Meridian.

16 March 2022

Submissions
Electricity Authority

By email: mdag@ea.govt.nz

Price discovery under 100% renewable electricity supply:
Issues discussion paper

Meridian welcomes the opportunity to comment on the Market Development Advisory Group's (MDAG) issues discussion paper *Price discovery under 100% renewable electricity supply.*

This submission is structured to address:

- the technical expertise and analysis underpinning the MDAG paper;
- the questions posed by MDAG;
- the importance of timing for any regulatory considerations associated with the transition to 100% renewable electricity; and
- next steps.

Responses to MDAG's specific consultation questions are included as Appendix A.

The technical expertise and analysis underpinning the MDAG paper

MDAG has assembled an impressive group of experts to provide the reports and modelling that underpin the consultation paper. These expert reports are a high quality analytical base. Meridian broadly agrees with the observations and modelling results, which are generally consistent with Meridian's own internal modelling of an increasingly renewable electricity market.

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The questions posed by MDAG

MDAG is asking the right questions about a 100% renewable electricity future. These are fundamental questions about the future of the market and acceptability of outcomes under the current energy-only market design. Each of the questions posed warrants rigorous consideration.

At times, the MDAG paper jumps into solution mode, particularly in respect of Question 8 and the options that are to be progressed to the next stage for detailed consideration. It seems somewhat premature to jump to solutions when MDAG has not established a problem with the current market design that needs to be resolved now. MDAG observes (rightly) that increased spot price volatility will need to be publicly and politically accepted. However, it has not been established that there definitely will be a lack of acceptance or that acceptance is likely to be an insurmountable issue.

From an engineering, mathematical, commercial, and economic perspective an energy-only wholesale market can perform well in a 100% renewable future. Such a market can deliver low carbon emissions and a resilient power system with well-balanced security of supply and energy costs. Wholesale prices in such a market should fall with investment to reflect the low and falling cost of new renewable generation investments over time. Such a market is capable of accommodating today's current electricity demand but also the growth that is likely to result from electrification of the New Zealand economy, particularly transport and industrial process heat.

That said, no market design is perfect. The current market design has been refined and improved over the course of its existence and this process of refinement should continue and if possible be accelerated as appropriate as the power system becomes increasingly renewable and new challenge arise.

Many of the options that MDAG contemplates progressing fit this description of improvements to the current market design including:

- improvements to forward scheduling, demand forecasting, dispatch rights;
- improvements to the range of ancillary services procured;
- options to improve market confidence and acceptance of price volatility in a 100% renewable electricity market;
- ongoing improvements to hedge-market arrangements;

- facilitation of demand side response markets; and
- improved processes for thermal retirement.

Meridian supports more detailed consideration of all these options. In particular, we see value in consideration of an additional firming ancillary service to help manage intra-day risk and the coordination of dispatchable resources like vehicle to grid, grid batteries, and hydro generation.

However, some of the mandatory contracting options contemplated by MDAG (such as a reserve capacity market or a firm energy or capacity market) would be more fundamental changes to the entire market design. Alternative market designs like this may help to alleviate concerns in respect of increased volatility however, they potentially bring significant problems of their own, including:

- a loss of diversity and innovation to solve capacity or energy supply issues;
- questions over whether reserve plant or capacity will in fact be available and generate when needed and therefore a likely need for the contemporaneous introduction of detailed penalty regimes that end up serving much the same purpose as scarcity pricing in an energy-only market;
- susceptibility to increased lobbying and the risk of short-term political influence or interference and therefore the risk of increased cost and uncertainty due to frequent rule changes or changes in operations for reserve plant and in respect of the procurement of firm energy or capacity; and
- increased costs to consumers due to the administrative complexity of centrally procured schemes and the established tendency to over procure to gold plate security of supply.

Trading one set of problems for a different set of problems will not necessarily benefit consumers and any detailed investigation, even one that considers carefully both the benefits and costs of alternative market designs will necessarily be to some extent a highly speculative exercise and the results of any reforms will be subject to the yet to be determined details of any alternative market design.

