. This will have very significant implications for how the system is managed.

4.43 As Transpower's Chairman, Keith Turner, explained that with many participants making decisions, not just one:

> "you need a different way of responding to that. This is much more like a neural system than it is about a prescribed single investment..." [29]

28 See page 61 of Transpower's Whakamana i Te Mauri Hiko – Empowering our Energy Future report at https://www.ea.govt.nz/documents/1097/06-100-Renewable-Electricity-Supply_-Simulation-Assumptions-and-Results.pdf.

29 Dr Keith Turner, Chairman, Transpower New Zealand, Interview with Kathryn Ryan, "Nine To Noon" Radio New Zealand, 5 October 2022 at 21'30" and 22'25".

4.44 Vector's chief executive, Simon MacKenzie, has also spoken about the coming changes. Vector is working with Amazon and Google-X to develop digital platforms to interface with the multitude of technologies expected to proliferate at the consumer-level as transition to renewables unfolds in the coming years. Simon MacKenzie noted that:

> "It's a very different type of mind-set and technology [relative to] the traditional systems. It's because multiple flows are now occurring in the networks … 'Decentralised' is taking into account much more understanding what is going on at the customer level".[30]

4.45 In short, our system is becoming far more diverse and decentralised. This offers significant benefits to consumers. However, it will still need to be tightly coordinated if it is to be reliable. This will require new approaches that recognise the much more 'neural' characteristics of the system.

Constant adaptation to new technologies

4.46 A technological revolution in renewable energy is underway around the world.[31] Myriads of organisations – private and public, for profit and philanthropic – in many different parts of the world are focused intensely on developing solutions to replace fossil fuels with renewable sources of electricity.

4.47 For example, new generation is becoming smaller, more modular, quicker to build, and (in combination) having the potential to provide better 'security'.[32]

4.48 Innovation will continue – especially given the global push to decarbonise. This means that our system should expect constant change and innovation in the way buyers and sellers of electricity look to meet demand.

30 Simon MacKenzie, Chief Executive, Vector, interview with Kathryn Ryan, "Nine To Noon" Radio New Zealand, 6 October 2022 at circa 15'02".

31 "Innovative solutions are reshaping the energy system and opening new possibilities for a decarbonised future much faster than expected" – IRENA (2021) at p18, World Energy Transitions Outlook: 1.5°C Pathway, International Renewable Energy Agency, Abu Dhabi, Innovation also referred to by Dr Keith Turner, Chairman, Transpower New Zealand, Interview with Kathryn Ryan, "Nine To Noon" Radio New Zealand, 5 October 2022 at 12'46".

32 See Sonia Aggarwal and Robbie Orvis "Wholesale Electricity Market Design for Rapid Decarbonization – Visions for the Future", JUNE 2019 - https://energyinnovation.org/wp-content/uploads/2019/07/Wholesale-Electricity-Market-Design-For-Rapid-Decarbonization.pdf.

5. Why a market?

5.1 Before considering possible improvements to the wholesale electricity market, we need to consider a prior question – *does New Zealand need a wholesale electricity market at all*?

5.2 After all, the current market was designed 30 years ago and may not be well-suited to the challenges and opportunities described in the previous chapter. We also recognise that some stakeholders question whether a market is the best way to deliver an essential service.

5.3 These are legitimate questions and we have consciously considered the relative merits of a market and other approaches.

What we mean by a 'market'

5.4 We need to start by clarifying what we (MDAG) mean by a 'market'. At its core, we see a market as a platform that enables a diversity of parties to offer competing solutions to meet consumers' demand, and for consumers to be able to choose the solutions that best meet their needs.

5.5 The end result should be that better solutions displace less efficient solutions – in both the near-term (the least cost suppliers/demand response providers are called upon each half hour) and over time (the least cost investments proceed) – to deliver reliable electricity at lowest possible cost to consumers.[33]

5.6 So when we consider whether we want a market in future, we are asking, in effect, whether there are better ways to fulfil those functions in a renewables-based system. In MDAG's view, a market is clearly the best way to do this for the following reasons.

Innovation stronger under a market approach

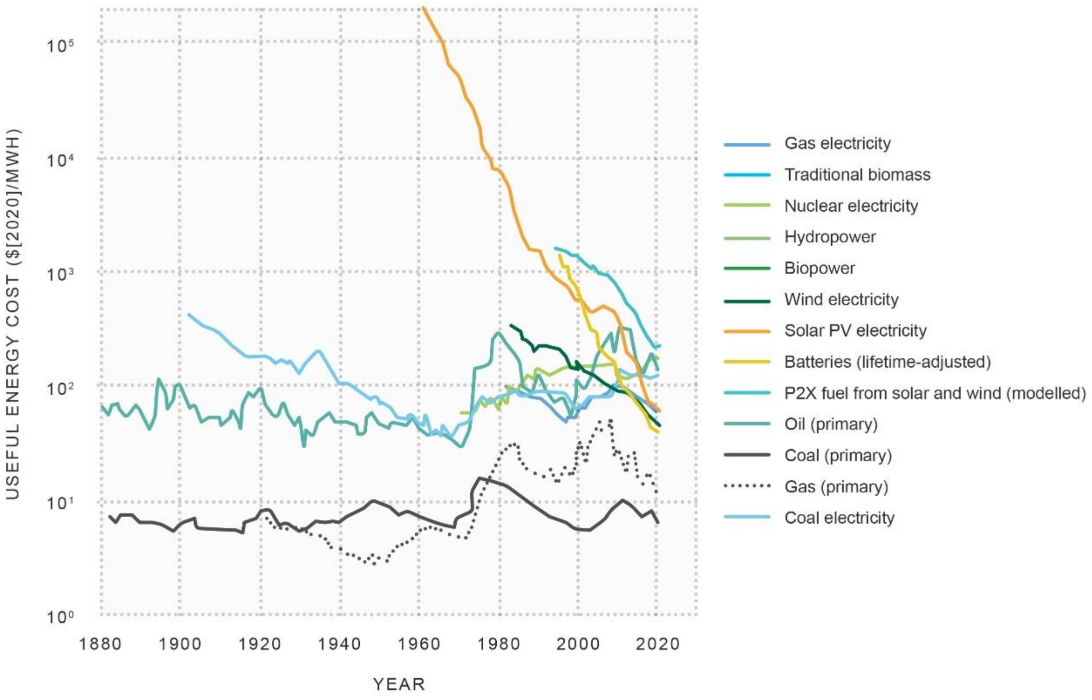
5.7 A key lesson from history is that no single person or small group of decision-makers can see or deploy the full range of optimal solutions. It requires a diversity of participants searching for different solutions – and a filtering mechanism that rewards the best solutions.

5.8 These considerations are even more critical in environments where the future is very difficult to predict – exactly the situation in the modern power industry. Predictions and solutions that look good today may well be overtaken by better options.

5.9 This unpredictability is illustrated by Figure 11 which shows cost trends for a wide variety of energy sources (note the logarithmic cost scale).

33 In essence, the market's purpose is to provide reliable electricity to consumers at least cost, see Prof. Peter Cramton, "Electricity market design", Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612.

Figure 11: Cost trends for different energy sources



5.10 Costs for some renewable sources have been steeply declining. By contrast costs for fossil fuel sourced energy were fairly constant in real terms since 1880 (bar the Middle East 'oil shocks').

5.11 Harnessing innovation will be critical to meeting New Zealand's goal of delivering clean, reliable electricity at least cost to consumers.

Example of unpredicted innovation

Few people predicted that the cost of solar PV would fall by more than **90%** since 2000

5.12 A well-structured wholesale market is the best platform to facilitate and reward successful innovation. It enables a diversity of parties to compete in offering solutions for meeting electricity demand. It also allows consumers to choose the solutions that best meet their needs. The result is that it allows better solutions to displace less efficient solutions.

5.13 As Transpower's Chairman, Dr Keith Turner, put it:

> "We're going into a system now which is not as prescribed and as lumpy and as precisely defined as it used to be, and we are dealing with uncertainty every day. We are dealing with many people making decisions, not just one…
>
> The market is a way of discovering the lowest cost price. When I was power planning engineer, there was one decision-maker about the future of our power system. Now we've got thousands of decision-makers and if someone finds an innovation, they're in there like a robber's dog – and that's fantastic".[34]

34 Dr Keith Turner, Chairman, Transpower New Zealand, Interview with Kathryn Ryan, "Nine To Noon" Radio New Zealand, 5 October 2022 at 21'30" and 26'59".

More diversity enabled by market approach

5.14 We noted earlier how changes in technology potentially allow many new types of players (including households) to provide generation, energy storage or demand response services. For example, some industrial consumers may be able to alter their grid demand by deferring production or using cool stores as batteries. Similarly, so-called virtual power plants (VPP) can provide supply, using cloud-based platforms that aggregate thousands of smart homes together and dispatch them like a power plant.[35]

5.15 Without a wholesale electricity market, it would be harder for non-traditional players to enter the industry, due to the lack of a platform on which they could offer services. It is possible that some non-traditional players could sell services to larger established parties. While that route may be efficient in some cases, a wholesale market gives non-traditional players more choices and fosters competition.

5.16 Furthermore, it is very hard to see how diverse resources could be coordinated without a wholesale market. By coordination, we mean decisions about things such as:

(a) when to charge and discharge batteries (including those in electric vehicles);

(b) when to use/save other types of stored energy such as water in hydro reservoirs; and

(c) when consumers should best utilise any flexibility they have over usage patterns.

5.17 Put simply, a spot market[36] that accurately signals the value of energy at each location and time is the only viable option we have identified to efficiently coordinate *operational decisions* under a renewables-based system. This finding reflects an assessment of practicalities rather than any preference for a market approach.[37]

5.18 This view is echoed by many international experts. For example:

> "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."[38]

More downward pressure on costs under market approach

5.19 Maintaining reliable supply while shifting to a renewable-based system is obviously critical. But it is equally important to minimise costs. In practical terms, this means we want to develop the right types and mix of resources (generation, storage or demand response) at the right times and in the right places.

5.20 There is a lot at stake on this front. In Table 1 of our Issues Paper we estimated that $27-37 billion of new investment in generation, batteries and demand response capability will be required by 2050. These are large sums by any standard and getting things off beam will quickly rack up large costs.

35 For example, SolarZero trades grid stability services from its VPP made up of household battery systems. See www.solarzero.co.nz/virtual-power-plant and www.scoop.co.nz/stories/SC2211/S00014/solarzero-enables-world-first-trade-in-nz-electricity-reserves-market.htm.

36 This refers to the whole set of arrangements to coordinate resources in the period leading into, and in real time. It includes scheduling, short-term forecasting, ancillary service arrangements, as well as dispatch.

37 As Professor William Hogan of Harvard University observed in 2018, "…increased arrival of renewables and greater reliance on distributed resources both point to fundamentals that reinforce rather than invalidate the fundamental logic of electricity spot market operation and pricing" – see Prof William W. Hogan, "In My View, Best Electricity Market Design Practices", (forthcoming in IEEE Power & Energy), 3 October 2018.

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

5.21 If we over-build the electricity supply base, that will impose unnecessary harm on the economy and on the environment. If we build more expensive solutions than needed, that will impose costs on the economy. And, in both cases, we would waste scarce capital that should be applied to better uses. Finally, if we build too late that will reduce reliability and harm consumers. In short, investment efficiency will count for a lot in how we deliver a clean and reliable electricity system.

Investment efficiency

As noted in our Options Paper, "the real prize is getting new generation built as cheaply as possible, in the right places, at the right times"

5.22 This raises the question of how to decide what, where, and when investments should be made in generation, storage and demand response. In this area there is a choice between approaches that rely more on centralised decision-making and markets in which decisions are more decentralised.

5.23 Centralised approaches come in various forms (such as capacity mechanisms, which we considered in some depth in paragraphs 3.36 to 3.57 of our Library of Options). Their common features include:

(a) A single party determines *when* investment will occur via its projection of demand and assessment of existing supply capabilities.

(b) A single party strongly *influences the mix of investment*, via its determinations about how each resource will 'count' toward meeting future demand. For example, it will determine the deratings to apply to wind generation in different locations for their relative firmness, and the degree of firmness that will be accorded to different types of demand response capability.

(c) Investment costs (and sometimes operating costs) are recovered from consumers via a levy or compulsory contracting arrangement.

5.24 We consider that a market approach will deliver lower costs than centralised approaches, particularly in a renewables-based system, for three key reasons. First, decision makers in the centralised approach have weaker incentives to minimise costs. This is because they do not directly bear the cost of poor decisions. By contrast, in decentralised approaches investment costs are borne by suppliers themselves and/or consumers (to the extent forward contracts share risks with consumers). This creates strong incentives on suppliers and consumers to find the least cost investment options, and to carefully manage construction processes.

5.25 Second, there is a tendency towards over-investment with centralised approaches. This is because of the asymmetry of incentives on central decision makers. If they cause too little investment to be built, that will be readily apparent (i.e. through blackouts), whereas the costs associated with over-investment are less visible and harder to measure. For this reason, even the most well-intentioned central decision maker will find it hard to resist the tendency toward over-procurement.

5.26 This observation is borne out by a variety of studies. For example, a 2016 survey of capacity mechanisms by Professor Frank Wolak found:

> "experts generally contend that the capacity markets have achieved the goals of providing the required reserve margin, but in an economically inefficient way [and] these costs appear to be mainly due to a higher reserve margin than would be economically optimal." [39]

39 Bhagwat, P. C. et al. (2016). Expert survey on capacity markets in the US: Lessons for the EU. Utilities Policy 38.

5.27 By contrast, under decentralised market approaches the timing of investments is determined by the proponents risking their capital, not the forecast of a central agency. This means the cost of over-investment will be borne directly by investment proponents. This makes it much less likely that over-investment will occur.[40] This raises the question of whether decentralised market approaches will lead to under-investment.

5.28 We think that risk is real if market arrangements are not well-designed – but the risk stems from the specific rules rather than a market approach per se. On this front, we note that New Zealand has used a decentralised market approach for investment decisions for almost 30 years. During that time there is no evidence of under-investment in capacity.[41] On the contrary there has been an increase in security margins (see box).

Generation investment adequacy in New Zealand

Contrary to some perceptions, security has actually increased since we've had an electricity market. Between the 1940s and 1960s, supply shortages were frequent. The security standard was around 1-in-10 years. Between 1987 and 1992 (under ECNZ), it increased to 1-in-20. From 1992 to 1997, it lifted further to 1-in-60.* Since the start of the market in 1999, it increased to around 1-in-100.

* After the Inquiry into the 1992 shortage.

Source: https://energylink.co.nz/news/blog/1992-shortage-revisited

5.29 The third reason for favouring decentralised approaches is that we think they are better suited than centralised approaches for renewables-based systems. The underlying reason is that centralised approaches work best with technologies that have relatively standardised and well-established performance characteristics such as thermal stations.

5.30 By contrast, it is hard for centralised decision-making processes to properly assess the future supply contribution of technologies whose performance is naturally heterogeneous. For example, the supply contribution of solar and wind generation will differ between Northland and Canterbury because of differing solarity and wind patterns. Equally importantly, the firm supply contribution from any single renewable facility will depend on what else has been built on the system because of diversity effects.[42]

5.31 The importance of these heterogeneity and diversity effects will grow as the renewable share of supply increases over time. For example, Professor James Bushnell, a leading US expert, has written that:

> "As resources become more diverse, the challenge of forecasting their value for reliability months and years in advance greatly increases." [43]

5.32 Capacity mechanisms come from, and are strongly influenced by, culture and politics. Capacity mechanisms tend to be based around thermal-dominated systems and in response to historical challenges, but not so well suited to the nature of innovation and opportunity in the coming years.

5.33 Of course, the challenge of assessing the supply contribution of diverse renewable resources does not evaporate with decentralised decision-making. However, it does shift that responsibility from a single body onto parties with better information about each specific option and with stronger incentives to make cost-effective decisions (i.e. prospective developers and their customers).

40 Keep in mind that this propensity in more centralised systems to over-invest does not necessarily imply better security or reliability of supply. Location, timing, fuelling and other availability factors for generation capacity are all significant elements in gauging their performance in adding to security and reliability. These elements are often not well managed in more centralised decision-making systems.

41 There have been occasions when the system was very tight in droughts or when some plant was not available to run – but neither of those issues arose from a lack of investment in capacity.

42 See quote by Sonia Aggarwal and Robbie Orvis at paragraph 5.20 of our Options Paper.

43 See James Bushnell et al., *Capacity Markets at a Crossroads*, Working paper, Energy Institute at Haas, April 2017.

Market approach is preferred

5.34 For the reasons set out above, our conclusion is that a market approach is preferred over the alternatives in which decision-making is more centralised. Indeed, with the pressing trend toward more diversity and innovation, we need a well-functioning market approach more than ever, and the need for information sharing and coordination will only increase.

5.35 This preference reflects an assessment of pragmatic rather than philosophical considerations – just as households might prefer cats that are best at catching mice, irrespective of whether they are black or white.[44]

5.36 The preference for a market approach appears to be shared by some leading international experts. For example, we understand the European Union Agency for the Cooperation of Energy Regulators has been leaning towards this model.[45]

5.37 Similarly, Rob Gramlich and Michael Hogan concluded in 2019:

> "A market structure with a central spot market and active de-centralised forward procurement between wholesale buyers and sellers (including exchange-based trading) will lead to sufficient investment to achieve resource adequacy, will facilitate a sufficiently rapid decarbonization, and will do so at the lowest reasonable cost to consumers”.[46]

5.38 Finally, Professor Peter Cramton, a leading international expert and former proponent of more centralised approaches thought that rising renewables will increasingly challenge the more centralised capacity mechanism model. Professor Cramton observed in discussions with MDAG:

> "A [centralised] capacity or firm energy market is not the tool to promote innovation and investment … They have so many 'knobs and dials', and everyone lobbies for their type of resource…"

Cooperation in competition

5.39 There is a sense among some wider stakeholders that we need a more cooperative approach, rather than framing our approach around competition among buyers and sellers. A key point to keep in mind is that competition is not antithetical to cooperation. Introducing new and better solutions to meet consumers’ electricity needs relies fundamentally on individuals, groups, communities, and firms coalescing in a multiplicity of ways to share ideas, skills and interests. It is competitive in the sense that each new solution is competing to find its niche and, in effect, displace alternatives that may be less beneficial for the intended user.

44 Chinese saying advocating pragmatism, possibly coined by Deng Xiaoping (1904–97).

45 See paragraph 3.47 of our Library of Options discussing capacity mechanisms.

46 Rob Gramlich and Michael Hogan, Wholesale Electricity Market Design for Rapid Decarbonisation: A decentralized markets approach, June 2019 – see energyinnovation.org/wp-content/uploads/2019/07/Wholesale-Electricity-Market-Design-For-Rapid-Decarbonization.pdf.

6. Core elements to be beefed up

6.1 The preceding chapter explained why we consider that a wholesale electricity market remains the preferred mechanism to match demand and supply in real time, and to coordinate investment and other decisions to meet future demand.

6.2 In this chapter, we discuss the core elements required for our wholesale market to do its job.

Essentials of a well-functioning wholesale market

6.3 The essence of a well-functioning wholesale electricity market is many different parties, managing their own risks, responding to competitive pressures and accurate price signals, continually looking for ways to serve their current and potential customers more effectively than their competitors.

6.4 As explained in the previous chapter, this competitive process is better than alternative centrally directed models, particularly in a high-renewables world, for delivering the core policy goal of reliably meeting electricity demand at the lowest cost.

6.5 Four pillars must be present for a wholesale electricity market to function well:

(a) **Accurate (efficient) prices** – there must be a transparent process of discovering prices that accurately signal the value of an additional unit of electricity in the short, medium and longer term at different locations,[47] including allowing high prices to signal scarcity when required. In effect, these marginal prices become targets that market participants are competing to beat.

(b) **Tools and incentives to manage risk** – market participants need tools to efficiently manage their risks. These tools can be physical options (e.g. an ability to increase supply or reduce demand) or financial arrangements where parties contract with others who can manage the underlying risk at a lower cost.

(c) **Sufficient competition** – the market needs a level of competition[48] among market participants to provide the best solution to meet demand such that no party has the means and incentive to exercise significant market power.[49]

(d) **Public and political confidence** – there is a particular need for:

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

(ii) general public and political acceptance that volatility and high prices 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;

47 We explain the price discovery process in paragraphs 237-240 of Annex 3 of MDAG's High Standard of Trading Conduct Discussion Paper (originally published in February 2020, and republished alongside our Issues Paper in February 2022). We further note the view of Reeve, Stevenson and Murray (at Sapere) (July 2021) that "efficient pricing delinks from observable cost because observable costs contain insufficient information for efficient pricing over time".

48 Recognising that competition can sometimes include cooperation, for example with joint ventures or consortia.

49 Market power becomes significant when its exercise would have a net adverse impact on economic efficiency, which includes productive, allocative and dynamic efficiency. This concept is reflected in Electricity Industry Participation Code 2010 at cl 13.5A.

(iii) confidence among consumers and politicians that investment will be timely and competitive; and

(iv) confidence in the rule maker and rule making process to create an efficient platform for processing information and coordinating actions among many electricity suppliers and consumers.

6.6 Achieving (d) above (public and political confidence) is highly influenced by whether (a) to (c) are satisfied. Those core elements are like the DNA or 'engine' of the spot, contracts and new investment markets.

Figure 12: Pillars of a well-functioning wholesale electricity market

6.7 They depend on and feed off each other:

(a) Accurate price signals come from a process of 'price discovery'[50] with parties competing to offer supply into the spot market, to buy and sell hedges, and to invest in new generation and demand-side options, with robust rules governing how and when pricing information is published.

50 Explained in paragraphs 237-240 of Annex 3 of MDAG's High Standard of Trading Conduct Discussion Paper (published 25 February 2020 republished alongside our Issues paper in February 2022).

(b) Tools and incentives for risk management come from competing parties responding to efficient market information and innovating with other parties to share risk, supported by ‘common good’ facilitation where efficient.

(c) Competition relies on (among other things) efficient market structure, risk management tools and efficient market information (also a key input to accurate price discovery).

(d) Public confidence relies on the market delivering reliability at lowest cost, and this public confidence (as a virtuous circle) enables accurate price signals (even when very high), which in turn drives incentives in the market to manage risk and invest in new supply.

6.8 These four core elements of our wholesale market are outcomes of market structure, rules and physical systems. They can be ‘tuned’ or strengthened by adjusting the structure, rules and systems on which they are built.

Why accurate prices are so important

6.9 Our future electricity system will be far bigger with many more players, and with a lot more individual operational decisions to coordinate in real time. Many of those operational ‘decisions’ will be executed via smart devices rather than by fingers hitting switches. However, they still need coordination – and spot prices provide the *heartbeat*.

6.10 If *spot prices* are not accurate, it will lead to poor *operational decisions* which will raise costs and/or cause reliability problems. For example, it could mean electric vehicles are charged during peak demand times, which increases the amount of new generation (and network infrastructure) that needs to be put in place. And this in turn will increase costs to consumers and the environment.

6.11 Accurate *contract market prices* are also critical to coordinate *decisions over longer periods* – such as whether to use or conserve discretionary resources (like hydro storage or potentially curtailable demand) and when to invest in new supply or demand response capability.

Investment efficiency

A BERL study in 1994 found that average pricing of electricity 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 can be avoided if wholesale buyers see the full cost of producing an extra unit of electricity.

Source: *“The State of the New Zealand Environment, 1997”, Ministry for the Environment, section 3 at page 24.*

6.12 In the spot market, accuracy means fully signalling the increased volatility in spot prices. This will pose financial risks for customers or suppliers with exposure to spot prices. However, it is important to address these risks by using tools to mitigate exposure to spot prices, rather than by muffling spot market signals at their source.

6.13 Artificially suppressing or elevating spot prices would mean suppliers and consumers do not face accurate signals about the true value of energy. This would encourage inefficient levels of consumption or investment (see ‘investment efficiency’ side box).

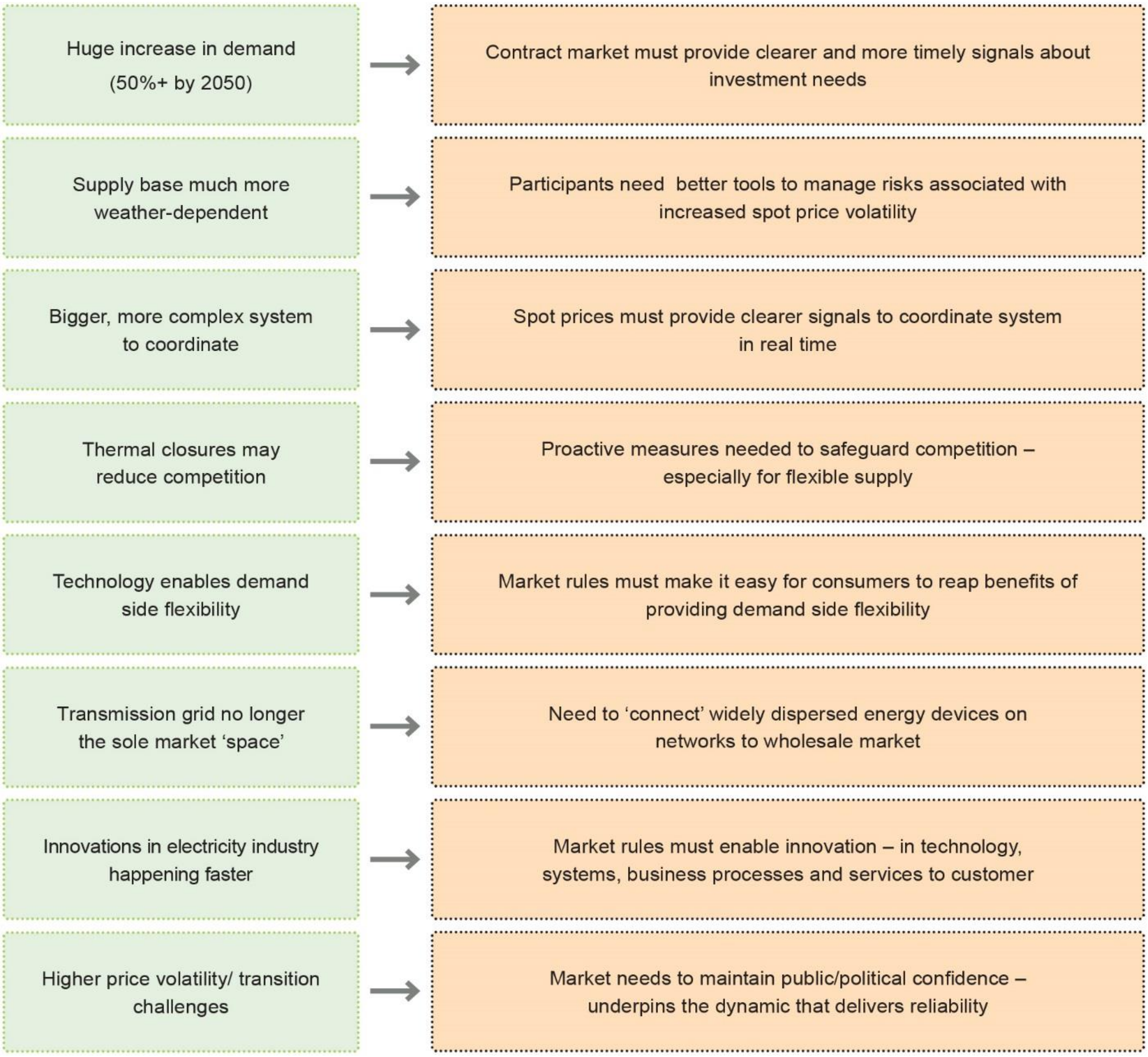
6.14 The potential adverse consequences would be very significant. Among other things, suppressing spot prices or giving parties a ‘soft landing’ for failing to properly hedge their exposure to spot prices tells parties they don’t have to properly manage their price risk, which has the flow on effect of both reducing the amount of capacity, energy and/or demand-side response available to cover periods of shortage and mucking up the timing and choice of new investment to meet new demand.

6.15 In short, making wholesale prices reflect the cost of producing an extra unit of electricity in a given timeframe and location (rather than, say, averaging prices) is crucial for harnessing innovation and driving costs down over time for the benefit of all consumers.[51]

Impact of renewables transformation on wholesale market design

6.16 The physical changes to our electricity system described in Chapter 4 have significant implications for the design of our wholesale electricity market. These implications are distilled below.

Figure 13: Physical system changes and implications for wholesale market design



6.17 First, a massive investment is needed to meet rising power demand. We estimate that $27-$37 billion of new investment in new demand-side flexibility (DSF), batteries and generation will be needed by 2050. There is a big payoff from making the right investments at the right time and place. This is where the contract market has a critical role to play. It needs development to send clearer investment signals. In particular, it must provide more granular signals about the benefits of investment in flexibility – on both the demand- and supply-side of the system.

51 The reasons for marginal cost pricing – and why not 'pay as you bid' pricing – are explained in our Options Paper at paras 6.13-6.16.

6.18 Second, our system will be more sensitive to the weather. This is a natural consequence of relying more heavily on solar and wind generation. Spot prices will become more volatile (with both low and high prices more common). We should not try and mask the effect of weather on spot prices, but we do need to make sure participants have access to the necessary tools to manage and mitigate increased spot price volatility. Political and public acceptance of increased spot price volatility is also fundamental for wholesale market participants to properly manage their risks.

6.19 Third, there will be a big increase in the number of active participants on the system, as many more parties (and devices) connect to the system as suppliers, storage providers or flexible users. We liken this change to moving from a string quartet to a full orchestra. A conductor is needed to coordinate this orchestra, and the most practical solution is the spot market. But the spot market will need to work harder than before to provide the signals required to coordinate actions across the entire grid.

6.20 Fourth, we will rely much more on the hydro generation system for flexibility as existing fossil-fuelled generation winds down. This increased reliance on flexible hydro generation may significantly weaken competition in some key areas of the wholesale market. We need to guard against that outcome and have measures available to address that risk if it appears to be crystallising.

6.21 Fifth, technology changes in metering, sensors and data processing are making it much easier for consumers (or their devices) to actively vary their demand. It is imperative that the wholesale market design facilitates full engagement by consumers who want to reap the rewards from active demand response.

6.22 Sixth, the wholesale electricity market ‘boundary’ has traditionally matched the geographical footprint of the transmission grid, with limited reach into distribution networks. However, with increasing numbers of active participants and devices being located within distribution networks themselves, new wholesale market tools/processes will be needed to enable tighter optimisation across the nation’s electricity networks – irrespective of their classification as transmission or distribution assets.

6.23 Seventh, innovation in technology and business models is expected to accelerate, as the world embarks on a quest to electrify much of its energy demand. It is vital to ensure that New Zealand’s wholesale market arrangements remain open to technical and commercial innovations where these provide benefits to consumers.

6.24 Finally, the physical changes to the system are already happening. Spot price volatility has stepped up and the renewables transition is underway. New Zealand needs to work at pace to strengthen the wholesale market so it can deliver clean, reliable power at least cost to consumers, and maintain public and political confidence.

We need WEM 2.0

New Zealand’s current wholesale electricity market (WEM) was designed in the mid-1990s and can be thought as ‘version 1.0’.

A step change is required to adapt the market’s design to meet the challenges of a high-renewables world.

Our recommendations set out the blueprint to deliver ‘version 2.0’ – an updated design to deliver reliable, renewable electricity at lowest cost for the long-term benefit of consumers into the future.

Task at hand

6.25 Put simply, the task at hand is to strengthen the wholesale market for a high-renewables world.

7. Our package as a whole

7.1 In this chapter we outline, as a whole, what needs to be fixed and how.

Measures need to work for New Zealand

What we do has to work best for needs and features of our system. New Zealand's physical characteristics and lack of any grid interconnection to other countries mean the challenges and opportunities we face are unique in many areas.[52] Also keep in mind that New Zealand's wholesale market design already has many features that overseas jurisdictions are looking to put in place.[53]

As general guidance, the considerable experience of Professor Peter Cramton across a range of countries is salient:

> "Electricity market design is far from static. New challenges are emerging with the ongoing transformation of the electricity industry. The forces driving change are the expansion of renewables, demand response, distributed generation, smart homes, and battery storage…
>
> "Electricity markets are necessarily complex. This follows from the complexity of the engineering and economic problems that must be solved. Still designers should strive to keep the design as simple as possible. Complicating features should only be added if they are necessary and consistent with market principles". [54]

Structure of package

7.2 We are recommending an integrated programme of 31 measures to strengthen the four pillars of the wholesale market (described in Chapter 5) to enable it to meet the challenges of a high-renewables world (described in Chapter 4).

7.3 All recommended measures contribute to all four pillars. For the purposes of grouping, however, each action (or measure) is sorted by the pillar to which it contributes with more emphasis (or with a higher profile).[55]

7.4 Our recommended packaged is both sizeable and demanding in its timeline – but this simply reflects the volume and pace of work required[56] to equip the wholesale market so it can do its job well in delivering a renewables system.

7.5 At a practical level, we recommend that our package is implemented in three tranches:

(a) Tranche 1 comprises measures that are required urgently – to address issues already arising, to support a smooth transition, or to lay the foundation for later work.[57]

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

53 For example, overseas experts commented favourably on the fact that the New Zealand market has nodal pricing which encourages efficient locational choices for new investments, and that purchasers and suppliers see a uniform spot price, which facilitates demand-side flexibility.

54 Peter Cramton, "Electricity Market Design", Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612.

55 In some cases, the difference in a measure's contribution to one core market component relative to other core component is not great (e.g. Recommendation 8, standardised flexibility contracts – strongly contributes to both price discovery and competition)

56 As noted later, more resource is required to deliver these upgrades on time to a high standard.

57 As noted below, some measures in Tranche 1 are already underway.

(b) Tranche 2 comprises measures that are important, but which can be prioritised behind those in Tranche 1 based on current information.

(c) Tranche 3 comprises measures that are recommended, but implementation can come after Tranche 2. Most tranche 3 measures are *contingent,* as explained below.

7.6 A handful of our recommended measures are *contingent.* In particular, we are recommending a chain of actions for competition where implementation of the next action in the chain depends on whether the previous actions are sufficiently effective in practice. Whether the previous actions are sufficiently effective is to be decided by a pre-scheduled assessment by the Authority. The timing, process and broad indicators for this assessment should be set in advance as far as practical. This is explained further in the 'Tranche 3' sections later in this chapter and in Appendix D.

7.7 Our recommended package of actions is presented in this paper in three levels (starting 'wide-angle' moving to 'close-up'):

(a) First (in this chapter), a brief description of each recommended action grouped by tranche and the market pillar that it strengthens the most;

(b) Then (in Chapter 9), an index (table) of our recommendations followed by a schedule of information on each measure; and

(c) Then (at the most close-up level), we drill into five sets of measures in some depth: demand-side flexibility (Appendix A), standardised flexibility contracts (Appendix B), enhanced stress testing (Appendix C), backstop competition measures (Appendix D), and guiding principles for the Future Security and Resilience Project (Appendix E).

Accurate price signals – spot and contract markets

Why it matters

7.8 Accurate price signals act as the musical conductor for the electricity market. With a much greater range of players and more physical resources to coordinate, it is even more important for price signals to be accurate and clear. Upgrades are required to the information that powers the price discovery processes, in both the spot and contract markets. Improvements are also required in the pricing processes themselves. To this end, we recommend the following actions to strengthen accurate price signals.

Tranche 1 as it relates to accurate prices

7.9 There are five accurate pricing measures for urgent implementation in Tranche 1:

(a) **Short-term forecasts** *(Recommendation 1)* – Improve short-term forecasts of wind, solar, and demand. This will provide better information for decision-makers leading into real-time. Accuracy in these forecasts is critical to help participants make good decisions about things like when to charge/discharge batteries, utilise flexible generation or undertake demand response. Making good decisions in these areas will help to minimise system costs and maintain reliable supply. The Authority is already working to improve the accuracy of solar and wind generation forecasts – the work should continue and be accelerated if possible.

(b) **Hedge market transparency** *(Recommendation 2)* – Improve transparency of hedge market activity (especially non-baseload contracts). Where practical, enhanced disclosure should include information on contract offers and bids, as well as executed contracts. This measure is urgent because it addresses challenges that are already emerging in the transition to a renewables-based system. Making that information more transparent will help potential buyers and providers of those products with their risk management and investment decisions. The Authority is already working on this measure – it should continue and be accelerated if possible.

(c) **Demand-side flexibility (DSF) activity monitoring** *(Recommendation 3)* – Monitor provision and uptake of DSF-rewarding activity (including tariffs) and publish a DSF scorecard. Empirical evidence of trends over time in development and consumer uptake of DSF tariffs is critical and to date is largely absent. As detailed in Appendix A, this action combines with a range of other measures to deliver an integrated strategy for DSF.

(d) **Pricing to optimise distribution investment** *(Recommendation 4)* – Authority and Commerce Commission to work together to do more to cause more wide-spread and sooner use of efficient pricing signals for flexibility on distribution networks. If possible, use (or *enable* use of) the Part 4 regime for this purpose. Progress towards pricing structures that signal distribution network needs has been slow and so pricing signals to consumers considering DSF investment are likely to understate its potential to lower network costs.

(e) **Price-driven secure distribution dispatch** *(Recommendation 5)* – Establish a significant multi-year project to develop an efficient form of security constrained economic dispatch (SCED) on distribution networks for the purpose of 'integrating' into the wholesale market widely dispersed DSF and other distributed sources of 'supply'. As a market design exercise, this should be led by the Authority and overseen by a small, enabling group that brings in expert perspectives that span wholesale market design, distribution, transmission, and system operation.

Tranche 2 as it relates to accurate prices

7.10 There are six accurate pricing measures for implementation in Tranche 2:

(a) **Scarcity pricing parameters** *(Recommendation 16)* – Update the security standard and associated settings for the spot market to ensure they properly reflect the value of reliability to consumers. These have not been updated for many years. In addition, consider indexing shortage values (like Australia) and undertake further updates where required. If the parameters are set too low, the system will be less reliable than consumers want (and vice versa).

(b) **Information on development pipeline** *(Recommendation 17)* – Collate and publish comprehensive and regular updates on the demand trends and outlook, project development pipeline, and projected energy/capacity margins. Participants need better information about the supply and demand outlook to make high quality contracting and investment decisions. Transpower's connection enquiry dashboard has significantly improved the visibility of generation and load projects (and so this recommendation is not so urgent as to be put in Tranche 1). However, there are still some significant information gaps.

(c) **Sunset profiling** *(Recommendation 18)* – Change the Code to require use of half-hourly metering data rather than default demand profiles if smart meters are in place. Default profiles are still used for ~40% of users even though 90% of connections have half-hourly metering capability. Continued use of default profiles seriously diminishes incentives to offer and use DSF-rewarding tariffs.

(d) **Network capacity in DSF dispatch** *(Recommendation 19)* – Make Code changes to amend the Default Distributor Agreement (DDA) to require coordination protocols in relation to distribution system limits. This is an interim measure pending development of an efficient form of price-driven secure distribution dispatch *(Recommendation 5).*

(e) **Consumer awareness of DSF** *(Recommendation 20)* – Increase consumer awareness of the opportunities and benefits from providing DSF to the wholesale market, which is low. The Energy

Efficiency and Conservation Authority (EECA), tariff comparison providers and the Authority all have roles to play.

(f) **Market-making for flexibility products** *(Recommendation 24)* – This action is *contingent* on assessing whether previous measures are sufficiently effective, as explained further in Appendix D.

Tranche 3 as it relates to accurate prices

7.11 There are four accurate pricing measures for implementation in Tranche 3. These are all *contingent*:

(a) **Undesirable Trading Situation (UTS) over-ride** *(Recommendation 26)* – Remove the UTS over-ride of trading conduct provisions, *subject to* the trading conduct provisions continuing to perform satisfactorily. Participants' reliance on spot price signals is likely to be compromised if they believe there is significant chance that prices could be revised after the time they apply, particularly for 'last resort' supply when spot prices are high but accurate.

(b) **Ahead market** *(Recommendation 27)* – Investigate and put in place an ahead market *if on review* in 2027 it becomes apparent that adding an ahead market would likely yield significant net benefits. This would be a major change and needs to be considered carefully before any implementation steps are taken.

(c) **Market making for longer-dated futures** *(Recommendation 28)* – Enhance price discovery by requiring market making for longer dated futures. A longer forward curve would help parties facing investment and/or retirement decisions. Putting this measure in place is contingent on *first assessing* whether previous actions have been sufficiently effective.

(d) **Negative offers/prices** *(Recommendation 29)* – Investigate negative offers/prices in the wholesale market as a tool to manage temporary periods of oversupply, *if on review* in 2027 it becomes apparent that the current spot market process could be significantly improved (with benefits greater than costs) by allowing negative offers/prices.

Tools to manage risks

What we mean by 'tools' and why they matter

7.12 Market participants need access to tools to efficiently manage their risks. These tools can be physical options (e.g. an ability to increase supply or reduce demand) or financial arrangements where parties contract with others who can manage the underlying risk at a lower cost on their behalf. Effective risk management of spot price volatility also includes demand-side flexibility (DSF). More intermittent supply will make increased DSF particularly valuable.

7.13 The contract market plays two vital roles. First, it provides products that wholesale buyers and suppliers can use to manage their exposure to spot price risks. The contract market's second critical function is to provide signals to guide longer term decisions – especially investment in generation, storage and demand-side capability.

7.14 We are moving into a world where the electricity system will be much more sensitive to weather effects and participants will need better tools to manage the resulting spot price volatility and associated risks.

7.15 To this end, the contract market must be strengthened so it can do more of the heavy lifting in future. In particular, the market for 'flexibility contracts' needs to develop significantly (see side-box for description of flexibility contracts).

7.16 This finding is based on a range of qualitative and quantitative work, which is set out in our Options Paper. For example, we looked at whether the availability and liquidity of hedge products – especially flexibility contracts – will be sufficient to allow parties to workably manage risk in a renewables-based system.

7.17 Another critical conclusion is that consumers can play a much greater role as a source of flexibility to the system – by shifting their demand in time, or by altering their total demand depending on system conditions. This will bring benefits for consumers (lower bills) and for the system (more resilience). We recommend a range of measures to activate the demand-side market, as explained further in Appendix A.

7.18 Third, we recommend new tools be introduced or explored to reflect the system's changing physical characteristics.

Tranche 1 as it relates to tools

7.19 There are six measures for urgent implementation relating to 'tools' in Tranche 1:

(a) **New reserve product** *(Recommendation 6)* – Develop a new reserve product to cover sudden supply reductions from intermittent sources. This new product should harness the full range of potential resource providers including batteries and demand-side flexibility, be co-optimised with the wider spot market and conform to causer-pays principles. We understand the Authority is working on the design of a new ancillary service product – this work should continue as a priority issue.

(b) **Stress testing** *(Recommendation 7)* – Change the Code to enhance the stress test as recommended in the 'blueprint' set out in Appendix C. Our proposed changes reflect the existing core philosophy that participants must decide their own risk appetite and preferred risk management strategies. The aim of the change is to reinforce participants' incentives to actively manage their exposure to spot price risk, which (in aggregate) underpins the provision of adequate physical resources to ensure reliable supply.

(c) **New flexibility products (standardised)** *(Recommendation 8)* – By a co-design process with the industry, develop one or more standardised flexible supply contracts using the framework set out in Appendix B as a base. Forward price discovery and hedging for flexible supply and DSF products are critical market functions in a renewables-based world, and both are impeded by the lack of any standardised flexibility product(s). Flexibility contracts are expected to become the market's 'secret sauce' – enabling a range of wholesale market processes to function effectively.

What is a flexibility contract?

A flexibility contract (or product) is the term we use to describe a hedge contract that provides the buyer with protection against high spot prices at specific times – such as when intermittent supply is low and/or demand is especially high. This type of contract is expected to become increasingly important in future because it can be used to 'firm' the output of intermittent supply sources, such as wind or solar, that are expected to account for the lion's share of new supply.

We also called this a 'shaped product' in the Issues and Options Papers, because it contrasted with baseload or 'flat' contracts that have the same price mitigation effect in every half hour period.

(d) **Contract process disclosure rules** *(Recommendation 9)* – Develop rules requiring disclosure of process steps by parties negotiating over-the-counter (OTC) contracts.[58]

(e) **DSF interface systems and protocols** *(Recommendation 10)* – Develop a range of new standards and protocols[59] to enable efficient interface among the chain of participants in the DSF market.[60]

58 Better enabling enforcement of any anti-competitive conduct under the relevant legislation.

59 This includes System Operator visibility of DSF activity, communications protocols and standard market contract templates.

60 This includes DSF provider (consumer), retailer/flex-trader, distribution, transmission, and System Operator.

(f) **FSR Project as it relates to demand-side flexibility (DSF)** *(Recommendation 11)* – Future Security and Resilience (FSR) project to bring forward the priority of improving visibility of DSF for the System Operator and remove Code barriers to DSF offering ancillary services. As explained elsewhere, the DSF 'market' will be vital in a renewables system to ensure lowest cost reliable supply for consumers. How this measure fits into our recommended approach to DSF overall is explained more fully in Appendix A.