One thing is certain – any decision to fundamentally redesign the market will create significant transition costs and uncertainty. Market redesign on this scale would likely take several years to develop and implement. During that time there would be considerable investment uncertainty. While different market designs may well be viable in practice, none will be perfect, and all come with unique problems to manage. More than anything else the effects of disruption lead Meridian to think that improvements to the current market design may well be preferable to a completely new market design.

The importance of timing for any regulatory considerations associated with the transition to 100% renewable electricity

Given the scope and ambition of the questions posed by MDAG, it may be that the project needs to be broken into more manageable pieces on different timeframes.

Meridian suggests that the initial focus in the next round be on options to incrementally improve the energy-only market design and prepare for an increasingly renewable electricity market. This would be a low-risk, least-regret approach.

In the longer term, fundamental market design questions are worthy of further consideration and should not be ruled out. However, change should not be pursued in the absence of evidence of significant and likely insurmountable problems with the current market design. A change to the fundamental design of the market will be disruptive, will threaten investment and will therefore likely come at a short term cost to consumers (regardless of the merit or otherwise of the end state relative to the status quo).

There remains considerable uncertainty regarding the pace of the transition to a 100% renewable electricity market. The Climate Change Commission's final advice recommended that the Government replace the 100% target with a goal of aiming to achieve 95-98% renewable electricity by 2030. In addition, the Interim Climate Change Committee demonstrated that moving from 98% renewable electricity to 100% renewable electricity would cost about $1,280 for every tonne of carbon dioxide abated and would result in higher electricity prices. The Government's NZ Battery Project could have a significant impact on the pace and cost of change but at this stage there has not been any commitment to generation investment by the Crown and even if an option like pumped hydro was to proceed the planning and construction times to follow would be several years. It therefore seems likely that some gas peaking will remain a part of the generation mix for at least the rest of this decade and possibly longer.

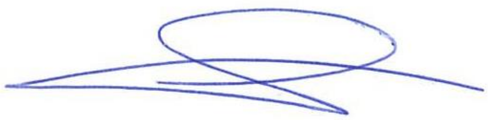
Given the uncertain pace of change, there is a question about how far MDAG progresses options that seek to address issues that might arise in a 100% renewable electricity market. Many of the issues that could arise would not be a feature or would be far less of a feature in a 98% renewable electricity market. The closer MDAG and the Authority get to agreeing on options for implementation, the more important the timing considerations become. Meridian suggests timing will need to be an explicit consideration in later stages of the MDAG project. For example, MDAG might need to consider what conditions might trigger implementation of certain options, whether consideration of some options should be saved for a later date, or whether some options are developed to be ready “on the shelf” and implemented only if/when certain preconditions arise.

Next steps

Meridian looks forward to further detailed engagement in the next stages of this MDAG project. At this stage we are not convinced the case has been made that there are significant and insurmountable problems with the existing market design. The market can always be improved incrementally, and we encourage MDAG to focus in the next stages on some of the more immediate changes that might help during the transition as well as in a 100% renewable electricity market (whenever that might eventuate).

Please contact me if you have any queries regarding this submission.

Nāku noa, nā



Sam Fleming
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Appendix A: Responses to consultation questions