Tranche 3 as it relates to tools

7.20 There are no measures relating to 'tools' in Tranche 2 but there is one *contingent* action in Tranche 3 – namely, **'Last resort' demand-side flexibility (DSF) scheme** *(Recommendation 30)*, which calls for a procurement process for 'last resort' DSF.

Ensuring adequate competition

Why it matters

7.21 Competition is fundamental to finding and supplying the least cost way of reliably meeting the next increment of demand. As the Commerce Commission explained: "Competitive behaviour is a dynamic process – one that emerges from the rivalry of market participants". It is a process the puts downward pressure on costs and prices, particularly by promoting continuous improvement and innovation. In the words of the High Court: "The practical context is the existence of sufficient rivalry between firms (sellers) to push prices close to efficient costs".

7.22 Adequate competition can be difficult to achieve in electricity markets. However, as Michael Hogan observes:

> "Ensuring competition is a non-negotiable prerequisite for the market in general, much less for proper energy price formation." [61]

Measures for competition in general

7.23 Pursuing the competition goal has permeated all of our work. We believe competition needs to be 'designed in' to market arrangements – not treated as an add-on. That thinking underlines many of the recommendations we have already described. For example:

(a) *Recommendations 3-5, 8, 10-11, 18-20 and 30* will promote greater demand-side flexibility, strengthening competitive disciplines in the spot and contract markets.

(b) *Recommendation 2* will improve information about hedge contract terms and prices and promote competition in the contract market. Improved information on the supply and demand development pipeline under *Recommendation 17* will help competition in new investment and related hedging decisions.

(c) Similarly, *Recommendation 9* will make it harder for any supplier to limit competition via process obstacles or unreasonable non-price terms by increasing transparency of behaviour by parties seeking to agree OTC contracts (rather than mandating contracting terms/practices).[62]

61 Hogan, M., (2016), "Hitting the Mark on Missing Money: How to Ensure Reliability at Least Cost to Consumers", see www.raponline.org/wp-content/uploads/2023/09/rap-hogan-hitting-mark-missing-money-2016-september.pdf.

62 Better enabling enforcement of any anti-competitive conduct under the relevant legislation.

Risk of less competition in flexible supply

7.24 While ensuring adequacy of competition has been a broad motivation, we have given special consideration to one particular area of the wholesale market. Analysis in the Issues Paper and the Options Paper highlighted the potential for a thinning of competition in the provision of flexibility contracts covering periods of a week or longer. This is because a sizeable slice of this flexibility comes from fossil-fuelled generation, and this is expected to progressively shrink.

7.25 New sources of flexibility are likely to emerge over time – such as flexible demand sources, pumped hydro storage, or biofueled thermal operation. Nonetheless, a significant thinning of competition in the provision of longer duration flexibility products is possible because much of the existing physical capacity to back such products is held by parties with the major flexible hydro schemes. Analysis in the Options Paper showed that larger generators with substantial flexible hydro bases may well have greater means and incentive to exercise market power in the supply of flexibility products as thermal generation declines.

7.26 A thinning of competition for flexibility products could tear at the fabric of the broader market. That is because flexibility products provide a critical bridge to integrate intermittent supply into products suitable for retail consumers. Put simply, weaker competition for flexibility products could also undermine competition in the retail and new investment markets.

7.27 Although our analysis cannot be determinative because of uncertainties about the future, it highlights a risk that we think cannot be ignored. Our view is that the risk of declining competition for longer-duration flexibility contracts must be proactively managed – rather than adopting a 'wait and see' approach.

Measures for competition in flexible supply

7.28 As noted earlier, we are recommending a progressive chain of actions for competition in flexible supply where implementation of the next action in the chain depends on whether the previous actions are sufficiently effective in practice. It is, in essence, a three-step ladder, with progression between the steps determined by assessing a dashboard of competition indicators.

Tranche 1 measures for competition

7.29 There are two measures in Tranche 1 as it relates to competition in flexible supply. As explained below, *Recommendation 8* (standardised flexibility products), which is described under 'Tools to manage risk' above, is also a key element on the first rung of the step ladder.

(a) **Competition dashboard** *(Recommendation 12)* – Authority to develop dashboard of competition indicators for flexibility segment of the wholesale market. Indicators could include: (i) the availability and pricing of standardised flexibility products, (ii) availability and pricing of non-standardised flexibility products – such as 'sleeves' or other firming contracts, (iii) the extent to which independent generators and retailers are able to access flexibility products of reasonable terms from the market, and (iv) the extent of actual or planned entry or exit by providers of flexibility – such as biofueled generators or demand response providers.

(b) **Virtual disaggregation – high level outline** *(Recommendation 13)* – Develop high level outline of 'virtual disaggregation' *(Recommendation 31)*, to 'put in the drawer' ready for use if other measures are not effective. If a structural solution is ultimately required to address competition problems in flexibility services, it should be put in place with the least possible delay. That means some initial scoping work in Tranche 1 as a precautionary step, even if it turns out structural options were not ultimately needed.

(c) **New flexibility products (standardised)** *(Recommendation 8)* – As recommended under 'Tools to manage risks' above, by a co-design process with the industry, develop one or more standardised flexible supply contracts using the framework set out in Appendix B as a base. Forward price discovery and hedging for flexible supply (including demand-side flexibility) are foundational for the wider market in a high-renewables world, and both are impeded by the lack of any standardised flexibility product(s). Flexibility contracts will become the market's 'secret sauce' enabling a range of core wholesale market processes to function effectively.

7.30 Some parties might regard it as premature to consider backstop options. We think a 'wait and see' approach would be unwise for a number of reasons. First, it will take time to design backstop options and put them in place. Waiting for a problem to fully emerge before starting that work could mean that an extended harm occurs before a solution is in place. Second, it could lead to hasty and sub-optimal solutions being implemented if a problem emerges. Third, confidence in competition is a foundational 'must have' element for an electricity market. If that confidence is not present, parties will be unlikely to invest at the pace needed to provide reliable and affordable power and there is a continual risk of government intervention.

Tranche 2 measures for competition

7.31 One of the measures in Tranche 2 – **Market making for flexibility products** *(Recommendation 24)* – is grouped under 'accurate price signals' (above). While this reflects its primary emphasis, it is also a key action on our step ladder to safeguard competition in flexible supply. As explained above, this measure is *contingent* on assessing whether previous measures are sufficiently effective. See Appendix D for more information.

Tranche 3 measures for competition

7.32 There is one measure in Tranche 3 as it relates to competition in flexible supply – namely **virtual disaggregation** of parties with undue market power in the supply of flexibility service *(Recommendation 31)*, using the outline developed in Tranche 1 under *Recommendation 13.*

7.33 Based on a range of analysis and advice (set out in paragraph 10.10 of our Options Paper and distilled in Appendix D below), our recommended approach is to first try the menu of conduct measures in Tranches 1 and 2, but then, if they are not sufficiently effective, implement virtual disaggregation. In this context, virtual disaggregation refers to the splitting of the flexible supply capability of the relevant participant(s) into two components:

(a) a portion that would be required to be offered by a defined process and on approved terms – effectively creating one or more additional sources for the supply of longer duration flexibility products; and

(b) the balance of the relevant participant's supply capability, which would remain available to them to use as they think fit.

7.34 If such a backstop measure is needed, it will likely be due to very high concentration of control of flexibility resources in the hands of very few parties, with little or no prospect that new entry or other market processes will alter that market structure in an acceptable timeframe. Put simply, it is possible that supplier concentration for longer-duration flexibility could be so great that market-making arrangements (and other tools in Tranche 2) are insufficient to address the underlying structural market power. In that case, it would be necessary to consider structural solutions to reduce that market power at its source.

7.35 This is described more fully in Appendix D.

Public understanding and confidence

Why it matters

7.36 Public and government confidence in our electricity system is foundational in enabling it to deliver reliable and clean supply at least cost for consumers. Electricity systems are quite complicated and any government's understanding of the fine detail of how they work is always likely to be relatively thin. So what matters is trust in the surrounding institutional arrangements – a sense that there are processes and expertise in place that the public and government can trust to provide the required assurance it all works the way it is supposed to, and strong guidance on how to fix problems if they emerge.

7.37 Achieving public and political confidence is highly influenced by whether there is sufficient competition and whether tools for managing spot risk are properly available, which support efficient new investment and, in turn, adequacy of supply. In this regard, the other measures recommended in this paper are fundamental for delivering public and political confidence in the wholesale market. The measures outlined below are focused on improving public information and understanding, working in conjunction with those other measures.

7.38 Public information is also essential. It must be neutral, clear, timely and relevant for consumers, so it can improve the public understanding of what to expect from our electricity system (about both quality and price) and opportunities for consumers to get better value.

Tranche 1 as it relates to public confidence

7.39 There are two measures relating to public confidence in Tranche 1:

(a) **Governance of FSR project** *(Recommendation 14)* – Incorporating into the terms of reference for the FSR Common Quality Technical Group (CQTG) the tasks of helping to (i) identify and address key economic and technical trade-offs, (ii) oversee that application of the guiding principles, (iii) examine issues where Transpower (or the Authority) may be perceived as having potential conflicts of interest, and (iv) support periodic stakeholder engagement. Recommended guiding principles are set out in Appendix E. We also recommend adding to the CQTG a person with strong experience in economic and technical trade-offs.

(b) **Seasonal outlook report** *(Recommendation 15)* – The Authority to publish quarterly briefings on current and expected market conditions (akin in concept to the quarterly reports published on the primary sector) with a view to regularly calibrating public and political expectations in relation to the wholesale electricity market. We recommend that the Authority draw on various experts to prepare a model seasonal outlook briefing following a process that tests 'mock up' with a sample of the target audience (opinion-makers in policy and public circles), iterating to find a template that achieves the intended communication goals.

Tranche 2 as it relates to public confidence

7.40 There are three measures relating to public confidence in Tranche 2, which should be put in place following Tranche 1. None of the measures in Tranche 2 are contingent on any other actions – they have been spaced simply to make implementation digestible:

(a) **Monitoring and enforcement of Code** *(Recommendation 21)* – Authority to increase resourcing for its monitoring activity, as well as making its monitoring function more independent from its rule-making function by establishing a monitoring and enforcement 'unit' within the Authority.

(b) **Information programme for opinion-makers** *(Recommendation 22)* – Strengthen structured information programme for wider stakeholders on how the market works.

(c) **International experts** *(Recommendation 23)* – Improve international linkages via hosting visiting experts, initiating secondments, hosting a conference or similar measures. We can learn much (both 'dos' and 'don'ts') from experiences in other countries.

Tranche 3 as it relates to public confidence

7.41 There is one measure relating to public confidence in Tranche 3, which should be put in place following Tranche 2 – namely, a **periodic 'warrant of fitness' for the regulatory agency** *(Recommendation 25).* It is not contingent on any other actions. Every five years, carry out a review involving external experts of whether the Authority is delivering the outcomes expected under the regulatory framework. Given that governments' understanding of how the electricity market works in any detail is always likely to be relatively thin, it is crucial that governments have confidence that the institutional arrangements for an independent regulator overseeing the electricity market are sound.

Demand-side flexibility

What it is

7.42 Demand-side flexibility (DSF) comes from consumers shifting their demand in time, or by altering their total demand, depending on system conditions. As the renewables world unfolds, DSF has the potential to play a significant role as both a risk management tool and a source of flexible 'supply' competing with some forms of generation, delivering benefits for both consumers (lower bills) and the system as a whole (more resilience).

7.43 DSF has been talked about a lot over the last 30 years, but not a lot has happened. Demand-side response still plays a relatively limited role in our system[63] – it is starting from a relatively embryonic level.

Integrated measures to activate market

7.44 With this in mind, our three-tranche package of measures contains a combination of actions that tie together to 'activate' DSF in the wholesale market – that is, to enable the core components of a market-driven process in DSF.

7.45 Our approach to DSF is derived from, and fits within, the common framework we are applying to all other aspects of the wholesale electricity market.

7.46 Given the importance of this field, we explain our rationale and recommendations as they relate to DSF in some depth in Appendix A.

An international perspective on DSF

"As it stands today, electricity demand can be increasingly flexible, but precious little has been done to access that flexibility. As new technologies come online at an ever-increasing pace, it's worth taking a closer look to see whether existing wholesale market structures are equipped to handle today's technology."

Source: Sonia Aggarwal and Robbie Orvis "Wholesale electricity market design for rapid decarbonisation – Visions for the Future", June 2019

63 Demand-side response's most significant contribution has come from energy efficiency, rather than dynamic demand. Notwithstanding that, in the New Zealand context, hot water control has been extensively used to manage peak network loadings since the 1960s, public conservation campaigns were used to manage dry years in 2001 and 2003, and some large industrials (e.g. Norske Skog Tasman) became quite sophisticated at dynamically managing demand in response to wholesale and transmission pricing signals.

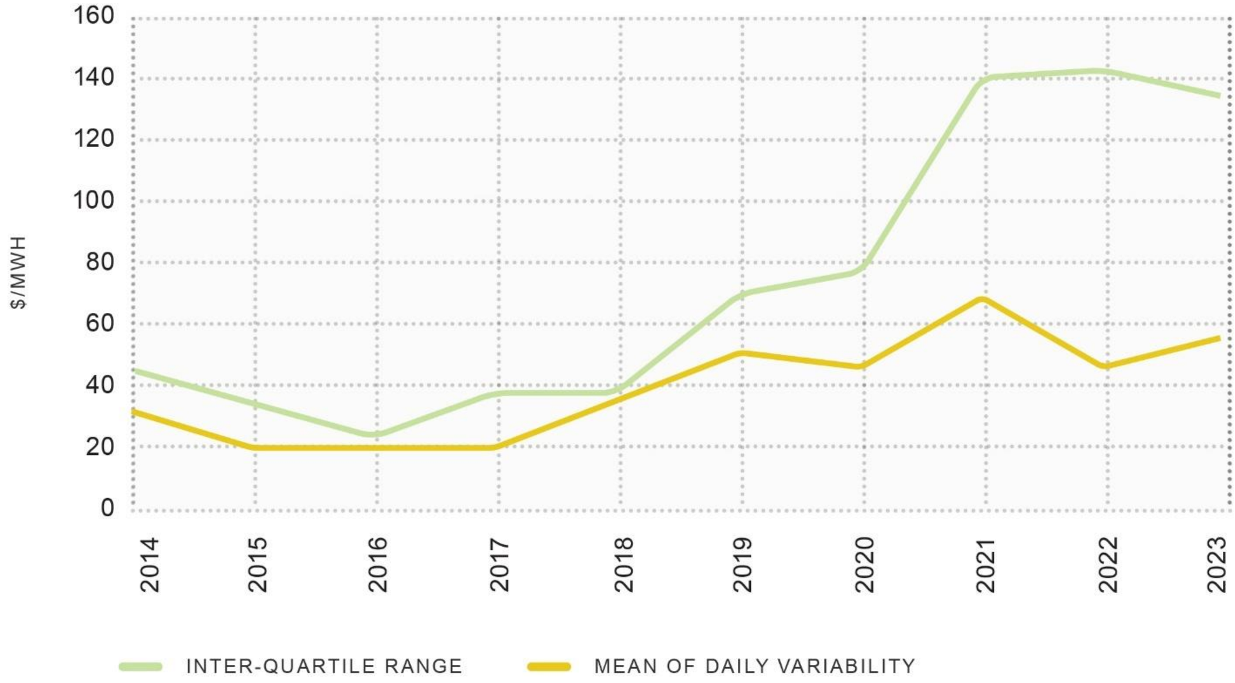
8. Navigating the transition and getting the work done

The future is arriving faster than expected

8.1 Our core task is to identify the changes needed to ensure the electricity market will facilitate and support a shift to a renewables-based system. When we started this project in mid-2021, the destination looked to be sufficiently far into the future that we need not consider the journey of how to get there. With those factors in mind, we focused largely on the 'destination' of a renewables-based system.

8.2 However, it has become increasingly clear that the transition is already underway. Renewable generation averaged 82% in the five years to 2021 and is forecast to reach around 95% by 2025.[64] Spot price volatility has also increased substantially in recent years – with more frequent occurrence of half-hours with very low prices and also more frequent occasions with high spot prices. Figure 14 shows this trend using two measures of spot price variability – and both measures have stepped up markedly in recent years.

Figure 14: Spot price volatility[65]



Keep a clear eye on longer term objectives

8.3 The industry is focused on various issues that feel quite 'pointy' in the near-term. For example, these include potential concerns about reliability for winter 2024, and what to do about forward wholesale prices that appear stuck at high levels well above the cost of new generation. To a large degree, these issues are outside our core brief and are being considered under other workstreams.

64 See BusinessNZ Energy Council's Times NZ modelling at times.bec.org.nz/insights/ and Genesis Energy Insights on Biofuels at media.genesisenergy.co.nz/genesis/investor/2022/Genesis%20Energy%20-%20Biofuels%20Insights.pdf. Both figures are average levels across different weather years.

65 "Inter-Quartile Range" is the price in the 75th percentile half-hour for each year minus the price in the 25th percentile half-hour. "Mean of daily variability" is the mean of each day's standard deviation of half-hourly prices within a year. Years are year ending September. Values are adjusted for inflation, but not mean spot price.

8.4 However, we think some of these pointy issues are manifestations of (or at least related to) the transition that is underway towards a renewables-based system. As a broad observation, we need to ensure that policy responses address underlying causes, rather than resorting to adopt ad hoc or temporary measures that only address symptoms. Experience elsewhere shows that such measures tend to delay the transition by increasing investor uncertainty and/or extending the dependence on fossil-fuelled plant.

Will the transition from fossil-fuelled generation be orderly?

8.5 A core concern in the transition is whether there will be a smooth displacement of fossil-fuelled generation with new renewable sources, or whether the shift will become disorderly. Experience from Australia and some other jurisdictions indicates that a smooth transition is not necessarily a given.

8.6 In our view, there are three distinct risks to consider in relation to thermal transition:

(a) Operational coordination issues, especially poor commitment of slow-start thermal units;

(b) Premature closure of existing thermal plant; and

(c) Inadequate investment in new thermal plant.

8.7 We discuss each of these risks below. In proposing remedies, we also are mindful of the need to avoid ad hoc or temporary 'add on' solutions. This approach is reflected the sage advice from Prof. Peter Cramton cited earlier:

> "Electricity markets are necessarily complex. This follows from the complexity of the engineering and economic problems that must be solved. Still designers should strive to keep the design as simple as possible. **Complicating features should only be added if they are necessary and consistent with market principles.**"[66] [Emphasis added]

Risk of operational coordination problems

8.8 Thermal generation is undergoing a transition. Baseload operation is declining and thermal plant is increasingly being used as a source of flexibility – especially fast-start operation. Some existing thermal units are less well-suited to this role because they take 8-12 hours to start if they are cold. These units need to be 'committed' ahead of time if they are to be available for use. This means that operators need to form a view of whether to start their units based on spot price forecasts some hours into the future. They will be mindful that if the forecasts are wrong, start-costs will be incurred without offsetting revenue.

8.9 The need to make unit commitment decisions is not new.[67] Furthermore, market arrangements are intended to encourage operators to commit units if the benefits to consumers will exceed the start-up costs. For example, if a unit will be required to help satisfy demand for (say) this evening's peak, an operator is likely to commit the unit because of the spot revenues it will earn. This decision is arguably even more likely if the operator has sold forward contracts that mean it would be a net purchaser during the evening if the unit is not running. In short, a combination of clear spot price incentives and contracting activity should produce reasonable unit commitment decisions.

8.10 However, the environment for making unit commitment decisions does appear to be getting more challenging. Start costs have increased substantially due to higher fuel and carbon charges. There is also increased uncertainty in spot forecasts as intermittent generation rises. Finally, the declining *average* use of thermal also means there is a greater frequency of unit commitment decisions being required (i.e. slower-start units are less likely to already be warm or hot).

66 Prof. Peter Cramton, "Electricity Market Design", Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612.

67 Nor are they unique to thermal units. Other resource owners can face similar needs to make decisions ahead of time – such as demand response providers or hydro operators.

8.11 There are already some signs that operational coordination is becoming more challenging. A key indicator in this area is the growing frequency of 'near miss' events where insufficient generation was offered to maintain normal reserves cover and satisfy demand. Such events were very rare after scarcity pricing was introduced in 2013. However, since mid-2021 they have occurred multiple times and there was an actual shortage of generation in August 2021. Unit commitment issues appear to have been a contributing factor in most (if not all) of these events. Importantly, the increased frequency of the events does not reflect an investment adequacy issues, because there was no material change in the installed capacity margin for the North Island over the last five years.

8.12 In summary, unit commitment issues for slower-start thermal are likely to become more challenging in the transition. To help address this issue, the Authority implemented a set of measures to improve information and coordination for winter 2023. These appear to have been beneficial and were recently extended into 2024.[68] We believe the risks can be further reduced through some of the measures in this package, as set out in Table 1 at the end of this chapter.

8.13 The transition challenges have raised questions about the possible merits of some sort of capacity mechanism, such as 'warming contracts'. This would be an ad hoc measure responding to symptoms, not causes. Further, such a mechanism presupposes that directing slow-start thermal generators to 'warm up' (paid for by the industry as a whole) is the lowest cost option for ensuring reliability to cover winter peaks. This precludes other solutions that may be less costly. As discussed in Chapter 5 a key lesson from history is that no single or small group of decision-makers can see or deploy the full range of optimal solutions – consumers end up paying more than they should.

8.14 Another key reason we do not favour warming contracts is the likely chilling effect on contracting and investment incentives, and the consequent risk of undermining reliability. We think it is better to focus on mechanisms that find the least cost solutions, as we do in matching supply and demand in any other time interval.[69]

Risk of premature closure of existing thermal plant

8.15 Thermal plant owners face a declining revenue outlook as renewables account for a rising share of total supply. However, this should not necessarily cause *premature* thermal plant closures. This is because units that are providing a service whose value to consumers exceeds the go-forward retention costs should in principle produce net revenues for their owners. Hence, the real question is whether there are factors that will depress revenues below the value of plant retention to consumers.

8.16 Based on current information, we think the answer is likely to be 'no' in New Zealand, unlike some other countries. First, we are not aware of any evidence to show that market rules or processes are causing spot prices to be artificially suppressed when thermal plant is required. On the contrary New Zealand introduced a robust scarcity pricing arrangement in 2013.[70]

68 See www.ea.govt.nz/news/general-news/three-winter-2023-options-to-be-retained/.

69 This is addressed more fully in the Authority's consultation on efficient solutions to promote consumer interests through winter 2023 (see www.ea.govt.nz/projects/all/managing-peak-winter-electricity-demand/consultation/driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023/).

70 Having said that, we are proposing a review of the values used in the scarcity pricing mechanism to ensure they are accurate for the contemporary and future system.

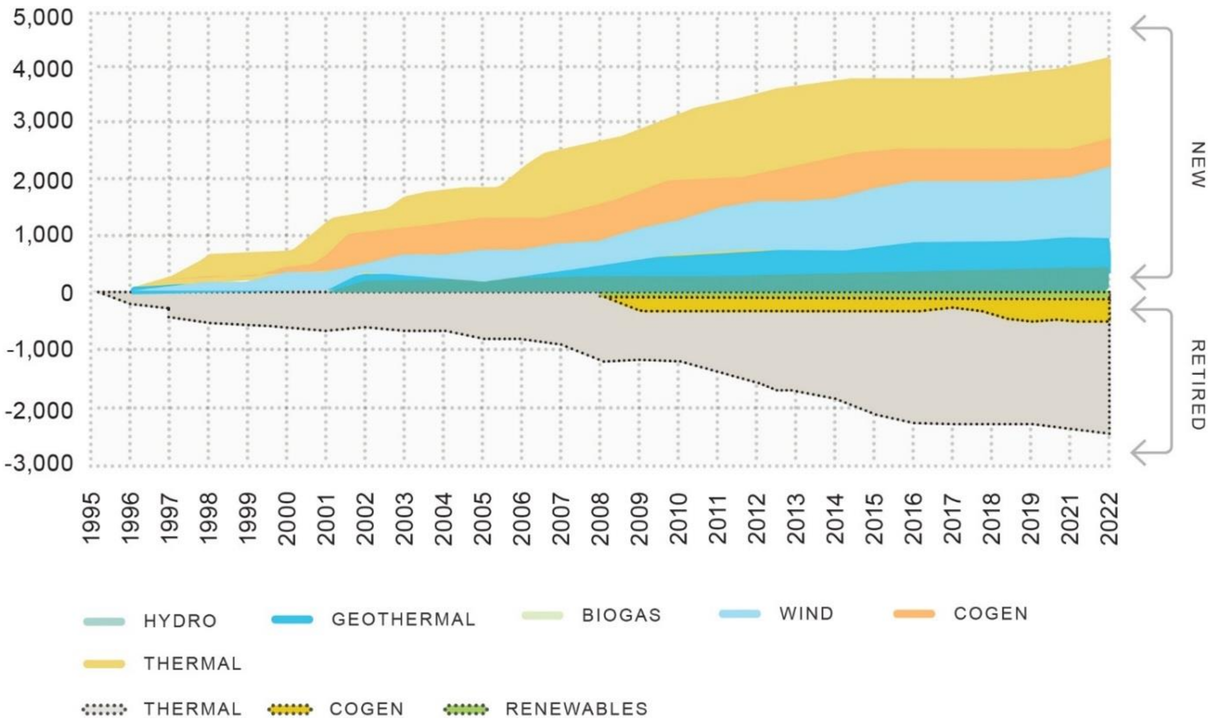
8.17 Of course, thermal operators will likely want some degree of certainty about forward revenues, rather than relying solely on expectations of future spot prices to inform their retention/retirement decisions. Historical experience suggests the process of negotiating such contracts can be noisy as parties manoeuvre to strike the best possible deal from their perspective. Nonetheless such contracts have been concluded in the past, and it appears deals are continuing to be struck in recent years. For example, Meridian announced it had concluded deals with Contact and Nova.[71]

NZ wholesale market inherently coordinates renewable entry and thermal exit

8.18 In some other jurisdictions renewables are heavily subsidised by instruments outside of the wholesale market. This can make it harder for thermal units to earn sufficient spot or contract revenue in the wholesale electricity market to justify retention. This has been referred to as the 'merit order' effect.[72]

8.19 This factor does not currently apply in New Zealand because renewables are competitive without subsidies. Both renewable and thermal generation types obtain their revenue exclusively from the wholesale electricity market. This provides a natural coordination mechanism, because new entry (of any type) tends to reduce the wholesale revenue pool available for other generation, which in turn induces retirement of higher-cost (especially thermal) plant.[73] This is illustrated by Figure 15.

Figure 15: Entry and exit of renewable and thermal generation since 1995



71 See www.meridianenergy.co.nz/news-and-events/meridian-and-contact-agree-swaption-and-cfd-deal and www.meridianenergy.co.nz/news-and-events/meridian-and-nova-agree-swaption-deal.

72 As noted by Prof Paul Simshauser, this merit order effect is only unwound when thermal plant is forced to exit as a result of "financial distress arising from policy-induced [Variable Renewable Energy] plant entry". See Simshauser (2019), "On the Stability of Energy-Only Markets with Government-Initiated Contracts-for-Differences" Energies 2019, vol 12, page 11.

73 By contrast, in overseas jurisdictions where there are explicit policy instruments which incentivise the entry of renewables, Prof Paul Joskow notes that the "policy of incentivising large scale entry of intermittent solar and wind has been made relatively easy so far by free riding on the declining existing stock of dispatchable generating capacity." He notes that in a situation where entry continues to be driven by centralised policy, while exit of thermal is determined by market-driven energy and ancillary service prices, it is not at all clear whether the system will find the lowest-cost solution to consumers. See 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.

8.20 In summary, there should not be a high risk of premature thermal plant retirement in New Zealand. However, some of the measures to improve risk management and investment discussed in Chapter 7 should further reduce the risk. The measures of particular benefit in the transition are summarised in Table 1 below.

Risk of insufficient investment in additional flexibility resources such as additional fast-start thermal plant

8.21 It is likely that investment in additional flexible resources will be needed at some point – such as bio-fuelled generation. In principle, such investment ought to be forthcoming if it is genuinely required because of the contracting and investment incentives generated within the wholesale market. However, a range of measures in this package should further reduce the risk of any delay for efficient investment. These include *Recommendation 6* (new reserve product), *Recommendation 7* (stress testing) and *Recommendation 8* (new standardised flexibility products).

8.22 Finally, investors considering the development of new flexibility solutions are likely to be quite sensitive to policy uncertainties, such as fuel sector and emissions policy settings. The Authority should ensure that agencies in charge of fuel and emission policy have a thorough understanding of the implications in the electricity sector of any measures that would extend or magnify policy uncertainty.

8.23 In addition, the incoming government's announcements in relation to the NZ Battery Project should reduce the uncertainty issue referred to above. Similarly, timely statements of the government's policy would be helpful in relation to:

(a) whether any additional policy instruments (beyond the Emissions Trading Scheme) will be put in place enacted to restrict fossil fuel use for power generation; and

(b) the importance of market participants taking steps to prudently and proactively manage spot price risk, recognising that spot prices are volatile and have the potential to be very high during periods when supply is tight.

Recommended measures to facilitate an orderly transition

8.24 Many of the measures recommended earlier in this paper will help to ensure an orderly transition. However, the measures in Table 1 are especially important and we recommend they be prioritised for early action.

Table 1: Measures of particular importance to facilitate orderly transition

RECOMMENDATION NO.	OPTION NAME	HOW IT FACILITATES ORDERLY TRANSITION
1	Short-term forecasts	Better information will assist operational coordination (unit commitment) decisions
2	Hedge market transparency	Improves investment signals and supports greater confidence in the market
6	New reserve product	New ancillary service should reduce exposure to sudden large fluctuations in wind/solar output
7	Stress testing	Encourages appropriate forward contracting
16	Scarcity pricing parameters	Supports accurate price signals to assist operational coordination (unit commitment) decisions and promote efficient pricing in periods of scarcity,[74] which is extremely important over time to achieve efficient consumption and investment decisions in our energy-only market.

74 See Annex 3 of MDAG's High Standard of Trading Conduct Discussion Paper for more explanation on why efficient price signals in periods of shortage is so important in our energy-only market. As Prof George Yarrow and Dr Decker point out, short-run

Getting the work done

Urgent action needed as electricity system is already changing

8.25 The transformation of New Zealand's electricity system has already begun:

(a) There has been a surge in renewable investment in the last few years and renewable generation is projected to reach around 95% by 2025 – compared to an average of 82% in the five years to 2021.[75]

(b) Spot price volatility has also increased greatly.

8.26 In short, time is of the essence to put in place the measures required to strengthen the core elements of the wholesale electricity market to meet the challenges of the new era.

Recommendations are a package and require quality and timely implementation

8.27 It may be tempting to view our recommendations as a kind of 'regulatory buffet' of disparate measures from which interested parties can pick and choose what to put on their plate – 'a little of this, a little of that, none of those things, and in an appetiser portion'. But this approach won't work.

8.28 Our recommendations form an integrated package to be implemented as a sustained and coordinated programme of action over the coming years.

8.29 If the wholesale electricity market over the last 20 years has been 'version 1', our recommendations are designed to accelerate the arrival of 'version 2', fit for purpose to deliver reliable renewable electricity at lowest cost for the long-term benefit of consumers.

8.30 In Chapter 9, we give clear guidance on the priority, sequencing and key parameters for the implementation process for each recommended measure.

8.31 For some measures, we have given more specific guidance:

(a) For developing standardised flexibility products *(Recommendation 8)*, we have developed an initial framework as a platform for further work in an industry co-design process (Appendix B).

(b) For enhanced stress testing *(Recommendation 7)* we have developed a 'blueprint' to enable early implementation (Appendix C).

(c) For the high level of outline of virtual disaggregation *(Recommendation 13)*, we have set out a framework of the key design elements to be considered (Appendix D under "Virtual disaggregation is preferred backstop tool").

(d) For FSR project governance *(Recommendation 12)*, we have developed a 'blueprint' for the Guiding Principles to enable early implementation (Appendix E).

efficiency requires clearing prices to reflect economic cost, which includes scarcity rents - Yarrow, Decker, Nov 2014 at p.4, 2nd to last para. Further, as Prof Paul Joskow points out, scarcity pricing is not a departure from the basic principle of short run marginal cost pricing. Rather, changes in price (moving along the demand curve) when capacity constraints are binding reflect represent consumers' short run marginal opportunity cost of having more or less generating capacity - Joskow, Paul L. 2008, "Capacity Payments in Imperfectly Competitive Electricity Markets," Utilities Policy, 16:159-170.

75 See BusinessNZ Energy Council's Times NZ modelling at times.bec.org.nz/insights/ and Genesis Energy Insights on Biofuels at media.genesisenergy.co.nz/genesis/investor/2022/Genesis%20Energy%20-%20Biofuels%20Insights.pdf. Both figures are average levels across different weather years.

How to undertake the work

8.32 Many of the actions recommended in this paper are ‘bread and butter’ regulatory measures. They should fit well with the typical approaches used by the Authority when considering possible amendments to the Code – i.e. analytical work (possibly including an advisory group or targeted stakeholder engagement) followed by formal consultation and then decision-making on the final form of any amendments.

8.33 However, some of the recommendations are market acceleration or facilitation measures rather than regulatory instruments. For example, work on standardised flexibility products *(Recommendation 8)* or certain measures to activate a market-driven development of demand-side response (for example, *Recommendation 10)*.

8.34 For these actions, we believe the Authority should (at least initially) undertake a facilitation and sponsorship role. This means more of the onus would be placed on stakeholders to co-design solutions, working with a framework established (and monitored) by the Authority. The Authority (and its predecessors) have successfully used market facilitation approaches in the past, especially for issues that were relatively complex and in an early stage of development.

8.35 We think the Telecommunication Carriers Forum’s (TCF) process for developing codes covering non-price elements for competitive access to the ‘monopoly’ local telecom wires may also be a useful point of reference.[76] For example, an analogous process could be used to progress *Recommendation 8* (co-design of standardised flexibility products).

8.36 Success in the TCF multilateral process relied (among other things) on wide participation of market participants, a rigorous analytical framework,[77] and a shared commitment to a disciplined process in which all participants understood that a co-designed common-good solution would better than the regulated alternative.[78]

8.37 There may also be a case for using a hybrid approach in some cases with market facilitation followed (if necessary) by regulation. This would allow issues to be initially explored in a less formal (and hopefully more collaborative) environment, followed by Code development to address outstanding issues. An example where a hybrid approach may be useful is *Recommendation 9* (contract process disclosure rules).

8.38 A table of measures and recommended approach to implementation is set out at the start of Chapter 9.

Resources for wholesale market development work

8.39 This report is recommending a sizeable package of changes to strengthen the wholesale market. Furthermore, we think fast progress is needed on many of measures because the transition is well underway. If our recommendations are accepted by the Authority, there will be a need to make a step-change in the rate of development of electricity sector arrangements.

8.40 As discussed above, most of that development work would fall to the Authority to undertake or lead. It is possible that the Authority may be able to free up some resources by reprioritising existing activities. However, reprioritisation alone is very unlikely to free up the level of resources needed to undertake the proposed work. It is therefore imperative that the resourcing for the Authority be reviewed to enable implementation of the workplan with urgency. It is also imperative that the Authority give serious consideration to a co-design or hybrid process for certain measures to enable it to tap into the resources and expertise of the wider industry.

76 In 2006/07, the TCF delivered a suite of significant agreements on non-pricing terms for access seekers using Telecom’s local loop network. These TCF agreements were substantially reflected in the relevant Commerce Commission standard terms determinations (STDs) issued during 2007 and 2008. The role and framework of the industry’s working groups are set out in sections 2 and 3 of this TCF report – see www.tcf.org.nz/news/2006-local-loop-unbundling-and-ndsl-phase-1-report. The government of the day backed the industry’s process – see www.beehive.govt.nz/release/telco-forum-praised-llu-agreement.

77 With clearly defined objectives and criteria focused on efficient outcomes for the long-term benefit of consumers.

78 In the TCF process, the Commerce Commission had the power to prescribe an access code.

9. Our specific recommendations

Outline

9.1 This chapter sets out the specific recommendations that form the building blocks of our package of changes for the wholesale electricity market.

9.2 As explained earlier, we have divided our recommendations into three tranches based on their relative priority:[79]

(a) **Tranche 1** – comprises measures that are required urgently – to address issues already arising, to support a smooth transition, or to lay the foundation for later work;[80]

(b) **Tranche 2** – comprises measures that are important, but can be prioritised behind Tranche 1 measures based on current information; and

(c) **Tranche 3** – comprises measures that are recommended, but implementation can come after Tranche 2. Most tranche 3 measures are *contingent*, as explained below.

9.3 A recommended measure is *contingent* if its implementation depends on an assessment of whether previous actions have been sufficiently effective in practice. This is explained further in the relevant measures below.

9.4 As explained in Chapter 6, our package of recommendations is designed to strengthen the four core elements (or pillars) of the wholesale electricity market for a high-renewables future.

9.5 All recommended actions contribute (directly or indirectly) to all four core elements of the wholesale market. For the purposes of grouping, however, each action (or measure) is sorted by the core market element to which it contributes with more emphasis (or with a higher profile).[81]

9.6 The relevant core market elements are shown using the following icons:

9.7 In describing each measure, we also note and provide a link to its origins in our Library of Options paper.

79 This reflects the suggestions raised in submissions about the need for a clear prioritisation of recommendations. For example, Aurora submitted that "there will need to be a triage process whereby the various recommendations are considered in terms of their benefits, costs, capacity and capability to execute or implement" and by the BusinessNZ Energy Council submitted that "it could be beneficial to rank each option by priority. For instance, identifying and ranking what must happen now in 2023 to ensure New Zealand is on the path to 100% R.E, and what could occur later, once we witness the full extent of more renewable penetration."

80 As noted below, some measures in Tranche 1 are already underway.

81 In some cases, the difference in a measure's contribution to one core market component relative to other core component is not great (e.g. Recommendation 8, standardised flexibility contracts – strongly contributes to both price discovery and competition).

9.8 In addition, we summarise the general views of submitters (with some examples) and identify key issues raised for each option that forms the basis of our recommendations. Keep in mind that not every submitter expressed a view on every option – most options were only discussed by a portion of submitters. When discussing trends in submitter feedback, we refer only to submissions that expressed a view on the specific issue or option. (More information on submissions is set out in Appendix G).

9.9 In describing each recommended measure, we have also noted ‘who makes it happen’. Usually, we expect the Authority to be the party to implement the measure, but in some cases this may be in conjunction with other parties (e.g. industry co-design),[82] or led by another organisation altogether.

9.10 But first we set out (for ease of reference) a table of all our recommended measures. A schedule for each measure follows.

82 Several parties expressed support for this approach in their submissions. For example, Manawa noted that it “strongly supports the MDAG recommendation for a wide stakeholder group to utilize the “Co-design” or “Hybrid” process for developing solutions, with the Electricity Authority (the Authority) to undertake a facilitation and sponsorship role.”

Table 2: Tranche 1 measures

Recommendation Number	Name	Key action	Accurate pricing (price discovery)	Tools (to manage risk)	Competition	Public confidence	Responsible party	Options Paper code	Comments relative to Options Paper
TRANCHE 1									
1	Short-term forecasts	Improve short-term forecasts of wind, solar, and demand	✓				Authority (in progress)	A1	
2	Hedge market transparency	Improve transparency of hedge info (especially non-base load) covering offers, bids and agreed prices	✓				Authority (in progress)	B1 D2	
3	DSF activity monitoring	Monitor provision and uptake of DSF-rewarding activity (including tariffs)	✓				Authority (in progress)	C1	
4	Pricing to optimise distribution investment	Use Part 4 regime to require distribution pricing signals for DSF	✓				Authority and Commerce Commission	C11	
5	Price-driven secure distribution dispatch	Develop design and trial tools to enable security constrained economic dispatch on the distribution network	✓				Authority for concept design then 'common good' EDB trials	C12	A longer term solution is required for coordination on distribution networks. This is a new measure arising from consideration of Option C12.
6	New reserve product	Develop new reserve product to cover sudden reduction from intermittent sources		✓			Authority (in progress)	A4	
7	Stress testing	Strengthen existing stress testing regime		✓			Authority	B4	
8	New flexibility products (standardised)	Develop standardised flexibility product(s) (including DSF)		✓			Industry co-design with Authority as backstop	Combined B5 C4	B5 and C4 were previously separate measures. Now integrated into common standardised products
9	Contract process disclosure rules	Develop rules requiring disclosure of process steps by parties negotiating OTC contracts		✓			Authority (with stakeholder input)	B6 D3	

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Table 3: Tranche 1 measures (continued)

Recommendation Number	Name	Key action	Accurate pricing (price discovery)	Tools (to manage risk)	Competition	Public confidence	Responsible party	Options Paper code	Comments relative to Options Paper
TRANCHE 1 CONTINUED (from previous page)									
10	DSF interface systems and protocols	Broad based trials (with significant funding from government) to establish common system interface protocols for DSF across full value chain		✓			MBIE and Ara Ake	C5	
11	FSR Project (as it relates to DSF)	Improve visibility of DSF for System Operator and remove Code barriers to DSF offering ancillary services		✓			Authority (in progress)	C8	
12	Competition dashboard	Develop dashboard of competition indicators for flexibility segment of wholesale market			✓		Authority	D1	
13	"Virtual disaggregation (high level outline)"	Develop high level outline of 'virtual disaggregation', to 'put in draw' ready for use if other measures are not effective			✓		Authority	D7	Gives effect to paras 3.65, 10.25 + 10.29 of Options paper: "an outline..should be developed early on…"
14	FSR Project (Governance)	Strengthen governance for next phase of FSR project with guiding principles				✓	Authority (in progress)	A2	
15	Seasonal outlook report	Calibrate public expectations with quarterly briefings on current and expected market conditions				✓	Authority	E2	

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Table 4: Tranche 2 measures

Recommendation Number	Name	Key action	Accurate pricing (price discovery)	Tools (to manage risk)	Competition	Public confidence	Responsible party	Options Paper code	Comments relative to Options Paper
TRANCHE 2									
16	Scarcity pricing paramaters	Update default shortage values in Code factoring in related elements	✓				Authority	A3	
17	Information on development pipeline	Publish aggregated information on pipeline of new developments, energy and capacity adequacy	✓				Authority or Transpower (with stakeholder input)	B3	
18	Sunset profiling	Sunset profiling if smart meters in place	✓				Authority (in progress)	C2	
19	Network capacity in DSF dispatch	Ensure distribution network capacity is reflected in wholesale DSF dispatch	✓				Authority	C12	C12 has been split into two related but separate recommendations. R19 is the interim solution, R5 (price driven secure distribution dispatch) is the longer-term solution
20	Consumer awareness of DSF	Increase consumer awareness of the opportunities and benefits from providing DSF to the wholesale market	✓				Authority	Combined C13 C14	Previously separate measures for large users and domestic customers
21	Monitoring and enforcement of Code	Enhance monitoring and enforcement of the Code with more autonomy				✓	Authority	E4	
22	Information programme for opinion-makers	Strengthen structured information programme for wider stakeholders on how the market works				✓	Authority	E1	
23	International experts	Increase inter-change with international experts				✓	Authority	E3	
TRANCHE 2 - CONTINGENT MEASURES									
24	Market making for flexibility products	Enhance price discovery by requiring market making in flexibility products	✓				Authority	B8 D5	To be put in place if previous measures not sufficiently effective

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Table 5: Tranche 3 measures

Recommendation Number	Name	Key action	Accurate pricing (price discovery)	Tools (to manage risk)	Competition	Public confidence	Responsible party	Options Paper code	Comments relative to Options Paper
TRANCHE 3									
25	WoF for regulatory agencies	Establish periodic warrant of fitness review for independent regulatory agencies				✓	Authority and MBIE	E5	
TRANCHE 3 - CONTINGENT MEASURES									
26	UTS over-ride	Remove UTS over-ride of trading conduct provisions	✓				Authority	A7	Subject to the trading conduct provisions continuing to perform satisfactorily
27	Ahead market	Investigate and develop ahead market	✓				Authority	A6	To be considered if previous measures not sufficiently effective
28	Market making for longer-dated futures	Enhance price discovery by requiring market-making for longer dated futures	✓				Authority (with stakeholder input)	B2	To be put in place if previous measures not sufficiently effective
29	Negative offers/ prices	Allow negative offers/ prices in the wholesale market as a tool to signal oversupply	✓				Authority	A8	To be considered when resources are available
30	'Last resort' DSF scheme	Develop procurement process for 'last resort' DSF		✓			Authority	C10	To be developed in place if previous DSF measures not sufficiently effective
31	Virtual disaggregation	Implement virtual disaggregation of flexible generation base (use outline developed under R13)			✓		Authority	D7	To be put in place if previous measures not sufficiently effective

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Tranche 1 measures

Recommendation 1 – Short-term forecasts

Improve short-term forecasts of wind, solar and demand

Issue to be addressed	Short-term forecasts (e.g. for 12 hours ahead) of demand and intermittent supply can be misleading and cause inefficiencies or reliability problems. Accuracy in these forecasts is critical to help participants make good decisions about things like when to charge/discharge batteries, utilise flexible generation or undertake demand response. Making good decisions in these areas will help to minimise system costs and maintain reliable supply.
Options Paper proposal	Improve short-term forecasts of wind, solar and demand (see Option A1).
Submitter feedback	Submissions generally supported the proposal, although SolarZero noted that improved forecasts will not be sufficient solution on their own.[83]
MDAG comment	The Authority is already working to improve the accuracy of solar and wind generation forecasts. This work should continue and be accelerated if possible.
MDAG conclusion	The Authority should improve short-term forecasts of wind, solar and demand by: • continuing (and accelerating) work to improve short-term forecasts of wind and solar generation; • providing information to help participants understand the sensitivity of spot prices to variations in demand and intermittent generation; • seeking feedback from participants on whether additional types of forecast information would be useful for short-term planning decisions; and • regularly reviewing the accuracy of forecast inputs to ensure they provide the right information, and updating forecasting arrangements as necessary to reflect the changing characteristics of the system.
Implementation	**Tranche**: 1 **Timing**: Immediate start, in place as soon as possible. This measure is urgent because it addresses challenges that are already emerging in the transition to a renewables-based system. **Who makes it happen**: The Authority **Method**: Decisions by the Authority on Code changes and/or procurement of forecasts from service providers

83 SolarZero submitted that "potentially better forecasts help, but still need better systems for coping with the variability."

Recommendation 2 – Hedge market transparency

Improve transparency of hedge information (especially non-base load) covering offers, bids and agreed prices

Issue to be addressed	Participants have limited information to assess the value of non-baseload contracts because the existing hedge disclosure regime does not cater well for these products. This inhibits contracting for such products with flow-on consequences for risk management and investment decisions.
Options Paper proposal	Greater transparency of hedge information (especially non-baseload) covering offers, bids + agreed prices (see Option B1 and Option D2).
Submitter feedback	Submissions generally supported the proposed change, although a few submissions expressed reservations relating to disclosing unsuccessful bids/offers or that the change would incur significant administrative costs.[84]
MDAG comment	We acknowledge that there are still some details to work through, particularly in relation to establishing a minimum threshold at which an inquiry will be considered a valid bid or offer that must be disclosed. However, we consider this measure to be worth pursuing as these non-baseload contracts are already important and will become increasingly more so as the system shifts towards renewable supply. Disclosure of contract offers and bids not 'married' is important information in the market's price discovery process for hedges.
MDAG conclusion	The Authority should improve the transparency of contract information,[85] especially non-baseload products, by: • providing more information on non-baseload (i.e. flexibility) products; • providing information on prices for contract modifications/extensions (currently these may not trigger disclosure); and • providing information on contract offers/bids that did not result in an executed deal (subject to these meeting a minimum threshold of validity). In addition, the arrangements should ensure that information is disclosed in a timely way.
Implementation	**Tranche**: 1 **Timing**: Immediate start, in place by late 2024. This measure is urgent because it addresses challenges that are already emerging in the transition to a renewables-based system. The Authority has already begun work in this space – this should be accelerated if possible **Direct linkage**: This recommendation has a direct interdependency with Recommendation 8 – new standardised flexibility products. **Who makes it happen**: The Authority with stakeholder input on the detailed rule design **Method**: Decisions by the Authority on Code changes

84 For example, while Meridian supported "extending the disclosure obligation to include information on contract offers/bids that do not result in an agreement" Genesis did not support this on the basis that "the limited potential benefits are outweighed by the potential for this information to be misinterpreted or miscommunicated (intentionally or otherwise)." Contact was concerned that the option could create significant administrative costs and was "unsure how this option could improve security of supply".

85 To view hedge disclosure data, see www.electricitycontract.co.nz.

Recommendation 3 – DSF activity monitoring

Monitor provision and uptake of demand-side flexibility (DSF) rewarding activity (including tariffs)

Issue to be addressed	The Authority needs to monitor a range of measures to properly understand and track the degree to which DSF is opening up in the marketplace. This is information is not routinely collected (at present, it tends to be ad-hoc), and does not allow any trends to be established. This is essential for the Authority to gauge the degree to which recommended measures are working and whether any further changes are required.
Options Paper proposal	Monitor provision + uptake of DSF-rewarding tariffs (see Option C1)
Submitter feedback	Submissions generally supported this proposal. Some parties disagreed on the basis that independent flexibility traders need to be considered,[86] and others queried the measure's effectiveness.[87] Enel X submitted (in response to options relating to DSF-rewarding tariffs generally) that such a solution "doesn't get to the heart of the problem: that without competition in providing flexibility services, retailers do not have a natural incentive to offer them".
MDAG comment	A small number of submitters opposed this proposal on the basis that it was not clear how it would increase DSF uptake. However, the recommendation is intended to improve the evidence available to the Electricity Authority, which would be used to design further measures (if necessary) to facilitate DSF uptake. MDAG agrees that independent flexibility traders should be included in the monitoring regime. The Authority has undertaken some initial work on this measure, however it should be accelerated if possible.

86 Contact did not agree that "retailers are in the best position to optimise the use of DSF across network and wholesale benefits" and if they did "then it is essential this information is made available in order to enable independent flex traders to grow a competitive DSF market".

87 Flick queried "whether the costs associated with setting up an ongoing monitoring function – involving all retailers – will achieve a net benefit and the desired outcome" as uptake of time-of-use tariffs "does not necessarily translate to greater off-peak usage."

MDAG conclusion	The Authority should change market rules to require participants to regularly disclose: • available tariffs that reward DSF[88] (including any that see the flexibility operated by a third party), and the number of consumers using these tariffs, across the full spectrum of customer types; • the proportion of consumption volumes being reconciled via profiles rather than half-hourly data; and • the usage and performance of its dispatch notification product, as well as any DSF providers registering as dispatch capable load stations. The Authority will need to develop and define subcategories of tariffs that fit the "DSF rewarding" subcategory. Ideally, monitoring and disclosure requirements should apply beyond just electricity retailers and include flexibility traders who are not retailers but are providing commercial arrangements that reward DSF. The Authority should combine this quantitative data with other qualitative information to produce an annual industry "DSF scorecard". Qualitative information would include surveys of large customers regarding their use of, or planned investment in, DSF; use of dynamic operating envelopes in distribution networks; arrangements providing flexibility intermediaries access to hot water control)[89] The primary objective of this scorecard would be to assess the degree to which the industry is making progress in respect of providing a variety of arrangements available to customers that incentivise them to provide flexibility to the market. The scorecard could take a similar form to Recommendation 12 – Competition dashboard.
Implementation	**Tranche**: 1 **Timing**: Immediate start, in place by mid-2024. Trends over time in development and consumer uptake of DSF tariffs will be especially important as an evidence base, so the sooner data collection can begin, the sooner trends will become apparent. **Linkages**: Monitoring commercial arrangements beyond retailers could be linked with the Authority considering the place of flexibility traders under the Code. **Who makes it happen**: The Authority with expert input from industry (e.g. via the FlexForum) **Method**: Decision by the Authority on Code changes.

88 Our intention is to include DSF that is incentivised over short and medium timeframes, to allow for the eventuality that some intermediaries may develop tariffs that incentivise conservation in a low inflow period or dunkelflaute situation,

89 The FlexForum's Flexibility Plan 1.0 has a number of steps about visibility of data relating to flexibility opportunities – the Authority could integrate this data into the scorecard. See www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf.

Recommendation 4 – Pricing to optimise distribution investment

Monitor provision and uptake of demand-side flexibility (DSF) rewarding activity (including tariffs)

Use Part 4 regime of the Commerce Act to require distribution pricing signals for DSF

Issue to be addressed	Across New Zealand's 29 electricity distribution businesses (EDBs), distribution pricing is an imperfect reflection of network 'scarcity' as distribution tariffs are pre-determined and applied across broad areas of the network. The Authority reports that EDB progress towards pricing structures that signal network needs (to the extent possible within the constraints of static tariffs) has been slow.[90] In short, the distribution pricing signal to consumers considering DSF investment is likely to understate its potential to lower network investment costs.
Options Paper proposal	Ensure distribution pricing reflects network needs (see Option C11)
Submitter feedback	Submitters generally supported this option.[91] No submitters directly opposed the option, but some identified concerns or particular areas of focus.[92] EDBs submitted that there are practical limits to how dynamic network pricing can be today, thus limiting their ability to provide a signal that approximates the marginal cost of supply within the distribution network. Aurora observed that MDAG's timeline for this proposal was unlikely to be feasible, as EDBs' pricing will be constrained by the LFC regulations until 2027. Aurora proposed that an interim 2025 target could be that an agreed implementation plan is in place for each EDB. Aurora also argued that a 'market-led' model through contracted flexibility services would likely deliver better outcomes than more dynamic price signals.

90 A few electricity distribution businesses (EDBs) are making good progress in this domain. Most seem to be giving it lower priority. Some seem to be simply indifferent. As the Authority concludes: "there has been little progress in establishing price signals that reward flexibility, and some regression with respect to services subject to control" – see page 3 of "Targeted reform of distribution pricing: Issues Paper", Electricity Authority, 2023 at www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf.

91 For example, MEUG considered that "improvements here will be extremely beneficial, ensuring demand side participants have transparency of network congestion and better insight into the value of DSF at their location."

92 For example, Contact noted that it would "like to see a focus on ensuring that other network charges are cost-reflective, such as connection costs" and Orion submitted that the Authority should ensure it considers "interaction with other mechanisms, such as flexibility services … and the temporal or spatial granularity required to achieve optimal outcomes". Aurora submitted that "the Authority should consider whether a fully principles-based approach to regulation of distributors pricing methodologies is likely to be effective and is still fit for purpose".

MDAG comment	We accept Aurora's contention that the LFC phaseout is a constraint but note the Authority's view that more progress could be made today, even with the LFC regulation still in place.[93] We acknowledge EDBs' concerns regarding the limits of network pricing today to provide a dynamic signal for DSF. However, we reinforce that static network pricing can only ever be an imperfect substitute for a dynamic marginal price (see Recommendations 5 and 19). While MDAG agrees that contracting for flexibility services has a role to play, we are not convinced that relying on a contracting process *instead of* more transparent and dynamic price signals will lead to more rapid, sustainable and efficient deployment of DSF.[94] Further, without disclosure requirements, it would risk a lack of transparency in the value of flexibility, as considered more fully in Recommendation 2. MDAG believes that both approaches are required. Supporting our objective to achieve the lowest overall system cost to the consumer, we believe network pricing has a strong role to play, and significant improvements could be made over the status quo. Progress towards pricing structures that signal distribution network needs has been slow and so the distribution pricing signals to consumers considering DSDF investment are likely to understate its potential to lower network costs. We note that the Authority has recently consulted on a 'Targeted Reform of Distribution Pricing'.[95] This consultation signals a strengthened desire by the Authority for more distributors to move towards tariffs that, among other things, better signal periods of network congestion through elevated prices at those times. We endorse the near-term direction of the Authority's work, however, the Authority's currently proposed options for reform are very coarse – either a continuation of the current light-handed approach; a mandate or ban on particular pricing approaches, or a targeted 'call-in'. They also do not explicitly signal an expectation that distributors move away from static pricing to dynamic pricing.
MDAG conclusion	The Authority and Commerce Commission to work together to do more to cause more wide-spread and sooner use of efficient pricing signals for flexibility on distribution networks. If possible, use (or *enable* use of) the Part 4 regime to that end. For example: • explicitly as part of its consideration of customised and individual price path applications; • as a variant of the current incentives provided in the input methodologies (IMs) to encourage innovation, energy efficiency, demand-side management, and reduction of losses; and/or • as an information disclosure requirement (e.g. an independent expert report by each EDB verifying that the EDB has considered the role of pricing to minimise network operating and investment costs).
Implementation	**Tranche**: 1 **Timing**: Immediate start. The Commerce Commission's final decision on 2025-2030 reset of default price-quality path will be made November 2024. **Linkages:** The Authority's 'Targeted Reform of Distribution Pricing' initiative **Who makes it happen**: The Authority and Commerce Commission **Method**: Decisions by the Authority on Code changes (targeted reform) and changes by Commerce Commission to Input Methodologies

93 See paragraph 4.31 of "Targeted reform of distribution pricing: Issues Paper", Electricity Authority, 2023 at www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf.

94 Step 20 in the FlexForum's Flexibility Plan 1.0 is to "understand the interaction between price-based flexibility and contracted flexibility". See page 22 of www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf.

95 See www.ea.govt.nz/projects/all/distribution-pricing/consultation/targeted-reform-of-distribution-pricing/.

Recommendation 5 – Price-driven secure distribution dispatch

Develop design and trial tools to enable security constrained economic dispatch on the distribution network

Issue to be addressed	In a high renewables world with flexibility being provided by a large number of distributed consumer-owned equipment, a lack of integrated pricing signals and dispatch coordination will lead to sub-optimal outcomes for the consumer, increased network investment, or both.
Options Paper proposal	Investigate extending locational marginal pricing (LMP) into distribution networks (or an equivalent approach) (see Option C12). MDAG indicated partial support for this option.
Submitter feedback	Only a minority of submitters expressed a view on this option. Submitters generally either opposed it (on the basis that the costs and complexities outweigh any potential benefits)[96] or partially supported it (on the basis that should only be considered in the future once other network pricing and regulation has been allowed to develop).[97]
MDAG comment	MDAG is now of the firm view that the future electricity system will require some form of security-constrained economic dispatch (SCED) in the distribution network to connect the wholesale market to the expected myriad of widely dispersed new sources. By the nature, Recommendations 4 and 19 will only provide limited signalling to consumers (or their agents) weighing the value of, and available network capacity to, deploy DSF. In short, they are interim steps while the long-term solution (this Recommendation 5) is put in place. MDAG acknowledges the concerns expressed by submitters regarding the complexity of the task involved, particularly given the characteristics of the distribution network relative to transmission. However, this concern needs to be considered in the light of the significant advances in computing power, algorithms, and communications technology, which has occurred since the implementation of SCED on the national grid in 1996. Developing an efficient form of SCED in distribution networks for the wholesale market will be a major project. It will require significant enabling investment (including research, development, testing, as well as physical and virtual digitalisation and communications equipment), and it will take several years. But it is an essential piece of *wholesale market design* for a high-renewables world. The size of the prize is significant in lowering costs the consumer in better optimising network development (in particular, by avoiding substantial network investment) and enabling access for the wholesale market to the vast array of potential demand-side services across distribution networks.

96 For example, Transpower did not support this option as it would “divert significant industry resource in investigating a complex solution to an issue for which the problem and benefits are uncertain”. Contact and Enel X raised similar objections.

97 For example, Aurora noted that “the flexibility services industry needs to evolve before introducing regulations that risk stifling innovation” and WEL Networks considered that “efforts within distribution networks to manage and price network congestion, and congestion at the interface with the transmission grid, should be allowed to develop first.”

MDAG conclusion	Establish and fund as soon as possible a significant multi-year project to develop an efficient form of security constrained economic dispatch (SCED) on distribution networks for the purpose of 'integrating' into the wholesale market widely dispersed DSF and other distributed sources of 'supply'. To this end: • Develop design options for efficient distribution-level SCED, how it would integrate with the current wholesale market design, and any changes to the current framework for SCED; • Identify a preferred design, and provide the workplan and resourcing required for the detailed design, specifications and implementation of the preferred design; • Where possible, conduct trials and pilots that demonstrate how different design options, or components of design options could work; and • Work with FlexForum and the Future Network Forum to ensure that all learnings are disseminated quickly and comprehensively to all market participants and networks. As a *market design* exercise, this should be led by the Authority. It is vital that this project is governed and overseen by a small, enabling group that brings in expert perspectives that span wholesale market design, distribution, transmission, and system operation. Further, we strongly recommend that funding is granted subject to milestones that require rapid progress and a common-good approach to the sharing of all learning. This project needs to be resourced similarly to the multi-year effort that led to the implementation of the current version of SCED on the transmission system in 1996 (recognising that the adaptation of SCED for networks does *not* imply that it is the same as the SCED on the grid. Its design and development must deliver an efficient system where benefits clearly exceed costs). It should also work with and learn from national and global efforts to develop the necessary tools for distribution system operation and pricing.[98] Funding is required to support an expert team of specialists, as well as the rapid dissemination of knowledge to market participants and EDBs. Funding could be provided from: • an increased appropriation to the Electricity Authority; • MBIE's "Distributed Flexibility Innovation Fund", administered by Ara Ake; and/or • the Innovation Project Allowance under the Input Methodologies (although this may require amendments from its current form, which is limited to 0.1% of the EDBs forecast allowable revenues and requires 50% co-funding from the EDB).
Implementation	**Tranche**: 1 **Timing**: Start planning the project immediately. Clear leadership and milestones will be essential. Bringing together an expert design team is also key. Initial government funding is recommended for to get the project underway. This project needs to be established in such a way that it is not slowed down by bureaucratic processes or sector politics. The option for future innovation funding through the DPP needs to take advantage of the Commission's current deliberation of potential changes to the rules governing the innovation project allowance for DPP4, as well as Ara Ake's development of criteria for the Distributed Flexibility Innovation Fund. (We understand that Commerce Commission funding would only become available from 2025). **Linkages**: This project has potential funding linkages with Recommendation 10 – trialling DSF interface systems and protocols. **Who makes it happen**: Authority (leadership and potential funding) and Commerce Commission or Ara Ake (potential future funders)

98 This includes Orion's "Resi-flex" trial (exploring options to reflect network needs with greater spatial/temporal granularity), AusGrid's "Project Edith" (also exploring dynamic network tariffs) and Electricity Engineers Association's OpenADR (testing a form of instantaneous communications between flexibility buyers and sellers, including dynamic operating envelopes).

Recommendation 6 – New reserve product

Develop new reserve product to cover sudden reduction from intermittent sources

Issue to be addressed	Active energy is the main product traded through the spot market. A range of so-called ancillary service products are also procured alongside active energy to provide various fine-tuning or back-up products. The current set of ancillary service products reflects the historical physical requirements of the electricity system, and these products need to be updated as the system evolves. Recent experience highlights how supply from intermittent sources can reduce suddenly and unexpectedly. As intermittent supply makes up a growing proportion of generation, there is an increasing need for a new reserve product to maintain reliability during such reductions in supply.
Options Paper proposal	New reserve product to cover sudden reduction from intermittent sources (see Option A4).
Submitter feedback	Submissions generally supported the proposed change,[99] although some noted the need to carefully consider how this product would be designed.[100]
MDAG comment	We understand the Authority is working on the design of a new ancillary service product. This work should continue as a priority issue.
MDAG conclusion	The Authority should continue work to create a new reserve product to cover sudden reduction from intermittent sources. The new service should harness the full range of potential resource providers including batteries and demand-side flexibility, be co-optimised with the wider spot market and conform to causer-pays principles.
Implementation	**Tranche**: 1 **Timing**: Immediate start, in place by late 2024. This measure is urgent because it addresses challenges that are already emerging in the transition to a renewables-based system. **Who makes it happen**: The Authority to look at using a hybrid approach with market facilitation followed by regulation. This would allow issues to be initially explored in a less formal (and hopefully more collaborative) environment, followed by Code development to address outstanding issues. **Method**: Decisions by the Authority on Code changes and/or procurement of new reserve product from service providers

99 For example, Meridian considered it one of the "highest priority options" as it "address an immediate issue, particularly operational coordination during winter peaks in the near term".

100 For example, Transpower noted that "further design thinking ... plus building, testing, implementing and procuring all need to be worked through as part of this ancillary service development. In the interim as a stepping-stone the design may require more straightforward procurement approaches to ensure firm resource is available to support reliable supply". Contact, Energy Resources Aotearoa, Fonterra, Neil Walbran Consulting, and SolarZero also commented on aspects of the design of the reserve product.

Recommendation 7 – Stress testing

Strengthen existing stress testing regime

Issue to be addressed	Participants may not actively consider and manage their exposure to spot price risk. For example, they might not buy sufficient forward contracts to adequately cover their purchase commitments in the spot market. If such behaviour became prevalent, it would undermine the incentives to maintain or invest in adequate physical resources to ensure reliable supply.
Options Paper proposal	Enhance stress testing regime (B4).
Submitter feedback	Submissions generally supported the proposal. However, some submissions queried whether the proposal would cause undue costs. For example MEUG expressed reservations relating to the net benefit of this proposal.[101] Contact suggested a more limited step would be to improve disclosure requirements from independent retailers.[102]
MDAG comment	We have considered this recommendation in some detail (see Appendix C). The proposed changes are not expected to raise significant costs for participants. This is because the changes respect the existing core philosophy that participants must decide their own risk appetite and preferred risk management strategies. That said, the proposed changes should provide more assurance that parties are actively turning their minds to these issues. The changes also include some simplifications which should reduce compliance costs. We consider that the proposed changes will have net benefits in overall terms.
MDAG conclusion	The Authority should enhance the stress testing regime by adopting the 'blueprint' set out in Appendix C, which: • Includes a purpose statement; • Refines disclosures made about spot risk management policies; • Clarifies the certification standard; • Updates the stress tests; • Extends stress test horizon; • Enhances presentation of results to each participant; and • Simplifies the regime where possible The changes recommended in our 'blueprint' reflect the existing core philosophy that participants must decide their own risk appetite and preferred risk management strategies. The aim is to reinforce participants' incentives to actively managing their exposure to spot price risk, which (in aggregate) underpins the provision of adequate physical resources to ensure reliable supply.
Implementation	**Tranche**: 1 **Timing**: Immediate start, in place by late 2024. This measure is urgent because it addresses challenges that are already emerging in the transition to a renewables-based system. **Who makes it happen**: The Authority **Method**: Decisions by the Authority on Code changes

101 MEUG queried "whether there is a robust case for this, particularly whether the costs for impacted parties outweigh the possible benefits from enhanced requirements."

102 Contact submitted that "it may be appropriate to begin by improving disclosure requirements on independent retailers to demonstrate that they are sufficiently hedged. We expect that this will provide a clearer view of system security than the monitoring regime proposed in B1."

Recommendation 8 – New flexibility products (standardised)

Develop standardised flexibility product(s) (including DSF)

Issue to be addressed	Forward price discovery and hedging for flexible supply and DSF products is impeded by the lack of any standardised flexibility product(s).
Options Paper proposal	Develop standardised 'shape' product(s) (see Option B5) including to reward DSF (see Option C4).
Submitter feedback	Submissions generally supported the proposed options.[103] A few submissions disagreed on the basis that the market would provide these products if the demand was there, and that it would be difficult to develop such a product.[104] In relation to DSF products specifically, submitters tended to support the proposed option, although some noted the importance of being able to negotiate these contracts bilaterally as well.[105] Contact did not support the option on the basis that it was overly complex, and Genesis only partially supported it.[106]
MDAG comment	This recommendation is not intended to impede the development of bilaterally negotiated bespoke flexibility products. Rather, we think that some trading in standardised products could complement the development of bespoke products. While the market may provide standardised products organically, we think that process would be slow and uncertain. We consider that improving price discovery for flexibility products to be foundational for the wider wholesale market. In short, flexibility contracts will become the market's 'secret sauce' – enabling a range of wholesale market processes to function effectively. For these reasons we recommend a co-design process to develop products (and potentially a platform), facilitated by the Authority, as the best approach to ensure these products are delivered quickly. Appendix B provides some further information on possible candidate products and the proposed co-design process.
MDAG conclusion	The Authority should facilitate the development of one or more standardised flexible supply contracts as set out in Appendix B.

103 For example, Haast/Independent Retailers submitted that "regulation is needed as the incumbent market-makers have limited incentives or interest to offer profiled or capacity products."

104 Contact submitted "currently the market is delivering on shaped and peak products, and we expect this to expand if/when demand for these types of products grows" and "developing this sort of product would also prove to be very difficult" because different parties have different firming requirements/capabilities. Genesis submitted "these products will arise if they are valued by consumers. There is little value in developing a product for which there is no, or insufficient, demand."

105 Meridian noted that "having a standardised option 'on the shelf' will help potential demand side participants realise the benefits of flexibility without constraining the ability to negotiate alternative bespoke contractual arrangements with counterparties", while Fonterra noted that the option "is needed but should not be the only solution so that there can be some competition in the marketplace which will ensure DSF occur".

106 Contact considered "this is an overly complex solution" and Genesis submitted "central or compelled design of products should only be contemplated where there is clear market failure".

Implementation	**Tranche**: 1 **Timing**: Immediate start, in place by late 2024 **Who makes it happen**: A cross-industry group with an Authority-driven process as a backstop. Model on Telecommunication Carriers Forum's (TCF) 2006/07 process for developing codes covering non-price elements for competitive access to the 'monopoly' local telecom wires. The success of that TCF multilateral process relied (among other things) on wide participation of market participants, a rigorous analytical framework, and a shared commitment to a disciplined process in which all participants understood that a co-designed common-good solution would better than the regulated alternative. **Method**: The Authority sponsors the co-design process or (ultimately) uses Code amendment powers **Process parameters**: If industry co-design process is not successful with a given period, process defaults to Authority prescription. Related measures: If price discovery for and access to flexibility contracts are not effective after a defined period, recourse to market-making (Recommendation 24). Then, if still not effective after a further define period, recourse to virtual disaggregation (Recommendation 31)

Recommendation 9 – Contract process disclosure rules

Develop rules requiring disclosure of process steps by parties negotiating OTC contracts

Issue to be addressed	Bilateral forward contracting in the over-the-counter (OTC) market will be hindered if parties with significant market power can use that power to impose unreasonable non-price terms. The competition concern is particularly relevant for bilaterally negotiated flexible supply contracts.
Options Paper proposal	Develop long-term flexibility access code (non-price elements) (See Option B6 and Option D3).
Submitter feedback	Submissions generally supported the proposed change.[107] A few submissions argued that more evidence of significant market power or access issues is needed before such a measure is taken.[108]
MDAG comment	The primary purpose of this recommendation is to strengthen the basis for regulatory scrutiny of non-price terms and behaviour by parties seeking to agree OTC contracts. As noted in paragraph 5.10 of our Library of Options, "enforcement against any anti-competitive conduct in the provision of flexibility products would rely on the trading conduct provisions in the Electricity Industry Participation Code … or the Commerce Act". The measure would be directed at increasing transparency to the Authority (and the Commerce Commission) of behaviour by parties seeking to agree OTC contracts (rather than mandating contracting terms/practices). A useful starting point for these rules is the voluntary Code of Conduct for over-the-counter market participants created by an industry working group (and facilitated by the Authority) earlier in 2023.[109]
MDAG conclusion	The Authority to develop and introduce disclosure rules for OTC contracting. These rules should provide for disclosure of processes leading to the formation of OTC contracts. The rules should apply to all OTC trading, noting that the competition concerns are more acute for flexibility contracts but apply across the contract market.
Implementation	**Tranche**: 1 **Timing**: Immediate start, in place by late 2024 **Linkages**: This recommendation supports Recommendation 12 (competition dashboard). **Who makes it happen**: The Authority with input from stakeholders. Look at using a hybrid approach with market facilitation followed by regulation. This would allow issues to be initially explored in a less formal (and hopefully more collaborative) environment, followed by Code development to address outstanding issues. **Method**: Decisions by the Authority on Code changes

107 For example, Vector supported this option on the basis that "clearly, current hedge prices are significantly out-of-step with new generation costs."

108 Genesis considered that "there is insufficient evidence of a problem to justify this work and the risks it entails today. There should be a high bar to cross before introducing obligations/restrictions on how participants interact commercially." Contact also submitted that "this may be a case of a solution being developed ahead of a problem (which may never eventuate)."

109 See www.ea.govt.nz/news/general-news/voluntary-code-of-conduct-for-over-the-counter-market-participants/.

Recommendation 10 – DSF interface systems and protocols

Broad based trials (with significant funding from government) to establish common system interface protocols for DSF across full value chain

Issue to be addressed	The emerging world of DSF is going to require organisations across the electricity ecosystem to interact in new ways to supply DSF into the wholesale market to enable DSF to compete properly with supply-side flexibility. This will require a range of new standards and protocols to enable efficient interface among the chain of participants in the DSF market.[110]
Options Paper proposal	Provide significant funding for pilots/trials to kick-start dynamic tariff use (see Option C5).
Submitter feedback	Submissions generally supported this option,[111] although some expressed concern that the proposed trials focused too much on retail offerings rather than on other solutions.[112] MEUG did not support this option on the basis that it "comes at a cost, with a lack of clarify about who the beneficiaries will be and how these options will be funded".
MDAG comment	We agree that pilots and trials relating to standards and protocols need to allow for a broad range of participants across the flexibility 'ecosystem', and should not be focused on retailers exclusively. Indeed, the very point of standards and protocols is to make interactions *among* DSF market participants more efficient. We also agree with submitters that trials funded by taxpayers need to be (continually) subject to cost-benefit analyses, to ensure that the benefits to the market (in terms of enabling efficient competition from DSF) outweigh the costs. (This is a perfectly normal requirement). Orion raised the model of Ofgem's Strategic Innovation fund, which provided funding in stages,[113] which is worthy of consideration. Finally, EDBs also raised challenges they are experiencing in funding innovation trials due to particular aspects of the Part 4 regulatory regime. We expect that these matters will be raised by the EDBs in the context of the Commerce Commission's review process in relation to DPP4.[114]

110 Which includes DSF provider (consumer), retailer / flex-trader, distribution, transmission, and System Operator.

111 For example, WEL Networks considered that "'Learning-by-doing' seems to be a low-regret approach."

112 For example, Contact considered that considered that "any trial should include a broad range of flexibility market participants, including technology providers, flex traders, distributors, industry" and not just retailers, and Enel X noted that "there is a broader role for funding pilots and trials to support the development and acceleration of DSF markets".

113 Orion submitted that "funding should encourage a phased approach to project delivery, such as Ofgem's Strategic Innovation Fund. By increasing the scale of funding at each phase, governing bodies encourage exploration while ensuring funding is used efficiently as concepts evolve."

114 Default Price-Path for Period 4.

MDAG conclusion	Develop a range of new standards and protocols to enable efficient interface among the chain of participants in the DSF market.[115] The process of developing these standards and protocols requires a diversity of well-designed pilots and trials to test a range issues and possible solutions. This is an industry-good undertaking (that is, for the benefit of the industry as a whole) and therefore all results must be shared openly with all interested stakeholders. The results also need to be integrated to guide the emergence of solutions that seem be well suited to become industry standards or protocols. In most cases, EECA is responsible for formalising standards[116] and the Authority is responsible for Code changes if required to formalise a protocol.[117] The FlexForum[118] seems to be well placed to serve as the body facilitating these steps and provide the funding agency with an overview of the trials and steps to be funded in order to develop the required standards and protocols. Funding is to cover (1) scoping the issues to be resolved and designing trials for that purpose; (2) executing the various trials; (3) analysing and integrating results, and sharing all results with the industry; and (4) working with EECA and the Authority to promulgate standards and required Code changes. Funding should come from MBIE and/or Ara Ake. MBIEs “Distributed Flexibility Innovation Fund” could be a source of funding for these trials. We also recommend reallocating money from the Government Investment in Decarbonising Industry (GIDI) Fund. Funding is to grow common-good industry capability. This therefore excludes funding for solutions available only to a limited number of parties.
Implementation	**Tranche**: 1 **Timing**: Start scoping and trial design by mid-2024. Pace is required in order to obtain a high degree of learning and establishing standards and protocols before significant DSF activation. **Who makes it happen**: FlexForum with funding via MBIE and/or Ara Ake[119] **Examples of trials:** An excellent example of a current trial is the Electricity Engineers Association’s (EEA’s) “FlexTalk” project. Other examples of trials to be funded are described in FlexForum’s Flexibility Plan,[120] which include connection and integration into EDB and flexibility suppliers IT systems (Flexibility Plan steps #31, #35), monitoring EV charging status and ability to respond to emergency events (#26, #31, #35), and exploring the implications of communication security (#26, #31). These standards/protocols need to align with what the flexibility provider (household or business) expects and is prepared to tolerate.[121]

115 Which includes DSF provider (consumer), retailer / flex-trader, distribution, transmission, and System Operator.

116 For example, standards relating to energy-consuming devices.

117 For example, changes of information between market participants and the wholesale market (e.g. reconciliation and settlement).

118 An industry-established body bringing together a wide cross section of industry participants.

119 Irrespective of who funds the trial, Ara Ake is established specifically as a vehicle for deploying funding for energy-related innovation, pilots and trials. FlexForum is established with the primary purpose of coordinating and collaborating across the flexibility ecosystem, and oversees the Flexibility Plan, which has a set of practical tasks to accelerate the uptake of flexibility. The Authority, EECA and Commerce Commission are key regulators in respect of flexibility (and are observers of the FlexForum).

120 See www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf.

121 There is a rich literature on the need for standards and protocols with respect to DER/DSF that provides a strong basis for trials in NZ. See Australia’s “DER interoperability assessment framework” (2021); the UK’s publicly available specifications “PAS 1879:2021 Energy smart appliances – Demand side response operation – Licensed Code of practice” and “PAS 1878:2021 Energy smart appliances –System functionality and Licensed architecture – Specification” as examples.

Recommendation 11 – FSR Project (as it relates to DSF)

Improve visibility of DSF for System Operator and remove Code barriers to DSF offering ancillary services

Issue to be addressed	If DSF responds to wholesale and network price signals 'off market' (i.e. without providing information to the System Operator in advance) the dispatch process becomes more uncertain. This has the risk of increasing the need for more conservative dispatch management (e.g. through an increase in the procurement of frequency keeping). This, in turn, increases costs to consumers. Put another way, security constrained optimal dispatch needs to be able to (within reason) correctly anticipate the contribution of DSF at any given point in time, otherwise the uncertainty around dispatch outcomes will increase, likely leading to an increase in the cost of reactive flexibility (e.g. frequency keeping). Avoiding this cost requires a sufficient quantity of DSF to be formally bid into the market, whether as a dispatch-capable load station (DCLS), or through DNx
Options Paper proposal	FSR – Improve DSF visibility and remove Code barriers (see Option C8)
Submitter feedback	Submissions generally supported this option.[122]
MDAG comment	The Future Security and Resilience (FSR) roadmap has been finalised and includes activities relating to the visibility of distributed energy resources (Activity 2.3, 2026-2027) and enhancing the Code and market systems dispatch capability to accommodate DER bids and offers (Activity 1.1, 2025-2026).[123] Since our Options paper was published, the new dispatch notification (DNx) service was launched, which was intended to provide a low-compliance and low-cost way for demand response (and small generation) to be bid into the dispatch process. Internal MDAG discussion, as well as a recent Authority consultation on dispatch notification,[124] has highlighted the lack of incentives that flexibility traders have to use DNx, despite the relatively low compliance requirements. In many situations, developing systems to bid demand in, even under DNx, incur costs and resources. However, for a flexibility trader, there is very little incremental benefit from bidding in under DNx (or as a dispatch capable load station, or DCLS) compared to responding off-market.
MDAG conclusion	In the Future Security and Resilience (FSR) project, bring forward the priority of improving visibility of DSF for the System Operator and remove Code barriers to DSF offering ancillary services: • As a first step, the Authority to prioritise a study of the likely increase in future system cost that would arise as a result of various levels of non-bid off-market DSF. (This should provide an approximation of consumers' 'willingness to pay' for DSF to be bid into the market); and • The Authority to then develop Code changes that provide flexibility traders with incentives (commensurate with the results of the study above) to bid DSF into the market, via DCLS or DNx.

122 For example, Enel X submitted that it "supports removing barriers to DSF participation wherever possible. We also recognise the need for the System Operator to have a degree of visibility over DSF."

123 See www.ea.govt.nz/documents/1980/Covering-Paper-FSR-Final-Roadmap-and-Phase-Three.pdf.

124 See www.ea.govt.nz/projects/all/rtp/consultation/dispatch-notification-enhancements/. The Authority's workplan indicates that a decision paper on Dispatch Notification Enhancements and Clarifications is due in late 2023.

Implementation	**Tranche**: 1 **Timing**: Immediate implementation. **Linkages**: The Authority has signalled that a decisions paper for Code amendments paper on Dispatch Notification Enhancements and Clarifications is imminent and may address this issue.[125] The Authority's intended consultation on bringing flexibility providers into the Code (to improve visibility and coordination between participants) is also relevant.[126] Similarly, this recommendation has linkages with Recommendation 19, which may result in additional processes to reconcile DSF bids with distribution system limits. **Who makes it happen**: The Authority with expert input from System Operator, EDBs and flexibility traders. **Method**: Code change process

125 If this recommendation is not incorporated into the pending Authority decisions paper on Dispatch Notification Enhancements and Clarifications, we propose a start date of 2025, commencing with the analysis described above. Arrangements to incentivise DSF bidding should be in place by 2026. This is accelerated by one year relative to FSR project timelines for this item (2026-2027). However, based on submissions to the Authority's recent dispatch notification paper, we believe this issue is more urgent than initially thought when the FSR timelines were set.

126 See www.ea.govt.nz/documents/3929/Work_programme_Oct_231406907.13.pdf.

Recommendation 12 – Competition dashboard

Develop dashboard of competition indicators for flexibility segment of wholesale market

Issue to be addressed	Flexibility products provide a critical bridge to integrate intermittent supply into products suitable for retail consumers. Put simply, weaker competition for flexibility products could undermine efficient risk management and competition in the retail and new investment. MDAG is recommending a progressive chain of actions to safeguard competition in flexible supply, where implementation of the next action in the chain depends on whether the previous actions are sufficiently effective in practice. A dashboard of indicators of competition in the provision of flexibility products is required to inform this (annual) assessment.
Options Paper proposal	Develop dashboard of competition indicators for flexibility segment of wholesale market (see Option D1)
Submitter feedback	Submissions generally supported the proposal,[127] although MEUG considered more details were required to help parties form a stronger view.[128]
MDAG comment	The dashboard is intended to provide a framework of relevant quantitative and (where useful) qualitative indicators to guide the Authority's regulatory judgements at each scheduled stocktake (or 'gateway').[129] The dashboard is not a formula or prescription that contrives to generate outcomes by purporting to process defined inputs. Also note that the dashboard is for competition in flexible supply, not competition in the wholesale market as a whole. The indicators to be included in the dashboard are to be decided by the Authority taking into account advice from expert advisers.
MDAG conclusion	The Authority should develop a dashboard of indicators to monitor and assess competition in the provision of flexibility products. A well-designed dashboard should be used as a key tool in deciding whether and when contingent measures in tranches 2 and 3 are required to support competition in the provision of flexibility products. Dashboard indicators should include the: • availability and pricing of standardised flexibility products; • availability and pricing of non-standardised flexibility products – such as 'sleeves' or other firming contracts; • extent to which independent generators and retailers are able to access flexibility products on reasonable terms from the market; and • extent of actual and planned entry or exit by providers of flexibility – such as biofueled generators or demand response providers. The form of the dashboard should be published by the Authority well in advance of the scheduled 'gateway' assessment on whether to move to tranche 2 or 3 measures. Among other things, this will inform participants of the competition factors that they and the market needs to work on
Implementation	**Tranche**: 1 **Timing**: Immediate start, in place by late 2024 **Linkages**: Supplementary pro-competitive measures (i.e. Recommendations 24 and 31) are recommended if other actions to ensure adequate competition are not sufficient. The dashboard is expected to provide the framework for making the assessment and the need for supplementary measures. **Who makes it happen**: The Authority **Method**: The Authority via its monitoring function

127 For example, NZWEA supported MDAG's initial focus on conduct-based measures, including option D1.

128 MEUG queried "what measures would be on the competition dashboard".

129 See Appendix D, Figure 23 for more detail.

Recommendation 13 – Virtual disaggregation (high-level outline)

Develop high level outline of 'virtual disaggregation', to 'put in draw' ready for use if other measures are not effective

Issue to be addressed	Some parties may have scope and incentives to abuse market power in provision of longer duration flexibility products.
Options Paper proposal	Virtual disaggregation of flexible generation base (see Option D7)
Submitter feedback	Some submissions did not support this option, with some submitters arguing that it should only proceed if there is clear evidence of a problem.[130] However, other submitters supported this option.[131]
MDAG comment	This recommendation is to undertake an investigation of what this measure would look like in broad terms if it were to be implemented, but to stop short of a full detailed design. Actual implementation of this measure (see Recommendation 31 in Tranche 3) would not occur unless other performance-based pro-competitive measures were not sufficient. See Appendix D for a discussion on our backstop competition measures, including virtual disaggregation of flexible generation base, and why we disagree with some submitter's concerns that the Authority should 'wait and see' whether anti-competitive behaviour is occurring before beginning a high-level specification of this measure.
MDAG conclusion	The Authority should develop a high-level design of a backstop competition measure (further information is set out in Appendix D.
Implementation	**Tranche**: 1 **Timing**: Immediate start, as a high level design would take some time to develop, and it may need to be able to be implemented quickly (in Tranche 3) if other competition measures are insufficient. **Linkages**: Enables timely implementation of Recommendation 31 if required **Who makes it happen**: The Authority **Method**: The Authority investigates the necessary considerations for how the flexible generation base could be virtually disaggregated using contracts

130 For example, the Business Energy Council submitted that "if any structural changes do take place, based on the premise of shrinking anti-competitive behaviour, there must be substantive evidence that the problem exists – or at least the extent of the problem justifies the significant intervention. The Authority's recent paper on competition in the wholesale market, expressed the lack of definitive evidence to confidently justify the claim that elevated prices were due to anti-competitive behaviour." Energy Resources Aotearoa cautioned that "the mere floating of potential significant interventions could have a chilling effect on investment." Mercury proposed "that MDAG does not fix a date to prepare a high-level specification of D7, as presently proposed, but instead monitor market conditions for issues regarding market conduct and address competition issues accordingly as they start to develop."

131 For example, Vector considered that "intervention of this nature is not unusual in competitive markets overseas (e.g. electricity, telco), and could go some way to ensuring there is a level playing field between the parties who own flexible generation and those who do not."

Recommendation 14 – FSR project (governance)

Strengthen governance for next phase of FSR project

Issue to be addressed	The Authority is undertaking the Future Security and Resilience (FSR) project with the System Operator to look at future real-time operations of the power system. The FSR project and MDAG's project are complementary in nature and the two project teams have maintained regular contact (through common participants). The FSR project naturally has a very strong technical focus and will run for longer. By contrast, MDAG's project is providing higher-level advice and applying a lens focused on the long-term benefits for consumers. Because the FSR project is expected to have a strong influence on future system coordination, it is important to ensure that the project also considers economic trade-offs.
Options Paper proposal	Strengthen governance for next phase of FSR project (see Option A2).
Submitter feedback	Submissions supported the above proposals,[132] although some submitters had suggestions for the FSR project generally.[133]
MDAG comment	The Options Paper proposed that the Authority adopt a set of Guiding Principles for the project and establish an external reference group to act as a sounding board. The Authority established the Common Quality Technical Group in July 2023.[134] The Guiding Principles set out as a preferred measure in our Options Paper have yet to be put in place. As the FSR project moves forward, we expect that obtaining high quality input from wider stakeholders will become even more important. In particular, some design choices could have very significant longer-term implications. Experience from other jurisdictions suggests that regular and close engagement between the core project team and a stakeholder reference group could be beneficial to supplement formal (and less frequent) written consultation processes.

MDAG conclusion	The Authority should strengthen governance of the FSR project by:
	• Incorporating the set of Guiding Principles in Appendix E into the terms of reference for the FSR project;
	• Incorporating into the terms of reference for the FSR Common Quality Technical Group the tasks of helping to:
	    o Identify and address key economic and technical trade-offs;
	    o Oversee that application of the guiding principles;
	    o Examine issues where Transpower (or the Authority) may be perceived as having potential conflicts of interest – such as the best division of responsibility between national and 'local' system operation, or the merits of an independent system operator model;[135] and
	    o Support periodic stakeholder engagement.
	• Adding a person with strong experience in economic and technical trade-offs

Implementation	**Tranche**: 1 **Timing**: Immediate start, in place by mid-2024 **Linkages**: This is an umbrella measure that will inform all other FSR issues, including Recommendation 11 (improving visibility of DSF for the System Operator) **Who makes it happen**: The Authority **Method**: Decision by the Authority

132 For example, MEUG noted that robust oversight of the next phase of the FSR project is important as "many of the options presented in Chapter 7 ("keeping the lights on") are … part of the Authority's Future Security and Resilience (FSR) project."

133 SolarZero submitted that "the whole FSR programme needs to be accelerated" and LMS Energy submitted that bioenergy should be considered as part of this project.

134 See www.ea.govt.nz/about-us/our-people/our-advisory-and-technical-groups/common-quality-technical-group/.

135 See for example the comments on distribution system operators in the submission from the Independent Electricity Generators Association on the Issues Paper.