	Question	Response
1.	Do you agree with the broad conclusions that emerge from the simulations in relation to spot price levels and volatility, in particular: (a) significantly more spot price volatility is likely with a 100%RE system, especially shorter-term weather-driven volatility? (b) New Zealand's sizeable hydro generation base is likely to moderate the growth in volatility to some extent, making extreme oscillations between zero and shortage spot prices relatively unlikely?	Yes. Meridian broadly agrees that significantly more spot price volatility is likely with a 100% renewable electricity system, especially shorter-term weather-driven volatility. The market is likely to oscillate between periods of renewable surplus (wet, windy, and sunny) and periods of deficit. Conditions may change from one to the other across any given week. In contrast, the difference between daytime and overnight periods may be less pronounced and the market may flatten out significantly as new demand-side response, vehicle to grid, and battery energy storage systems flex within a 24-to-48-hour timeframe. Meridian also broadly agrees that New Zealand's sizeable hydro generation base is likely to moderate the growth in volatility to some extent. However, this will only be the case if hydro generation is encouraged and allowed to moderate volatility, both politically and commercially. On a seasonal basis, typical lake levels will rise to create a buffer against extended periods of renewable electricity deficit. Communities and decision-makers will need to be comfortable with the increased hydro spill such operation would necessitate. The full lake range will also become increasingly important in extremes and will be needed from time-to-time, especially without thermal back up during dry periods. Contingent storage will increasingly be used, and communities and decision-makers will need to be comfortable with this or accept higher costs to consumers if the full extent of hydro flexibility is not allowed to be used. On a daily basis, hydro flexibility can moderate volatility, but hydro operators nationally may need to move towards a 'system flexibility' mindset. This may mean increased volatility in energy company profits and a need for greater acceptance of that risk. If, in the short-term, there is no thermal, and limited demand side participation then the flexibility in the system from hour-to-hour can only come from hydro and batteries. Increased wear and tear and operational costs and maintenance outages associated with more flexible hydro operations will also become more of a feature of the market and increasingly a factor for hydro offers.

2.	If you disagree, what is your view and the reasoning for it?	Meridian does not disagree.
3.	Do you agree that in a 100%RE system there will be many diverse and disaggregated resources to coordinate, and that a wholesale market will be the preferred mechanism to coordinate plans and actions among all the resource owners? If you disagree, what is your view and the reasoning for it?	Yes. From an engineering, mathematical, commercial, and economic perspective a 100% renewable power system in New Zealand can deliver low carbon emissions and a resilient power system with well-balanced security of supply and energy costs. In theory, wholesale prices should increasingly reflect the low and falling cost of new renewable generation (LCOE) that is expected over time. Such a market is capable of accommodating today's current electricity demand but also the significant growth in new demand that is likely to result from decarbonization and electrification of the New Zealand economy, particularly transport and industrial process heat. Meridian considers all of this to be possible within the framework of a wholesale market that is fundamentally similar to what we have today.
4.	Do you agree that these are the key issues in relation to real-time coordination? If you disagree, what is your view and the reasoning for it?	A dramatically more probabilistic and highly uncertain view of the near-term dispatch window is inevitable in a 100% renewable electricity market. The main question is how much does this matter to different actors within the system and do some or all of them need more certainty, i.e. do some parties need to have their spot generation or demand response offers and revenues de-risked to some extent to be commercially viable? One key to future real-time dispatch and market clearing working well is to ensure that all available resources, particularly hydro and demand side management, are made available at a price. As examples of what might encourage desirable outcomes a day ahead market, or other inducements might be considered. While any significant shortage should be avoided, with increased volatility there may be times when the ability to selectively shed load will be important. This could be considered hand-in-hand with the disaggregation of shortage prices based on different values of lost load for different types of electricity demand. For example, rather than a set $10,000 scarcity price whenever the system operator gives notice of a shortage situation and load shedding occurs, lower scarcity prices could be triggered first for types of load that opt in. Consumers that have a pre-set higher willingness to shed load at times could be identified and rewarded like other ancillary service

		providers through a procurement process or in coordination with retailers. This would be different to more active forms of demand side management offered into the market (either individually or via an aggregator) as it would be entirely passive and rarely utilised. One can imagine this working in a similar way to ripple control use today, albeit for energy shortage rather than (or as well as) for network peak capacity needs. Ripple control is already commonly activated at prices far below scarcity prices. **Forward scheduling** A probabilistic or confidence interval approach with a rolling time horizon for information seems sensible. One consideration is: is the appropriate concern the forward price or the expected dispatch volume or both? There is no free lunch with price uncertainty and an under / overs approach to price formation and market outcomes more generally is not unreasonable. A day-ahead financial commitment market could be of some use, particularly for demand side participants to secure reliable revenue when they withdraw consumption. But the more that decisions are "de-risked" for individual actors, then the more that the burden and costs of that "de-risking" must be carried and paid for by someone else. **Demand forecasting** Demand forecasts in an aggregate probabilistic sense will likely be reliable enough on average but on a half hourly or five minute basis it will be increasingly difficult. The uncertainty of demand forecasting will need to be well understood and flexible resources must be offered in to cover the range of possibilities. **Resources subject to dispatch** Formalisation of the dispatchable resources above some threshold will be useful and will require a change from today's "few and large resources" mindset. The treatment of the aggregation of demand side opportunities above some threshold at a GXP (or even regional) level is a good example. Aggregators may not be able to say with certainty at any point in time that they can deliver 50MW at $250/MWh (for example), but on average in the long run we should expect 50MW from them at around that price level. The treatment of grid-scale batteries and hydro as the last remaining sources