Recommendation 15 – Seasonal outlook report

Calibrate public expectations with quarterly briefings on current and expected market conditions

Issue to be addressed	Government and public confidence in the wholesale market is foundational. It feeds into the role government's play in reinforcing participants' incentives to manage risk properly in response to efficient spot price signals (including when those prices are high and/or volatile). Policy-makers and people who shape public opinion therefore have a reasonable understanding electricity system's current situation and outlook. In short, there is a strong need to regularly calibrate expectations, to avoid surprises and explain the weather linkages in more concrete terms
Options Paper proposal	Regular briefings for Ministers and officials on current and expected conditions (see Option E2). We have since expanded the target audience to policy-makers and people who shape public opinion, with the briefing becoming a seasonal outlook report (in a dashboard style).
Submitter feedback	Submissions generally supported the proposal, although SolarZero was neutral on the basis that the effect of this was unclear.[136] MEUG did not support pursuing this option.[137]
MDAG comment	As discussed in our Library of Options, we understand that current briefings to the Minister of Energy and Resources largely focus on the Authority's forward work programme and particularly significant events. We believe that regular updates on the outlook for the electricity system would be useful to assist in identifying and managing risks and to strengthen confidence in the electricity system.
MDAG conclusion	The Authority should publish quarterly (seasonal) outlook reports with a well-designed dashboard for policy-makers and people who shape public opinion on the electricity system current situation and outlook, including (as discussed in paragraph 6.5 of our Library of Options): • demand trends and projections • energy storage levels • investment trends • climate outlook • price implications.
Implementation	**Tranche**: 1 **Timing**: Immediate start, in place by late 2024 **Process**: We had intended to develop a 'blueprint' for this publication, but due to the constraints of time we were not able to do so. However, we recommend that the Authority develop a test template (dashboard style) drawing on relevant expertise (communications, and understanding key outlook indicators); test a 'mock up' with a sample of the target audience and iterate the template to arrive at a form that achieves communications goals. **Who makes it happen**: The Authority **Method**: The Authority prepares material and briefs Ministers and officials

136 SolarZero submitted that "The risk is that there are issues with the market but these are explained away as normal working of the market. The flip side is that more briefings may enable greater scrutiny of the market. Another view is that repeatedly telling people that the market is working may, in itself, not work."

137 MEUG did not support options E1 to E4 on the basis that they were "not convinced there is a market failure in this area, to support action over and above the status quo."

Tranche 2 measures

Recommendation 16 – Scarcity pricing parameters

Update default shortage values in Code factoring in related elements

Issue to be addressed	The Code includes various parameters that ultimately have an important influence on security of supply. These include the default shortage values (also called 'value of lost load' or VoLL) that apply if forced load shedding is required, and the economically determined security of supply standard.[138] If the parameters are set too low, the system will be less reliable than consumers want (and vice versa).
Options Paper proposal	Update shortage price values (see Option A3).
Submitter feedback	Submissions supported the proposal,[139] with Transpower noting that such an update needs to take into multiple elements of the scarcity pricing regime,[140] and Nova suggesting that the concept of VoLL be extended to include controlled hot water (i.e. "VoLL $_{light}$").[141]
MDAG comment	We agree with Transpower that there are a number of elements that feed into the security standard settings in addition to shortage price values. It makes sense to update the wider security standard and associated parameters as they have not been reviewed for over a decade. This could also include consideration of Nova's VoLL $_{light}$ proposal. It could also make sense to index shortage values to inflation, as occurs in the Australian National Electricity Market.
MDAG conclusion	The Authority should update the security of supply parameters and associated settings for the spot market to ensure they properly reflect the value of reliability to consumers. In addition, consider indexing shortage values (like Australia) and undertake further updates where required.
Implementation	**Tranche**: 2 **Timing**: As soon as practical once Tranche 1 measures are being progressed. **Who makes it happen**: The Authority **Method**: Decisions by the Authority on Code changes

138 See clauses 13.58AA and 7.3(2) of Code.

139 For example, Contact noted that "accurate scarcity prices will be critical to making the business case for flexible capacity like batteries and some demand response."

140 Transpower noted that "this update will need careful considerations taking into account the interaction of the different elements of the spot market scarcity pricing regime which could require significant effort. This will also need to take into account any interaction with the additional ancillary service considered as part of A4."

141 Nova considered that VoLL light would be **"**considerably less than VOLL because the impact is comparatively minor, nevertheless, the load reduction effected under normal conditions reduces demand and as a result prices. Imposing VOLL light will better reflect market cost**s."**

Recommendation 17 – Information on development pipeline

Publish aggregated information on pipeline of new developments, energy and capacity adequacy

Issue to be addressed	Participants need better information about the supply and demand outlook to make high quality contracting and investment decisions.
Options Paper proposal	Publish aggregated information on pipeline of new developments, energy and capacity adequacy (see Option B3)
Submitter feedback	Submissions generally supported the proposed change, although a few queried whether this information was already available.[142]
MDAG comment	Transpower's connection enquiry dashboard[143] has significantly improved the visibility of generation and load projects, and as such this recommendation is not so urgent as to be put in Tranche 1. However, there are still some significant information gaps.[144] For example, developers do not need to disclose when projects have reached final investment decision and have commenced construction. While some developers (particularly those listed on the NZX) disclose such information, others do not (or at least not in a consistent basis). In late 2023, there appeared to be around 1,400 GWh of new supply capacity that was committed/under construction that was not necessarily publicly announced.[145] Most that that generation was likely to be operating within 1-2 years but the existence of the resource was not necessarily in the public domain, making it harder to assess the supply/demand outlook. We recommend New Zealand adopt the NEM approach. As a corollary benefit, we expect that enhanced information provision would be pro-competitive. This is because under current arrangements, participants must rely more on their own resources to collect information, and this is generally easier for the larger established parties.
MDAG conclusion	The Authority should publish (or require and assist Transpower to publish) aggregated information on the pipeline of new developments, energy and capacity adequacy.
Implementation	**Tranche**: 2 **Timing**: As soon as practical once Tranche 1 measures are being progressed **Who makes it happen**: The Authority (or Transpower as service provider) with stakeholder input **Method**: Decisions by the Authority on Code changes and/or procurement from service providers

142 MEUG queried whether the information was not already available through the System Operator's annual security of supply assessment and Transpower's connection enquiry dashboard, and Contact considered that "the EA have already undertaken similar work on an ad-hoc basis when necessary. We don't consider anything more formal is required."

143 See www.transpower.co.nz/connect-grid/connection-enquiry-information.

144 Especially when compared with, for example, Australia's National Electricity Market Generation information publications – see aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

145 2023 Investment Survey report prepared by Concept Consulting Group for Electricity Authority (unpublished at time of printing).

Recommendation 18 – Sunset profiling

Sunset profiling if smart meters in place

Issue to be addressed	The continued use of profiles in ~40% of reconciled volumes nullifies the impact of any individual customer's DSF response on the retailer's wholesale purchase costs, which seriously diminishes incentives for the retailer to develop DSF-rewarding tariffs. However, advanced meters, measuring half hourly demand, are in place at over 90% of ICPs. Based on the latest data provided to MDAG by the reconciliation manager,[146] there has been no discernible decrease in the use of profiles since we first investigated the issue.
Options Paper proposal	Sunset profiling if smart meters in place (see Option C2).
Submitter feedback	Submitters generally supported this option,[147] although SolarZero considered the relevance of metering data may decrease[148]
MDAG comment	While we acknowledge that revenue metering may in the future be usurped by data directly procured from smart devices, we need to make faster progress.
MDAG conclusion	Change the Code to require use of half-hourly metering data rather than default demand profiles if smart meters are in place.
Implementation	**Tranche**: 2 **Timing**: Rule change in 2024, sunset date 2026/27 (giving market participants still using profiles sufficient notice to put in the systems and processes required to transition to settlement on half-hourly metering data). **Linkages**: This measure is already under investigation by the Authority as part of its 'Targeted Reform of Distribution Pricing",[149] which states that the Authority will "investigate options to speed the transition to billing on actual data, recognising this may require investment by some retailers to enhance their information systems."[150] The work should be accelerated if possible to give the market as much notice as possible, allowing the necessary investment by market participants in systems and processes. **Who makes it happen**: The Authority **Method**: Decisions by the Authority on Code changes

146 As at November 2023.

147 For example, Meridian noted that it is "open to a sunset date on the use of profiling for reconciliation purposes for ICPs that have the capability to measure half-hourly data" and Haast/Independent Retailers submitted that "these are arrangements that should never have been allowed to continue".

148 SolarZero submitted that "the traditional ICP meter may become much less relevant and a very different role in the near future as metering shifts to individual devices, such as EV chargers, battery inverters, hot water systems."

149 See paragraphs 8.10-8.30 of http://www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf#page=55.

150 Ibid, paragraph 8.24.

Recommendation 19 – Network capacity in DSF dispatch

Ensure distribution network capacity is reflected in wholesale DSF dispatch

Issue to be addressed	Neither the prevailing wholesale price, nor a dispatch instruction from the System Operator, reflects the capacity (or lack of capacity) of the distribution network to support DSF service delivery to the wholesale market. Hence wholesale signals for operation of DSF could be incongruous with available distribution capacity, leading to safety issues on the distribution network, overly conservative restrictions being placed on DSF operators, and/or triggering distribution investment, the costs of which are passed on to consumers.
Options Paper proposal	We did not have a specific option for this issue.
Submitter feedback	Vector raised this issue in its Options paper submission to MDAG.[151]
MDAG comment	The long-term solution to this problem is a form of security-constrained economic dispatch (SCED) integrating the expect array of sources across distribution networks into the wholesale market (Recommendation 5). However, that work will take some time, so an interim solution is required. The Electricity Network Aotearoa (ENA) has proposed the Default Distributor Agreement (DDA)[152] as the vehicle by which operating protocols between DSF providers and EDBs would be put in place. These protocols would, for example, include methods for ensuring that the deployment of DSF recognises distribution system limits through static or dynamic operating envelopes. This approach would have relatively low transaction costs for retailers, who are already required to have DDAs with distributors to operate on their networks. However, this is not the case for (non-retailer) DSF aggregators.[153] Hence the Authority would have to extend the requirement to have a DDA to any participant deploying DSF on the network over a minimum threshold, whether or not they intend to formally bid their demand flexibility into the System Operator. This could be achieved by formally bringing flexibility aggregators into the Code. To guard against EDBs placing onerous requirements on DSF operators as part of the operating protocols, the protocols should have standard terms and conditions codified in a schedule to the DDA. EDBs may also seek to apply unnecessary conservatism in developing operating limits, especially when they are static. There should be transparency about the limits – static or dynamic – and the distribution service levels in these protocols. These limits and service levels should be monitored by the Authority. EDBs should also be required to describe, in their congestion management policies, how they intend to manage the potential for congestion arising from DSF (as they do for distributed generation). EDBs are already required to publish congestion management policies under Part 6 of the Code.

151 Vector noted in their submission that "taking the wholesale market beyond the grid exit point (GXP) will require all the constraints on the distribution network to be accounted for too. As the FlexForum Insights paper noted, available capacity on the distribution network changes every hour of every day, and not all possible actions from DER will be able to be accommodated by the distribution network. The only party with the knowledge of what actions are safe is the distribution network operator. This is a concerning gap in the market design."

152 ENA recommends that dispatch notification process participants, and other aggregators, be required to enter default distribution agreements (DDAs, aka Use of System Agreements) or equivalent contracts with EDBs. This would ensure the rights and obligations of each party are documented, and operating protocols are agreed (as is the case for retailers currently, under clause 5.6). See www.ea.govt.nz/documents/3843/ENA_submission_on_dispatchable_load_enchancement.pdf.

153 The Authority's recent consultation on DDAs did not consider whether, or how, the requirement for holding a DDA could be extended to DSF aggregators who weren't retail market participants.

MDAG conclusion	Authority to make Code changes to implement the above – in particular: • amend the Default Distributor Agreement (DDA) to require coordination protocols so that the activation of DSF stays within distribution system limits; • amend the Code to require flexibility aggregators to have DDA with any networks they are operating on; • amend Part 6 of the Code to require EDBs to describe how they intend to manage congestion arising from DSF in their congestion management policies; and • limits and service levels are to be monitored by the Authority to ensure that they are not unnecessarily conservative.
Implementation	**Tranche**: 2 **Timing**: 2024-2026. Urgency is dictated by the extent to which EDBs are seeing near-term deployment of DSF on their networks sufficiently large to cause unpredictable demand spikes as a result of 'herding'. **Linkages**: (1) The Authority's "Dispatch notification enhancement and clarifications" consultation paper and imminent decisions paper. (2) The Authority has also signalled a consultation on bringing flexibility providers into the Code to improve visibility and coordination between participants, as part of its "Delivering key distribution sector reform: work programme".[154] (3) This Recommendation 19 also has linkages with Recommendations 4 and 5. **Who makes it happen**: The Authority **Method**: Code change process.

154 See www.ea.govt.nz/documents/3929/Work_programme_Oct_231406907.13.pdf.

Recommendation 20 – Consumer awareness of DSF

Increase consumer awareness of the opportunities for providing DSF to the wholesale market

Issue to be addressed	Growing consumer awareness of DSF opportunities and benefits requires (among other things) (1) a discovery by consumers of how they can change their electricity consumption behaviour, (2) technology that can make this easy for them, (3) straight-forward information on gains they would get DSF, and (4) that the value of those gains sufficient to make it worth doing. A further challenge is predicting the future value of flexibility as the electricity system evolves towards higher renewables.
Options Paper proposal	Provide information to help large users with upcoming DSF investment decisions (see Option C13). Provide information to help domestic customers with DSF decisions (see Option C14).
Submitter feedback	Submitters were generally supportive of these options, although Enel X expressed concern that “they will be of limited value without additional mechanisms to encourage the development of DSF”. Flick and Haast/Independent Retailers specifically supported improvements to Powerswitch.[155] Contact considered that customers have a “low interest in understanding the detail” and that flexibility providers would provide this information. MEUG noted that simply providing consumers with more information wasn’t – by itself – likely to achieve the culture change that MDAG championed in its issues paper. Rather, MEUG proposed that action is focused on “understanding and strengthening the value proposition from the consumer-perspective” [156]
MDAG comment	MDAG agrees that achieving the culture change required to see a significant increase in DSF deployment will require a strong understanding of the consumer’s perspective, particularly the critical barriers to them investing in DSF capability. This does not, however, remove the need for information provision. Our option C13 (providing DSF information to large consumers) was prompted in part by an awareness that some large industrial consumers evaluating options for electrifying process heat were not considering what the *future* electricity system would mean for the value streams of DSF. For this reason, we prepared a set of case studies to demonstrate the kind of analysis (showing potential value based on possible future spot prices) that could be provided to this type of consumer. Our Recommendation 3 (monitoring DSF activity) is also relevant. More broadly across the customer journey, FlexForum’s Flexibility Plan 1.0 contains a number of steps relating to understanding customers and growing their awareness of opportunities.[157] Since our Options paper, we have considered in more detail the potential for domestic consumers to have easy access to information about tariffs that reward flexibility and know how to size up those tariffs. A tariff comparison provider highlighted the challenges currently faced in providing quick and accurate tariff comparisons due to problems in obtaining half-hourly customer data (critical for the evaluation of any flexibility tariff). Even a basic comparison between a current tariff and a DSF-rewarding tariff carries a high transaction cost, as the customer must request the data from their retailer, who in turn can take up to 5 days. Further, the release of customer data requirements in the Code only require the metering data used for billing to be released. As highlighted in Recommendation 18, a large portion of consumption is still reconciled via profiles, despite the presence of advanced meters, thus the data used for billing will be a total monthly consumption figure which provides no useful basis to assess the impact of DSF. There is no technological barrier to automated tariff comparisons for the vast majority of domestic consumers. Subject to the appropriate security and data exchange processes being in place (as they

155 For example, Flick “strongly supports Powerswitch having access to consumption data so that customers’ switch decisions are based on the most accurate information.”

156 MEUG also submitted that “these options come at a cost, it is not clear who the beneficiaries of this will be and how these options will be funded” and that “work needs to be done via one-on-one interviews or market research, to gain information from consumers, rather than provide information.”

157 See steps 1, 3, 4, 7, 8, and 12 at www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf.

	are under Part 11 of the Code), we can see no reason why the provision of customer data and therefore tariff comparisons can't be almost instantaneous.[158]
MDAG conclusion	Energy and Efficiency Conservation Authority (EECA) to lead the way in demonstrating how larger consumers and their advisers should evaluate DSF options in the context of electrification investment decisions.[159] Power-switch and other tariff comparison providers to enable consumers to readily see the benefits of DSF. The Authority to: • make consumer data relating to DSF-rewarding tariffs more easily accessible to consumers and intermediaries providing tariff comparisons; and • provide information to the EECA and other parties involved in providing advice to larger electricity consumers on potential DSF opportunities. This information from the Authority should include (for example) modelling scenarios on future wholesale price behaviour to help evaluate DSF investment decision.
Implementation	**Tranche**: 2 **Timing**: Authority releases future wholesale price data in 2024, with customer data provisions reviewed in 2024/25. DSF tariff uptake will be slowed if consumers cannot evaluate whether they will benefit from enabling flexibility. **Linkages**: Recommendation 18 (sunset profiling if smart meters are in place) is pivotal to the success of this recommendation. **Who makes it happen**: The Authority, EECA and providers of tariff comparison websites **Method**: Code change if required for provision of data to as recommended above (subject to normal privacy and commercial confidentiality protections).

158 We do accept that there are challenges associated with predicting how a consumer may respond once exposed to differential pricing, which will likely lead to tariff comparison service providers making conservative assumptions about behaviour change. However, this should not prevent the automation of tariff comparisons and customers being given the tools to provide their own estimates of behaviour change.

159 Similar in approach to the case studies linked above.

Recommendation 21 – Monitoring and enforcement of Code

Enhance monitoring and enforcement of the Code with more autonomy

Issue to be addressed	Active monitoring of the electricity market is critical to identify and address any areas of concern, and to contribute more broadly to public confidence in the electricity market and system.
Options Paper proposal	Enhance monitoring with more autonomy (see Option E4)
Submitter feedback	Submissions generally supported the proposal. MEUG did not support pursuing this option.[160]
MDAG comment	Active monitoring of the wholesale market is desirable to deter or detect Code breaches, and more broadly to identify any issues of concern. On the positive side, if the market is performing satisfactorily, robust monitoring will help to make this more apparent. We also considered whether this recommendation should include increasing the maximum size of the pecuniary penalty orders that the Rulings Panel can make for breaches of the Code, but we note that this has been recently updated in September 2022.[161]
MDAG conclusion	The Authority should increase resourcing for its monitoring activity, as well as making its monitoring function more independent from its rule-making function by establishing a monitoring and enforcement 'unit' within the Authority, which would (as described in the Library of Options): • have its own public budget (within the Authority's budget); • have its own web site presence and public performance reporting; • publish its operating protocols (prescribed by the Authority) which would set out how it is to operate and report; and • publish its guiding principles (for example: neutrality, objectivity, evidence-based approach, with the goal of ensuring compliance with the Code to achieve the statutory objectives).
Implementation	**Tranche**: 2 **Timing**: As soon as practical once Tranche 1 measures are underway. **Who makes it happen**: The Authority **Method**: Administrative matter for the Authority

160 MEUG did not support options E1 to E4 on the basis that they were "not convinced there is a market failure in this area, to support action over and above the status quo."

161 Section 54(1)(d) of the Electricity Industry Act 2010 was amended in September 2022 to increase the maximum penalty from $200,000 to $2 million (with a further $10,000 for every day the breach continues).

Recommendation 22 – Information programme for opinion-makers

Strengthen structured information programme for wider stakeholders on how the market works

Issue to be addressed	Many key stakeholders are unfamiliar with how the electricity system and market work. But public and government confidence in the wholesale market underpin at a fundamental level how incentives work among market participants. The measures recommended in this paper are all fundamental for delivering public and political confidence in the wholesale market. The measures outlined below are focused on improving public information and understanding, working in conjunction with those other measures.
Options Paper proposal	Structured information programme for wider stakeholders (see Option E1).
Submitter feedback	Submissions generally supported the proposal. However, MEUG did not support pursuing this option because it was unconvinced that there was any market failure[162] and Haast/Independent Retailers expressed concern that the measures could "decrease confidence if it is simply used to talk up how well the market is working".
MDAG comment	Most of the measures recommended in this report are designed to improve actual performance of the electricity system – i.e. they focus on substance. However, it is important to recognise that public understanding of, and confidence in, the electricity system is also very important. We consider the programme should aim to transparently explain aspects of the electricity system and market that may not be apparent to those outside the sector, including an honest appraisal of the challenges and opportunities for consumers, suppliers, and other stakeholders. This means strengthening the Authority's existing information programme.
MDAG conclusion	The Authority should strengthen its information programme on the electricity system and market to key stakeholders, explaining core dynamics (for example) how security of supply is managed, both physically and via contracting and the nuanced role that the government plays
Implementation	**Tranche**: 2 **Timing**: As soon as practical once Tranche 1 measures are underway. **Who makes it happen**: The Authority **Method**: The Authority via briefings and other communications

162 MEUG did not support options E1 to E4 on the basis that they were "not convinced there is a market failure in this area, to support action over and above the status quo."

Recommendation 23 – International experts

Increase inter-change with international experts

Issue to be addressed	New Zealand's relative isolation can be a barrier to learning from overseas experience and knowledge.
Options Paper proposal	Increase inter-change with international experts (see Option E3).
Submitter feedback	Submissions generally supported the proposal. Only MEUG did not support pursuing this option.[163]
MDAG comment	Many of the challenges and opportunities in New Zealand are shared by other jurisdictions. As a result, there is much that New Zealand can learn (both 'dos' and 'don'ts') from experiences in other countries. Certainly, the interchanges with overseas experts and regulators via zoom/teams has been invaluable for this project.
MDAG conclusion	The Authority should improve international linkages via hosting visiting experts, initiating secondments, hosting a conference or similar measures.
Implementation	**Tranche**: 2 **Timing**: As soon as practical once Tranche 1 measures are underway. **Who makes it happen**: The Authority **Method**: The Authority should lead and sponsor. Other stakeholders may also wish to contribute to spread costs.

163 MEUG did not support options E1 to E4 on the basis that they were "not convinced there is a market failure in this area, to support action over and above the status quo."

Recommendation 24 (contingent) – Market making for flexibility products

Enhance price discovery by requiring market making in flexibility products

Issue to be addressed	The Code provides for market-making[164] in baseload futures to enhance the efficiency of the futures contract market. Future contracts perform two key functions: • participants use them directly and indirectly to manage spot price risks • participants and other interested parties use the forward price curve from the futures market to inform a wide range of investment and risk management decisions. Flexibility products are becoming increasingly important as the system shifts to renewable generation sources but there is no market-making in this type of contract.
Options Paper proposal	Market making in caps or other shaped products (see Option B8 and Option D5)
Submitter feedback	Submissions were mixed on this option. Some parties strongly supported this option,[165] while others considered it expensive and unsuitable for the market.[166]
MDAG comment	The purpose of this recommendation is to help achieve price discovery for flexibility products. While we recognise the costs and complexities involved in market making (and hence have not placed this measure in Tranche 1), we consider that it may be required if there is insufficient competition for flexibility contracts. In particular, we expect that market-making in such contracts would: • give participants greater means to use flexibility contracts to mitigate their exposure to spot prices; and • create a more transparent forward price curve for flexibility products, and reduce generators' ability to exercise market power in that segment of the market.
MDAG conclusion	The Authority should introduce market-making for flexibility contracts[167] if needed to strengthen competition in this segment of the wholesale market (see Appendix D for more information).
Implementation	**Tranche**: 2 **Timing**: Reserve measure **Linkages**: This is a backstop measure for use if required. The implementation of Recommendation 8 – new flexibility products (standardised) – is a pre-requisite. **Who makes it happen**: The Authority **Method**: Decisions by the Authority on Code changes and/or service provider contracts

164 See footnote 21 of our Library of Options for an explanation of market making.

165 For example, Haast/Independent Retailers submitted that 'MDAG should recommend mandatory market-making for shaped/capped products as a priority."

166 For example, Meridian submitted that "the costs of market making are significant" and that "the other options proposed by MDAG will be sufficient to support forward price discovery and access to shaped forward contracts". Contact considered that they "do not consider regulatory defined shape products would best meet the needs of the market" and that bespoke contracts are a better option.

167 The Options Paper used the term 'shaped product', but it is the same idea.

Tranche 3 measures

Recommendation 25 – WoF for regulatory agencies

Establish periodic warrant of fitness review for independent regulatory agencies

Issue to be addressed	While electricity is so vital to the nation's well-being, any government's understanding of how the electricity market works in any detail is always likely to be relatively thin. So what matters is a government's trust in the surrounding institutional arrangements – their sense that there are processes and expertise in place that they trust to provide the required assurance that it all works the way it is supposed to, and to advise on how to fix problems if they emerge. Having a referee that is insulated from day-to-day political forces helps to ensure that there will be consistent application of the governing legal frameworks over time. This in turn helps to provide the confidence for suppliers and consumers to make long term investments As we move to a renewables-based system, it is important for the public and policy-makers to have confidence in their independent electricity regulators.
Options Paper proposal	Periodic warrant of fitness review for independent regulatory agencies (see Option E5).
Submitter feedback	Submissions generally supported the proposal, although some submitters expressed reservations as to how this would work in practice and that it could prevent more targeted reviews.[168]
MDAG comment	To ensure a transparent process, the terms of reference for such a warrant of fitness should be set by the Authority's monitoring agency (MBIE) working in conjunction with Authority. There is an analogous mechanism in the Reserve Bank Act. It requires the Bank to review and assess the formulation and implementation of monetary policy at least every 5 years. A further possible step would be to require the electricity regulators to commission external experts (possibly overseas based) to undertake such reviews, with secretariat support from the agencies. We understand that this is the approach taken with the central bank in Sweden. This approach should strengthen the credibility of the findings of periodic reviews.
MDAG conclusion	The Authority and MBIE should work together to establish a periodic 'warrant of fitness' review for the Electricity Authority, possibly by external experts, every five years or so.
Implementation	**Tranche**: 3 **Timing**: After Tranche 1 and 2 are underway. **Who makes it happen**: The Authority and MBIE **Method**: Decision by the Authority and MBIE on terms of reference.

168 MEUG submitted that "we would not want the introduction of this option to thwart opportunities for any ad-hoc reviews sought by Government, for example, consolidation of functions into a central agency." SolarZero was concerned that the option was "possibly a good idea, but how could it work in practice?"

Recommendation 26 (contingent) – UTS over-ride

Remove UTS over-ride of trading conduct provisions

Issue to be addressed	The undesirable trading situations (UTS) provisions are broad, effectively allowing the Authority to invoke 'martial law', giving it power to retrospectively reset spot prices (among other actions), subject to various safeguards. One of those safeguards prevents the Authority from invoking UTS powers if it could use existing remedies available to it under the Code. However, this safeguard has a carve out which allows the Authority to over-ride the Code's trading conduct provisions, even where the Authority considers the trading conduct provisions will remedy the underlying event or situation. This over-ride may erode the dependability of price signals and undermine the incentive to provide last resort resources such as DSF capacity. Participants' reliance on spot price signals is likely to be compromised if they believe there is significant chance that prices could be revised after the time they apply. In particular, providers of last-resort resource will likely be quite sensitive to the potential for high spot prices to be reduced after a tight supply event, as such events can generate concern about high prices, even if such prices were an accurate signal at the time. This does not mean that spot prices should never be revised. On the contrary, it is important that high prices are subject to proper scrutiny. However, it does mean the triggers and framework method for reviewing prices should be well defined
Options Paper proposal	Remove UTS over-ride of trading conduct provisions (see Option A7).
Submitter feedback	Submissions generally supported the proposed change,[169] although Meridian agreed that it is "less urgent". However, some submitters including the independent retailers strongly supported the status quo, arguing that conduct can give rise to both a UTS and a breach of the trading conduct rules at the same time, and that the proposed change would weaken the UTS.[170]
MDAG comment	We agree that the Authority should be able to invoke 'martial law'. However, to preserve the dependability of spot price signals this should be tightly prescribed. We think it is logical that the Authority should not be able to invoke UTS powers if an event or situation can be remedied by other Code provisions. We have not heard a convincing reason to make an exception for trading conduct rules. Nor would removing the over-ride weaken the UTS provision in our view. This is because the Authority can pursue a trading conduct breach, *and* still invoke UTS powers, provided that it considered that code breach action alone would be insufficient to satisfactorily resolve a UTS. Having made these points, we recognise the current trading conduct provisions are relatively new as they have only been in place since mid-2021. We therefore recommend that the Authority look to remove the UTS over-ride of trading conduct provisions subject to those provisions continuing to perform satisfactorily.
MDAG conclusion	The Authority should remove the UTS over-ride of trading conduct provisions, subject to the trading conduct provisions continuing to perform satisfactorily.
Implementation	**Tranche**: 3 **Timing**: After Tranche 1 and 2 measures are underway, and subject to satisfactory performance of the trading conduct provisions. **Linkages**: The trading conduct provisions are relatively new, so the Authority should ensure that they are performing satisfactorily for a time before removing the UTS over-ride **Who makes it happen**: The Authority **Method**: Decisions by the Authority on Code changes (subject to conditions above)

169 For example, Nova submitted that "providers of high-cost backup generation and demand response need to be able to have confidence that real time prices are most likely to stand so long as there has been no breach of the trading conduct provisions."

170 Entrust submitted that it "would not support any change that could weaken the UTS rules", and Haast/Independent Retailers considered that "it is not unusual that conduct can breach multiple different rules and regulations" and that the proposal "would result in boundary issues in determining whether a matter is a trading conduct breach or a UTS."

Recommendation 27 (contingent) – Ahead market

Investigate and develop ahead market

Issue to be addressed	No matter how good forecasts become there will be some uncertainty about how conditions will actually turn out in real-time. This uncertainty can present significant challenges for participants who need to make decisions in the lead up to real-time, such as battery owners or demand-side parties who need prior notice to organise their responsiveness. A tool used in some other countries to address this is a formalised ahead market in which all wholesale buyers and sellers of physical electricity must participate. An ahead market makes it easier for these parties to lock-in their plans ahead of real-time.
Options Paper proposal	Investigate + develop ahead market (see Option A6).
Submitter feedback	Submissions generally supported the proposed option,[171] although many noted the magnitude, complexity, and lead time that it entailed, and so were more supportive of investigation than full implementation at this stage.[172]
MDAG comment	We agree with submitters that the implementation of an ahead market would be a significant change to the electricity market and would require careful consideration before adoption. Our recommendation at this stage is to begin this investigatory process (when resources are available), which would include the consideration of the issues raised in submissions. We only recommend proceeding with implementation if this investigation stage determines that an ahead market would be net beneficial to the system, and that key risks have been considered and sufficiently mitigated.
MDAG conclusion	The Authority should investigate an ahead market mechanism. If, on review in 2027, it becomes apparent that the current spot market process could be significantly improved (with benefits greater than costs) in changing to an ahead market, then this measure could be implemented.
Implementation	**Tranche**: 3 **Timing**: Investigation to begin when resources are available, with implementation to occur if it is assessed as having net benefits. **Process**: During the investigation stage, voluntary use of short-term products (such as day ahead contracts) should be encouraged to aid with operational planning and coordination. **Who makes it happen**: The Authority **Method**: The Authority to lead investigation work and consult with Code amendment proposal if adoption of an ahead market appears beneficial.

171 For example, Transpower agreed that “an ahead market approach would help provide participants with greater certainty ahead of real-time which could be beneficial for those resources that require longer lead times to schedule resources”.

172 For example, Meridian considered further work should be done to understand the consumer impact of implementing an ahead market, as “there may be a risk that this proposal will drive increased costs to consumers at least in the medium term due the reduced investment certainty resulting from such a change”. Contact also supported further investigating ahead markets, but noted that “our current view is that bilateral contracts can already manage this risk and we don’t see a strong case for why this would be different in the future.”

Recommendation 28 (contingent) – Market making for longer dated futures

Enhance price discovery by requiring market-making for longer dated futures

Issue to be addressed	Participants need more information on expected forward prices to help make better longer-term investment/retirement decisions. Market-making is currently provided for baseload contract for the coming 3-4 years.[173]
Options Paper proposal	Market-making for longer dated futures (for price discovery) (see Option B2).
Submitter feedback	Submissions were mixed on the proposed change. Most that commented on this issue supported this option,[174] but others did not support it (or at least expressed reservations) based on the cost of market making[175] or a belief that the market will provide longer-term contracts if the demand is there.[176]
MDAG comment	This measure relates to futures products that already exist (i.e. baseload products only). A longer forward curve would help parties facing investment and/or retirement decisions. The latter are especially important in the transition to a renewables-based system. While it is unlikely to be cost-effective to provide market-making for very long-term futures (e.g. 10 years or more),[177] it would be good to extend the current time horizon which varies between 3 ¼ and 4 ¼ years into the future. However, this measure is in Tranche 3. While longer dated baseload futures products would be useful for the market, we consider that development of flexible products to be a higher priority (e.g. Recommendation 8) and that it may be desirable to introduce market making in one or more standardised products also (Recommendation 24). We also note the submitters concerns regarding the cost of market making, and as such only recommend this option on the basis that analysis is undertaken that shows expected benefits outweigh costs. The Authority is planning to review the market-making policy settings in late 2024 so we expect more information on this measure will be available in the future.
MDAG conclusion	The Authority should extend market-making for longer term contracts (subject to cost effectiveness test) if previous measures not sufficiently effective
Implementation	**Tranche**: 3 **Timing**: After Tranche 1 and 2 are underway and subject to conditions above. **Who makes it happen**: The Authority with stakeholder input **Method**: Decisions by the Authority on Code changes and/or service provider contracts.

173 The horizon extends a further 12 months on 1 October each year, to cover the following 16 quarters – i.e. on 1 January each year the forward horizon will cover 15 quarters, and so on.

174 For example, Fonterra submitted that “the extension of time horizon from three-year hedges out to five years as discussed in option B2 would be of value to the market as an indication of future generation entering the market.”

175 For example, Genesis submitted that “the cost of requiring market making of longer-term contracts is likely to outweigh the benefits” and that “market making is already an expensive exercise.”

176 Contact noted that “as the demand for these contracts increases, we expect the market to meet this need. For our part, we consider all reasonable offers made to us, and where we are able to provide a bid, we will always offer a fair and reasonable price.” Similarly, MEUG considered that “this option should be left up to the market to deliver” and that there are “risks from forcing parties to contract for longer periods, if this is not an option already being pursued by the individual parties”.

177 We note that the European Energy Exchange (EEX) has recently extended its listed baseload and peak derivatives to 10 years (previously 6 years, up from 3 years originally), motivated by the role these products can play in providing hedging to complement (or substitute for) Power Purchase Agreements, with the commensurate benefits that exchange traded products provide (e.g. counterparty default risk management) - See www.eex.com/en/newsroom/detail?tx_news_pi1%5Baction%5D=detail&tx_news_pi1%5Bcontroller%5D=News&tx_news_pi1%5Bnews%5D=3152&cHash=477b5c5e41041e6ca420b52c52ab73f2.

Recommendation 29 (contingent) – Negative offers/prices

Allow negative offers/prices in the wholesale market as a tool to signal oversupply

Issue to be addressed	As the share of supply from intermittent renewables rises, there will be more half-hour trading periods when the system is over-supplied temporarily. Some countries allow negative offers/prices in the spot market as a tool to help manage these periods and decide which generation will be dispatched.
Options Paper proposal	Negative offers/prices (see Option A8)
Submitter feedback	Few submissions specifically addressed this option. However, Transpower submitted that while it would have some complexities to implement, it could be worthwhile. It noted that “the issue of how to dispatch high volumes of competing low-SRMC renewable generation remains even if the negative offers prices might not be the preferred option”. NZX also submitted that “this initiative should be kept under periodic review and reconsidered if circumstances change”.
MDAG comment	We expect temporary periods of over-supply to become more frequent in New Zealand, and agree that a mechanism to dispatch competing low-SRMC generation will be required. Currently New Zealand has a mechanism in place to address oversupply (being the ‘must-run dispatch auction’, but we consider that negative offers/prices would be a more efficient mechanism. However, this issue is less pressing than other issues facing the market. Due to the complexities associated with implementation and because there is an alternative (albeit imperfect) mechanism already in place, this measure should not be prioritised above other recommendations. As such, it is in Tranche 3 and should only be pursued when resources are available (or if market dynamics shift significantly enough that negative offers/prices become more of a priority).
MDAG conclusion	The Authority should amend the Code to allow for negative offers/prices when resources become available, and subject to an assessment of the technical feasibility of this measure.
Implementation	**Tranche**: 3 **Timing**: Investigation of technical feasibility to begin when resources are available **Who makes it happen**: The Authority (with input from Transpower regarding implementation) **Method**: Decisions by the Authority on Code changes and/or service provider contracts.

Recommendation 30 (contingent) – 'Last resort' DSF scheme

Develop procurement process for 'last resort' DSF

Issue to be addressed	Market development of DSF-rewarding tariffs may lag what is required by an increasingly renewable system especially arrangements that target large customers whose willingness to be interrupted is restricted to only a very small number of occurrences in rare circumstances where scarcity is likely.
Options Paper proposal	Procurement process for high-scarcity DSF (RERT (see Option C10). **Partially supported by MDAG in Options Paper.**
Submitter feedback	Submitters generally supported this option. Some submitted that such a mechanism needed to be implemented faster than the proposed timeframe.[178] Contact agreed that the option should be further investigated, but that it "would need to be designed carefully to preserve the incentives on the energy market and be co-optimised with other markets".
MDAG comment	It is important that the Authority retain a backstop option should progress on DSF development be slow. Procurement of a last-resort demand interruption service could draw on international experience. We agree with Contact that it would need to be designed carefully to preserve wholesale market incentives. We note this contingent recommendation only addresses a very niche aspect of demand side flexibility, i.e. one that is outside the wholesale market and only triggered very rarely. It does, however, carry the risk of regulatory creep. We note that the Authority, in their "*Driving efficient solutions to promote consumer interests through Winter 2023*" Decision Paper decided to not progress its option K, which was very similar to MDAG's Option C10. The Authority cited a concern that out-of-market procurement may have the unintended consequence of removing DSF from wholesale market participation.
MDAG conclusion	If, through its monitoring of DSF under Recommendation 3, the Authority concludes that market participants are not delivering sufficient DSF to maintain security of supply, it should develop a procurement process for rare-event scarcity situations, along the lines of the NEM's Reliability Emergency Reserve Trader (RERT) scheme. MDAG is of the firm view that is better to solve a niche problem procured as (effectively) an ancillary service, than to force a regulated wholesale 'overlay' which would see regular payments to be made to customers based on the wholesale price behaviour (as outlined in our commentary on Option C7). However, we note that if a vibrant DSF market emerges, and is signalled to the System Operator via bids, formal procurement of 'last resort' demand response is unlikely to be net beneficial.
Implementation	**Tranche**: 3 **Timing**: 2026 at the earliest, if required. **Process parameters**: Monitoring data under Recommendation 3 would need at least 2 years of data to demonstrate a trend before this measure is introduced. **Who makes it happen**: The Authority **Method**: Decisions by the Authority on Code changes

178 For example, Transpower considered that it "could be investigated sooner than indicated by MDAG, as part of or as a stepping-stone for A4" and submitted that it should be prioritised to help shore up reliability, at least as a stop-gap measure until a permanent market-based solution is implemented."

Recommendation 31 (contingent) – Virtual disaggregation

Implement virtual disaggregation of flexible generation base (using outline developed under Recommendation 13)

Issue to be addressed	Some parties may have scope and incentives to abuse market power in provision of longer duration flexibility products.
Options Paper proposal	Virtual disaggregation of flexible generation base (see Option D7)
Submitter feedback	See Recommendation 13
MDAG comment	This recommendation is to implement the high-level outline developed in Recommendation 13. It would be contingent on other performance-based pro-competitive measures not being sufficient. See Appendix D for a description on our backstop competition measures, including virtual disaggregation of flexible generation base.
MDAG conclusion	The Authority should use the high-level outline developed as part of Recommendation 13 to achieve a virtual disaggregation of the flexible generation base if other performance-based pro-competitive measures are not sufficient.
Implementation	**Tranche**: 3 **Timing**: Contingent measure, only implemented if previous measures are not sufficient **Who makes it happen**: The Authority **Method**: Decisions by the Authority on Code changes

Appendix A Demand-side flexibility (DSF)

Why a separate appendix for DSF?

A.1 Our analysis of demand-side flexibility (DSF) is derived from, and fits within, the common framework we are applying to all other aspects of the wholesale electricity market. However, we have given DSF its own appendix to explain more clearly how our proposals for DSF tie together to as an integrated package, and to reflect the importance of the role DSF is likely to play in our future electricity system.

DSF's role in our market

A.2 As explained in Chapter 3, the wholesale market's core objective is to ensure that, in any interval of time (short, medium or longer term), demand for electricity is reliably met from the lowest cost sources of supply.[179]

A.3 This is best achieved by a diversity of parties offering competing solutions to meet consumers' demand, and consumers choosing the solutions that best meet their needs. The primary coordinating tool of this competition is a dynamic, locational-based, marginal price of electricity arising from security-constrained economic dispatch.

A.4 Like generation, demand-side flexibility is a 'resource' for matching supply and demand. It is also a tool for managing price risk.

A.5 However, while the importance of dynamic price signals are well understood on the supply side, it is much less familiar on the demand side. This is due to several factors, including:

(a) For the last 100 years, the overwhelming share of resources in the industry has been put into systems for the supply-side. So it is not surprising that the systems in place to enable demand-side participation are embryonic at best.

FPVV tariffs are embedded in our history and have neutered demand response

As a result, retail competition for the bulk of mass-market consumers has centred around the single fixed price in a Fixed Price Variable Volume (FPVV) contracts. Even though commercial and industrial consumers had interval metering, pricing arrangements were largely time-of-use (TOU) Variable Volume contracts, which signalled to consumers the general patterns of prices over the day and year, but still provided price certainty.

FPVV and TOU tell customers: consume as much as you like for a fixed price, whatever the *actual* scarcity of electricity supply. Things may be extremely tight, with wholesale prices spiking to signal significant constraints in the system, but the price seen by these consumers will signal that everything is exactly the same as it was in any previous period.

However, the retailer is charged for the customer's consumption at the wholesale price. By absorbing the ups and downs of the spot price and allowing its customers to use as much electricity as they wish at fixed prices under FPVV or TOU contract, the retailer is providing a risk management service to its customers. Of course, the retailer adds a margin for this service; hence it is reasonable to expect that consumers will pay more for an FPVV contract than they would under a dynamic pricing arrangement, over the long term.

In short, FPVV makes consumers completely impervious to any changes in supply and demand conditions, which of course is quite different to how pricing works for almost every other product relied on by consumers in New Zealand.

However, the expectation of FPVV pricing, immune to underlying system conditions, is quite deeply embedded in social expectations. Paying a higher tariff to have a retailer manage a consumer's risk may be entirely rational, depending on the consumer's aversion to risk. However, for large parts of New Zealand's history, signing up for an FPVV contract has been the *only* option for many consumers, hence there has been no basis on which a consumer could evaluate the implied cost of being anaesthetised from variation. As a result, our 'energy consumption culture' does not have widespread embedded habits around adapting our short-term consumption behaviour to electricity prices. And of course, except in a crisis, cultures take time to change.

The embedded expectation of FPVV is not necessarily an inherent trait in modern electricity systems. Consumers in other countries have had access to semi-dynamic retail pricing arrangements even prior to many of the technology changes listed above. Indeed, in Norway, the majority of mass-market consumers have consistently chosen wholesale-linked prices over fixed price arrangements for at least a decade.

179 Peter Cramton, Electricity market design, Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612 – with the addition of "renewable". This objective is reflected in the Electricity Authority's statutory objective, which is "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers" – section 15 of the Electricity Industry Act 2010.

(b) The wholesale market ‘architecture’ was largely designed around a small number of large grid-connected machines (generators, and direct connect industrials) who were expected to provide all the flexibility required in the wholesale market.

(c) Unlike the supply-side, the demand-side in general is not primarily focused on engaging in a market for electricity.

(d) In some situations, generator-retailers have less incentive to encourage or use DSF than an independent retailer or flexibility aggregator.[180]

(e) The cost and effort required for would-be DSF providers to monitor and respond to dynamic electricity prices have been seen as prohibitive.

(f) Given the relative stability of electricity prices in New Zealand,[181] the potential savings in electricity costs from responding to dynamic electricity prices has been quite modest.

(g) As a result, the potential “payoff” from changing electricity consumption in response to a dynamic price has been low, and therefore short-term electricity consumption decisions have been assumed to be highly inelastic.

A.6 It is also the case that dynamic pricing for consumers has not been practical until recently, as metering technology for most mass-market consumers has not been able to measure or readily communicate consumption levels in intervals that would measure their response to dynamic prices.

A.7 The upshot has been Fixed Price Variable Volume (FPVV) contracts for the bulk of consumers under which the price faced by most consumers is held constant over the day and year, whatever the underlying supply and demand situation (or any network price signalling that may have varied over the day and year). For commercial and industrial (C&I) customers, pre-determined time-of-use (TOU) prices have provided ‘static’ signals to shift demand where possible. In either case, FPVV and TOU tariffs have had the effect of neutering any incentives to change short-term consumption in response to dynamic price signals of relative scarcity for the vast bulk of consumers (see sidebar above).

A.8 To date, energy efficiency, partly driven by the longer-term trend in retail electricity prices, has provided the bulk of demand response (other than in some isolated situations).[182]

Today’s reality supports a move away from FPVV and towards more responsive demand

A.9 However, the context is changing, quite quickly:

(a) New Zealand has one of the highest penetrations of advanced metering systems in the world.

180 Given the size of their customer bases, there will be situations where generator-retailers reducing demand will lead to a reduction in the wholesale price. If, at that point in time, the generator-retailer is a net seller in the wholesale market, lowering the wholesale price would be commercially undesirable. In this situation, the generator-retailer may not deploy DSF at all, or may deploy a lower quantity that is unlikely to affect price. In situations where the generator-retailer is a net buyer from the wholesale market, or when its deployment of DSF would not reduce the market price, DSF is commercially beneficial to them. We are not aware of any analysis that attempts to estimate the degree to which this dampens the incentives faced by generator-retailers to invest in DSF. However, we reinforce that the portfolio effects described above only reduce the incentives, they do not eliminate them. This is evidenced by the fact that generator-retailers have begun releasing DSF rewarding tariffs over recent years, and actively exploring more advanced arrangements (e.g. virtual power plants comprising multiple demand-side technologies).

181 Due to the role of hydro.

182 As outlined in the Options Paper, large industrials and mass market conservation in extended periods of low inflows.

(b) The cost of storage devices (batteries) has reduced, and they are now more prevalent, either in the form of an electric vehicle or stationary batteries. This allows network-sourced electricity consumption to be ‘shifted’ with little or no impact on the household or business. In the coming years, we are likely to see a proliferation of batteries dispersed across the system.

(c) Technology (including communications) has advanced considerably, reducing the level of consumer engagement required to respond dynamically. A range of devices and machines (including hot water cylinders, batteries, electric vehicle chargers and heat pumps) can now automatically respond to an external signal (such as price).

(d) Wholesale volatility has increased (and is expected to continue to increase), improving the payoff for more dynamic management of consumption.

(e) The parties involved in a DSF market now extend beyond the traditional supply chain and include flexibility traders, technology and communications providers, research and development and electrical device standards organisations.

A.10 In short, the prospects for consumer-based flexibility to compete with generation to match supply and demand, based on dynamic price signals, are vastly improved. Of course, this is not true of all consumption. As it is on the supply side, not all consumption is flexible. However, true dynamic response is still possible where consumption can be shifted by using thermal or electrochemical storage, so that the service to the consumer is largely unchanged.

What could dynamic pricing arrangements look like in New Zealand?

As outlined above, the predominant mass-market contract in use today is a FPVV tariff, which provides no signal to consumers that reflects the immediate value (to the system) of them changing their consumption.

The 'purest' form of wholesale signalling to consumers would be for them to face the real-time wholesale price at every point in time. These 'spot' contracts have been available across the customer spectrum in New Zealand, albeit with limited uptake.* The retrenchment from spot pricing amongst domestic consumers in 2020 is an indication of the value consumers place on some degree of price certainty, which is very pertinent given the likelihood of increased future price volatility.

However, between FPVV and full spot pricing there are a variety of pricing arrangements that could incentivise price-responsive changes in consumption, thus delivering improvements in system efficiency. These include:

a) TOU pricing, where tariff prices are known in advance, but vary depending on the time of day and time of year. The prices are set by retailers to reflect the expected pattern on wholesale prices (and potentially changes in network charges, where time-varying pricing is increasingly used). TOU pricing varies from the simple 'free hours' in domestic tariffs, through to the more complex 144-part pricing arrangements that are commonplace in the C&I sector;

b) Contracts for difference, where the consumer is provided a certain price for a certain level of consumption, but pays (or earns) the wholesale price for additional consumption above (or reduced consumption below) the pre-bought quantity. These contracts are currently observed primarily in the large industrial space;

c) FPVV (or TOU) contracts where a third party (retailer or 'flexibility trader') provides an occasional signal when high wholesale prices arise, to incentivise a greater reduction in consumption (over and above the 'standard' FPVV to TOU rate). Internationally these arrangements are often known as 'critical peak pricing' arrangements;**

d) FPVV (or TOU) contracts where the customer allows a third party to manage a particular consumption appliance (e.g. an EV charger, hot water cylinder, heat pump or industrial boiler) dynamically in response to wholesale prices (or network signals). In return for assigning control to the third party, they receive a benefit (typically through a lower FPVV or TOU tariff).***

While spot pricing may be the most pure form of pricing, the degree to which it improves system efficiency over these other arrangements has not, to our knowledge, been assessed in the New Zealand context. There will be consumption devices that will only be able to respond at particular times, and/or for a limited period, due to in-built routines or scheduling of production. Some consumers will be happy to experience occasional reductions in service (e.g. warmth) to avoid very high prices, as long as they have control of how often this occurs, what the degradation in service is, and how long it will last. Other consumers will value predictability in price patterns, especially if they have complex processes to manage, or are using pre-set timers to automate the change in consumption. In these situations, it is unlikely that fully dynamic spot pricing will yield significant improvements in system efficiency over some of the more 'static' pricing arrangements described in (a) above.

We also note that, on the assumption that a third-party retailer or aggregator acts as a good agent for the consumer, option (d) achieves the desired improvement in system efficiency but removes any need for the customer to face dynamic prices. For the vast majority of customers today, their retailer faces all the time-varying wholesale and network costs on the customer's behalf. Hence the retailer should (noting concerns about generator-retailer incentives above) be commercially motivated to optimise the use of the customer's flexibility in order to reduce its purchase costs, and to share this benefit with the customer. We also note the emergence of flexibility aggregators who specialise in optimising flexibility, and could provide this service to either a customer directly, or to the retailer, in return for a share of the benefit (see the 'market access for flexibility traders who aren't aggregators' section of Appendix F, Option C7).

Finally, where the customer does face a dynamic signal, making the response 'easy' will require more than simple pre-set timers. As the system transitions to higher levels of intermittent renewables, it will become harder to predict what times of day will see high (or low) wholesale prices. This, in turn, will make TOU tariffs less reflective of system conditions at any point in time. Automation will then need to be driven by a dynamic signal that could arise at any time, rather than according to pre-set patterns. Hence the success of arrangements (b) – (d) go hand-in-hand with consumer investment in increasingly smart devices and systems.

* Spot contracts have been made available to the commercial and industrial segment for well over a decade. The advent of Flick in 2014 saw one of the first spot arrangements for domestic consumers. However, Flick in 2021 Flick suspended its wholesale product, and it remains unavailable to customers at the time of writing.

** We are not aware of this being offered in New Zealand as a wholesale market driven tariff, but we note that several EDBs (e.g. Orion and Aurora) use 'Control Period Demand' (CPD) charges as part of their network tariffs. CPD charges only apply when the network is reaching its peak, and the EDB sends a signal to large customers a few hours in advance to warn them of an impending CPD period. The Authority's 'Targeted reform of Distribution Pricing' (Appendix A) states that "one EDB applies a 'peak charge' based on each retailer's share of usage at the time of the 200 – 300 peak half hours during the previous winter."

*** EDB's ripple control of hot water (and night-store heating) is a widespread example of this tariff. In most situations, the customer simply pays a lower network charge in exchange for allowing the EDB to turn off their hot water cylinder for a limited number of hours per day (or in emergency situations).

Progress on tariffs and technology is already happening

A.11 The change in context appears to have triggered an increase in tariffs that incentivise consumers to use flexibility in their consumption to reduce their consumption costs.[183] TOU retail tariffs for mass market consumers are now relatively common, and a number of retailers are either trialling or releasing relatively sophisticated customer arrangements targeted at EV charging.[184] New market participants have emerged that are developing 'virtual power plants' achieved through the coordination of multiple household and business DSF. In the C&I market, we are aware of similar increases in sophistication.[185] We expect much of the market's progress towards new DSF arrangements will come from the entrepreneurial drive of customer-facing entities and technology developers offering services to suit different customer preferences and the spectrum of 'smart' devices available to them. Further, the mix of tariffs is likely to change over time as consumers and the technology they use becomes more sophisticated.

A.12 We are also encouraged by the range of initiatives across the industry, all seeking to increase the role the demand side can play in providing flexibility services to the electricity industry. These include:

(a) The FlexForum, a group of over 20 organisations across the value chain which fosters coordination and collaboration to maximise the benefit of distributed flexibility to households, businesses and communities. The FlexForum developed New Zealand's first Flexibility Plan 1.0, endorsed by MBIE, which details 39 low regret, practical steps to deliver increased flexibility;

(b) The ENA's Future Network Forum, which aims to harness the collective power of EDBs to help Aotearoa New Zealand reach its climate goals, and bring the ENA's Network Transformation Roadmap to life through EDB collaboration;

(c) The Electrical Engineers Association, which is conducting a pilot on communications protocols for flexibility ('FlexTalk');

(d) Ara Ake, New Zealand's future energy centre, which works with energy innovators to commercialise their offerings and enter the market, and is also administering MBIE's 'Distributed Flexibility Innovation Fund'; and

(e) A range of market participants and EDBs, which are trialling new arrangements and tariffs with the specific intention of using flexibility to meet network and customer needs.

A.13 The variety of groups beginning to work in the flexibility space reinforces the magnitude of work to be done, and also that the issues span a broad 'ecosystem' of organisations.

Essential ingredients of an efficient DSF market

A.14 From MDAG's work to date, including learnings from submissions and other jurisdictions, we can distil the core components of a well-functioning DSF market – that is, one that contributes efficiently to the overall goal of lowest cost reliable supply for the long-term benefit of consumers.

A.15 Some core components relate to how consumers are involved and remunerated. Others relate to soft infrastructure and technology.

183 For a useful history of the developments over the last 5-7 years, see www.energynews.co.nz/news/electricity/149248/contact-offers-free-peak-weekend-power-deal.

184 For example, see www.energynews.co.nz/news/electric-vehicles/149359/genesis-eyes-managed-ev-charging-scale.

185 See www.simplyenergy.co.nz/wp-content/uploads/2023/04/Case-Study-Open-Country-Dairy.pdf.

A.16 The following four core market components are required for consumers to engage in a DSF market:

(a) **Accurate (efficient) prices signals**: Dynamic wholesale prices that reflect the marginal cost of electricity at any point in time, incorporating transmission and distribution network limits;

(b) **Tools for managing risk**: Contractual arrangements between intermediaries (retailers, flexibility traders) and customers that manage their risk and optimise the use of flexible devices and equipment;

(c) **Technology**: The ability to make response easy through automation, as well as communicating signals and responses between the intermediaries and consumers' equipment; and

(d) **Awareness:** Potential sellers and buyers of DSF seeing the profitable opportunities to participate. For many parties, this will involve a change of mind-set and may require prompts from advisers or peers who can offer more insight.

A.17 Progress on only one or some elements is unlikely to do the job.[186] All four elements ((a)-(d)) above are required to properly unlock DSF's potential.

A.18 However, two further components are needed at the wholesale market level:

(a) **Coordinating infrastructure**: System operation that delivers security constrained economic dispatch and associated pricing, providing confidence that the flexibility can be delivered and properly valued (relative to supply-side sources of flexibility). This coordinating infrastructure includes many aspects of the automation and communications systems and protocols noted in (b) above; and

(b) **Effective competition driving innovation:** A diversity of parties competing to offer services to potential sellers and buyers of DSF in ways that better meet their needs and preferences. While outside the scope of MDAG's wholesale market brief, we observe that effective retail competition is crucial to the entrepreneurial drive to meet customers' needs.[187] Any serious consideration of retail competition – from the perspective of demand-side flexibility – must also consider whether 'flexibility traders' face barriers to accessing the wholesale market benefits of deploying flexibility (namely, the reduction in wholesale purchase costs and network charges, which is, by default, captured by the customer's retailer).[188]

A.19 At a high level, these six core requirements above are no different on the supply-side. Indeed, our analysis of DSF is derived from, and fits within, the common framework we are applying to all other aspects of the wholesale electricity market.

186 Developing customer-facing contract arrangements that reward demand-side flexibility is all very well, but unless the consumer can find ways to adapt easily (e.g. through automation), or assign the responsibility for dynamic response to another party, uptake will be limited to a small group of energy-conscious consumers (or risk bill shock). Widespread availability of automation and control features and systems in energy-hungry devices is welcome, but without a dynamic price signal, there is no payoff to consumers investing the time and effort in investing in and enabling these systems and features. And in order for there to be a 'happy marriage' of automation technology and tariffs that reward its use, consumers must be aware of both: knowledge of one without the other will lead to consumer frustration.

187 A number of important demand-side developments in New Zealand's recent history were instigated by independent retailers. Others have been introduced by organisations who aren't retailers (e.g. Enel X, SolarZero and Evnex).

188 See the 'market access for flexibility traders who aren't aggregators' section of Appendix F, Option C7.

But essentials are not in place

A.20 For the reasons set out in earlier in this Appendix, the current system settings are heavily geared to the assumption that flexibility is predominantly provided by the supply side. The core components for a DSF market are therefore not necessarily in place or well designed. Some parts of the DSF market exist today (wholesale pricing and system operation at the wholesale level). But key other parts are in their relative infancy (e.g. cost-reflective network pricing and coordination, DSF tariffs for consumers and automation).

A.21 Keep in mind that most of the DSF sources will be widely dispersed across 29 distribution networks. Even if they were to see some form of dynamic pricing (and risk management tools were in place), few of those DSF sources would be useable without interface systems and protocols and coordination infrastructure. Our previous work has highlighted current systems and practices that are likely to impede progress towards effective competition between demand side and supply-side flexibility.

Regulatory pricing ‘overlay’ not preferred

A.22 The approach of some overseas jurisdictions has been to leave the FPVV and some other DSF-disabling factors in place but ‘overlay’ a regulatory (administered) scheme to reward parties if they provide DSF.[189]

A.23 We have considered those schemes in depth and conclude that, while well-intentioned, they are designed for the market conditions of the past rather than future. They are also intended to be ‘temporary’ but they become hard to withdraw and have the potential to distort the role of DSF and impair progress toward more market-driven DSF. (Our view of administered DSF schemes is set out in Appendix F).

Better to activate the DSF market

A.24 Given the changes in technology and wholesale market signals now in progress, the essential elements for an efficient market in DSF can now be put in place. The reasons described Chapters 5 and 6 of this report for preferring a market approach therefore also apply to the choice of regulatory approach in relation to DSF.

A.25 The required change in dynamics is akin to stimulating human neuro-muscular pathways that are either new, or have previously lain dormant. In short, rather than looking to ‘tip the scales’ in any direction, it is better to activate the system’s pathways using accurate price signals, enabling parties to look for better ways to meet consumers' demand, and for consumers to choose the solutions that best meet their needs.

A.26 For this to happen, it will require a package of measures to activate the DSF market as part of our grid-based wholesale electricity market.

A.27 Below we explain how various measures recommended in Chapter 9 of this report *tie together* to enable this outcome of activating the DSF market. (To be clear, each measure is described in more detail in Chapter 9).

Recommended DSF Package 1: Activate DSF in the wholesale market

A.28 This package relates to price formation, tools for risk management, improving consumers’ ability to discover and assess options to enable DSF, and standards and protocols for coordination among market participants.

189 For example, the wholesale demand response mechanism in place in Australia.

A.29 We address network pricing and coordination issues in the next section of this appendix, which leads to our recommended DSF Package 2.

Measures to strengthen accurate (efficient) price signals

DSF activity monitoring (Recommendation 3)

A.30 Change market rules to require all intermediaries (retailers and flexibility aggregators) to regularly disclose:

(a) available tariffs that reward DSF, and the number of consumers using these tariffs;

(b) the proportion of consumption volumes being reconciled via profiles rather than half-hourly data; and

(c) metrics on the participation of DSF in dispatch notification or as a dispatch-capable load station.

A.31 The Authority (or an independent entity, such as the FlexForum) should combine this quantitative data with other qualitative information (e.g. surveys of large customers regarding their use of, or planned investment in, DSF; use of dynamic operating envelopes in distribution networks) to produce an annual industry 'DSF scorecard'.[190] The primary objective of this scorecard would be to assess the degree to which the industry is making progress in providing a variety of arrangements available to customers that incentivise them to provide flexibility to the market.

Sunset profiling (Recommendation 18)

A.32 Change the Code to set a sunset date on the use of default demand profiles at ICPs that have half-hourly metering capability. Default profiles are still used for ~40% of users even though 90% of connections have half-hourly metering capability. Continued use of profiles seriously diminishes incentives to offer and use DSF-rewarding tariffs. Based on the latest data provided to MDAG by the reconciliation manager, there has been no discernible decrease in the use of profiles since we first investigated the issue. Make the rule change in 2024, with sunset date to take effect in 2026/27, giving market participants still using profiles sufficient notice put in systems and processes required to transition to settlement on half-hourly metering data.

Measures to strengthen tools for managing risk

New flexibility products (standardised) (Recommendation 8)

A.33 By a co-design process with the industry, develop one or more standardised flexible supply contracts using the framework set out in Appendix B as a base. Forward price discovery and hedging for flexible supply and DSF products are critical market functions in a renewables world, and both are impeded by the lack of any standardised flexibility product(s). Flexibility contracts will become the market's 'secret sauce' – enabling a range of wholesale market processes to function effectively.

190 Qualitative information would include surveys of large customers regarding their use of, or planned investment in, DSF; use of dynamic operating envelopes in distribution networks; arrangements providing flexibility intermediaries access to hot water control). The FlexForum's Flexibility Plan 1.0 has a number of steps about visibility of data relating to flexibility opportunities – the Authority could integrate this data into the scorecard. See www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf.

Measure to increase awareness of DSF opportunities

Consumer awareness of DSF (Recommendation 20)

A.34 As outlined below, help a much larger number of consumers to become aware of the technology and tariff possibilities, in a way that is relatively effortless given their primary focus on living their lives and conducting their business. This is especially critical at the times consumers are making choices about an investment or upgrade in their energy-consuming devices or equipment.

A.35 In particular:

(a) The Energy and Efficiency Conservation Authority (EECA) to lead the way in demonstrating how larger consumers and their advisers should evaluate DSF options in the context of electrification investment decisions.[191]

(b) Powerswitch and other tariff comparison providers to enable consumers to readily see the benefits of DSF.

(c) The Authority to:

(i) Make consumer data relating to DSF-rewarding tariffs more easily accessible to consumers and intermediaries providing tariff comparisons; and

(ii) Provide information to EECA and other parties involved in providing advice to larger electricity consumers on potential DSF opportunities. This information from the Authority should include (for example) modelling scenarios on future wholesale price behaviour to help evaluate DSF investment decision.

Measures for coordinating infrastructure and technology

DSF interface systems and protocols (Recommendation 10)

A.36 Develop a range of new standards and protocols to enable efficient interface among the chain of participants in the DSF market. The process of developing these standards and protocols requires a diversity of well-designed pilots and trials to test a range issues and possible solutions. This is an industry-good undertaking (that is, for the benefit of the industry as a whole) and therefore all results must be shared openly with all interested stakeholders. The FlexForum seems to be well placed to serve as the body facilitating these steps and provide the funding agency with an overview of the trials and steps to be funded in order to develop the required standards and protocols. The results also need to be integrated to guide the emergence of solutions that seem be well suited to become industry standards or protocols.

A.37 Our recommended focus here is standards and protocols that enable and simplify the interactions between market participants (including flexibility traders), customers and the System Operator which, in turn, build confidence in market participants and consumers that flexibility can be delivered within system limits and rewarded appropriately.[192]

191 Similar in approach to the case studies linked above.

192 Examples of trials underway include the Electricity Engineers Association trial of OpenADR communications technology as part of its ‘FlexTalk’ project, and aspects of Orion and Wellington Electricity’s ‘Resi-flex’ project.

FSR Project as it relates to demand-side flexibility (DSF) (Recommendation 11)

A.38 In the Future Security and Resilience (FSR) project, bring forward the priority of improving visibility of DSF for the System Operator and remove Code barriers to DSF offering ancillary services:

(a) As a first step, Authority to prioritise a study of the likely increase in future system cost that would arise as a result of various levels of non-bid off-market DSF. (This would provide an approximation of consumers' 'willingness to pay' for DSF to be bid into the market); and

(b) Authority to then develop Code changes that provide flexibility traders with incentives (commensurate with the results of the study above) to bid DSF into the market, via DCLS or DNx.

A.39 Security constrained optimal dispatch needs to be able to (within reason) correctly anticipate the contribution of DSF at any given point in time, otherwise the uncertainty around dispatch outcomes will increase, likely leading to an increase in the cost of reactive flexibility (e.g. frequency keeping). Avoiding this cost requires a sufficient quantity of DSF to be formally bid into the market, whether as a dispatch-capable load station, or through dispatch notification.

Price-driven use of DSF on EDB networks and coordination with wholesale market

Why is this in-scope for MDAG?

A.40 The short answer is, making widely dispersed sources of DSF across distribution networks useable as a competitive alternative to generation is fundamentally a wholesale market issue.

A.41 The rapidly increasing number of potentially flexible devices will provide an unprecedented opportunity for greater consumer involvement in managing a high-renewables market – helping to mitigate market power, reduce emissions from peaking generation, and defer or avoid investment.[193]

A.42 However, DSF's ability to compete efficiently with supply-side resources in an increasingly renewable system is hampered by current pricing and coordination arrangements on the distribution network, and between the current wholesale market and distribution networks.

A.43 The wholesale market – specifically, the implementation of 'security-constrained economic dispatch' – was designed in the 1990s to extend only to the Grid Exit Point ('GXP', the point of interface with the distribution network). What happens beyond the GXP (in relation to price signals to users and operational coordination) has not, to date, been a primary concern for the wholesale market. However, looking forward, it is.

A.44 It is now clear that pricing and coordination functions for those distributed flexibility sources need to be properly 'integrated' with the wholesale market to realise their full potential.

Why distribution-level pricing and coordination is important (and hard)

A.45 DSF located within distribution networks can provide services to both national and local 'markets'. For example, an industrial facility that can shift demand forward by a few hours can be valuable to the national supply-demand balance, but also assist a distribution network manage local congestion and defer the need for network upgrades.

193 Equally, as discussed below, consumer involvement to this end could trigger significant, inefficient distribution network investment, due to the lack of coordination. This reinforces how far we are from achieving a set of system arrangements that deliver the lowest system cost to consumers.

A.46 From MDAG's perspective, the distribution-transmission pricing and coordination protocols are the most undeveloped 'muscles' needed for an efficient DSF market. As we expand on below:

(a) Price signals from the wholesale market are based on dynamic locational marginal pricing reflecting resources and system limits on the high-voltage grid.

(b) Price signals within the distribution network are largely pre-determined annually, using methodologies that are intended to balance the objectives of cost-reflectivity and recovering the EDB's revenue.[194]

(c) The response of distribution-connected DSF to a wholesale (TLMP) signal is not reconciled with the limits of the distribution system. Flexibility intermediaries have no visibility of these limits, and their host networks often have no visibility of the flexibility intermediaries' intended or actual activities in real time.

A.47 Looking forward, integrating distributed resources into the wholesale market will require careful consideration of the full network topology and limits in distribution networks – i.e. beyond the GXP – and how those limits are managed and dynamically reflected in signals for DSF.

A.48 In relative terms, determining the available capacity on distribution networks is more complex than on the transmission system. There are at least two orders of magnitude more 'nodes' on the distribution network than the transmission network in New Zealand. Power quality varies to a much greater extent on distribution networks, as do security levels,[195] making large parts of the network more susceptible to unplanned outages (e.g. car vs pole, extreme weather and faults). The nature of network topology also results in a higher degree of network switching.

A.49 This makes the proper integration of distribution networks into a wholesale market challenging. However, failure to provide coherent system-level signals to the consumer, recognise the practical limitations of the network, and/or represent these limitations in market models will prevent an efficient DSF market. It could also lead to significantly adverse outcomes (including safety) if network constraints are breached.

A.50 The recommendations in this second DSF package set out a process for establishing a longer-term solution to deliver integrated security-constrained economic dispatch across both transmission and distribution systems, along with two interim measures that will improve signalling and coordination while that longer-term vision is enabled.

Big benefits from system-level coordination

A.51 Distribution-transmission pricing and coordination protocols are arguably the most important DSF muscles to be activated. As noted by the Authority:

> "With projections of over $20 billion of distribution-related investment in each of the next three decades, cost-reflective prices, which send efficient signals of the cost consequences of network usage, will be crucial for helping direct users toward lowest-cost usage and investment choices. Such cost-reflective prices, by coordinating network usage and encouraging the right investment to occur in the right place at the right time, could save consumers billions of dollars through economising on investment in the coming years."[196]

194 While the cost-reflectivity of distribution price signals is increasing overall (see Appendix A of www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf), price-setting has traditionally been seen primarily as a means for recovering the EDB's revenue.

195 This is typically appropriate, as the cost of maintaining N-1 security to most ICPs in New Zealand would be astronomical.

196 See page 2 of www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf.

A.52 Indeed, in the absence of coordination, dispatch of distribution-level DSF based on wholesale market signals alone may unintentionally trigger upgrades to distribution networks, which actually *increase* costs to consumers overall.[197] Equally, any misalignment between TLMP and distribution signals may actually compromise the achievement of the lowest-cost outcome on the current *wholesale* market.[198] In addressing the current shortcomings of distribution signals, DSF response may be over-signalled or overly-constrained in distribution networks, and thus these resources will be inefficiently taken away from providing least-cost services to the transmission grid.

A.53 Delaying an efficient form of security constrained economic dispatch (and associated dynamic pricing) in large parts of the distribution grid will likely lead to inefficient deterrence of DSF, or inefficiently large network investment, or both. We need to develop a form of integrated system optimisation and management, based on the principle of marginal pricing, that enables the wholesale market to properly access and deploy the myriad of sources likely to be located across distribution networks.

A.54 From a whole-of-system perspective, marginal prices produced from security constrained economic dispatch will correctly incentivise[199] investment in DSF (as they do for all other resources) if the framework[200] for security and pricing is integrated over the whole transmission and distribution network. With a common underlying framework, flexibility traders and retailers can be confident they are optimising the deployment of a customer's flexibility across wholesale, network and ancillary markets, which (in turn) better achieve the wider objective of minimising whole-of-system costs to consumers.

Today's context

A.55 Security-constrained economic dispatch provides marginal pricing and coordination for the transmission grid and the resources offering into the wholesale market that is highly dynamic, reflecting supply, demand, and the transmission network capacity at any time of day and any location in the transmission network.

197 This may be accounted for in the Authority's reference to $20b (which in turn is a reference to BCG's "The future is electric"). Without understanding how BCG derived this figure, we cannot tell.

198 Note that this issue is not unique to DSF on the distribution network. As observed by Reeve, Stevenson and Comendant (2023), "where [distributed generation] participates in the market through a distributor's network then multiple [distributed generators at the same GXP] gets the same price signal. Where they have the same offer price then the SO must apply an arbitrary dispatch allocation. If at least some distribution network information was included in the pricing model (such as losses and capacity limits between GXPs and DG) then economic dispatch could still occur". See "Barriers to getting the full value of Distributed Generation in a highly renewable electricity system", appended to Manawa's submission to MBIE's Electricity Market Measures consultation.

199 We acknowledge that the existence of efficient prices alone does not guarantee the 'correct' level of investment. There are a number of other drivers, particularly consumer awareness and understanding of the options available to them, as described in Recommendation 20.

200 Not necessarily all the 'bells and whistles', but integration around the common principle of marginal pricing is important.

A.56 As noted above, this does not extend beyond GXPs. Nor does the modelling of security constraints. This results in two immediate issues:

(a) **Issue 1:** The wholesale price observed by a consumer that might provide flexibility is simply the marginal price at the nearest GXP,[201] reflecting only the conditions faced by the transmission network. This price does not signal how the customer's flexibility might help manage local distribution-level system limits. The only distribution-level signal received by a consumer is through distribution tariffs. As the tariffs are set (usually) once a year, the prices that apply at each time of day through the year, and the parts of the network they apply to, are pre-determined. As a result, the signal is usually not reflective of the actual system conditions that prevail at any point in time or location which, as noted above, are often more dynamic than on the transmission system.[202] In a small but increasing number of specific situations, the signals are based on flexibility service procured by EDBs,[203] and these arrangements could be dynamic, but the transparency of these signals to the wider DSF market is variable.

(b) **Issue 2:** Unlike on the transmission grid, neither the prevailing wholesale price, nor a dispatch instruction from the System Operator, reflects any thermal or power quality limits on the distribution network. Thus, DSF responding to wholesale-driven signals (such as increases in demand to charge distributed batteries at low wholesale prices) may compromise the distribution system.

A.57 The longer term solution to both issues is to develop a form of security-constrained economic dispatch that can integrate across transmission and distribution networks, producing marginal prices to a single wholesale market. (This is reflected in *Recommendation 5*, which we come to shortly). However, this longer-term solution will take a number of years to develop. We need to address Issues 1 and 2 in the interim.

Interim role of predetermined distribution tariffs to signal value of DSF

A.58 In our Options paper, our preferred option (Option C11) to address Issue 1 was distribution pricing that reflects the 'avoided cost' of network investment – in short, raising the costs of consumption (and thus increasing the benefit from demand reduction) during those periods when network capacity is scarce.

A.59 In discussing Option C11, our Options paper also pointed out[204] the limitations of 'static'[205] network tariffs to provide dynamic signals that reflected the scarcity of network capacity at a particular time and in a particular place. In a high-renewables world it is not possible to know in advance what period of the day will experience the lowest or highest wholesale prices. So there is a risk of wholesale-driven DSF (e.g. charging or injecting from batteries, or heating hot water) in a particular part of the network exceeding the network's capacity at any time of day.

201 Technically, the wholesale GXP price is adjusted by 'loss factors' which reflect – in a highly averaged and static way - distribution losses between the GXP and the consumer's location.

202 The exception to this would be Congestion Period Demand (CPD) network tariffs, such as that used by Orion and Aurora, which is a predetermined charge that applies to the consumer's demand level during the periods of highest network demand. However, the mechanism is somewhat dynamic in the sense that the EDB sends a signal to large consumers a few hours prior to the periods where the network is expected to see this high level of demand. CPD charges are applied coarsely over the network, hence are not necessarily reflective of network congestion in any particular location.

203 Examples of these directly procured network support contracts include Aurora's Upper Clutha (www.ena.org.nz/resources/publications/document/825); Powerco's solarZero contract (www.powerco.co.nz/what-we-do/our-projects/shoring-up-coromandels-power); and Orion's project in Lincoln (www.oriongroup.co.nz/corporate/corporate-publications/lincolnflexibilitytrial/). A list of RfPs undertaken by EDBs for flexibility services can be found here: www.ena.org.nz/resources/edb-requests-for-non-network-alternative-services/.

204 As did submissions to our Options paper – see, for example, Orion and Aurora submissions.

205 In the sense that they don't respond dynamically to real-time system conditions.

A.60 That said, there is still a critical role for distribution pricing to fulfil a long-term investment signalling role while other more dynamic options are developed (see below). Consumers are, today, making decisions about whether to invest in “smart” equipment – from domestic EV chargers to industrial electrode boilers. Part of this is a consumer’s decision whether any extra cost incurred by purchasing a ‘smart’ device is worth it. The potential for a smart device to reduce the consumer’s electricity costs – wholesale and network charges – should be available to the consumer as part of this decision.

A.61 Technology providers, retailers and flexibility traders are continuing to develop more and more sophisticated mechanisms by which smart-enabled equipment can automatically respond to network pricing. This automation should increase EDBs’ confidence that network pricing can reliably slow the growth of peak demand (as hot water control has historically), in turn reducing investment.

A.62 Yet it appears that widespread development of network tariffs that incentivise this sort of response is slow, despite some progress in the last 1-2 years.[206] Of concern to MDAG is the Authority’s conclusion that “there has been little progress in establishing pricing signals that reward flexibility, and some regression with respect to services subject to control”.

A.63 MDAG has therefore concluded that our preferred option C11 is required, as reflect in *Recommendation 4* below. We are encouraged by the direction indicated by the Authority in its recent “Targeted Reform of Distribution Pricing” Issues paper. We encourage the Authority continue this workstream at pace.

No pricing signals in EDB default price paths

A.64 While we acknowledge the limitation of predetermined distribution tariffs to signal the marginal value of electricity at any point in time and place (as happens on the transmission grid through the wholesale market), we believe every effort should be taken to ensure these tariffs are being efficiently deployed to reward flexibility that legitimately places downward pressure on network investment.

A.65 To this end, we are surprised at the very limited role that distribution pricing appears to play in the Commerce Commission’s consideration of network regulation. Our understanding is that – even in their consideration of a customised price path (CPP) – the Commission does not consider whether cost-reflective pricing is in place for the EDB as a factor in its determination. For setting default price path (DPP), this does not happen at all, even as part of how the Input Methodologies (IMs) provide incentives for innovation, energy efficiency, demand-side management and reduction of losses.[207] Similarly, there is no information disclosure requirement on EDBs to discuss how they are using pricing to optimise investment, which would ideally be included in their Asset Management Plans.[208]

206 See page 2 of www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf – “based on the evidence gathered from scorecards assessments since 2019, and analysis of other disclosed information, the Authority is concerned that progress toward more cost-reflective pricing is not occurring as consistently or as rapidly as required.”

207 Section 54Q of the Commerce Act

208 We are not arguing that distribution pricing is the only tool that should be better incorporated into the Part 4 regime. There are aspects of quality regulation that could lead to better optimised investment pathways. See Manawa submission to Energy Market Measures consultation, 2023.

A.66 We understand the philosophy of the IM regime is that, given the EDB's allowable revenue arising from the DPP, each EDB will be sufficiently incentivised to deploy any efficient means to reduce cost (whilst meeting quality thresholds), as the EDB can take the cost reduction as profit (within the regulatory control period).[209] Therefore, if cost-reflective pricing could be efficiently deployed to reduce capital or operational costs, the assumption is that the EDB will do it. This is, however, by no means assured. The Authority's scorecards, despite many years of publication, have shown that the inertia in EDB pricing is significant.[210]

A.67 MDAG's remit does not extend to the Part 4 regime, and we expect that the incentives that EDBs face to reduce costs under the regime has been debated at length over the 20-year history of the IMs. MDAG's remit under this project is, however, to consider how a high renewables electricity market will deliver the lowest overall system cost to consumers. Based on the Authority's review cited above, consumers' decisions about whether to invest in and enable these distributed devices to deliver flexibility services is missing a distribution-based pricing signal in many parts of the country.

Wholesale-driven DSF not reconciled with distribution system limits

A.68 This issue was highlighted by Vector in its submission to the Options Paper. FlexForum noted (as quoted by Vector) that:

> "Distributors can manage sudden falls in load. **Restoring load (including after a period of load control) requires more careful management.** A fall in wholesale prices, due to increases in wind or solar generation across a part of Aotearoa New Zealand, could see many distributed batteries, EV chargers and smart hot-water cylinders being dispatched on by the System Operator. Similarly, large numbers of DER, such as household batteries, are already being armed to respond at short notice to a fall in system frequency on the grid.
>
> "To enable flexible DER to provide services to national markets in a way that keeps distribution networks safe and stable, and maintain power quality to consumers within legislated limits, **distributors will need to provide operators of flexible DER with network access that represents not just maximum physical operating limits, but possibly also physical limits on the rate-of-increase of demand or output that the network can handle to avoid creating unmanageable surges** (which could happen if the wholesale price, or the system frequency, suddenly drops or increases)."[211] [Emphasis added by Vector]

A.69 Vector's submission highlighted that the current wholesale market dispatch process – even if the DSF is formally bid to the System Operator using dispatch notification or the more formal dispatch-capable load station framework (see *Recommendation 11*) – does not reconcile the resulting 'dispatch' outcome with the limits of the distribution system. As Vector noted more recently,[212] this could lead to risks to wider power system security if the System Operator dispatches a distribution-based response, and relies on it to keep the system in balance, when it cannot be physically accommodated by the host distribution network.

209 Noting that the DPP3 reset attempted to address the shortcomings of IRIS by rewarding innovation that had potential benefits beyond the immediate regulatory period through the Innovation Project Allowance. See Default price-quality paths for electricity distribution businesses from 1 April 2025: Issues paper, para I7.

210 We acknowledge the related issue of retailer pass-through where EDBs have developed tariffs the incentivise flexibility. As outlined earlier, lack of retailer pass-through is not a barrier to flexibility *per se*, as long as the retailer is developing customer arrangements which see the retailer or flexibility aggregator manage the response on the customer's behalf. This is why our Recommendation 3 – DSF activity monitoring – is so important.

211 FlexForum (2023) "Making better use of available distribution network capacity will enable more affordable and reliable electrification" pp 7-8.

212 Para 21, Vector cross-sub on Dispatch Notification. See blob-static.vector.co.nz/blob/vector/media/vector-2023/2023-10-13_vector_cross-sub_to_ea___dispatch_notification-cleaned.pdf.

Options for reconciling wholesale DSF dispatch with distribution limits

A.70 There are several options for reconciling wholesale DSF dispatch with distribution limits:

(a) Simplistic static or time-based limits on DSF deployment (e.g. default off-peak charging of electric vehicles), or routinely turning off hot-water cylinders in the morning and evening peaks through winter;

(b) EDBs identify parts of their network where deployment of DSF could create congestion or stability issues and facilitate an exchange of information with DSF suppliers about the extent to which DSF in particular parts of the network will be 'constrained', when these constraints are likely to occur, and how scarce network capacity will be allocated across different flexibility providers. This information exchange could be through static or dynamic operating envelopes being provided to DSF providers, noting that again, EDBs will need to determine how capacity within an envelope is allocated to multiple DSF providers; or

(c) Under Distribution System Operator (DSO) models, or through distribution constraints being included in SPD and solved as part of the dispatch process, constraints could be part of an optimal dispatch process and generate prices that signal to investors the value of energy. This relies on DSF (over a certain threshold) being formally bid into the dispatch process so that forecasts of DSF deployment can be prepared and solved to estimate power flows.

A.71 As we outline below, MDAG recommends (c) above as the longer-term pathway toward optimal secure dispatch of DSF (and DER more broadly) based on efficient marginal pricing signals in the distribution network.[213]

A.72 While the other two options above are suboptimal substitutes, they are useful interim measures while we develop the tools, processes and methodologies for the longer-term solution.[214]

Longer-term challenge of retrofitting SCED on to networks

A.73 As noted above, the longer-term solution to Issues 1 and 2 above is to develop an efficient form of security-constrained economic dispatch at distribution-level.

213 For the avoidance of doubt, our ideal long-term outcome is for locational marginal pricing to largely replace distribution tariffs – currently intended to recover the costs of owning and operating the network - as the locational and temporal scarcity signal, thus forming part of the wholesale reconciliation and settlement process. This would leave distribution pricing to fulfil the role of non-distortionary cost recovery. This would be consistent with the Authority’s current philosophy regarding transmission pricing, noting that there is still a debate about whether there is a role on the grid for RCPD charging.

214 The introduction of marginal energy pricing and dispatch on the distribution network would remove the need for distribution pricing – designed to recover the efficient costs of owning and operating a distribution network - being used as a signal to guide short-term operational signals. This is the prevailing philosophy on the transmission grid, where transmission pricing no longer has a short-term pricing signal (historically focused on regional coincident peak demand). Marginal energy prices would rise, increasingly incentivising investment in resource deployment that can deliver network services targeted at the congestion, until a point where network investment became net beneficial. We understand this is consistent with the proposed framework published by the Australian Energy Regulator.

A.74 The functions and roles of distribution system operation in New Zealand have been discussed, and programmes of work recommended, since at least 2019 when IPAG produced its Equal Access project report.[215] This was updated by IPAG in 2021 with a set of recommendations to the industry, the Authority and Commerce Commission that would facilitate market trading of distributed energy resources (including DSF) across both the transmission and distribution network.

A.75 We observe that this discussion and work has produced very little in terms of concrete progress since IPAG's report.

A.76 MDAG is of the strong view that a pre-requisite of a high renewables future is a market where devices and networks are able to coordinate intelligently through market-based pricing and dispatch across the entire electricity network - transmission and distribution.

A.77 Just as the current wholesale market design required a 'retrofit' of a security-driven market platform on the transmission grid (see 'SCED for distribution networks' sidebar), this next market design phase will need to retrofit a security-driven market platform on the distribution network and, in the process, may revisit some of the current wholesale market methodologies and platforms.

SCED for distribution networks

In 1996, at the commencement of the wholesale market, system-level optimal dispatch required an entire layer of software and market dynamics to be retrofitted on to an engineering-based system that had not been designed with a market in mind.

Yet New Zealand not only joined a very small number of countries that had implemented a market-based security-constrained economic dispatch (SCED) process, its introduction of locational marginal pricing (and well as reserve co-optimisation) as core parts of the process was a world first.

Indeed, the mathematical equations that underpinned locational marginal pricing had only been published 8 years earlier (Schweppe et al, 1988).

MDAG believes a modern version of SCED on the distribution network is warranted - indeed, necessary – in order to accommodate higher renewables and distributed DSF (and distributed energy resources more generally) without triggering inefficiently large network investment. Synchronising pricing and dispatch across the whole network will provide the best opportunity to deliver the lowest overall cost to the consumer.

This does not necessarily mean that SPD (in its current form), or that the role of the current transmission system operator, needs to be extended into the distribution network.

The vast improvements in computing power, communications, digitalisation, automation, AI and even our understanding of market design means the transactional framework for distributed resources - pricing and/or the limits of the network - could be significantly different from how we do things on the grid today. Indeed, these improvements should provide an opportunity to consider how to evolve pricing and dispatch arrangements across the transmission and distribution system as a whole.

Much work is being undertaken globally that could be drawn on, although there is every chance that New Zealand could again secure a position of global leadership.

A.78 New Zealand is no stranger to leading the world in overlaying dynamic market frameworks on a grid that was built from an engineering (rather than market) perspective. However, if real progress is not made towards this end, then the reality will be either stifled development of DSF, or significant and inefficient network investment – both of which will not deliver reliable supply at the lowest system cost to the consumer, and thus the sector will have failed in its primary objective.

215 IPAG (2021) Advice on creating equal access to electricity networks.

A.79 We are not blind to the investment required in enabling this to occur such as low voltage visibility, communications, and digitalisation, and the significantly elevated complexity in distribution networks.[216] These tasks are well canvassed as necessary steps in both the FlexForum's Flexibility Plan 1.0[217] and Electricity Networks Aotearoa's Network Transformation Roadmap.[218] But waiting for these enabling investments to be completed across all EDBs before developing distribution system operation services risks a world where the need to optimise distributed resources has overcome our ability to manage the system. This will result in significant cost to the consumer.

Re-framed preferred option

A.80 In our Options Paper, we considered whether the current wholesale methodology behind LMP, which provides spatial and temporal market signals, could feasibly be extended into distribution networks (option C12).

A.81 While it would solve the problem defined above most elegantly, it is currently computationally challenging and would likely lead to unhelpful pricing outcomes until a widespread deployment of distributed energy resources, bidding and offering into the market, occurred over significant parts of the distribution network. Several submitters offered caution in this respect.

A.82 In any case, it is by no means certain that distribution locational marginal pricing should be an exact replica of the prevailing pricing and dispatch model on the grid.[219] In the Options paper, we highlighted that other approaches were under development globally that could provide network-based dynamic price signals (e.g. AusGrid's 'Project Edith').[220] Further, in considering the use of marginal pricing and dispatch into the distribution network, we should look for the opportunity to leverage improvements in market design, computing, algorithms and communications across the whole system (transmission and distribution).

A.83 Irrespective of the ultimate design, we believe that work must start now on defining the pricing and coordination functions of distribution system operation and demonstrating how this can be solved 'in the field'. Which leads to our second package of recommendations for DSF.

Recommended DSF Package 2: DSF pricing and coordination on EDB networks

A.84 As discussed above, we are recommending two interim measures and (running in parallel) an integrated longer-term solution.

216 Indeed, the level of granularity of distribution-level constraints is much greater than on the transmission network. A capacity constraint on a single distribution transformer could impact just the five or fewer residential homes served by that transformer – and disclosure information suggests there are around 200,000 distribution transformers nationally. This compares to the ~280 nodes on the transmission network, many of which will serve many thousands of consumers.

217 See www.araake.co.nz/assets/Uploads/FlexForum-Flexibility-Plan-1.0-31-August-2022.pdf.

218 Electricity Networks Aotearoa, "New Zealand Electricity Distributor Network Transformation Roadmap: Overview".

219 In fact, it seems certain that it can't be, due to the far more important role of voltage on distribution networks, particularly beyond sub-transmission level. See paragraph 4.177 of our Options Library.