		of large dispatch (and for hydro, inertia) may need special consideration since they will do a lot of heavy lifting within the power system to keep supply and demand balanced. Below some threshold, i.e. domestic batteries and solar, it is unlikely that real-time co-ordination will be achievable by the system operator. However, this could be devolved in some fashion down to the distribution or retailer level, where an individual entity could effectively act as a proxy aggregator, much as happens with ripple control today. **Dispatch rights at zero prices** The ability to dispatch down baseload renewables during zero price periods will be useful. A variation of the existing must-run dispatch auction seems like an efficient mechanism, making sure there is equitable treatment for all sources of generation and load including new and distributed sources. The mechanism will need to enable dispatchable plant to stay on minimums so it is available if the system needs, even if that means renewable spill (e.g. solar and wind). **New mechanisms (such as a short-term commitment market) to coordinate resources that require a lead time to get ready** Large scale technologies like grid-scale batteries will be constructed and operated with an expectation that arbitraging price and optimising charge/discharge cycles will be a necessary reality and part of the productive efficiency role of the market. De-risking of operational revenues in this space would come at a cost. It is not clear whether such de-risking would benefit consumers in the long term. If the technologies are commercially viable now there does not seem to be a problem in need of solving. **Aggregators interacting with the spot market** We do not anticipate aggregators will have any problem interacting with the spot market provided they operate at sufficient scale, which implies some level of sophistication to manage the associated financial risks. One question is whether an initial period of 'de-risking' or support might encourage aggregated demand side businesses to enter the market. However, the short-term nature of such support should be clear because in the

		long-run we do not consider it in the best interests of consumers to prop-up any business model that is only viable with subsidies or reduced risk at the expense of others.
5.	Do you agree that these are the key issues in relation to ancillary services with 100%RE? If you disagree, what is your view and the reasoning for it?	Yes. Flexibility over all time frames will increasingly become important. Current governor response is an example of where over-use of an existing ancillary service could quickly become problematic. Frequency keeping could do with being formalised more clearly and cleanly as a procured product and co-optimised by the system operator. New ancillary services will become important as system needs evolve. In addition to inertia, "load following" reserve, analogous to extended frequency keeping may be needed in a 100% renewable electricity market to cope with the occasional drop in expected wind and solar output (especially if combined with an unexpected increase in demand). See the New Zealand Wind Integration Study carried out by Meridian and Goran Strbac, Danny Pudjianto, Answer Shakoor, and Manuel J Castro of the Imperial College London.[1] This study contemplated the system need for such products with higher renewable energy penetration. While some of the issues that might emerge could potentially be solved by frequent redispatch, a clear value placed on longer time scale frequency modulating reserve and other ancillary services would be useful in terms of transparency, stability, and price signalling. New ancillary services could be co-optimised in the market along-side instantaneous reserves, energy, and ideally frequency keeping. Decentralised distributed resources could also provide ancillary services via an aggregator or through formalised standing agreements for specific services (similar to ripple control but potentially co-ordinated via retailers or aggregators).
6.	Do you agree that these are the key issues in relation to price signalling with 100%RE as	**Whether higher prices (occurring with greater frequency) signalling genuine scarcity of supply will**