220 See www.ausgrid.com.au/About-Us/Future-Grid/Project-Edith.

Interim measures to strengthen accurate (efficient price) signals

Pricing to optimise distribution investment (Recommendation 4)

A.85 The Authority and Commerce Commission to work together to do more to cause more wide-spread and sooner use of efficient pricing signals for flexibility on distribution networks. If possible, use (or *enable* use of) the Part 4 regime to that end. For example:

(a) Explicitly as part of its consideration of customised and individual price path applications,

(b) As a variant of the current incentives provided in the input methodologies (IMs) to encourage innovation, energy efficiency, demand-side management, and reduction of losses, and/or

(c) As an information disclosure requirement (e.g. an independent expert report by each EDB verifying that the EDB has considered the role of pricing to minimise network operating and investment costs).

A.86 The Authority's currently proposed options for distribution pricing reform are very coarse – either a continuation of the current light-handed approach, a mandate or ban on particular pricing approaches, or a targeted 'call-in'.[221] They also do not explicitly signal an expectation that distributors move away from static pricing to dynamic pricing.

A.87 In addition, progress has been slow[222] and so distribution pricing signals to consumers considering DSF investment are likely to understate its potential to lower network costs.

Interim measure for coordinating infrastructure

Network capacity in DSF dispatch (Recommendation 19)

A.88 Authority to make Code changes to:

(a) Amend the Default Distributor Agreement (DDA) to require coordination protocols so that the activation of DSF stays within distribution system limits;

(b) Amend the Code to require flexibility aggregators to have DDA with any networks they are operating on;

(c) Amend Part 6 of the Code to require EDBs to describe how they intend to manage congestion arising from DSF in their congestion management policies; and

(d) Limits and service levels to be monitored by the Authority to ensure that they are not unnecessarily conservative.

A.89 Urgency is dictated by the extent to which EDBs are seeing near-term deployment of DSF on their networks sufficiently large to cause unpredictable demand spikes as a result of 'herding'.

221 See www.ea.govt.nz/projects/all/distribution-pricing/consultation/targeted-reform-of-distribution-pricing/.

222 A few electricity distribution businesses (EDBs) are making good progress in this domain. Most seem to be giving it lower priority. Some seem to be simply indifferent. As the Authority concludes, "there has been little progress in establishing pricing signals that reward flexibility, and some regression with respect to services subject to control" – see www.ea.govt.nz/projects/all/distribution-pricing/consultation/targeted-reform-of-distribution-pricing/.

Longer term solution to network price signals and coordination

Price-driven secure distribution dispatch (Recommendation 5)

A.90 Establish and fund as soon as possible a significant multi-year project to develop an efficient form of security constrained economic dispatch (SCED) on distribution networks for the purpose of 'integrating' into the wholesale market widely dispersed DSF and other distributed sources of 'supply'. To this end:

(a) Develop design options for distribution-level SCED, how it would integrate with the current wholesale market design, and any changes to the current framework for SCED;

(b) Identify a preferred design, and provide the workplan and resourcing required for the detailed design, specifications and implementation of the preferred design;

(c) Conduct trials and pilots that demonstrate how different design options, or components of design options could work; and

(d) Work with FlexForum and the Future Network Forum to ensure that all learnings from (i) and (ii) are disseminated quickly and comprehensively to all market participants.

A.91 As a *market design* exercise, this should be led by the Authority. It is vital that this project is governed and overseen by a small, enabling group that brings expert perspectives that span wholesale market design, distribution, transmission, and system operation. Further, we strongly recommend that funding is granted subject to milestones that encourage rapid progress.

A.92 Funding would be provided to support an expert team of specialists, as well as the rapid dissemination of knowledge and systems to EDBs. Funding could be provided via either:

(a) An increased appropriation to the Electricity Authority;

(b) MBIE's "Distributed Flexibility Innovation Fund", administered by Ara Ake; and/or

(c) The Innovation Project Allowance under the Input Methodologies (although this may require amendments from its current form, which is limited to 0.1% of the EDBs forecast allowable revenues and requires 50% co-funding from the EDB).

A.93 This project would be established in such a way that it is not slowed down by bureaucratic processes or sector politics. The size of the prize is significant in lowering costs the consumer in better optimising network development (in particular, by avoiding substantial network investment) and enabling access for the wholesale market to the vast array of potential demand-side services across distribution networks.

Appendix B Developing standardised flexibility contracts

B.1 *Recommendation 8* is to develop standardised flexibility contracts. This appendix explains why this recommendation is extremely important, sets out our initial thinking on possible contract types to explore as standardised flexibility contracts, and describes the proposed pathway for implementing the recommendation.

Why are flexibility contracts so important?

B.2 Some types of flexibility contracts are already in use today. For example, retailers and wholesale consumers might use peak contracts[223] as one of the tools in their portfolio to manage exposure to spot price risk at times when demand is higher.

B.3 Another type of flexibility contract is a 'swaption'.[224] Hydro generators sometimes purchase these from thermal generators as a risk management tool to reduce their spot price risk during periods of low hydro inflows.

B.4 The importance of flexibility contracts to the electricity system is expected to increase even further in future as the proportion of supply from intermittent sources rises. Indeed, we think flexibility contracts will become the market's 'secret sauce' – enabling a range of wholesale market processes to function effectively.

Recap – what is a flexibility contract?

A flexibility contract (or product) is the term we use to describe a hedge contract that provides the buyer with protection against high spot prices at specific times – such as when wind generation is low and/or demand is especially high.

This type of contract is already important for retailers and is expected to become increasingly important in the future because it can be used to 'firm' the output of intermittent supply sources, such as wind or solar, that are expected to account for the lion's share of new supply.

B.5 In the new investment arena, access to flexibility contracts is expected to be critical to allow the smooth flow of new intermittent generation into the system. Developers of intermittent generation might purchase flexibility products so they can sell firmed product to their customers. Alternatively, flexibility contracts may be bought by retailers or industrial consumers to firm up their purchases of intermittent generation output. In either case, the availability of flexibility contracts helps intermittent generation developers to create products that are useful to end-use consumers, and that in turn provides revenue to underpin ongoing investment.

B.6 Furthermore, as explained in paragraph 7.51 of our Issues Paper an intermittent generator can sell more of its output using standard baseload products without incurring undue spot price risk, if it has access to flexibility products. In essence, an intermittent generator's appetite to offer baseload hedges will be greater if it can access flexibility products to reduce its exposure to spot price risk when its output is low. Thus, the overall hedge capacity of the country's physical intermittent generation base will be enhanced by the availability of flexibility contracts.

B.7 And of course, potential investors in new physical sources of flexibility (such as batteries, demand-side response, green thermal or pumped hydro) will also benefit from trading flexibility products, because such products create more stable revenue streams and price signals that can assist them with investment decisions.

223 These contracts apply from 7.00am to 10.00pm on business days and have zero volume in other trading periods – see www.asx.com.au/content/dam/asx/markets/trade-our-derivatives-market/derivatives-market-overview/energy-derivatives/fact-sheet-new-zealand-energy.pdf.

224 These contracts give the buyer an option to activate a swap on pre-agreed terms, in exchange for an option fee.

B.8 Another arena where flexibility products play a vital role is the development of demand-side flexibility (DSF). As discussed in Appendix A we think consumers can play a big role as providers of flexibility to the system and reap a reward for that. A key factor hindering DSF uptake has been difficulty in valuing flexibility. We consider that the development of standardised flexibility contracts (with associated price signals) would help to overcome this issue.

B.9 In the retail arena, access to flexibility contracts is a necessary pre-requisite for effective retail competition because retailers need such instruments as a risk management tool. This is already a key issue and its importance will grow as spot price volatility rises due to increasing system sensitivity to weather effects. Effective retail competition in turn is critical to ensure that end-use consumers can obtain electricity at the lowest possible cost and participate in the provision of flexibility services where that makes sense.

B.10 Finally, as we discuss in Appendix D there is a risk that competition for the supply of flexibility products will thin as fossil-fuelled thermal generation is progressively displaced on the system.[225] We see development of standardised flexibility contracts as a key tool to address this competition risk, and we set out our recommendations on this in Appendix D.

Why develop *standardised* flexibility contracts?

B.11 We think *standardised* flexibility contracts could be very useful to participants, even though participants each have *unique* needs. This view is informed by the experience with standardised baseload contracts.[226] These have been very useful for the development of the wholesale market, even though few (if any) individual participants can fully satisfy their needs with such instruments.

B.12 More specifically, we think that development of standardised flexibility contracts would:

(a) Provide additional tools for wholesale buyers and sellers to manage their exposure to spot price risk. Even in standardised form, we expect that products could be very useful to participants as building blocks. For example, in the Issues Paper we included analysis (see Figure 20 of that paper) that showed how wind or solar generators could substantially reduce their revenue volatility through the use of simple standardised products;

(b) Improve forward price discovery about the expected distribution of spot prices. At present, forward price discovery is largely limited to baseload prices. This provides no direct information on how spot prices are likely to vary with demand or availability of intermittent supply. Trading in standardised flexibility products (whether ‘over-the-counter’ or on an exchange) would generate useful information about the expected distribution of prices (see *Recommendation 2*). This information would have two distinct benefits:

(i) Participants could use it as a reference point to sell/buy *non-standardised* flexibility contracts that they negotiate bilaterally;

(ii) Participants could make better hedging decisions. This is because parties must have a view on both the likely level *and distribution* of spot prices when making their hedge decisions. At present there is very little information available about the latter. Discovering more information about the price of flexibility would help participants to make better hedging decisions and improve risk management.

225 Competition for very short duration (e.g. within-day) flexibility products may increase as batteries become more widespread – but competition for longer duration flexibility products may decline as fossil-fuelled thermal retires, all else being equal.

226 Baseload contracts have been actively bought/sold in the exchange-traded futures market and the over-the-counter (OTC) market since the early 2010s.

Design of contracts should reflect trade-offs for natural buyers and sellers

B.13 The design process for flexibility contracts needs to recognise the differing interests of buyers and sellers. Buyers will ideally want to achieve 100% protection against high spot prices. On the other hand, sellers will want to limit their exposure to risks that are impossible or prohibitively expensive for them to manage (such as failure of upstream fuel supply or finite storage capacity of lakes or other energy stores). Ultimately a balance will need to be struck between the interests of buyers and sellers.

B.14 To assist in exploring the design of standardised flexibility contracts, we have given high level consideration to potential natural buyers and sellers, since their interests will inform the range of options that might be feasible – i.e. where the bid/ask spread between buyers and sellers might be bridged.

B.15 Looking into the future renewables-based system, natural buyers of flexibility contracts are likely to include:

(a) retailers/consumers wishing to manage their spot price risk during periods when their demand is high – especially if spot prices and their demand are highly correlated;

(b) retailers/consumers that purchase intermittent generation output and need another tool to manage the price risks for volume mismatches between the intermittent generation and their demand profile – especially if higher spot prices are correlated with periods of low intermittent generation output;

(c) solar/wind generators wanting to sell relatively firm supply to wholesale customers; and

(d) existing portfolio generators/gentailers wanting to reduce exposure to periods of low inflows, wind, solar, etc.

B.16 Turning to the natural sellers of flexibility contracts, they are likely to include:

(a) gas/biofuel/hydrogen/ammonia thermal generators or peakers. Many of these parties are likely to face limited storage and/or limits on supply flexibility (e.g. due to deliverability constraints for gas);

(b) consumers who can sell a flexibility contract by reducing (or shifting) their demand. This might be because the underlying need for electricity has some discretion (e.g. they reduce output) or because they can use stockpiles to create some flexibility in their electricity using process (e.g. they can turn off and meet orders from inventory for a period);

(c) hydro schemes with varying levels of medium-term storage. Many of these parties may also have supply constraints (for example, due to resource consent conditions or river chain supply constraints) which limit their flexibility;

(d) energy storage operators – such as large-scale batteries, pumped hydro schemes, or other energy storage technologies; and

(e) parties who aggregate flexibility from different sources listed above.

Simulation modelling used to explore issues

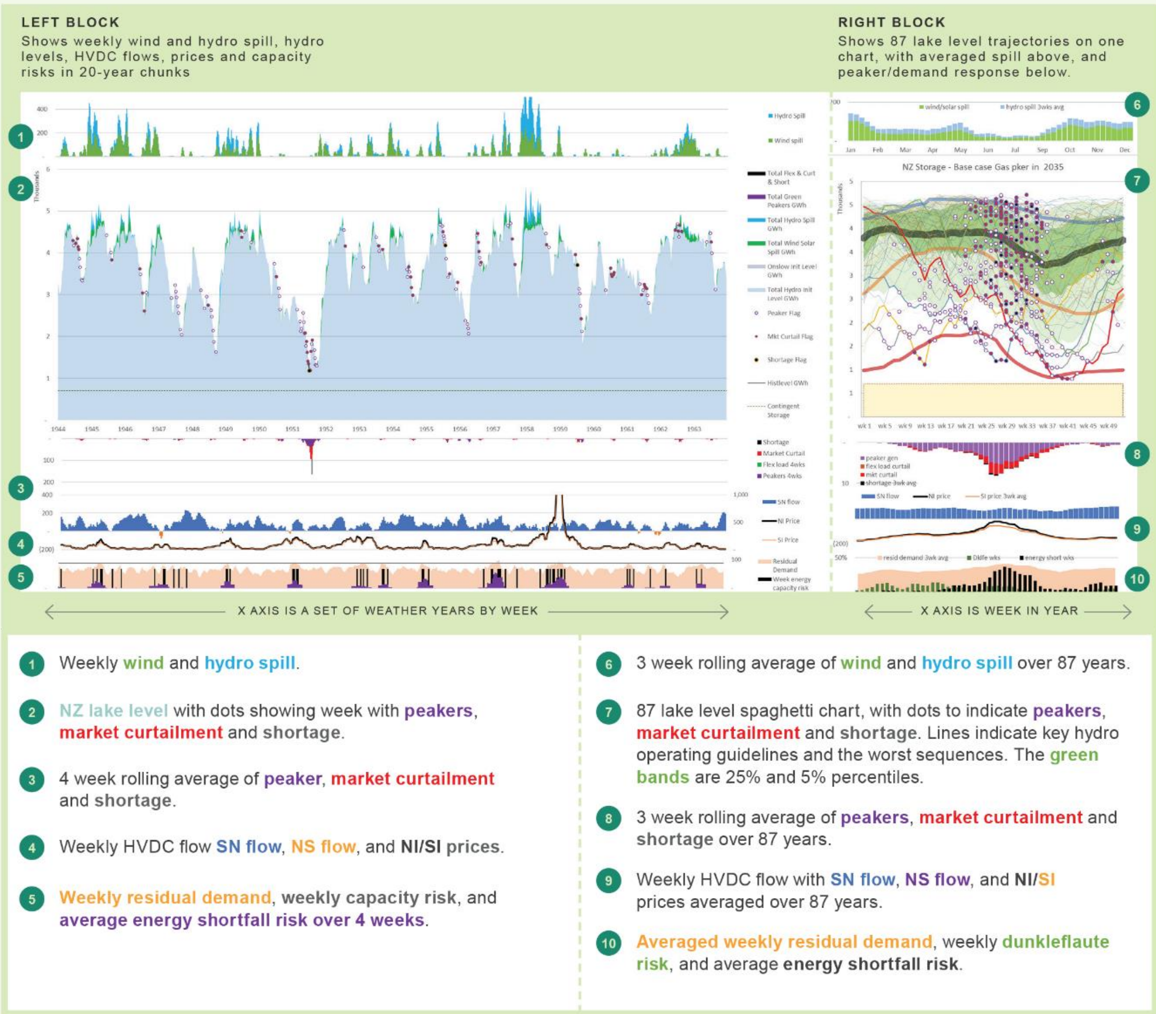
B.17 A key point from the above discussion is that most (potentially all) of the natural sellers of flexibility contracts will face energy limits of some kind that are expensive or difficult to overcome. This means they can provide flexibility for ‘bursts’, but eventually run into a physical constraint. For example, a thermal fuel stockpile will allow finite operation before it is exhausted, and increasing the stockpile’s capacity or the replenishment rate is expected to have costs. Likewise, a flexible industrial consumer will face costs to establish and maintain an inventory from which it can satisfy final product orders at times when it reduces output to lower electricity usage – and increasing the inventory size has a cost.

B.18 While many sellers may prefer a contract form that has some type of energy limit, it is important to consider how much such limits (or their form) would reduce the risk management benefits to buyers.

B.19 To help in understanding those issues, simulation modelling of the system was undertaken. The simulations used the same model (with some further developments and updates) as the Issues Paper modelling. The recent simulation work considered the system in 2035, by which time intermittent generation was assumed to have grown to account for 28% of total supply, and renewable generation as a whole was 97%. Most of the balance of generation came from fossil-fuelled thermal (paying a high carbon charge). Note that some of the modelled effects may already be occurring, so 2035 should not be regarded as the earliest date at which the analysis is relevant.

B.20 Importantly, the modelling considered results over 87 different weather years. These weather years are based on a mix of historical data (87 years for hydro inflows) and weather-matched solar and wind data (drawn from 40 years of historical data for wind and solar). The simulation tool allows a wide range of issues to be explored, including the effects of hydro inflow variation and dunkelflaute[227] events. A sample of the output is shown in Figure 16.

Figure 16: Sample output from market simulations for 2035



B.21 Key results from that simulation modelling are included in the relevant sections below.

227 See text box on page 21.

Possible candidates for flexibility contracts

B.22 In this section we set out some possible candidates to consider as standardised flexibility contracts. These candidates have been compiled from a mix of sources including stakeholder input, overseas experience and simulation modelling.

B.23 We are not proposing that all of these options be developed into standardised flexibility contracts. Rather, we are suggesting these as possible candidates for further work by a co-design group (see Chapter 9.).

B.24 We would also note that it is possible more than one type of flexibility contract will be useful. For example, the most useful type of contract for supporting intermittent generation development may differ from the most useful type for providing energy-firming for droughts. Having said that, liquidity and price discovery will be enhanced if trading is concentrated in fewer contract types.

Super peak swap

B.25 A 'super peak swap' is a product with its volume profiled to target intra-day demand peaks. This type of product was recently introduced in the Australian NEM to cover the higher demand hours in the morning and evening with zero volume in the middle of the day (when solar is higher) and other off-peak periods (when demand is lower). In the NEM we understand the contract covers from 15:00-19:30 in summer months (Q1 & Q4) and 06:00 – 09:00 and 16:30 – 19:30 in the winter months (Q2 & Q3).

B.26 The product sellers are likely to be dispatchable, peaking generators (e.g. hydro stations and gas peakers), energy storage operators (e.g. pumped hydro and batteries), and demand-side flexibility providers with the ability to curtail or shift load for a few hours at a time each day.

B.27 The natural buyers of the product are likely to be retailers or wholesale consumers looking to hedge their exposure during the periods of the day with higher demand. Feedback from some stakeholders indicates there could already be strong interest in this product.[228]

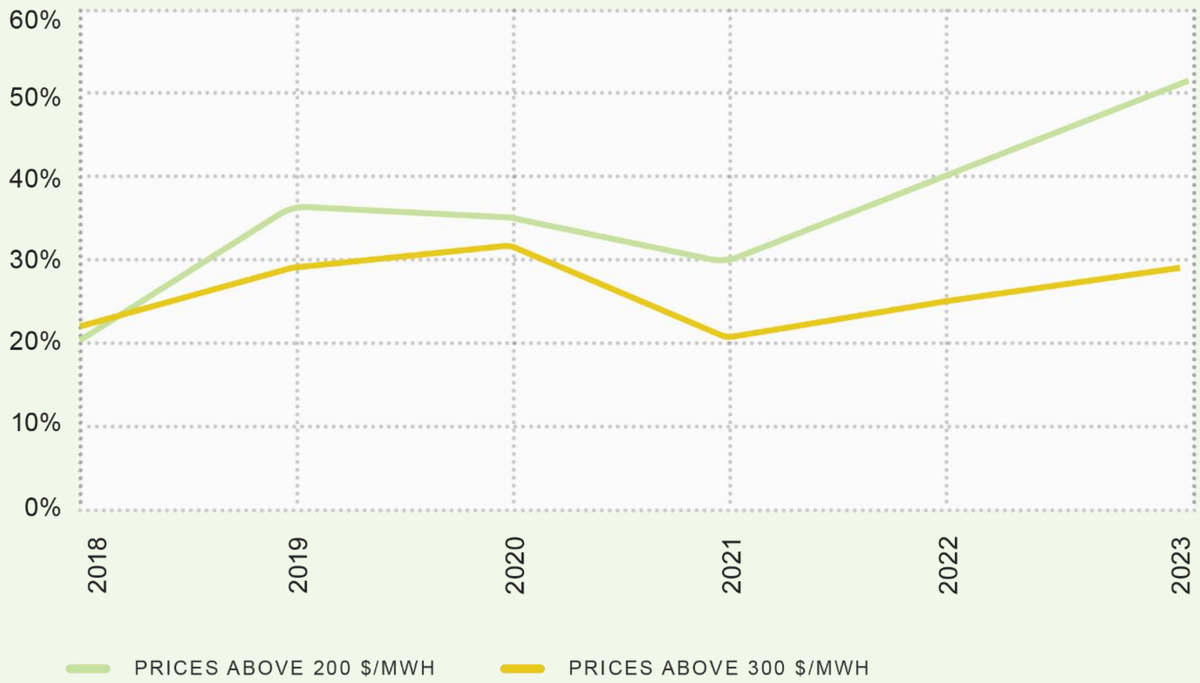
B.28 Key advantages of this product are that it should be relatively simple to implement and there already appears to be some demand for it. It is also inherently 'energy-limited'[229] and should therefore not pose undue risk for sellers. Key disadvantages are that it only provides protection at the times that are fixed in the contract (when *demand* is typically higher) and this is not necessarily when *spot prices* will be higher. As the proportion of intermittent supply increases, it is likely that spot prices will be less correlated with demand and more highly correlated with periods of low intermittent generation in each half-hour.[230]

228 Feedback from informal discussions with some independent retailers.

229 This is because it only applies for a few hours each day.

230 Strictly speaking, it will be an inverse correlation with the residual difference between demand and uncontrollable supply.

Figure 17: Proportion of higher price periods covered by 'super peak' contract



Having said that, analysis of spot prices over the last five years suggests that the product could have significant hedging benefits because of the correlation between spot prices and demand. This is illustrated by Figure 17 which shows the proportion of higher priced trading periods that fell into 'super peak' intervals in each of the last five years.[231] For example, for trading periods in 2023 that recorded a price above $300/MWh, more than 50% were in the super peak time intervals. Given that such intervals accounted for only 15% of the total hours in a year, there was clearly still a strong correlation between spot prices and these higher demand periods.

B.29 In light of this analysis, we think a super peak product may well be useful as a flexibility contract, at least for the next few years. Longer term, its usefulness may diminish as the correlation between demand and spot prices weakens and other products may be more suitable (see below). However, it may still be very useful as a transitional product.

Option over baseload futures contract

B.30 Some participant feedback has suggested that an option over quarterly electricity baseload futures would be useful as a flexibility contract. Options of this type are listed on the ASX for the New Zealand electricity market. In essence, parties can use them to hedge movements in the average baseload price for coming quarters. We understand that there has been some trading in these contracts, but it has been very limited to date.

B.31 Because this contract has a flat structure for each quarter, it is likely to have relatively limited usefulness for hedging the types of risks that are expected to grow as intermittent sources rise as a share of supply – i.e. to address within quarter variations in the supply/demand balance.

B.32 We received feedback that one of the challenges of this contract for sellers is that it can be difficult to determine whether it is in- or out-of-the-money until late in a quarter, by which time sellers may have little time to undertake physical actions to mitigate their contract exposure. A suggestion was made that moving to a monthly structure could help address this, which could facilitate trading.

231 The data for 2023 is for a part year.

B.33 More generally, it is possible that this contract type is useful for hedging risks that affect average prices in a quarter, such as hydrology variation or delays in commissioning major generation or demand increments. However, given the inability to hedge intra-quarter risk, we have not analysed this contractual alternative further at this stage.

Energy-limited caps

B.34 As noted earlier, a super peak product has attributes that make it a worthwhile candidate to explore as a flexibility product for the immediate future. Further out it is likely to be challenged by the expected weakening in the correlation between demand and spot prices. This is because the variation in supply from intermittent sources is expected to have a growing influence on the supply/demand balance in each trading period.

B.35 This is illustrated by examination of the simulation analysis for 2035. Around 19% of periods recording $200/MWh or above are expected to be in super peak periods in 2035. That compares with 20-30% observed in recent years. Similarly, around 20% of periods recording $300/MWh or above are projected in super peak periods in 2035, compared with 20-50% in recent years. These results suggest that a super peak product would deliver less hedging benefit in a more renewables-based system in future. In essence, buyers are likely to seek products that provide protection at times of high spot prices, irrespective of the time of day or week.

B.36 A contract type utilised for this purpose in many other electricity markets is a cap contract. This type of contract provides buyers with protection in any trading interval in which the spot price exceeds the strike price. For example, ASX listed cap futures with a strike price of 300 A$/MWh have been available in the Australian NEM for many years. The strike prices have been set at levels intended to approximate the variable costs of fast-start peaker plants using liquid fuel – ensuring there are natural sellers of such products. From a buyers' perspective a cap contract can be viewed as the gold standard of flexibility contracts, given that it will provide protection against all instances where the spot price exceeds the strike price. This raises the question of whether cap contracts are a useful candidate to explore in New Zealand.

B.37 Based on current information we think this would be very challenging. The key reason is the different risk profile that sellers of caps face in New Zealand compared to other countries (including Australia). In essence, caps are traded in jurisdictions where the seller can be very confident about the likely maximum duration when the cap will be active. In Australia this is driven by relatively brief periods of capacity constraint associated with extremely high air conditioning demand. When they occur, they last for a few hours and recur for a few days at most. Sellers of caps can size their fuel (or DSF) requirements with that in mind.[232]

B.38 By contrast in New Zealand, periods of elevated prices may be brief (due to very high demand or, say, a series of days with low wind) or last for weeks or even months (in an extreme drought). This variability makes it harder for sellers to price the risk associated with sale of caps – especially in an electricity system where the risk profile is changing. For this reason, we have considered energy-limited caps as a potential alternative.

232 Another important difference is that the Australian NEM has a cumulative price threshold (CPTs) that limits the risks that sellers of caps face. CPTs are challenging to apply in an energy-constrained system (like that in New Zealand) where adverse supply events can last for more than a few days. Australia unexpectedly encountered such conditions in mid-2022 and found the CPT to have unintended effects – see www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-market-suspension-and-operational-challenges-in-june-2022.pdf.

B.39 The natural buyers of the product are likely to be retailers, wholesale consumers and intermittent generators selling products that are not generation-following.[233] These parties are likely to want to hedge their exposure during the periods when prices are relatively high, recognising that the timing of such periods is not necessarily predictable.

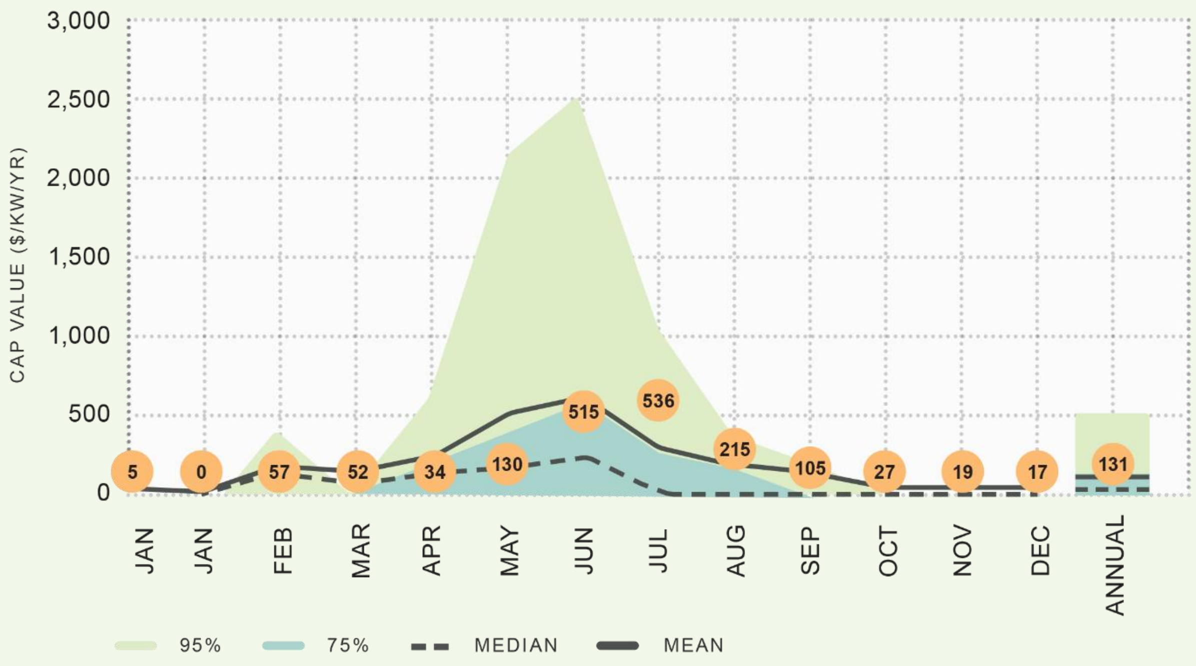
B.40 The natural sellers of the product are likely to be dispatchable, peaking generators (e.g. hydro, or gas peakers), energy storage operators (e.g. pumped hydro and batteries), and demand-side flexibility providers with ability to curtail or shift load for a few hours at a time each day. These resources would need to be flexible over short periods, with the ability to ramp up or down very quickly.

B.41 We used the simulation analysis to explore how energy-limited caps might perform in terms of risk mitigation for buyers. The starting point is to understand how the value of an unconstrained cap contract is made up. This is summarised in Figure 18 which shows the expected difference payments that would be received by a cap buyer each month across a year in 2035, expressed in \$/kW/yr. The chart shows how expected payments are very heavily concentrated in winter. This is because this period is characterised by higher demand (largely for heating and lighting) and reduced supply (mainly due to lower hydro inflows and solar generation).

B.42 The chart also provides information on the distribution of expected payouts to contract buyers across weather years. The large difference between the mean and median, and between the 75th and 95th percentiles indicates that there are a handful of very extreme weather years that significantly affect the results.

B.43 Finally, we note that the estimated cumulative value of payments across the year equates to the carrying cost of a peaker plant. This arises because the reference case assumes the system is in equilibrium – i.e. no new plant would be economic and existing plant is revenue adequate).

Figure 18: Estimated distribution of value (reference case simulation)[234]



233 Generation-following products have a volume profile that matches the output of the relevant generator. There is therefore no volume mismatch risk (in aggregate or by time interval) for the seller.

234 Eagle-eyed readers will notice that "Jan" appears twice on the x-axis. This is because the axis measures 4-week time blocks rather than calendar months. The results should be interpreted with that issue in mind.

B.44 We now turn to the effect of introducing energy limits into the cap contract. Given the extreme concentration of value in winter periods, we have analysed a cap that commences its coverage on 28 May and runs for 180 days – i.e. a winter period cap.

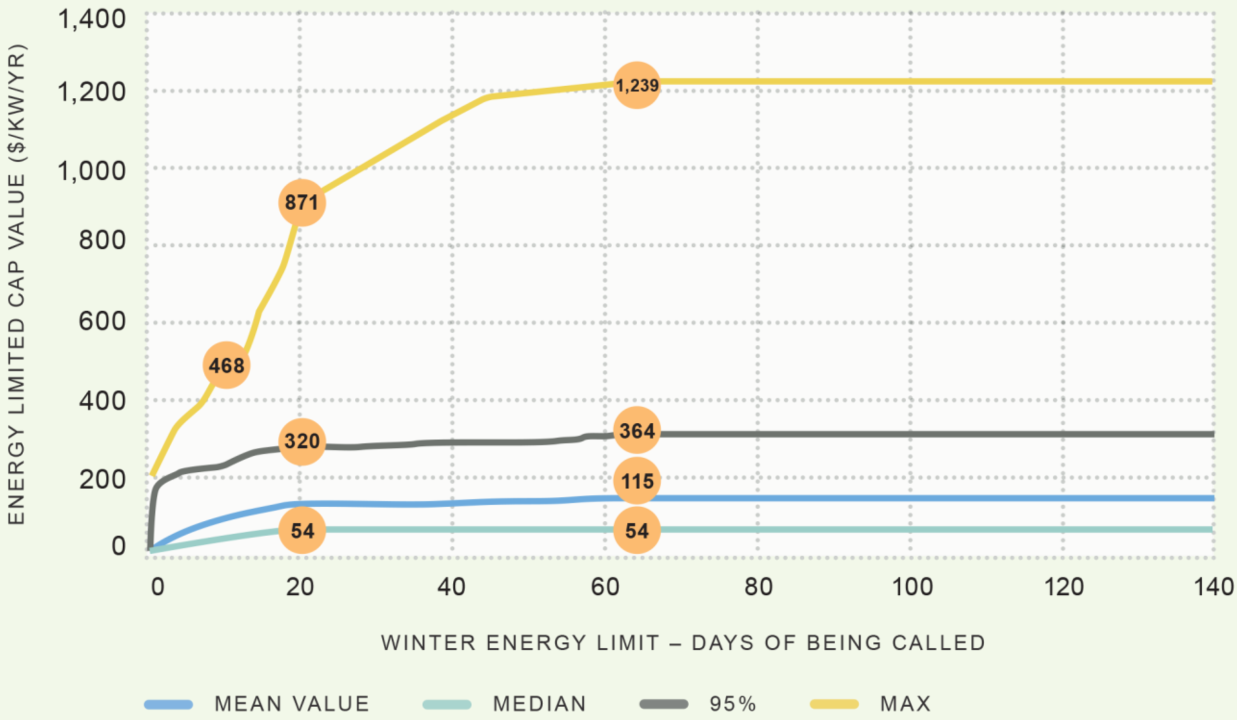
B.45 Figure 19 below summarises the results for two different forms of energy-limited cap contract. The analysis in the left-hand chart assumes sequential settlement, where the contract protection is activated each hour after contract commencement on a chronological basis until the relevant limit is reached. Thus a buyer with a 10-day energy limit would be protected for the first 240 hourly occurrences of spot prices exceeding 300 $/MWh, but would not receive any spot price protection from the contract for trading periods above 300 $/MWh that occurred later in winter after the limit was reached.

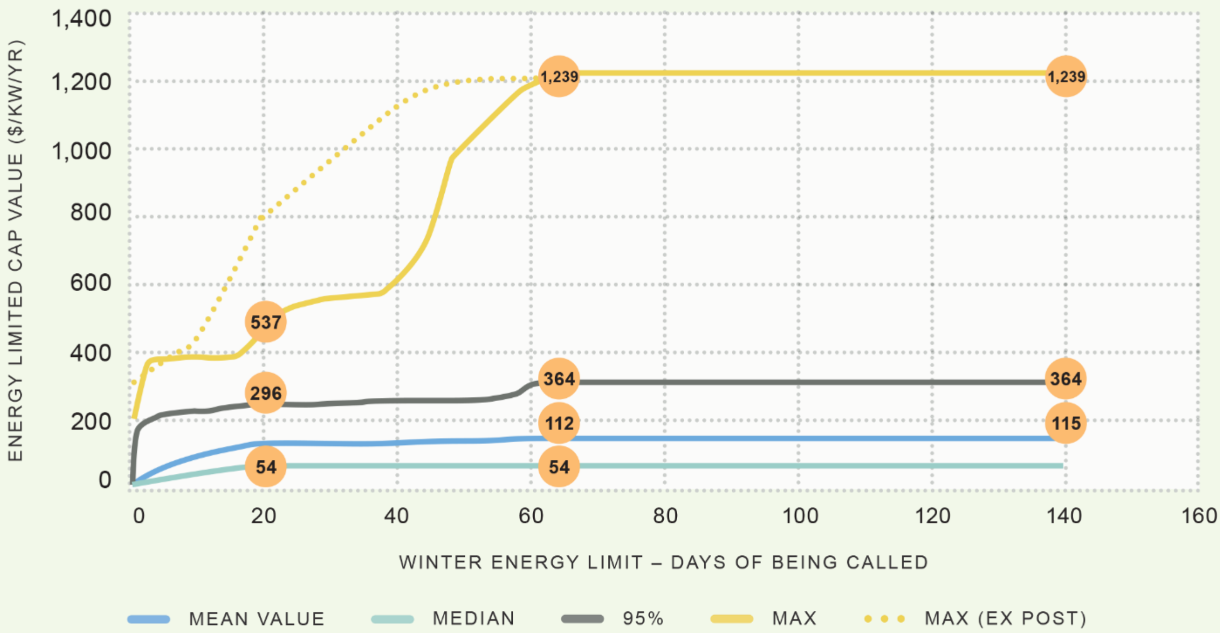
B.46 In the right-hand chart the analysis assumes ex-post settlement with the available cover apportioned across the trading periods in the six-month period in which the highest spot prices are recorded. This approach would provide buyers with greater spot price mitigation, but sellers reliant on physical resources to back the contract would have greater challenges to manage their resources because they would not know until the end of winter which trading periods were actively covered by the cap contract.

B.47 The vertical axes for both charts show the value of the contract to a buyer (i.e. the cumulative value of difference payments arising from spot prices above 300 $/MWh) expressed in $/kW/year. The higher this value, the greater the risk mitigation effect of the contract for the buyer, with a maximum potential payout of 1,239 $/kW/year in the example.

B.48 The horizontal axes show the energy limit expressed in days of cover out of a possible maximum of 180 days in the winter period. Note that the analysis was undertaken using hourly time blocks so 10 days is actually 240 hours of cover in the six-month period.

Figure 19: Energy-limited caps





B.49 Key observations from the charts include:

(a) Contracts with relatively tight energy limits (e.g. 20-30 days out of theoretical 180 maximum) would provide a significant (though not complete) level of cover for buyers. As a result, if there were potential suppliers with (say) energy limits that equated to 20-30 days, such contracts could be attractive to buyers even though they don't provide complete coverage.

(b) Contracts with energy limits equivalent to 70 days of cover would provide complete protection for the modelled events. In the simulation it was not necessary for buyers to have 180 days of coverage to achieve full protection. This is important because there are likely to be more potential sellers for contracts with a limit of 70 days of coverage than for unlimited (i.e. the full 180 days) coverage. Of course, there may be events outside those simulated (e.g. wars, pandemics or large earthquakes) that could mean 70 days of coverage is insufficient. However, pricing the risk for those events is likely to be extremely difficult. And seeking to price them into a cap (i.e. not including any limit) could significantly narrow (or eliminate) the range of possible sellers.

(c) The results for sequential and ex-post settlement are relatively similar – especially for contracts with limits equivalent to 40 (or more) days of coverage.

B.50 Finally, the two settlement approaches (sequential and ex-post) can be regarded as potential bookends. It is possible that some intermediate approach could be applied. For example, the contract might allow buyers to nominate when the contract applied on an ex-ante basis, subject to the energy limit. That would allow buyers to better optimise the timing of coverage if they wished, and sellers would not have greater certainty about when the contract cover is activated. However, if the contract allowed nominations, this could mean it is hard (or impossible) to structure as an exchange-traded product, because the value of individual contracts would depend on how many remaining nominations are available. This is the sort of consideration that would need to be explored further, along with other factors such as contract duration (e.g. six months vs. shorter), level of energy limits, etc.

B.51 Overall, the initial analysis suggest that energy-limited caps may be a useful avenue to explore as potential flexibility contracts.

Energy-limited swaptions

B.52 Energy-limited swaptions are similar to energy-limited caps, except the underlying product is a swaption. The analysis assumed the swaption was settled against daily (rather than hourly) average spot prices above 200 $/MWh, and that the product is nominated a day ahead basis.[235]

B.53 The natural buyers of the product are likely to be retailers, wholesale consumers and intermittent generators selling products which are not generation-following. These parties are likely to want to hedge their exposure during the periods when prices are relatively high, recognising that the timing of such periods is not necessarily predictable.

B.54 The natural sellers of the product are likely to be dispatchable, peaking generators (e.g. hydro stations or gas peakers), energy storage operators (e.g. pumped hydro and batteries), and demand-side flexibility providers with ability to curtail or shift load for a few hours at a time each day. These resources would also need to be flexible over short periods, with the ability to ramp up or down very quickly.

B.55 Two different settlement approaches were modelled:

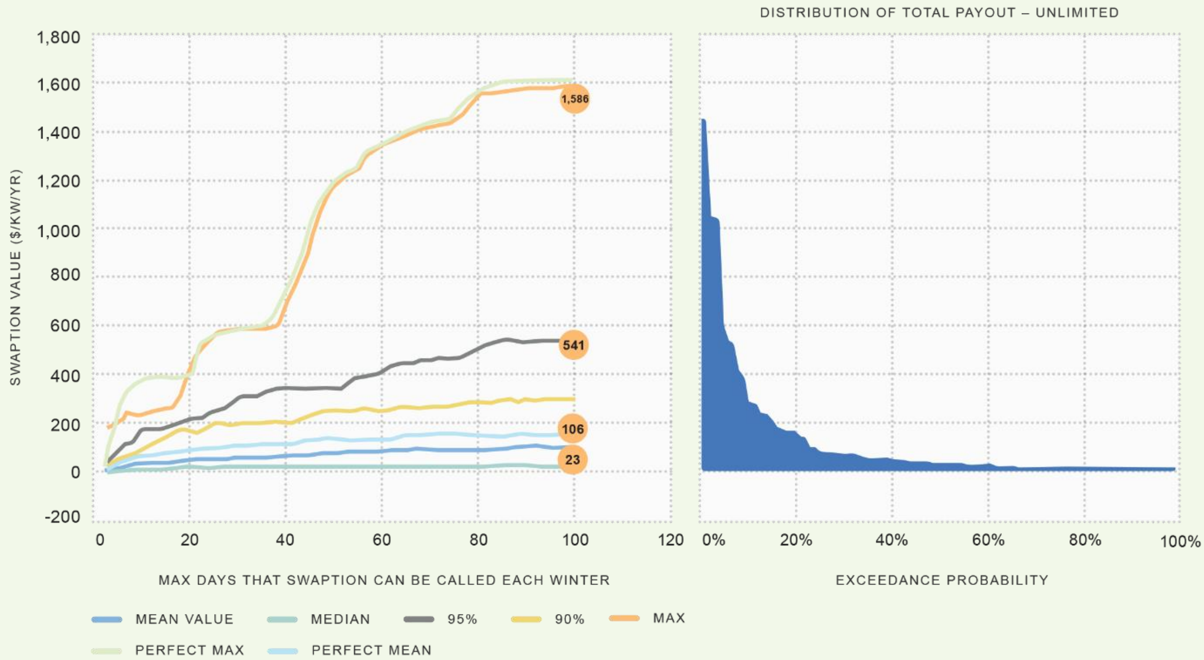
(a) Perfect foresight where the buyer always forecasts the day ahead price accurately; and

(b) Naïve forecasting where the buyer calls the product for tomorrow if today's spot price exceeds 200 $/MWh. Under this approach the buyer sometimes becomes a payer because the actual spot price on the day settles at a value less than the swap price.

235 Some feedback has suggested that this product could be difficult to back physically if it allows daily nomination, because of the potential for frequent starts and stops for the underlying supply or DSF resource. This type of issue would require further exploration if this product is developed further.

B.56 As with the cap analysis, the two settlement approaches can be regarded as potential bookends. In practice buyers are likely to utilise relatively sophisticated forecasts to judge whether to exercise the swaption. Figure 20 shows the results of analysing the energy-limited swaptions.

Figure 20: Energy-limited swaption



B.57 Key observations from the charts include:

(a) Contracts with energy limits of around 40-50 days (out of theoretical 180 maximum) would provide a significant (though not complete) level of cover for buyers. As a result, if there were potential suppliers with (say) energy limits that equated to 40-50 days, such contracts could be attractive to buyers even though they don't provide complete coverage.

(b) Contracts with energy limits equivalent to 100 days of cover would provide complete protection for the modelled events. In the simulation it was not necessary for buyers to have 180 days of coverage to achieve full protection. This is important because there are likely to be more potential sellers for contracts with a limit of 100 days of coverage than for unlimited (i.e. the full 180 days) coverage. As with caps, there may be events outside those simulated.

(c) The results for sequential and ex-post settlement are relatively similar – especially for contracts with limits equivalent to 40 (or more) days of coverage.

B.58 Once again, the analysis suggests that energy-limited caps may be a worthwhile product to explore as a flexibility product which provides protection for buyers, while not being unduly difficult for sellers to back with physical resources.

Solar shape contracts

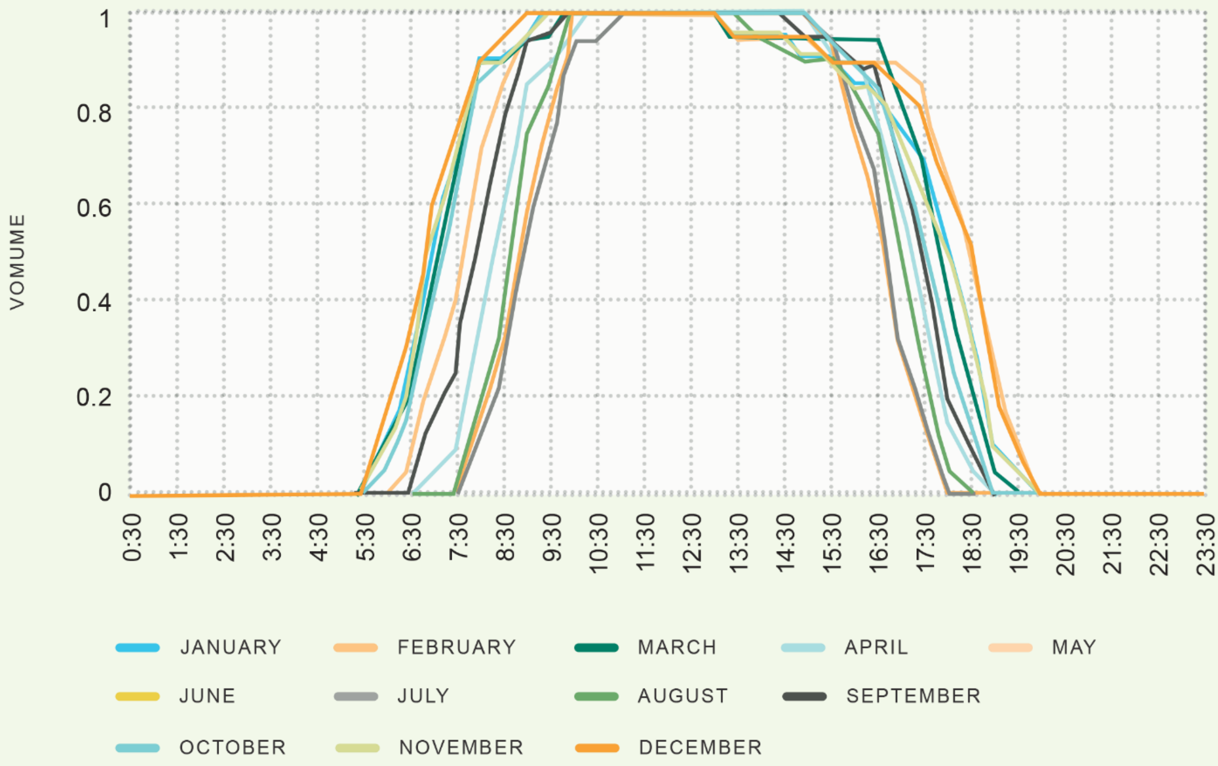
B.59 Solar shape swaps are products tailored to match solar generation profiles. Two variants have been considered:

(a) Solar Shape Swap – a swap contract with the generation profile for a generic solar farm that has single axis tracking; and

(b) Inverse Solar Shape Swap – a swap that is inverse to the Solar Shape Swap. The half-hourly profile across the year represents the energy required to firm the Solar Shape contract to a flat (i.e. baseload) swap.[236]

B.60 While the peak volume of the Solar Swap Contract is constant, the shape of the contract would change monthly to account for seasonal changes in irradiance as shown in Figure 21. The profile would also be consistent across the country with this consistency facilitating improved liquidity.

Figure 21: Illustrative profile for solar shape swap[237]



B.61 The natural sellers of the Solar Shape Swap would be solar developers and the natural buyers would be retailers or wholesale consumers seeking to purchase a contract based on a solar profile.

B.62 The natural sellers of the Inverse Solar Shape Swap would be dispatchable generators with flexibility in their generation profile, both within each day and across seasons. The natural buyers would be retailers or wholesale consumers looking to combine it with the Solar Shape Swap or a solar power purchase agreement, to create a flat product. Alternative the Inverse Solar Swap could be of interest to solar generators looking to on-sell a relatively flat product to customers.

B.63 Because the two products reflect an averaged solar shape across New Zealand, there will be mismatches between individual solar generators and the standard products. However, the mismatches are not expected to significantly reduce the hedging value of the products. Furthermore, the standard products may be preferred by some parties over bespoke contracts because they are more readily tradable for participants wishing to adjust their positions. The standard contracts could also serve as pricing reference points for bilaterally negotiated contracts for solar sale agreements, or solar-firming agreements. We understand that both types of solar shape products have traded in the Australian NEM.

236 The same product could be synthesized by selling a baseload swap and buying the Solar Shape Swap.

237 See page 25 of Renewable Energy Hub's Knowledge Sharing Report 1: Contract Performance Report, November 2020 (arena.gov.au/assets/2020/11/contract-performance-report-renewable-energy-hub-nov.pdf).

B.64 We consider that there could be benefit in further exploring solar shape products.

Night and day swap products

B.65 A product that would have broadly similar properties to the Inverse Solar Swap is a Night Swap. This product would have a constant volume in the hours of darkness and zero volume in daylight hours. The exact hourly cut-offs between day and night could vary across the contract year to reflect changing daylight hours. In principle, a companion product would be the Day Swap which would have the mirror profile to the Night Swap.

B.66 The natural buyers and sellers of these products would be the same as the two Solar Swaps. In particular, the Night Swap would provide purchases with some protection against high spot prices during non-daylight hours, if they are purchasing output from (or own) solar based generation.

B.67 This product would be simpler than the solar swaps which could make it easier to implement. On the other hand, it would be less effective at matching solar generation profiles (since it is ‘on’ or ‘off’, with no graduation of volume across the day). This type of product could be explored as an alternative to the solar swaps.

Wind shape/inverse swaps

B.68 The logic behind the Solar Shape Swap and the Inverse Solar Swap could be applied to develop analogous products for wind generation. In this case, a ‘standard’ wind profile would be used to set the half-hourly volume profile. This standard profile would not be set ex-ante, but instead follow and average of wind generation across New Zealand, or a reference profile, such as a site in Manawatu region (since most wind generation is correlated with generation in that area).

B.69 The natural buyers and sellers of the products would be similar to the equivalent solar products, except that it would be useful for wind rather than solar generation customers/developers.

B.70 A key issue with this product is that traders would not know the profile ex-ante – unlike for the equivalent solar swaps. This could make it challenging to attract sellers for the Inverse Wind Swap.

B.71 Based on initial analysis, we think that compared to wind shape/inverse swaps, the energy-limited cap and swaption may be able to provide similar benefits to buyers and would be likely to attract more interest from sellers. We therefore suggest that wind shape/inverse swaps not be pursued further at this stage.

Energy storage products

B.72 The preceding products are designed to complement physical resources controlled by demand response providers or generators and assume there is a net purchase/sale of energy into the spot market. While some of those products may be of interest to energy storage operators, they have not been designed with such parties as the natural counterparty because their value is driven by the absolute level of spot prices at particular times. An alternative product designed specifically for storage providers would derive its value from the *difference* in spot prices between ‘charge’ and ‘discharge’ intervals.

B.73 For example, an energy storage product designed with battery providers in mind could be structured as follows:

(a) Buyers of the storage product would simultaneously sell a fixed MW block of low-priced energy ‘charge’ and buy a block of higher priced energy ‘discharge’.

(b) The product would be energy-neutral for simplicity (charge/discharge legs would be the same MWhs even though losses would occur in practice).

(c) Settlement values would be calculated daily based on the actual lowest and highest priced intervals each day to reflect the charge and discharge periods. The number of intervals would be fixed based on the assumed battery characteristics, e.g. two or four hours.

(d) The contract price would be the agreed price spread between bought and sold legs (i.e. the expected energy arbitrage value).

B.74 The natural sellers of the contract are battery operators (or possibly demand response providers) because they could use the contract to de-risk their energy arbitrage value. The natural buyers of the contract are retailers (or perhaps other wholesale purchasers) seeking to manage their intra-day exposure to spot price differences (e.g. because they have peaky load but relatively flat hedges).

B.75 In principle, storage contracts of longer durations (i.e. settlement periods of greater than each day) could also be developed. However, we suggest that it would be useful to start with daily settlement contracts as these are simpler to implement. They are also likely to match well with batteries as natural providers, whereas natural sellers for longer duration energy storage are more heterogeneous.

B.76 We think storage contracts are worth exploring further.

Trading platform also important

B.77 The preceding discussion focused on possible contractual structures. Another important issue to consider is whether flexibility contracts would be traded bilaterally, via a public platform (where prices are published but the contract is settled bilaterally – aka a bulletin board), or on a cleared exchange (i.e. settled centrally).

B.78 We strongly prefer the latter two alternatives because of their greater price transparency. These could be existing (such as the ASX) or new platforms (such as the short-term contract trading platform proposed by Aotearoa Energy). We think the merits of the various alternatives should be considered as part of the further work on standardised flexibility contracts.

Process to use

B.79 As we set out in Chapter 8 we recommend that the Authority support a process in which industry participants would have an opportunity via a co-design process to develop flexibility contracts and (potentially) a trading platform with support from the Authority. The participants would need a clear task and timetable. They should be selected based on their ability to make constructive and well-informed contributions to the contract development process.

B.80 The Authority would also need to be clear about the alternative (i.e. a regulated set of contracts) that would apply if the industry process did not achieve results.

B.81 A possible set of stages for the industry process co-design process could be:[238]

238 These draw on insights from a similar process run in Australia that was sponsored by ARENA. See arena.gov.au/projects/renewable-energy-hub-marketplace/.

(a) Product development – the industry group would develop specifications for a range of new hedge contracts. These product designs would be built up through consultation with the wider stakeholders as well as broader market consultation processes. Several of the possible candidates as new products are presented earlier in this Appendix.

(b) Pilot transactions – the new hedge contracts would be progressively released into the market to test that they can be used in negotiated pilot transactions between parties. Pilot transactions will be used to build familiarity with contract specifications and requirements, prepare legal documentation to support trades, and enable market participants to build an understanding of the drivers of value and pricing.

(c) Platform build – this workstream would involve the design, build and delivery of an online market platform to support the new contracts. The platform would provide users with up-to-date pricing and product information, tools to enable comparison of different hedge contracts so buyers and sellers can establish fair value, and tools to test the performance of hedging strategies under different scenarios and support trade execution and confirmation.

(d) Knowledge sharing – the knowledge sharing activities and deliverables of the project would include a series of reports, presentations and workshops on the performance of new hedge contracts as well as the market impact of the project.

Appendix C Enhance stress testing regime

C.1 This appendix provides more detail on *Recommendation 7* (stress testing). In effect, it provides a blueprint that the Authority can utilise to speed up the implementation of this recommendation.

What is the purpose of the stress testing regime?

C.2 A cornerstone of the current wholesale market design is that participants are responsible for managing their own supply risks via access to physical resources and/or entering into financial contracts (aka hedge contracts) with other parties.

C.3 There is no mandatory payment for supply capacity or requirement for wholesale purchasers to hold a certain minimum level of forward contracts or generation judged by a central agency to be sufficient to cover that purchaser's projected demand. Rather, our market design recognises that:

(a) Risks, and optimal options for managing them, vary among market participants; and

(b) Each market participant is best placed to understand the risks they face and the mix of tools and cover to best manage those risks.

C.4 Keeping the responsibility for risk management on participants rewards those who search out the lowest cost options, including for investment in new supply. And investment efficiency represents the largest single impact the electricity industry has on the New Zealand economy.

C.5 Market participants' risk management decisions affect the physical level of reliability the system will deliver. This is because risk management decisions will (in aggregate) drive forward wholesale prices, and (in turn) influence decisions about plant availability, fuel management, and investment in new supply.

C.6 While placing risk management responsibility on participants creates strong investment cost disciplines, it does rely on participants proactively assessing and managing their spot price risks. Two particular concerns can arise on this front:

(a) **Accidental inattention** – participants may accidentally take on more spot price risk exposure than they intended. For example, they may under-appreciate the potential risks associated with their spot price exposures or may pay insufficient attention to a changing risk landscape. While poor risk management by individual parties of modest size would not be expected to undermine the reliability of the system, if such behaviour was widespread or occurred within large participants, it could do so.

(b) **Moral hazard** – participants may consciously choose to 'under-insure' against spot price risk if they think a future government (or regulator) will provide them with some insurance cover, for example by intervening to limit spot prices in a tight supply event. In economic literature, the tendency of a party to exhibit more risky behaviour if another party is bearing (or sharing) the risk is called moral hazard.[239] Despite the term, participant behaviour of this type need not have any immoral intent – indeed, arguably it would be irrational for participants to incur insurance costs if they believe subsequent government/regulatory action will make such insurance moot. However, if an expectation develops that the government/regulator will 'save' under-insured parties, it can become a self-fulfilling prophesy. This is because the greater the number of parties who are under-insured, the more likelihood that governments/regulators will feel compelled to intervene in tight supply events, and so on.

[239] The term originated in health economics, with the observation that patient behaviours can be affected by their insurance cover. The term is now widely used in many fields of economics.

C.7 Such concerns are not new – they were recognised at the outset of the wholesale market in the mid-1990s.[240] The Code includes a stress testing regime that seeks to address these concerns and therefore support system reliability while maintaining the policy that wholesale participants retain ultimate responsibility for their risk management decisions.[241]

Current stress testing regime

C.8 The stress testing regime seeks to address the accidental inattention concern by providing certain participants (called disclosing participants)[242] with information about potential spot price risk scenarios and requiring them to compute the financial impact of those scenarios on their business.

C.9 The stress testing regime seeks to address the moral hazard concern by requiring disclosing participants to report the results of applying stress tests in a disclosure statement to a registrar appointed by the Authority (currently NZX). Disclosing participants must also certify that their board has considered the organisation's stress test disclosure statements at least annually. These requirements are intended to reduce the scope for any participant to credibly argue that it was unaware of its exposure to spot price risk.

C.10 Finally, the stress testing regime seeks to maintain the onus on participants to manage spot price exposure risks by emphasising that the regime is not supervisory in nature. While stress tests results must be reported to the registrar, there are no passes or fails. Furthermore, the regime does not allow the Authority to receive stress test disclosure statements from individual organisations. This means that it cannot use the regime to monitor the risk position of individual organisations, even if it so wished. Rather, the Authority just receives and publishes anonymised/aggregated stress testing disclosure data.[243]

How should the stress testing regime be enhanced

C.11 We recommend the Authority implement the actions below to enhance the stress testing regime. The actions have been developed to update the regime for a shift to a renewables-based system (e.g. extending the stress test horizon) and to address areas of weakness identified in light of experience since the regime started.

Include purpose statement in the Code

C.12 Although the regime is clearly not supervisory in nature, this is not necessarily well understood by stakeholders. Misapprehensions can be fostered by the existence of supervisory stress testing regimes in other sectors such as banking.

C.13 For the electricity sector regime to operate effectively, it is very important for industry participants to properly understand its purpose. In particular, it is critical that stress testing not be misconstrued as a supervisory regime as that could weaken participants' incentives to proactively manage risks. Furthermore, it is important that stakeholders understand how the regime, via a reliance on participants managing their own financial spot price risk exposures, contributes to physical reliability for the system.

240 See *Managing "Dry-Year" Risk in a Fully Competitive Market: Issues and Options* – report from John Culy for Officials Committee on Energy Policy, May 1995.

241 See Code Part 13, Sub part 5A.

242 Participants that purchase from the Clearing Manager and/or electricity users who are directly connected to the grid.

243 See www.emi.ea.govt.nz/Wholesale/Reports/HPUUJB.

C.14 To this end, we recommend that a purpose statement be included in the Code at the start of the section on stress testing. A draft of the purpose statement is included in the box below:

Proposed purpose statement (New clause 13.236A of Subpart 5A)

(insert before existing 13.236A and renumber the rest of 13.236A-N)

(1) In the **wholesale market**, each **disclosing participant** is responsible for managing its own supply risks and the **rules** do not define mandatory minimum requirements for hedging

(2) The purpose of this Subpart 5A is to promote awareness by each **disclosing participant**:

a) Of its exposure to spot price risk* and the importance of taking steps to prudently and proactively manage spot price risk, recognising that spot prices are volatile and have the potential to be very high during periods when supply is tight;

b) That the consequences for a **disclosing participant** of not adequately managing its exposure to spot price risks rests with the **disclosing participant**;

c) That security and reliability of supply for the electricity system as a whole arises from the actions of all **participants**;** in particular, **disclosing participants'** risk management decisions (which include buying and selling hedges,*** and demand-side responses) in aggregate drive forward **wholesale market** prices, which in turn strongly influences investment decisions in relation to new supply, which in aggregate determines reliability of supply over the short, medium and longer terms.

(3) For the avoidance of doubt:

a) Each **disclosing participant** is responsible for determining the range of adverse spot market scenarios to apply in assessing whether its risk managements arrangements are satisfactory;

b) The **stress test** is not, and is not to be used or interpreted as, a forecast of spot prices or an indication of the range of spot prices that a **disclosing participant** is likely to face; and

c) The Authority is not responsible for ensuring the financial strength of any **participant.**

* Drafting note – "spot price" is used in Rule 13.236E (1A)(b), otherwise the Rules refer to "spot price risk disclosure statement"

** Drafting note – see Electricity Authority, *Interpretation of the Authority's Statutory Objective,* 14 February 2011 at A.35.

*** Drafting note – "hedge market" is used in the Rules' definition of "wholesale market". Using the term "contract cover" may be an alternative.

Refine disclosures made about spot risk management policies

C.15 Participants are currently required to disclose whether they have an explicit risk management policy in respect of exposure to the wholesale market. If they answer yes, participants are required to disclose their 'target cover ratio'[244] in relation to each stress test.

244 The formula for this ratio is defined by the Authority, and it is a measure of the proportion of expected spot market purchases that are hedged by physical means or forward contracts.

C.16 We understand that most (if not all) disclosing participants have explicit risk management policies, but many find it hard to accurately comply with the requirement to disclose target cover ratios. We understand that this is because it is generally difficult to translate risk parameters embedded in policy documents into simple numerical ratios. Our view is that the requirement to compute and disclose target cover ratios should cease.

C.17 We think the better approach is to require a fuller qualitative disclosure about risk management policy. More specifically, we consider that parties should be required to certify that they have a written policy in relation to the management of spot price risk, that the policy reflects the risk tolerance of their organisation, and that the Board of the organisation actively monitors compliance with that policy.

C.18 A provision of this sort would provide better assurance that participants are monitoring and managing their spot price risk exposures – whilst still being consistent with the position that participants are solely responsible for determining their risk appetite and managing their operation consistent with that appetite.

C.19 With these factors in mind, we recommend that policy related disclosures be amended to include the wording below. This wording would replace the existing requirements at Q7 and Q8 of the current spot price risk disclosure statement format.

Proposed disclosure relating to spot price risk management policies

1. The organisation has a Board-approved written policy governing the management of spot price risk, and the policy has been reviewed within the last three years.
2. The organisation considers the policy to be appropriate for its requirements, having regard to all the relevant factors, including the nature of price volatility in electricity spot markets, the organisation's business scope, physical assets and financial resources.
3. The Board actively monitors the organisation's compliance with the policy.

C.20 It would be surprising if any disclosing participant could not positively confirm the statements above. However, if an organisation did not (for example) have a written policy governing spot price risk management, that would mean it is unable to positively certify the disclosure statement and that would be a breach of the Code.

C.21 While we think such situations are unlikely to arise, we think it appropriate that a compliance breach would be triggered in such circumstances. We take this view because an inability to positively affirm any of the three requirements would be a strong prima facie indication that the organisation was not proactively managing its exposure to spot price risk. Hence, we consider that invoking the compliance procedures would be entirely appropriate. We also note that, in practice, such procedures are likely to result in rapid action on the part of the disclosing participant to avoid and/or swiftly remedy any breach.

Clarify certification standard

C.22 Stress test disclosure statements currently include no explicit reference about the representation being made by signatories. We recommend that disclosure statements adopt a standard similar to those made by distribution companies under Part IV of the Commerce Act. This would mean signatories make a representation along the following lines:

> I ______ being a [director/officer] of ______ certify that, having made all reasonable enquiry, to the best of my knowledge, the information containing in this Disclosure Statement in all material respects complies with the requirements of clauses xxx of the Electricity Industry Participation Code

C.23 We also recommend that the requirement for disclosing participants to annually certify that their disclosure statements have been reviewed by their Board would be retained.

Update the stress tests

C.24 The Code provides for the Authority to specify the form of the stress tests that participants must apply. Since its inception the regime has required the application of two tests – an 'energy' stress test intended to simulate the potential effect of a prolonged drought, and a 'capacity' stress test intended to simulate the potential effect of a short (i.e. hours) adverse supply shock such as the unexpected failure of a large generation unit or station.

C.25 We recommend that the Authority review and update these tests in light of expected future system circumstances (e.g. review the assumed level and duration of higher spot prices in the tests). We also recommend that the Authority consider whether a test reflecting a dunkelflaute type event should be added, since this appears likely to be a new type of risk in future.

C.26 As with the existing tests, we encourage the Authority to keep the tests fairly simple and 'generic', noting that they are not intended to provide detailed representations of the full range of possible spot market price risks.

C.27 As noted in the proposed purpose statement above, it is also important for wholesale buyers and sellers to keep in mind that each participant is responsible for determining the range of adverse spot market scenarios to apply in assessing whether its risk managements arrangements are satisfactory. The stress tests set under the Code are not definitive for all participants.

Extend stress test horizon

C.28 At present the regime requires participants to apply tests only for the coming quarter, as it was designed to address risks associated with near term droughts or transitory capacity shortages. As a result, it does not provide any information to participants about exposure to longer term risks, such as investment delays or changes in demand growth, or sizeable movements in fuel or carbon prices.

C.29 These types of risks are expected to be much more relevant in a system that has significant demand growth and is shifting toward renewables. Indeed, recent experience has shown how these types of factors can appreciably shift spot price risks.

C.30 We recommend that the stress test horizon be extended to allow the Authority to require tests for up to the coming three years. We expect the form of disclosures for periods beyond the coming quarter could be relatively simple. For example, participants could report the percentage of projected annual purchase volume for each future year (on a rolling basis) that is hedged by contracts or physical resources.

C.31 We expect that requiring this type of information would be a useful prompt to ensure participants are considering the forward horizon. Furthermore, in combination with the next action (enhanced presentation of results), this type of information would help participants to gauge how their longer-term hedge position compared to the rest of the market.

Enhance presentation of results to each participant

C.32 Disclosing participants do not currently receive any information on how their organisation's results compare with others. Indeed, strictly speaking they do not receive any individual 'results' as they simply provide data inputs to the registrar. These are processed by the registrar and sent in anonymised form to the Authority who published a summary.

C.33 We recommend that the registrar provide each disclosing participant with a clear and easy to understand report each quarter that shows how their results compare with all other disclosing participants. The comparator reports would obviously need to preserve confidentiality for other parties.

C.34 From a practical perspective, it is clear that the registrar is able to compile such ‘you-are-here’ reports. We understand there were produced in Q1 2018 when the Authority wished to draw participants attention to elevated supply risks in a quarter when planned HVDC outages coincided with reduced gas supply due to remedial work at the Pohokura gas field.

C.35 Our view is that you-are-here reports would help participants to assess the appropriateness of their risk positions, while further reinforcing the stance that participants have ultimate responsibility for making risk management choices in relation to spot price risk exposure.

Simplify regime where possible

C.36 We believe the stress testing regime can be simplified in some areas. As noted above, we recommend that the requirement to compute and disclose target cover ratios should cease. This would remove one aspect of the tests that many participants find it difficult to accurately comply with.

C.37 Another area of simplification relates to way stress test calculations must be performed. This is set out in a Guidance Notice issued by the Authority.[245] We recommend that the Authority simplify the requirements where practical – with less prescription and more reliance on general principles. For example, at present the Notes become out of date each time a new grid exit point is created. Simplifying the Guidance Notes should reduce compliance costs for participants and the Authority.

Contextual information for Code change process

C.38 Clearly, implementation of our recommended changes to the stress test will require a Code change following the normal proposal process. The background context in the Authority’s proposal paper should also include an outline of the statutory framework of how the wholesale market is regulated and where the stress test fits within in it, and the policy history and objectives of the stress test.[246]

245 See www.ea.govt.nz/documents/2012/Stress_testing_regime.pdf.

246 With a view to assisting a court to readily discern the framework and policy rationale. This reflects an informal insight from a senior legal person with whom we discussed our recommended changes.

Appendix D Competition measures for flexibility contracts[247]

D.1 *Recommendation 31* is for the Authority to undertake work on competition measures to address a possible thinning of competition for supply of longer-duration flexibility. This appendix provides further information on why we think these competition concerns are especially important.

D.2 This appendix also describes the graduated approach that we recommend the Authority adopt to address the competition concerns, including the development of backstop competition measures.

Competition could significantly reduce for some forms of flexible supply

D.3 Competition is a vital ingredient to any successful electricity market. Without effective competition, consumers and policy makers will not have confidence in electricity spot or contract prices. A lack of confidence in competition can also be bad for suppliers. If policy makers lack confidence in competition, the policy/regulatory environment will be less stable. That in turn can have a chilling effect on the incentive to invest in new supply and demand-response capability.

D.4 Our Issues Paper (paragraphs 7.140 to 7.142) found that the shift to a renewables-based system may strengthen competition in some areas. For example, the expected widespread deployment of chemical batteries appears likely to increase competition in the provision of short-duration flexibility (a day or less) and for some ancillary services in the spot market.

D.5 Conversely, competition may thin in some other areas. The provision of flexible supply for periods of a week or longer into the spot market is the area of greatest concern. This is because much of this physical flexibility comes from fossil-fuelled plant that will progressively withdraw in the shift to a renewables-based system. Batteries are unlikely to be economic for cycling over a week or longer.[248] This means the control of medium and longer-duration flexibility would become more concentrated among parties with the flexible hydro generation capacity and the remaining thermal capacity, all other things being equal.

D.6 New physical sources of longer-duration flexibility are likely to emerge over time and would increase competition in the spot market. These potentially include flexible demand sources, a degree of renewable over-build, pumped hydro storage, and/or biofueled thermal operation. However, the size and timing of deployment for these resources is uncertain, creating the potential for thinning of competition in the meantime.

Insights from international experience and experts

D.7 In considering the potential for competition problems to emerge, our thinking has been informed by insights from overseas experience and experts. Our information gathering from overseas included a review of published literature and discussions with electricity competition experts.[249]

D.8 Key points that emerged from this international review include:

247 As discussed in the appendix, there are specific concerns about the competitive availability of *longer-duration* flexibility contracts. For brevity, we refer to these as flexibility contracts in this appendix, noting that strictly speaking the term has a broader meaning.

248 Chemical batteries have a high cost to increase their storage capacity and are unlikely to be economic for the provision of longer-duration flex.

249 This included a review of literature and virtual meetings with Professor George Yarrow and Dr Chris Decker (both of whom are United Kingdom-based competition experts) and personnel at the Australian Energy Market Commission.

(a) If access to flexible resources in the spot market were to become a bottleneck in competition terms, that could have very significant implications for functioning of the wider electricity market. For example, if there is inadequate competition for the provision of firming services for intermittent generation, that could in turn reduce competition in the upstream generation investment market and/or in the downstream market for electricity retailing. Limited competition for flexibility services was a concern in the United Kingdom in early 1990s when two players were regarded as controlling most of the flexible generation on that system.

(b) When assessing how competition for flexibility could affect the wider market, it is important to consider the structure of spot prices. If some parties have sufficient market power to sustainably alter the structure of spot prices, those parties would likely have scope to influence competitive dynamics in other parts of the wholesale market. A particular concern would if parties could increase the 'volatility of volatility' (see below) – i.e. appreciably increase uncertainty about the future structure of spot prices as that might deter some types of new entry and therefore increase *average* prices.

(c) There is no universal approach to apply when analysing competition in the future. However, one useful approach is to consider the likely degree of *change* in parties' ability or incentives to exercise market power. This information, combined with knowledge about current levels of competition, provides a basis for assessing whether competition concerns are likely to grow or recede.

(d) Market power can be regarded as significant if the economic cost of the harm exceeds economic cost of the remedy.[250] In this context, it is important to note that electricity markets are unusual – appreciable harm can occur in a relatively short period.

(e) As Prof. Paul Joskow observed: "Market power is a significant potential problem in electricity markets, but the cure can be worse than the disease. Try to deal with potential market power structurally ex ante rather than ex post." [251] This implies a preference for measures that alter incentives (new entry, enforced divestment, contracts markets and the like), rather than relying solely on ex-post conduct measures.

Simulation analysis undertaken for 2035

D.9 The Options Paper used simulation analysis to further explore the potential competition issues that could arise in relation to longer-duration flexibility. It analysed a scenario for a renewables-based system in 2035. By then demand will have grown appreciably and around 1,000 MW of new intermittent supply is assumed to have been added to the system. The modelled scenario also assumed the Tiwai smelter would not be operating. If the smelter continues to operate, the conditions in the scenario would be reached at an earlier date than 2035, likely around 2031.

D.10 A new concept identified in the analysis is so-called 'volatility of volatility'. This refers to an increase in the uncertainty about the structure of future spot prices in a renewables-based system. This is illustrated by Figure 22 which shows spot price duration curves (PDCs) from the Options Paper simulation analysis. Each PDC shows the simulated spot prices under different physical conditions (demand fluctuations, weather years etc) ranked from highest to lowest and for a given hydro offer strategy.

250 This is the definition proposed by Professor Yarrow and reflected in trading conduct provisions of the Code. Of course, there may be instances where the economic cost of the harm is very sizeable, but nonetheless smaller than the economic cost of the remedy. Further, the exercise of market power is not made acceptable by high costs to remedy or prevent it.

251 For example, see Joskow, 2007, Lessons Learned from Electricity Market Liberalization, page 14 – (economics.mit.edu/sites/default/files/2022-09/Lessons%20Learned%20from%20Electricity%20Market%20Liberalization.pdf) .

D.11 Importantly, each PDC represents an equilibrium outcome for the system – i.e. all existing resources are recovering their costs (including economic returns on capital) and it is not economic for further entry to occur.

D.12 The Options Paper analysis found that different possible PDC structures could satisfy new entry equilibrium conditions in a renewables-based system.[252] As shown in the chart, the PDCs are quite similar in the upper and lower ranges but have differing profiles through the mid-range. For example, the grey profile has a lot more periods of very low prices, and more periods of very high prices, as compared to the blue or orange profiles.

D.13 In effect, the existence of multiple equilibria implies spot price volatility would be affected not just by physical conditions but also by how major hydro suppliers choose to offer their resources. Their choices would still be constrained by the threat of new entry. For example, if the day/night price differential increased (and made solar entry less attractive) that would tend to make battery entry more likely. However, they would have some latitude to alter the shape of the PDCs without causing disequilibrium – and hence potential changes in their offer strategy would introduce 'volatility of volatility' into the system which would not necessarily self-correct through new entry.

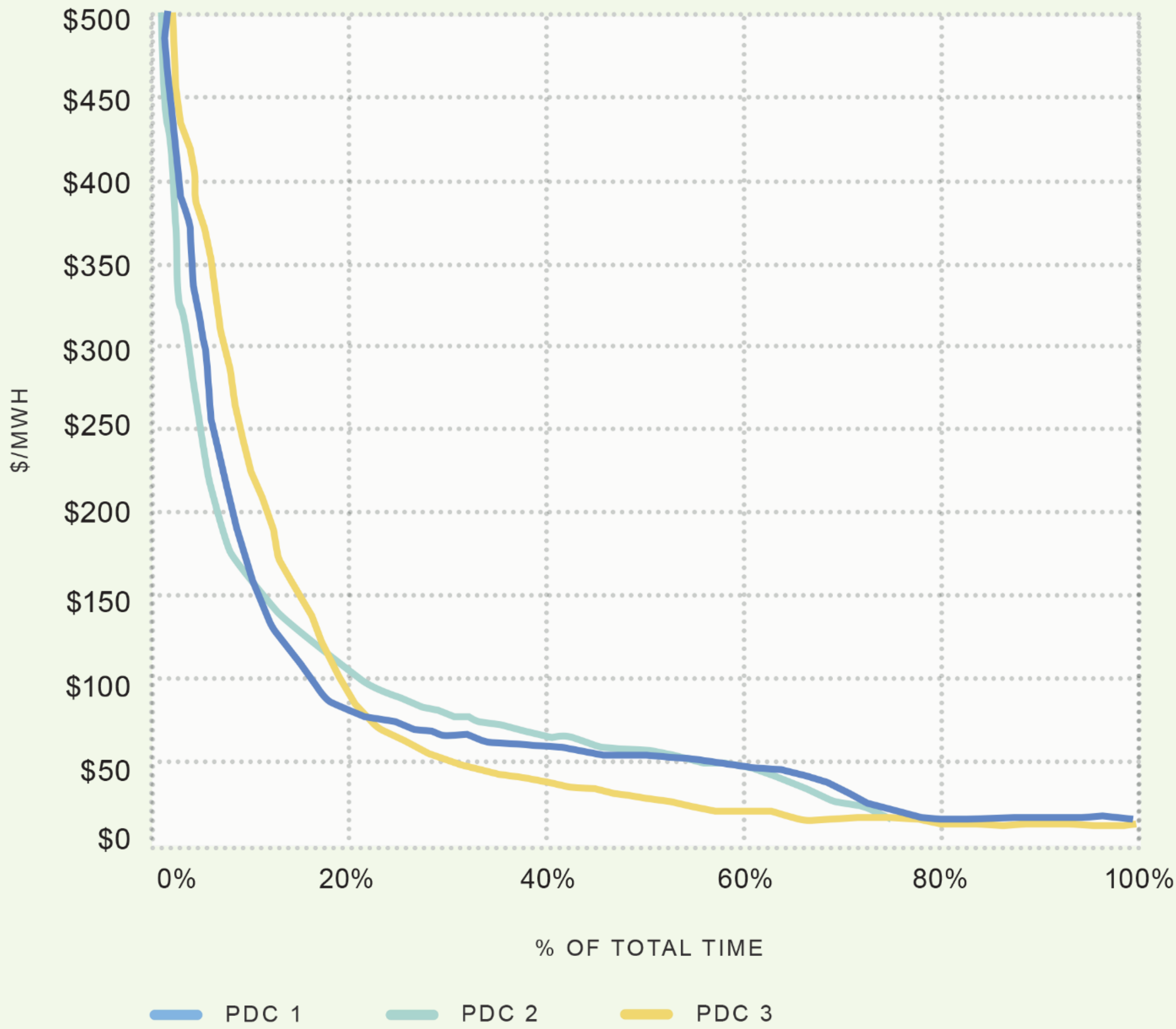
D.14 Before moving on, a few caveats should be noted. First, the results should not be interpreted as precise predictions of the future. That is clearly unrealistic given the estimation uncertainty that inherently applies with this type of analysis. Rather, the results should be viewed as indicating the potential for a perceptible change to occur in the nature of spot price volatility in a renewable-based system. This change is one of degree compared to today's system – but it is a change nonetheless.

D.15 Second, the simulation assumed low elasticity short-run demand response will occur. However, it did not include any significant medium term demand elasticity that might arise from sustained demand responses, eg from large electricity intensive loads altering their demand for long periods in response to price changes. The presence of any users that had such demand response properties would be expected to further constrain the new entry equilibrium.

D.16 Third, the simulation analysis assumed that all major hydro operators pursued similar offer strategies. It was not feasible to test the effect of variations in offer strategies of individual operators.

252 Obviously, there are some modelling uncertainties, and the results were within the bounds of these uncertainties.

Figure 22: Illustrative price duration curves (2035 simulation)



D.17 Having concluded that multiple PDCs could satisfy new entry equilibria, the analysis considered the potential implications for competition. In particular, whether generators with the larger flexible hydro bases could have the means and incentives to exercise market power in the spot market. The key observations from this aspect of the competition analysis were:

(a) Larger generators with significant flexible resources may well have greater means to raise the volatility of volatility (i.e. cycle between PDC structures) in the spot market under a renewables-based system than in the past.

(b) Larger generators with significant flexible resources would not appear to face much direct cost or disruption from raising the volatility of volatility in the spot market.

(c) It seems likely that significant volatility of volatility in the spot market would deter (or raise costs for) potential new entrant intermittent generators.

(d) If increased volatility of volatility in the spot market did hinder (or raise entry costs for) new intermittent generation, that could lead to higher *average* prices which could be of significant benefit to incumbent suppliers.

D.18 On the other hand, the simulation analysis also found that the competition concerns in the *spot market* could be appreciably reduced if wholesale buyers could access flexibility contracts on reasonable terms. The availability of such contracts would be expected to support competition in three key ways:

(a) Wholesale purchasers would be able to better manage their spot price risk exposures because of the availability of an instrument that provides protection during periods of high spot prices. For example, the analysis showed how the availability of cap contracts would lower the risks otherwise faced by standalone wind or solar generators. That in turn should enable those suppliers to offer more of their output for sale on a firm or semi-firm basis, and therefore promote competition in new supply, all other things being equal. A similar beneficial effect would be expected in the retail market, although that was not explicitly modelled.

(b) The natural sellers of flexibility contracts would include the generators with significant flexible hydro bases (i.e. the parties of principle concern from a competition perspective). The greater the degree of forward contracting by those parties, the smaller the incentive they would have to exercise market power in the spot market. Furthermore, forward sales of flexibility contracts by these parties would implicitly reveal their expectations about the likely structure of future spot prices. Put another way, the volatility of volatility would be likely to be lower, because parties' offer behaviour in the spot market would be likely to align with their (already committed) forward contracting.

(c) Finally, sales of flexibility contracts with a visible forward price would provide a benchmark against which other sources of flexibility could compete and make investments. This includes resources such as demand response or bio-fuelled generation. Absent a visible forward price for flexible supply, it is harder for parties to judge whether such investments are likely to be worthwhile.

D.19 The analysis described above is relatively complex and a simple analogy may help to illustrate the key points. In some ways, operating in the electricity system can be likened to participating in a game of cards. Players choose how much to stake and face the uncertainties associated with the random drawing of cards (analogous to the uncertainties pertaining to weather and demand fluctuations etc). This is the game that players are familiar with.

D.20 Now, consider a shift to a renewable-based system. The random dealing of the cards (e.g. weather) remains the major source of uncertainty. However, in addition, there is now some scope for the rules of the game to flex depending on how some participants choose to play their hands. Those players do not set the rules unilaterally. But they can subtly alter the rules making it harder for others to win while preserving their own position. If they can gain from it, players with this potential influence would be naturally tempted to use it to their advantage. An example would be demanding higher expected rewards to play.

D.21 Extending the analogy a little further, the introduction of forward contracting would be similar to declaring all of the rules before the cards are dealt in each hand. This is because parties in the electricity market need to take a view about the future spot prices (and implicitly reveal it) when entering into forward contracts. Hence, greater trading of forward flexibility contracts is a way to address the market power concerns in the spot market.

D.22 In summary, the simulation analysis indicated:

(a) There is potential for generators with substantial flexible hydro bases to increase the volatility of volatility.

(b) Such an outcome could deter or raise entry costs for independent suppliers and retailers and therefore potentially lift average prices which would likely be beneficial for incumbents suppliers.

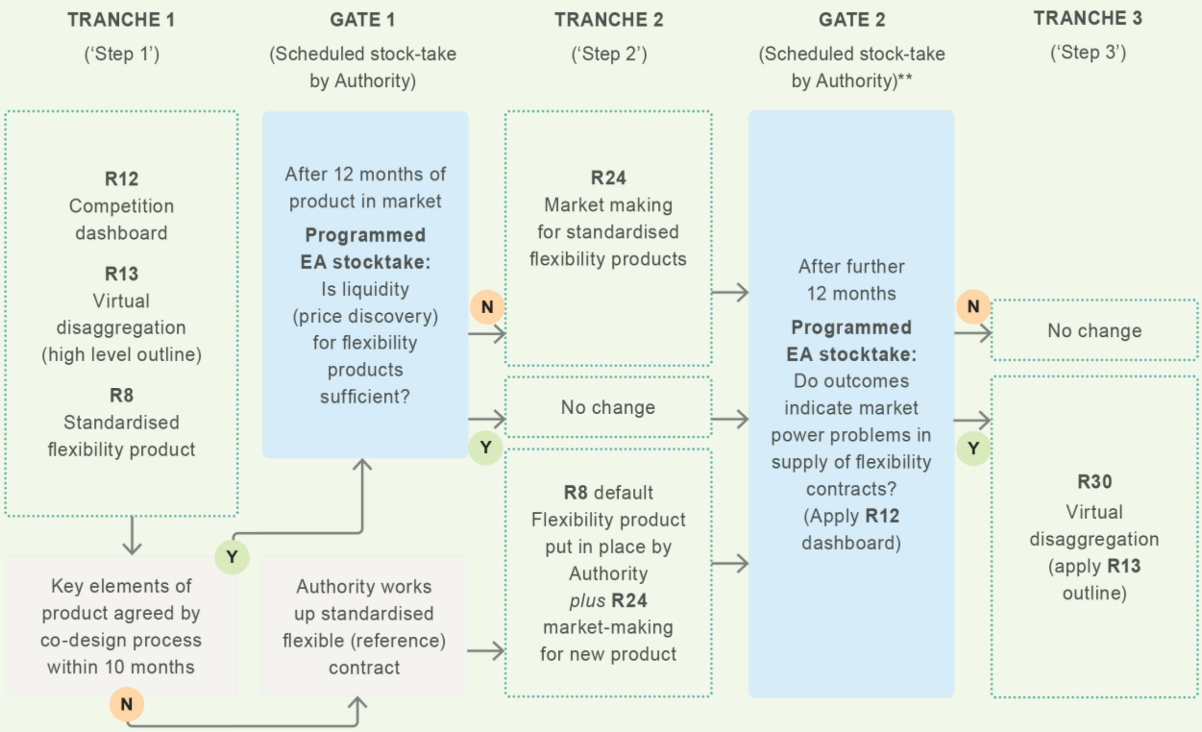
(c) The availability of longer-duration flexibility contracts on reasonable terms should be able to appreciably reduce the competition concerns in the spot market.

Graduated set of pro-competitive measures are recommended

D.23 As set out above, competition for supply of longer-duration flexibility in the spot market is expected to thin (at least for a period) as fossil-fuelled generation declines. Ideally, this thinning of competition will self-correct as new sources of flexibility enter the market. However, the strength and timing of such entry is far from certain. We also know that significant damage can occur in a short time in electricity markets if competition wanes.

D.24 Given these factors and the critical and growing importance of flexibility to the electricity system, we recommend the Authority pro-actively pursue a graduated set of measures to safeguard competition for flexible supply.

Figure 23: Progressive 'ratchet' steps for competition in supply of flexibility contracts



* **Other pro-competitive measures** (not shown) include improved information (Recommendations 1, 2, 3, 17), contract process disclosure (Recommendation 9), DSF (Recommendations 3, 4, 5, 8, 10, 11, 18, 19, 20) and stronger monitoring and enforcement (Recommendation 21).

** Competition stock-takes by Authority continue every 12 months.

D.25 The measures fall into three Tranches as set out in Figure 23. The Tranches are described more fully below. However, in brief, Tranche 1 measures should be pursued immediately. Tranche 2 and 3 measures are each more 'heavy duty' than their preceding measures. Decisions on whether and when these second and third Tranches are adopted should be made by the Authority at the appropriate 'gate', based on an assessment of milestones and competition indicators (see further below).

D.26 This progressive structure reflects our preference for first pursuing measures that have lower risks of unexpected adverse consequences. However, the progressive structure and pre-defined gates also recognises that 'heavy duty' measures may be required.

D.27 Finally, we think that by laying out the full progression of potential measures, there is a greater likelihood that industry stakeholders will engage constructively with the Authority on the earlier Tranches.

Tranche 1 – Design and use of standardised flexibility contract(s)

D.28 The central measure in Tranche 1 is the design and use of standardised flexibility contracts (aka flexibility products). In Appendix B we described a range of possible candidates to consider as standard products and outlined our thinking about how to best undertake the necessary further development work. Readers should refer to that appendix for a fuller description.

D.29 In brief, we think there are candidate products with attractive properties. For example, the 'super-peak' contract has some properties that make it potentially attractive as an initial product. We think the full range of products should be explored and the best contender(s) developed via an industry co-design process with sponsorship from the Authority. We also note our strong preference for the standardised flexibility contracts to be traded on a platform to promote price transparency.

D.30 The Authority should set clear policy goals and a timeline for completing the flexibility contract development work, with the expectation that if the timeline is not met, the Authority itself will develop a set of standard flexibility products and associated support arrangements (see Tranche 2 discussion below).

D.31 We think the industry participants should be motivated to develop a solution, given that they have the best information about the costs and benefits of different options. We acknowledge that commercial interests among parties will not be fully aligned creating a risk of slow or dead-locked progress.

D.32 However, the Authority (and other regulators) have successfully sponsored similar co-design exercises in the past. For example, we think the Telecommunication Carriers Forum's (TCF) process for developing codes covering non-price elements for competitive access to the 'monopoly' local telecom wires may be a useful point of reference.[253] Success in the TCF multilateral process relied (among other things) on wide participation of market participants, a rigorous analytical framework,[254] and a shared commitment to a disciplined process in which all participants understood that a co-designed common-good solution would better than the regulated alternative.[255]

D.33 We believe the development of standardised flexibility would mutually reinforce other measures to improve the electricity contract market, including *Recommendation 2* (hedge market transparency) and *Recommendation 9* (contract process disclosure rules).