[1] https://www.meridianenergy.co.nz/assets/Investors/Reports-and-presentations/Industry-reports/3bd492e060/New-Zealand-Wind-Integration-Study-2008-2759764-1.PDF

	summarised in paragraph 3.42 above? If you disagree, what is your view and the reasoning for it?	**be accepted in the wider political economy of the market** This has been the 'missing money' concern since the start of power markets globally, and the primary reason, along with security concerns, why many jurisdictions went down the 2-part (capacity plus energy) market design pathway. Broader acceptance of high prices at times of genuine scarcity will to some extend turn on whether politicians, regulators, industry (including the full range of industry participants) and other significant actors in the economy are themselves confident that the market is working as intended for electricity consumers and happy to say so. Given the vested interests at play during times of high prices (and political sensitivities) the likelihood of such collective confidence being sustained at all times and under all circumstances is questionable. By the same token, given the importance of electricity in all our lives, it is unlikely that any market or electricity sector design or arrangement will at all times have the full confidence of those operating under it. Ongoing market scrutiny and challenge is inevitable and to a large extent is highly desirable. Challenge provides the impetus for improvement. However, decision-makers will always need to be willing to look past partisan voices in the industry calling for self-interested change during times of market stress. This highlights the need for a strong, firmly independent, and economically-minded regulator and public service willing to stand up to short-term lobbying and political pressures and take a long-term view of what will best serve the interests of consumers. Importantly, assuming the availability of options to contract out of price volatility, there is no reason why a more volatile, peaky, energy-only price market should not be seen as acceptable to all parties.
7.	Do you agree that the preconditions in paragraph 3.38 would need to be in place for an energy-only market design to be effective? If you disagree what is your view and the reasoning for it?	In general, yes. We discuss each precondition further below but at a high level: • price will need to be high at times of scarcity and low at times of surplus; • prices will need to reflect this reality as well as on average being linked to LCOE; and

		• contracting solutions should evolve naturally to reflect average prices and enable participants to insure against extreme high or low price events. Meridian considers the energy-only market capable of delivering these outcomes. Public and political acceptance of those outcomes at times of scarcity is likely to be the greater challenge. **Prices that reflect real supply and demand conditions, including very high prices in times of scarcity** Agreed, this is what the mathematics and economics suggest is necessary. Note that the mathematics also suggests that the current market design can deliver a power system with falling average prices (reflecting the LCOE of new generation), lower carbon emissions, the accommodation of new decarbonised grid load, and adequate security of supply. Meridian's modelling suggests that with some amount of renewable spill and some amount of dispatchable load, battery discharge, and flexible hydro, the 'peakiness' of future energy-only prices is less dramatic than might be assumed, while still enabling commercial returns on new generation investment. For example, in a dynamically efficient 100% renewable electricity future, our modelling indicates that peak weekly LWAP only needs to be >$200/MWh in less than 4.5% of all weeks (and hydrological outcomes) by 2035, falling to <1.5% by 2050 as LCOE continues to decline and new sources of flexibility come to market. This can be compared to historic market outcomes since 2010 where LWAP (real) has been >$200/MWh for around 3% of all weeks. **Confidence among wholesale buyers and sellers that the high prices make sense, (which means confidence in the structure and rules of the market, including the sufficiency of competition)** Yes, we agree. The increased scrutiny the Electricity Authority has applied to the new trading conduct rules should grow confidence amongst wholesale participants over time. Confidence among wholesale buyers and sellers in a market is difficult to measure and should not be conflated with expressions of self-interest calling for either lower or

		higher prices. In particular, self-interested concern about wholesale prices during periods of relative scarcity should not be conflated with a loss of confidence in the market (even if the parties exposed claim that they have lost confidence). The risks associated with such conflation are significant and will grow as the New Zealand power system becomes increasingly renewable and prices become more volatile. **Availability of tools for wholesale buyers and sellers to manage their exposure to spot price risks** Yes. Hedge products will continue to be necessary and are likely to evolve with the market over time. Meridian expects the hedge market to evolve naturally as new or different risks arise and parties with complementary risk profiles recognise the financial stability that they can offer each other. **General public and political acceptance that volatility and high prices (in times of scarcity) in the wholesale market are, in fact, in the best long-term interest of consumers, and that measures to 'soften the landing for unhedged participants' can trigger a vicious circle of undermined investment incentives and higher future prices** Yes. Allowing soft landings after the fact will not encourage contracting and will lead to missing-money problems. Avoiding knee jerk political reactions to high prices can be challenging. "Time inconsistency" in respect of public and political acceptance is observable even in today's market. What some participants say they understand and accept at one point in time typically changes when they experience an example of what happens in the extremes, even if that extreme lines-up entirely with what they were told would happen and accepted as preferable to alternatives. It is noteworthy that calls for market reform only became a priority for wholesale electricity purchasers after the 2018 Pohokura outages and subsequent gas supply issues arose. **Confidence among consumers/politicians that investment will be timely and competitive** Yes. Timely and competitive investment is the primary purpose of the market. If the market does not deliver the generation that is needed, then it will be entirely reasonable to question the efficacy of the market. Whether investment is "timely" is of course not a straight-

		forward question. However, with diverse investors, a level playing field, and lack of barriers the market collectively should identify the "sweet spot" of timely investment.
8	Do you agree that we should take forward to the next stage of the process (options identification and analysis) the measures referred to in paragraph 3.43 above? If you disagree, what is your view and the reasoning for it?	Meridian responds in turn to the measures referenced in paragraph 3.43: **Measures to increase confidence in spot prices during genuine scarcity events** Yes. These options warrant further consideration and would be reasonably low risk and low regret options. Teaching the media, consumers, and politicians about energy economics will not be without challenges and will require steady attention so that the messages are not quickly forgotten or ignored when scarcity and high spot prices arise. One thing that may have merit is clear long-term expectations or forecasts of prices, including clear reference by regulators to the possibility (and expectation) of very high prices from time to time. Stress testing could be expanded further to cover a wider range of scenarios and the Authority could consider a public disclosure element to the effect that disclosing participants must make a declaration that they are financially capable of riding through the stress test scenarios over the next quarter. If that is not the case, consumers might like to know the risk involved in transacting with the disclosing participant. While this might add compliance costs it would significantly sharpen the attention that is given to stress testing by Boards and Executives and better highlight to them potential market risks that may need to be proactively managed. Such steps would be useful to counter any reluctance to change business practices in light of stress testing. It seems that rather than proactively manage risks, some participants prefer to utilise the free option of complaining to regulators, media, and politicians when they do not like price outcomes. It is unclear what MDAG means by "strengthening processes for reviewing high price events". Presumably this is about ongoing monitoring of market outcomes and appropriate and quick escalation when Code breaches occur, or when the Authority identifies a need to reconsider market rules. There are likely to be many more high-priced events in a 100% renewable electricity

		future, so the use of ad hoc reviews under section 16(1)(g) or section 18 of the Act should be used sparingly by the Authority. The Authority should instead maintain a strong focus on its Code making and enforcement functions such as ongoing monitoring of trading conduct rules in the Code. The Authority's improvements to monitoring of the trading conduct rules appear to be a success so far. Future overuse of ad hoc "reviews" that do not lead to tangible Code making or enforcement action would consume considerable time and resources at the Authority and across the industry while not delivering participants any certainty. At worst, overuse of ad hoc "reviews" would risk eroding confidence over time in both the regulator and the market. There is, however, a role for ongoing market monitoring and a good example of this is the Authority's efforts in monitoring trading conduct since the introduction of the new trading conduct rules in the Code. Where rules are established in the Code and monitoring of those rules put in place, participants have some certainty regarding what is expected and confidence in the Authority's actions and the processes that will be followed should expectations not be met. Options to strengthen the process for determining UTS claims would be welcome, including longer term consideration of future investment incentives. Recent UTS processes appear to have followed a range of different processes, timeframes, and decision-making frameworks – some of this may be the result of the different issues at stake in each case. Furthermore, all UTS actions have been initiated following participant allegations rather than the Authority proactively considering the situation in the market. Meridian would like to see the Authority initiate UTS investigations rather than wait for participants to raise a 'UTS claim' (noting that although it has become established in practice there is actually no process in the Code for a party to make such a claim; the Code contemplates that the Authority will initiate UTS investigations without waiting for a claim). As Meridian noted in its submission on the 9 August 2021 alleged UTS, the Authority's application of the test in the Code has at times not been well explained and seems at some times to focus on an assessment of whether market outcomes were outside the normal