D.34 Our view is that the around 10 months should be allowed for the industry co-design process. That should deliver products (and possibly a platform) for trading in late calendar 2024 (assuming the Authority endorses the recommendations in this report). We think a further 12 months should be allowed for trading to develop in the standardised flexibility products.

D.35 At the end of that 12-month period (i.e. late 2025) the Authority should assess progress and whether further pro-active measures are required at that point. We refer to this as Gate 1. This Gate 1 assessment should use the competition dashboard (*Recommendation 12*).

D.36 In the flexibility contracts space, indicators that the Authority should consider include:

253 In 2006/07, the TCF delivered a suite of significant agreements on non-pricing terms for access seekers using Telecom's local loop network. These TCF agreements were substantially reflected in the relevant Commerce Commission standard terms determinations (STDs) issued during 2007 and 2008. The role and framework of the industry's working groups are set out in sections 2 and 3 of this TCF report – see www.tcf.org.nz/news/2006-local-loop-unbundling-and-ndsl-phase-1-report. The government of the day backed the industry's process – see www.beehive.govt.nz/release/telco-forum-praised-llu-agreement.

254 With clearly defined objectives and criteria focused on efficient outcomes for the long-term benefit of consumers.

255 In the TCF process, the Commerce Commission had the power to prescribe an access code.

(a) The availability and pricing of standardised flexibility products;

(b) The availability and pricing of non-standardised flexibility products – such as ‘sleeves’[256] or other firming contracts;

(c) The extent to which independent generators and retailers are able to access flexibility products on reasonable terms from the market; and

(d) The extent of actual or planned entry or exit by providers of flexibility – such as biofueled generators or demand response providers.

D.37 Finally, we note that if the co-design process for flexibility products did not yield a successful outcome, that would bring forward the Gate 1 assessment into (roughly) late 2024.

D.38 Irrespective of the timing of the Gate 1 assessment, the Authority should use that process to determine whether and when the Tranche 2 measures are required.

D.39 Other measures in Tranche 1 are:

(a) **Virtual disaggregation – high level outline** (*Recommendation 13*) – The Authority develops high level outline of ‘virtual disaggregation’ (*Recommendation 31*), to ‘put in draw’ ready for use if other measures are not effective. If a structural solution is ultimately required to address competition problems in flexibility services, it should be put in place with the least possible delay. That means some initial scoping work in Tranche 1 as a precautionary step, even if it turns out structural options were not ultimately needed.

(b) **Monitoring and enforcement of Code** (*Recommendation 21*) – Authority to increase resourcing for its monitoring activity, as well as making its monitoring function more independent from its rule-making function by establishing a monitoring and enforcement ‘unit’ within the Authority. This is described further in Chapter 9.

Tranche 2 – Facilitate trading and price discovery for standardised flexibility contract(s)

D.40 Tranche 2 consists of measures designed to establish the trading of standardised flexibility products (if that has not already occurred), and/or to further facilitate that trading (if it has been established but further support is judged to have net benefits).

D.41 As noted above, we are cautiously optimistic that the trading of standardised flexibility products can be established under the auspices of an industry co-design process. However, were that process to be unsuccessful the Authority would need to take a more active hand. In practical terms, it would need to finalise the design of standardised flexibility contract(s) and associated arrangements (such as a platform). We expect the Authority would not be working from a zero base, as the industry co-design process would likely have yielded some useful outputs. Nevertheless, the Authority would need to assume the mantle of designer – albeit with input from stakeholders and other sources as required.

D.42 Another action that the Authority would need to consider in Tranche 2 is how and whether to facilitate trading and forward price discovery for the standardised flexibility contracts. This would definitely arise if the industry co-design process was not successful but could also arise if there is insufficient trading in co-designed products to generate reasonable forward discovery about the expected structure of spot prices.

256 These are products that absorb the differences between an intermittent generation profile and a customers demand profile.

D.43 If additional measures are judged desirable to strengthen trading activity, an obvious contender would be some form of market-making in standardised flexibility contracts. Considerable knowledge and experience have been gained about market-making for baseload contracts over the last decade, and we expect that much of that knowledge would be applicable for standardised flexibility contracts.

D.44 Having said that, a cookie cutter approach would not necessarily be appropriate. The Authority would need to make decisions on a range of issues including:

(a) What time horizon would be covered by market made products (i.e. how many years ahead)? This may or may not be the same as for baseload contracts.

(b) What maximum bid/ask spread would be permitted, noting that this would affect the quality of forward price discovery and hedging effectiveness for flexibility products?

(c) What volume of products would be market-made each period (i.e. what are the initial volume and refresh requirements)? This would affect the market depth and availability of market-made contracts.

(d) What safeguards would apply for market making (e.g. fast-market rules)? This would affect the risks to which market makers and others are exposed.

(e) How would market-making be established (e.g. procured or mandated or a hybrid approach)? This would obviously be an important issue for market-makers and other participants.

D.45 More generally, there may be other additional (or alternative) steps that the Authority could take to facilitate the trading and forward price discovery for flexibility contracts if that is judged to be desirable. For example, it might be the case that modifying the form of the standardised flexibility contracts, or modifying the trading platform, could broaden the number of trading participants and improve forward price discovery and liquidity.

D.46 Similar types of changes have occurred over time with the trading of baseload contracts (such as the reduction in minimum volume size). Judgements about these kinds of issues would need to be considered at the time Tranche 2 decisions are being made.

Tranche 3 – Backstop competition measures

D.47 We think it likely that a combination of industry co-design activities and (if necessary) Code-based support measures should be sufficient to ensure adequate competition for flexibility contracts. However, there is a chance that these actions may not be sufficient and that a competition backstop could be required.

D.48 If such a backstop option is needed, it will likely be due to very high concentration of control of flexibility resources in the hands of very few parties, with little or no prospect that new entry or other market processes will alter that market structure in an acceptable timeframe. Put simply, it is possible that supplier concentration for longer-duration flexibility could be so great that market-making (and other tools in Tranche 2) are insufficient to address the underlying structural market power. In that case, it would be necessary to consider structural solutions to reduce that market power at its source.

Physical break-up not recommended as backstop tool

D.49 If structural options are required, this raises the question of whether ownership transfers of physical generation assets, or ownership separation between generation and retail activities should be pursued. Our view is that neither of these approaches would address the key area of concern – which is the concentration of control of *flexible supply resources*.

D.50 Dealing first with transfer of ownership of physical generation assets, that tool was used successfully to strengthen competition in 1996 when Contact was separated from ECNZ, and again in 1999 with the three-way physical split of ECNZ. Options for further transfers of physical generation assets were looked at in 2009.[257] One key challenge identified in that work was the potential for coordination inefficiencies to arise if management of closely related hydro stations on single river chains was split between multiple parties. That work ultimately led to the transfer of the Tekapo A and B stations from Meridian to Genesis.

D.51 As matters stand, there are few opportunities for further physical disaggregation of the New Zealand's hydro generation base without splitting ownership of closely related stations on river chains. Such splits could lead to coordination inefficiencies.[258] More importantly, splitting assets on the same river chain would not address the root issue, which is the concentration of market power in relation the main source of storage on the river chain.

D.52 In other words, some disaggregation of the rights to longer term storage in major hydro schemes would be required. However, there is no feasible way to partition storage in physical terms. Put simply, given that the storage within each scheme is largely held in one upstream reservoir, providing for separate ownership of downstream stations would not appreciably increase competition for the supply of flexibility. For this reason, ownership transfer of physical generation assets is not viewed as a viable or effective structural solution to improve competition for flexible supply.

D.53 We have also considered whether a retail-generation split would improve competition for flexible supply. The short answer is no, because the source of the market power (i.e. a concentration of ownership for flexible supply assets) would be unchanged by such a split.

Virtual disaggregation is preferred backstop tool

D.54 If a structural measure is required, we propose that virtual disaggregation should be utilised as the tool to reduce market power at its source. In this context, virtual disaggregation refers to the splitting of the flexible supply capability of the relevant participant(s) into two components:

(a) A portion that would be required to be offered by a defined process and on approved terms – effectively creating one or more additional sources for the supply of longer duration flexibility products.

(b) The balance of the relevant participant's supply capability would remain available to them to use as they think fit.

D.55 Virtual disaggregation measures would be applied only to the participant(s) assessed as having undue market power in the relevant market segment. Virtual disaggregation could also be expressed as a mandatory offer requirement for flexibility contracts.

257 The study was undertaken by the Electricity Technical Advisory Group, which reported to the Minister of Energy and Resources in 2009. Appendix 15 describes a range of options that were considered. See www.beehive.govt.nz/release/electricity-review-released.

258 The same type of challenge is the reason that some stations are combined into groups for dispatch purposes under the 'block dispatch' provisions of the Code.

D.56 Some parties might regard it as premature to consider backstop options. We think a wait and see approach would be unwise for a number of reasons. First, it will take time to design backstop options and put them in place. Waiting for a problem to fully emerge before starting that work could mean that an extended harm occurs before a solution is in place. Second, it could lead to hasty and sub-optimal solutions being implemented if a problem emerges. Third, confidence in competition is a foundational ‘must have’ element for an electricity market. If that confidence is not present, parties will be unlikely to invest at the pace needed to provide reliable and affordable power and there is a continual risk of government intervention.

D.57 Given these factors, we recommend (as noted above) that preliminary work should be undertaken on a backstop measure to ensure it can be adopted in a timely way if required, and that it is well designed. That does not mean the measure needs to be developed in full. Indeed, that would not be wise given the resource constraints and other priorities. However, sufficient work should be undertaken to ensure viability and effectiveness.

D.58 In the following sections, we describe some of the important areas that would need to be considered in a preliminary design phase, and set out our own preliminary views on key issues.

Decision maker

D.59 A key threshold question is which organisation should determine the design of a backstop competition measure. Our view is that it should be the Electricity Authority because it is an independent regulator and is the organisation with the most relevant expertise. A further reason is that the backstop measure should ideally align closely with other measures under the Authority’s control.

D.60 A possible alternative to the Authority is the Commerce Commission. While the Commerce Commission is also an independent regulator and has extensive competition experience and expertise, we think the particular requirements of the wholesale market make the Electricity Authority the preferable option. This would not preclude the Electricity Authority from conferring with the Commerce Commission. Indeed that would be sensible. However, ultimately one organisation needs to be accountable for design and implementation decisions and we think factors point strongly toward the Authority being the more appropriate body.

D.61 We do not favour a model where detailed design or implementation decisions would be made by Ministers. This is because the backstop measure is by nature a regulatory instrument, and to ensure robust and neutral decision-making an independent regulatory body is strongly preferred.

D.62 Finally, we have not assessed whether the Authority has the requisite powers under the Electricity Industry Act to make Code to implement a backstop measure of the type described below. If existing powers are not sufficient, that should be addressed in a timely way.

Form of regulated contracts

D.63 As noted above, under the backstop mechanism certain participants would be required to offer a portion of their capacity via flexibility contracts whose terms (minimum volumes, prices etc) would be regulated, thereby creating one or more additional sources of supply for longer duration flexibility products.

D.64 The form of the contracts would obviously be a key issue. Our view is that these contracts should be designed to facilitate the broader development of trading and price discovery for flexibility contracts as far as possible, rather than being ‘off to the side’ – i.e. a regulated instrument that is highly bespoke.

D.65 This suggests that the regulated contracts should adopt a standardised financial contract form and cover a period of (say) one calendar quarter. A range of possible starter candidates for the contract type are set out in Appendix B.

D.66 An important consideration for the design will be balancing the needs of purchasers and sellers. In particular, we think it unlikely that conventional caps would be the preferred instrument. While they provide the fullest protection for buyers, they are likely to be expensive and consume a lot of risk capacity for each unit sold. For that reason they would be likely to unduly sterilise available risk capacity in the wider market. Instead, some form of energy-limited instrument is likely to be preferred, as outlined in Appendix B.

D.67 Another consideration in the design of contracts is that it would be desirable for them to qualify as prudential security for purchases from the clearing manager in the electricity spot market – or at least be in a form that facilitates some indirect recognition of their prudential benefits.

D.68 More information would be available about design requirements and trade-offs at the time a decision on a backstop is made, and that should also inform the final design of the regulated contracts.

Offer / release mechanism

D.69 We envisage that relevant participants would be required to progressively offer contracts via some form of auction or tender mechanism. The auction/tender rules should be designed to promote robust price discovery. For example, it would be important to consider whether a single or multi-stage bid processes are used in each auction round.

D.70 The frequency of offers would need to strike a balance between providing timely price discovery and reducing transactions costs. Based on current information, a quarterly offer frequency could be a reasonable balance. However, a decision should be made at the time a design is finalised in light of then current information.

Pricing of regulated contracts

D.71 We envisage that prices for the regulated contracts would be set via the auction/tender process itself. However, there may be justification for a reserve price to limit the extent of financial risks for sellers. If any reserve prices were to apply, they should be set by the Authority rather than sellers, as reserve prices could otherwise be used as a means of withholding supply from the market.

Time horizon for contract offers

D.72 The time horizon for contract offers should reflect the goal of achieving better forward price discovery for operational and investment decisions, but not so far ahead that it creates practical difficulties for buyers and sellers. Experience from the ASX futures market and the financial transmission rights (FTR) may be useful in this respect.

D.73 Based on current information, we envisage a time horizon of around 3-4 years would be reasonable, noting that final decisions should be made in light of the best available prevailing information.

Management of credit risk issues

D.74 Parties to contracts formed via the regulated offer mechanism will be reliant on the performance of their counterparties. This raises the issue of how creditworthiness issues should be addressed. This issue is also linked to the type of contract being sold. For example, if the contract is swap-based (e.g. a super-peak contract), then buyer and seller each face counterparty risks. Conversely, if the contract is in form of an energy-limited cap, the creditworthiness of buyers is much less of an issue because the contract will never be out of the money.

D.75 More generally, in relation to seller creditworthiness, this is likely to be relatively high given that only parties with substantial market power (and hence asset bases) are likely to fall within the offering obligation. Nonetheless, it would be important to consider how default risk is managed for these parties as their financial structure will affect their credit profile.

D.76 For buyers, the significance of credit risk would depend in part on the type(s) of contracts being offered. If the contract type did expose sellers to default risk by buyers, then some credit arrangements would need to apply. The design of those arrangements must balance the need to ensure contract obligations can be performed, while also avoiding credit standards becoming an undue barrier for participation in contract auctions by buyers.

D.77 While the issue is likely to have some complexities, it is not new and is encountered routinely in the existing over-the-counter market. We expect that experience from that market could be drawn upon to determine how this issue should be best managed for regulated contract offers.

Obligation to make offers limited to certain participants

D.78 If the mechanism is introduced, there is the question about which parties should be required to make contracts available via the offer mechanism. As with the threshold decision to introduce the mechanism, there should be close alignment with the problem definition – e.g. mechanism should only apply to those parties with undue market power in the provision of longer-duration flexibility.

D.79 Issues that the Authority would need to consider include:

(a) Would the assessment of market power be gross or net of existing contracts/commitments?

(b) What notice period would apply before a party became subject to a contract offer obligation (to avoid undue disruption or ‘sterilisation’ of contracting capacity)?

(c) Would the contract offer obligation vary between parties, and if so, how?

Commencement/termination arrangements for backstop contractual offer mechanism

D.80 The proposed backstop measure would by its nature be relatively intrusive. To minimise dynamic efficiency risks (e.g. chilling investment incentives) the commencement test/trigger should be as clear as possible beforehand (noting some judgment will inevitably be necessary).

D.81 The commencement test/trigger should be closely aligned with the problem definition regarding competition for flexible supply and would desirably link to the competition dashboard proposed in *Recommendation 12*.

D.82 Potential competition indicators to consider in the design of test/trigger include:

(a) Availability of flexibility contracts from incumbent suppliers with significant market power (e.g. is there any evidence of withholding supply).

(b) Trends in forward pricing of longer duration flexibility contracts.

(c) The degree to which competition in new generation and retail markets is being affected by the availability/pricing of flexibility contracts.

D.83 Maintaining a tight linkage between commencement test/trigger and competition concerns should:

(a) Increase likelihood of participants seriously engaging with the Tranche 1 and 2 measures.

(b) Facilitate smooth transition to a backstop mechanism if it is required.

D.84 Similarly, suspension/termination triggers should also be specified in advance, given that the need for the backstop measure may fall away over time, for example if entry of new flexibility sources alleviated the concerns about undue market concentration. Upon suspension or termination, there would no longer be a requirement on the specified participants to make further regulated offers of flexibility contracts. Existing contracts that had already been executed would run until their expiry.

Appendix E Future Security and Resilience Project - Guiding Principles

E.1 *Recommendation 14* is that the Authority should incorporate a set of guiding principles into the terms of reference for its Future Security and Resilience (FSR) project. This appendix sets out a recommended set of guiding principles.

Proposed guiding principles

E.2 The following principles are proposed to guide the development of proposals by the FSR project:

(a) Take a first-principles approach to enabling the participation of new generating technologies in the wholesale market over the medium to longer term – MDAG considers this would better promote efficiency and long-term consumer benefits, compared with an ad-hoc, piecemeal approach which would (i) be likely to raise significant barriers to having a coherent, effective Code over time and (ii) raise the risk of inefficient investment decisions in new generating technologies (due to a lack of information for stakeholders on expected changes to regulatory settings).

(b) **Create a durable framework that allows efficient adaptation** – the framework should be durable across a range of uncertain future scenarios, while allowing efficient evolution of rules to enable better ways of achieving required outputs.

(c) **Favour arrangements that are technology-neutral to foster competitive neutrality** – define services in terms of required outputs and remain neutral as to which technology can deliver the required output in the most economically and technically efficient manner. Set a ‘level playing field’ from a competition standpoint – that is to say, market arrangements should not ‘pick winners’ or give some technologies special treatment relative to others. For example, don't give a competitive advantage in the Code to a generating plant based on technology, size or connection type.

(d) **Encourage competitive solutions** – recognise the importance of fostering and capturing the benefits of innovation over time, which means encouraging competition on an on-going basis to provide services across the spectrum. Also recognise the benefits of market-based arrangements, making fully transparent the cost of providing/using energy services and ancillary services.

(e) **Signal the full costs and benefits of potential solutions to participants** – signalling marginal costs is crucial to foster competition and innovation with the marginal cost serving as the price to beat for alternative solutions.

(f) **Prioritise** – effort should be directed towards issues with greatest expected benefit to consumers, while also taking account of lead times to achieve results.

Appendix F Options not recommended

F.1 Table 6 lists measures raised in the Options Paper that we recommend not be taken forward at this time. The name of each option links to where this was discussed in the Options Paper.

F.2 Most are measures that were included in the Options Paper for completeness but were not proposed for further work. A few are measures where our views have changed in light of submissions or further analysis. These are Option A5 and Option B7/D4 (which were previously supported) and Option C3 (which was previously partially supported as a backup option), which are now not recommended. The table also summarises the key reasons for our final recommendation on each measure.

Table 6: Measures not recommended for further action

OPTION PAPER CODE	OPTION NAME	RATIONALE
A5	Offer price reductions after gate closure	Some resources are ill-suited to operating at partial output because of physical inflexibilities – such as some gas turbines and demand response. To avoid being on the margin (where partial output could be required), such resources typically offer/bid at low prices to ensure they are fully dispatched if forecast prices indicate utilisation will be desirable or offer/bid at high prices if forecast prices indicate their utilisation will not be desirable. Because they cannot change their offer/bid prices within one hour of real time (called gate closure) they are exposed to unexpected differences between forecast and actual spot prices. One consequence of these factors is that resources may sometimes be willing to operate to reduce spot prices but cannot signal that because their offer/bid was locked down by gate closure. To address this issue the Options Paper suggested parties be allowed to reduce their offer price if they have been dispatched on the margin. This would allow resource providers ill-suited to marginal operation to bid their true reservation prices at gate closure, in the knowledge they can be revised downward if dispatched on the margin. Having considered submissions, we now think this proposal should not be progressed. The key reason is that allowing marginal resources to change offers/bids after gate closure will increase uncertainty about system operation, as offer/bid changes of marginal plant could alter dispatch and power flow patterns, potentially resulting in unanticipated binding constraints on the grid closer to real time or overloads in real time for which no constraint was created. Allowing marginal plant to re-offer/bid could make another resource marginal which might also be averse to being on the margin, resulting in multiple offer changes further increasing uncertainty of real time dispatch conditions. We consider the Recommendations 6 and (potentially) 27 are better ways to address the inflexibility of some resources without increasing uncertainty closer to real time that may compromise system security.[259]
A9	Centralised commitment based on complex offers	Centralised commitment offers potential benefits for optimising the operation of some resources (e.g. slow-start generation or demand response) across trading intervals. However, the size of the benefit is uncertain and centralised commitment would be complex and resource intensive to introduce. It may also favour better-resourced parties (e.g. larger generators) relative to consumers and new entrant suppliers because of the greater complexity of market processes and pricing. We think it is preferable to focus on other solutions to support efficient commitment decisions including Recommendations 1, 6, 7, and 16.
A10	Warming contracts	Warming contracts are likely to weaken participants' own incentive to enter into forward contracts (i.e. self-insure). As a result, warming contracts would be unlikely to increase reliability. Furthermore, a procurer (e.g. the System Operator or Authority) of warming contracts may face difficulty in obtaining competitive prices if it is required to enter into such contracts.

259 See Transpower submission on Options Paper.

		Rather than seeking to treat symptoms, we think reliability concerns are better addressed by working on underlying causes (i.e. information and incentive gaps) via Recommendations 1, 6, 7, 16 and 17.
B7 D4	Extend trading conduct rules to hedge market	The trading conduct provisions in the Code require spot market participants to make offers that are consistent with those expected from a party if no parties had significant market power. Our Options Paper proposed extending these obligations to parties participating in the hedge market. After considering submissions on this proposal and further analysis, we no longer favour this measure. In particular, we consider that it could (in effect) place the Rulings Panel in the position of regulating the prices for certain contracts.[260] Our view is that there are better ways to address competition concerns in the contract market as described in Appendix D. As such, we are not recommending the Authority pursue this option further.
B9	Capacity mechanism	International experience indicates that capacity mechanisms (CMs) are likely to raise costs due to an inherent bias toward over-investment. In addition, CMs require a high degree of prescription and are not well-suited to renewables-based systems. Designing and adopting a CM would be costly and take 3-4 years and would likely impede investment in the intervening period. We think it is better to address information and incentive gaps at their source, including via Recommendations 1, 6, 7, 16 and 17. As the European Commission noted in November 2016, parties should first seek to "address their resource adequacy concerns through market reforms [..] no capacity mechanism should be a substitute for market reforms".[261]
B10	Strategic reserve	Previous experience in New Zealand and overseas shows it is very hard to get a strategic reserve to work as intended. There is a high likelihood it will not improve reliability because the presence of reserve resources tends to defer investment in alternative resources. Furthermore, reserves may raise costs because they operate outside the full competitive discipline of the normal market. Rather than seeking to treat symptoms, we think reliability concerns are better addressed by working on underlying causes (i.e. information and incentive gaps) via Recommendations 1, 6, 7, 16 and 17.
C3	Require retailers to offer DSF tariffs	This option would see the Electricity Authority introduce mandatory requirements that retailers and flexibility aggregators develop tariffs that reward DSF. In the Options paper, MDAG proposed that this option be retained in the event that the uptake of DSF was deemed to be insufficient. It was not a preferred option, but a backup option. A number of submitters argued against this option, for a variety of reasons. The most compelling reason was that this measure would be largely ineffective, due to a number of definitional issues. MDAG had raised this risk in the Options paper. The fact that, today, many retailers have tariffs that reward flexibility (even through simple TOU-based tariffs) means that there is a high chance that most flexibility intermediaries would be compliant with any pragmatic mandate before it came into effect. On the other hand, complexities and inefficiencies would inevitably arise in formulating the rules and assessing whether parties have complied. Further, if the mere availability of tariffs was deemed insufficient, there would be the obvious temptation to mandate aspects of the price structures, leading to a risk of creep toward shadow price regulation, when more pro-competitive measures are available as a better avenue of regulatory policy. Hence MDAG no longer believes this is a useful backstop measure.
C6	Use Customer Compensation Scheme to reward DSF	The Customer Compensation Scheme (CCS) requires retailers to make payments to qualifying customers during an Official Conservation Campaign, but these payments to not provide material incentives for consumers to reduce consumption. This could be amended to require retailers to reward customers for consumption reductions during such periods. There are a range of complexity concerns that would arise from this measure, particularly in relation to baselining, as the measure would be similar to a nega-watt scheme and face similar challenges (see discussion on Option C7 below). As such, we consider that unless strong evidence emerges that the market is incapable of evolving tariffs which achieve the same outcome as this kind of measure, we do not recommend using the CCS to reward DSF.

260 Meridian noted that this measure "would not be a simple undertaking" and identified several aspects of the design of this measure that would need to be carefully considered, including how it would differ from the new section 36 of the Commerce Act.

261 See www.eumonitor.eu/9353000/1/j4nvirkkkr58fyw_j9vvik7m1c3gyxp/vk9q8ejzirzx.

C7	Negawatt scheme for wholesale market	The primary arguments advanced for pursuing the design of a wholesale demand response mechanism, like that in the NEM,[262] is that market-driven DSF is not likely to develop sufficiently for the following reasons: i. it will remain stunted by generator-retailers' conflicting incentives to sell their generation, rather than reward DSF ii. without the additional payment provided by a nega-watt type scheme – that is, a payment at the wholesale price for the electricity not consumed – potential DSF suppliers (particularly commercial and industrial consumers) are unlikely to find investing in load shifting or obtaining energy supply from an alternative source commercially attractive. As a result, it is argued, insufficient DSF will come to market. Proponents also argue that such schemes can: iii. incentivise DSF to be formally bid into the System Operator (e.g. via dispatch notification), thus improving market forecasts and limiting the need for additional ancillary services (e.g. frequency keeping) that respond to dispatch uncertainty iv. provide an explicit role for flexibility aggregators who are not also retailers – thus solving a potential market access problem for flexibility traders who rely on retailers sharing the benefits from the traders' deployment of flexibility. While they could be solved through an administered wholesale demand response mechanism, reasons (ii) and (iii) can be solved independently of such a mechanism. The incentives to participate in demand-side bidding is considered in Recommendation 11. The issue of market access for flexibility aggregators who are not retailers is briefly discussed below. So, in essence, the case for an administered mechanism is that the market will not develop sufficient DSF at an adequate pace. **MDAG's reasoning** MDAG's does not favour an administered demand response payment scheme (Option C7), but rather recommends activating market-driven DSF. As outlined from page 43 of our Library of Options, some markets internationally have developed administered demand response payment mechanisms that attempt to 'correct' for the neutering effect of FPVV tariffs on efficient, wholesale-triggered demand response. Regulators introducing these mechanisms have acknowledged that market-driven tariffs, developed by market participants who face the wholesale price, are the ideal route. This has been endorsed by one of the most advanced electricity markets in the world, PJM, and by its market monitor.[263] Despite this, administered demand response schemes were introduced primarily due to frustration that retailers were not developing tariffs that rewarded wholesale demand response. The perception was that the market was unlikely to evolve away from widespread FPVV towards a dynamic that reflected consumers' willingness to provide response (either themselves, or by assigning control rights to an intermediary). MDAG's conclusion to not pursue an administered wholesale mechanism to reward demand response was based on several factors, including: • There is likely to be a significant regulatory cost, complexity and risk in designing and implementing the mechanism in a way that integrates with New Zealand's electricity market design; • The extent to which generator-retailers' incentives to deploy DSF are muted has not been quantified, and logic would suggest these incentives are still present in a range of situations; • The aspiration to reach a particular level of DSF, deemed to be 'sufficient', is misplaced – MDAG's objective is not to achieve a pre-determined level but rather to enable a process of competition where the most efficient resource is used; • Such mechanisms are not equivalent to typical market instruments (e.g. full spot exposure, or CfDs) and – at best – approximate wholesale incentives for DSF. They can inefficiently

262 Described in more detail in the appendix to the Options Paper, Overview of Australian Wholesale Demand Response Mechanism (WDRM).

263 "Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation." Monitoring Analytics, Section 6, 2021 *State of the market report for PJM,* p331.

incentivise DSF, can be gamed, and thus risk inefficient deployment of DSF[264] and lower the liquidity of tradeable market instruments;

- In particular, the 'additional payment' under a nega-watt type scheme – that is, a payment at the wholesale price for the electricity not consumed – amounts to a distortion. It provides the 'benefits' of reduced demand in high price periods as if it were a CfD arrangement, but not the downsides of a CfD contract (i.e. payments back to the counterparty during low price periods, or the spot cost of increased consumption over the contract level). Rather the negawatt consumer switches to a FPVV arrangement;[265]
- At the time of the Options paper, there was no evidence that the retail market was blocking the development of tariffs which reward DSF, as had been the case in other jurisdictions
- There is a view that lower cost mechanisms to encourage the development and uptake of market-based DSF tariffs should be pursued first (Options C2, C4, C5, C13 and C14), and progress monitored closely (Option C1).

Appendix A of this paper sets out a range of reasons why there has been little development of DSF-rewarding tariffs in New Zealand, not least that there had been relatively low short-term market volatility in New Zealand's hydro-based system compared to other thermal-based markets. MDAG's modelling suggests that a continued trend to higher renewables would increase market volatility compared to this historical period – indeed, the period 2019-2022 illustrated this.

At the time of writing our Options Paper, we were aware of retailers beginning to release tariffs that incentivised flexibility. Since that time, mass-market DSF-rewarding tariffs have continued to emerge in New Zealand,[266] and we are aware of a range of mechanisms being agreed between retailers and large consumers to reward DSF that will be triggered by the wholesale price. We understand that a number of retailers are also developing 'managed service' offerings encompassing EV charging and hot-water heating,[267] to manage both energy price volatility and TOU distribution charges.

In this context, the development of an administered scheme – with attendant rules around participant eligibility, baselining, and how payments are shared and funded – would raise questions about how it would apply to wholesale DSF tariffs that had emerged and been agreed with consumers.[268] Potentially worse, it could stall further market-based development of DSF tariffs while participants waited for the final design of such a scheme to be agreed. This is an important consideration, given the likely time it will take to develop meaningful levels of DSF under almost any scenario.[269]

Finally, both the AEMC[270] and jurisdictions in the US have expressed the expectation that administered wholesale DR mechanisms will be transitory, to be removed when more sophisticated retail tariffs were available. PJM has endorsed this preferred long-term market-driven direction, as has its market monitor:

> *"The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they*

264 This is particularly true of demand shifting. A fully spot exposed consumer would use storage to shift demand from a high-price period to a low-price period – essentially, the payoff is the difference between the two wholesale prices (adjusted for any efficiency losses incurred in shifting demand). Under a demand response mechanism, the consumer is rewarded by the difference between the high price (in the period of response) and the FPVV tariff in the period when the demand is recovered. In any situation where the wholesale price is higher than the FPVV tariff in the period of demand recovery, the consumer is over-rewarded compared to the spot-exposed customer.

265 This distortion is even more significant where the customer has agreed a FPVV arrangement such as that highlighted as option (d) in the Appendix A text box 'What could dynamic pricing arrangements look like in New Zealand?', where the retailer is assigned the ability to request demand response during high price periods, and the FPVV rate has been lowered to recognise this.

266 See from paragraph 8.10 of the Authority's Targeted Reform of Distribution Pricing issues paper (www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf).

267 See octopusenergy.nz/blog/hacking-hot-water-to-save-money, octopusenergy.nz/intelligent-octopus, and www.electrickiwi.co.nz/blog/this-is-how-you-can-lower-your-power-bill-by-saving-on-water-heating/.

268 For example, would consumers who had already agreed a DSF-rewarding tariff be ineligible? Would the nature of baselining in their tariffs have to adopt the scheme's standard?

269 We note the low uptake of demand response resources after two years of the Australian WDRM. We do not believe this is evidence that the scheme has failed; rather it simply reflects the time it takes for market participants to adapt systems and practices to the new arrangements, and for consumers to become aware of the scheme.

270 See paragraph 4.103 of our Library of Options.

		wish, accounting for market prices in any way they like, and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification." [271] , but has also expressed the concern that – even as those market-based tariffs emerge – it is likely that 'unpicking' the administered schemes from market-based arrangements will be complex.[272] We also note there is a risk of regulatory creep around all parameters required for an administered scheme, and we understand this is beginning to be observed in Australia. In summary, MDAG's view is that market-driven DSF tariffs are most likely to lead to economically efficient and sustainable provision of DSF in the electricity system, and that the costs, complexity and risks associated with introducing a new administered demand response scheme in New Zealand are not warranted at this stage. **Market access for flexibility traders who aren't retailers** Non-retailer flexibility aggregators could be an important part of the overall DSF 'ecosystem', especially since their sole business focus will be on the efficient deployment of flexibility. We expect that a flourishing market for DSF would have a mix of consumer-driven, retailer-driven and aggregator-driven flexibility services. However, we recognise that in order to earn revenue, flexibility traders need access to the benefit stream that results from the use of demand response – which is either savings by the customer (via the retail tariff or direct spot exposure), or savings by the retailer. In their submission to the MDAG Options Paper, Contact argued that: "*Currently a flexibility trader must establish an agreement with the customer's energy retailer to gain access to the DSF value (given the direct beneficiary of the DSF accrues to the retailer through reduced wholesale energy purchase costs). Reaching these agreements can be challenging. Our experience aligns with that described in Australia where the AEMC found that "there are commercial barriers to developing the required partnerships between retailers and demand response providers". For example, the retailer may not want the hassle of dealing with a flexibility trader, they may see little value in flexibility because the risks are already managed by their hedging strategy, or they may consider the flex trader to be a competitor to their own retailer or energy services business. In cases where retailers have entertained an agreement they have looked to retain a significant portion of the DSF value leaving little to share with the customer or fund the DSF setup and systems."* The reasons put forward by Contact span transaction costs, the generator-retailer issue outlined above, and the nature of competition. In terms of competition, if the flex trader is also a retailer, whether there is a market access issue requires a distinction between the normal workings of competition, and the existence of some unfair advantage afforded to the customer's incumbent retailer. We note that other regulators are developing frameworks that would make it easier for aggregators/traders to enter the market.[273] We recommend that the Authority proceed with such an analysis, independently of an administered demand response mechanism.
C9	FSR - accelerate new ancillary services for DSF uptake	Accelerating the introduction of new ancillary services through the FSR process could improve value stacking opportunities for DSF, and thus lead to faster DSF uptake. However, we are not convinced that there are net benefits to accelerating the design of these products ahead of their need. The value of DSF to ancillary services is currently small compared to its value to the wholesale market and network investment.[274] While the value of DSF to ancillary services may increase in the future, we recommend prioritising other aspects of the FSR workstream, such as the efficient access of DSF to existing ancillary markets (i.e. as part of Recommendation 11).
D6	Physical disaggregation of flexible generation base	Physical disaggregation would likely cause river chain coordination inefficiencies raising costs. In addition, much of the flexibility is associated with storage, and physical disaggregation of storage

271 Monitoring Analytics (2022), "State of the market report for PJM", Chapter 6, p337.

272 See paragraph 4.104 of our Library of Options.

273 In Europe, ACER (who MDAG engaged with extensively as part of the Options paper development) argued for "a framework for the role of aggregators in the system. While the precise role of aggregators would be defined separately by each Member State, the proposals ensure that contracts between customers and aggregators can be made without the consent of the customer's retailer, and can be terminated within three weeks at the request of the customer. Aggregators can enter the market without consent from other market participants and will not be required to compensate suppliers or generators, except in situations where they cause imbalances to another market participant resulting in a financial cost."

274 Reeve, Stevenson and Comendant (2021), "Cost-benefit analysis of distributed energy resources in New Zealand".

		is not feasible. For this reason, contractual (aka virtual disaggregation) is preferred if structural solutions are required – see Recommendations 13 and 31 and Appendix D..
D8	Price caps applied in the electricity spot market	Spot market price caps have a significant risk of chilling investment (e.g. in batteries) and causing coordination difficulties. Other New Zealand reviews have also identified risks with spot price caps, such as the Commerce Commission investigation in 2009.[275] We think it is preferable to work on measures to strengthen competition via Recommendations such as 2, 8, 13, 17, and 31.

OPTION PAPER SUPPORTED MEASURE OPTION PAPER PARTIALLY SUPPORTED MEASURE OPTION PAPER DID NOT SUPPORT MEASURE

275 See Commerce Commission electricity investigation report; paragraph 659, 21 May 2009 (comcom.govt.nz/__data/assets/pdf_file/0025/219094/Electricity-investigation-Investigation-report-21-May-2009.PDF).

Appendix G Submissions on Options Paper

G.1 We received submissions on our Options Paper from the following stakeholders:

Table 7: List of submitters

CONSUMERS	DISTRIBUTORS /GRID OWNER	GENERATOR-RETAILERS	GENERATORS	RETAILERS	OTHER
• Consumer Advocacy Council (CAC) • Fonterra • Major Electricity Users' Group (MEUG) • NZ Steel	• Aurora Energy • Electra • Entrust • Orion • Transpower • Vector • WEL Networks	• Contact • Genesis • Mercury • Meridian • Nova	• Manawa • New Zealand Wind Energy Association (NZWEA) • SolarZero	• 2Degrees • Electricity Retailers' Association of New Zealand (ERANZ) • Flick • Haast and Independent Retailers • Octopus Energy (unofficial email submission)	• BusinessNZ Energy Council (BEC) • Enel X • Energy Resources Aotearoa (ERA) • Electric Power Optimization Centre (EPOC) • Jim Newfield • LMS Energy • Neil Walbran Consulting • NZX

G.2 We have benefited greatly from the number and quality of submissions on our Options Paper. We reviewed each submission thoroughly and thoughtfully, systematically noting each key point in our taxonomy of submissions.

G.3 A summary of submissions on our Issues Paper is also available here.

Appendix H Navigation tables

H.1 The tables below provide a guide to how option codes and names in our earlier Options Paper have been re-labelled and re-grouped in this paper.

Table 8: Navigation table (operational coordination options)

OPTIONS PAPER				RECOMMENDATIONS PAPER				
Topic	Code	Name	MDAG View	Code	Name	Location	Notes	Tranche
Reliable and efficient operational coordination	A1	Improve short-term forecasts of wind, solar and demand		R1	Short-term forecasts	Page 77		
	A2	Strengthen governance for next phase of FSR project		R14	FSR Project (Governance)	Page 96		1
	A3	Update shortage price values		R16	Scarcity pricing paramaters	Page 98	Renamed	2
	A4	New reserve product to cover sudden reduction from intermittent sources		R6	New reserve product	Page 85		1
	A5	Offer price reductions after gate closure		N/A	[Not recommended]		No longer recommended	N/A
	A6	Investigate + develop ahead market		R27	Ahead market	Page 111		3
	A7	Remove UTS over-ride of trading conduct provisions		R26	UTS over-ride	Page 110		3
	A8	Negative offers/prices		N/A	[Not recommended]			N/A
	A9	Centralised commitment based on complex offers		N/A	[Not recommended]			N/A
	A10	Warming contracts		N/A	[Not recommended]			N/A

SUPPORTED IN OPTIONS PAPER PARTIALLY SUPPORTED IN OPTIONS PAPER NOT SUPPORTED IN OPTIONS PAPER

Table 9: Navigation table (risk management options)

OPTIONS PAPER				RECOMMENDATIONS PAPER				
Topic	Code	Name	MDAG View	Code	Name	Location	Notes	Tranche
Effective risk management and efficient investment	B1	Greater transparency of hedge info (esp non-base load) covering offers, bids + agreed prices		R2	Hedge market transparency	Page 78		1
	B2	Market-making for longer dated futures (for price discovery)		R28	Market making for longer-dated futures	Page 112		3
	B3	Publish aggregated information on pipeline of new developments, energy and capacity adequacy		R17	Information on development pipeline	Page 99		2
	B4	Enhance stress testing regime		R7	Stress testing	Page 86		1
	B5	Develop standardised 'shape' product(s)		R8	New flexibility products (standardised)	Page 87	Combined with C4	1
	B6	Develop flexibility access code (non-price elements)		R9	Contract process disclosure rules	Page 89		1
	B7	Extend trading conduct rules to hedge market		N/A	[Not recommended]		No longer recommended	N/A
	B8	Market making in caps or other shaped products		R24	Market making for flexibility products	Page 108	Now recommended	2
	B9	Capacity mechanisms		N/A	[Not recommended]			N/A
	B10	Strategic reserve		N/A	[Not recommended]			N/A

SUPPORTED IN OPTIONS PAPER PARTIALLY SUPPORTED IN OPTIONS PAPER NOT SUPPORTED IN OPTIONS PAPER

Table 10: Navigation table (DSF options)

OPTIONS PAPER				RECOMMENDATIONS PAPER				
Topic	**Code**	**Name**	**MDAG View**	**Code**	**Name**	**Location**	**Notes**	**Tranche**
Lift demand side participation	C1	Monitor provision + uptake of DSF-rewarding tariffs (incl automation)		R3	DSF activity monitoring	Page 79		1
	C2	Sunset profiling if smart meters in place		R18	Sunset profiling	Page 100		2
	C3	Require retailers to offer DSF tariffs		N/A	[Not recommended]			N/A
	C4	Develop standardised shape-related hedge products to reward DSF		R8	New flexibility products (standardised)	Page 87	Combined wth B5	1
	C5	Provide significant funding for pilots/trials to kick-start dynamic tariff use		R10	DSF interface systems and protocols	Page 90		1
	C6	Use Customer Compensation Scheme to reward DSF		N/A	[Not recommended]			N/A
	C7	Negawatt scheme for wholesale market		N/A	[Not recommended]			N/A
	C8	FSR – improve DSF visibility and remove Code barriers		R11	FSR Project (as it relates to DSF)	Page 92		1
	C9	FSR – accelerate new ancillary services for DSF uptake		N/A	[Not recommended]			N/A
	C10	Procurement process for high-scarcity DSF (RERT)		R29	'Last resort' DSF scheme	Page 113		3
	C11	Ensure distribution pricing reflects network needs		R4	Pricing to optimise distribution investment	Page 81		1
	C12	Investigate extending LMP into distribution networks		R5	Price-driven secure distribution dispatch	Page 83	Split into two separate (amended) measures	1
					Network capacity in DSF dispatch	Page 83		2
	C13	Provide info to help large users with upcoming DSF investment decisions		R19	Network capacity in DSF dispatch	Page 101	Combined with C14	2
	C14	Provide info to help large users with upcoming DSF investment decisions		R20	Consumer awareness of DSF	Page 103	Combined with C14	2

SUPPORTED IN OPTIONS PAPER PARTIALLY SUPPORTED IN OPTIONS PAPER NOT SUPPORTED IN OPTIONS PAPER

Table 11: Navigation table (competition options)

OPTIONS PAPER				RECOMMENDATIONS PAPER				
Topic	**Code**	**Name**	**MDAG View**	**Code**	**Name**	**Location**	**Notes**	**Tranche**
Strengthen competition	D1	Develop dashboard of competition indicators for flexibility segment of wholesale market		R12	Competition dashboard	Page 94		1
	D2 (=B1)	Greater transparency of hedge info (esp non-base load) covering offers, bids + agreed prices		R2	Hedge market transparency	Page 78		1
	D3 (=B6)	Develop flexibility access code (non-price elements)		R9	Contract process disclosure rules	Page 89		1
	D4 (=B7)	Extend trading conduct rules for hedge market		N/A	[Not recommended]			N/A
	D5 (=B8)	Market making in caps or other shaped products		R24	Market making for flexibility products	Page 108	Now recommended	2
	D6	Physical disaggregation of flexible generation base		N/A	[Not recommended]			N/A
	D7	Virtual disaggregation of flexible generation base		R13	"Virtual disaggregation (high level outline)"	Page 95	Split into two separate (amended) measures	1
				R30	Virtual disaggregation	Page 114		3
	D8	Price caps applied in the electricity spot market		N/A	[Not recommended]		Combined with C14	N/A

SUPPORTED IN OPTIONS PAPER PARTIALLY SUPPORTED IN OPTIONS PAPER NOT SUPPORTED IN OPTIONS PAPER

Table 12: Navigation table (public confidence options)

OPTIONS PAPER				RECOMMENDATIONS PAPER				
Topic	Code	Name	MDAG View	Code	Name	Location	Notes	Tranche
Increase public confidence	E1	Structured information programme for wider stakeholders		R22	Information programme for opinion-makers	Page 106		2
	E2	Regular briefings for Ministers and officials on current and expected conditions		R15	Seasonal outlook report	Page 97		1
	E3	Increase inter-change with international experts		R23	International experts	Page 107		2
	E4	Enhance monitoring with more autonomy		R22	Monitoring and enforcement of Code	Page 106		2
	E5	Periodic warrant of fitness review for independent regulatory agencies		R25	WoF for regulatory agencies	Page 109		3

SUPPORTED IN OPTIONS PAPER PARTIALLY SUPPORTED IN OPTIONS PAPER NOT SUPPORTED IN OPTIONS PAPER