		operation of the market and at others to focus on market participants' blameworthiness. We agree MDAG could further consider the UTS process and any potential effect on investment incentives. However, at the same time, we recognise that the UTS discretion granted to the Authority is necessary and necessarily broad to cover situations not contemplated by the Code. **Explore backstop measures** These alternative market design options merit further consideration. However, these are solutions looking for a problem that does not exist today in the energy-only market. While MDAG and the Authority might consider these options now, there remains a critical timing question – if an alternative market design is deemed to be better for some reason, what is the need or trigger to put that reform in place and would the cost of the reform outweigh any potential benefit? A conditional forward contracting obligation if projected demand exceeds supply (say) three years into the future (similar to the retailer reliability obligation in Australia) may be worthy of further consideration. An option like this could help to solve some of the demand side 'free rider' issues that we see today where security of supply is to some extent funded through large swaption contracts signed by large participants like Meridian and Contact. However, mandatory contracting obligations of any kind are not without challenges. Requiring contracts (particularly firm cover rather than just peak cover) is a potentially significant cost imposition and could have chilling effects on smaller retailers. Some smaller retailers say they cannot cope with or meet existing prudential requirements, credit risk requirements, and ISDA requirements today so mandated contracting may drive some retailers out of the market. This may simply be an indication of the relatively low barriers to entry for retailers in New Zealand. However caution and balance would need to be exercised in considering any mandatory contracting and assessing the costs and benefits. A reserve energy or capacity scheme with standing costs for reserve plant recovered from beneficiaries (i.e. parties that do not have forward cover for firm demand) could

		merit further consideration. However, the devil is in the detail of reserve schemes, for example: • When/how does the plant operate? • When/how does the plant retire? • How should costs be allocated? • Will the basis for these decisions change over time with little warning (as was the case for New Zealand's previous reserve scheme at Whirinaki)? Analysis by Concept Consulting suggests that mandatory contracting arrangements, be they reserve schemes, or capacity markets, or firm energy markets, are likely to be a more expensive way of meeting the power system's energy/capacity needs relative to energy only markets.[2] Reserve schemes also suffer from political whims and inconsistent operation over time, which will inevitably chill investment and limit market based innovation to solve the evolving peak and dry-year risks. Firm capacity or firm energy markets are typically about ensuring sufficient investment, or the right kind, at the right time – determined by a central planner rather than diverse participants responding to price signals. They have a mixed performance internationally, add a lot of complexity and opaqueness to an already poorly understood power market, and can suffer from both gaming and from cost allocation problems while typically failing to clearly improve national security levels. The biggest issue is that capacity providers are paid for having kit on the ground, while there is no guarantee that the kit will be available to generate when required. Experiences internationally show that there is considerable focus on penalty regimes to incentivise availability in much the same way as scarcity prices would incentivise availability in an energy only market.

[2] Concept Consulting *Capacity markets and energy-only markets: a survey of recent developments* February 2020, available at:
https://www.concept.co.nz/uploads/1/2/8/3/128396759/eom_cm_design_-_final.pdf.
Note that Concept uses the term "capacity market" to refer to the spectrum of mechanisms which create a regulated revenue stream that is distinct from spot market payments, including formal capacity markets, strategic reserves, and firm energy markets.

		New Zealand does not have a demonstrable investment issue, at least today. Therefore, a capacity market does feel like a solution without a problem. Rather than investigation of complete market overhaul, Meridian would like to see smaller steps taken to improve the energy-only market. The same fundamental physical and economic (i.e. return on investment) considerations will be at play regardless of the market design adopted. There are no magic solutions or "perfect" market designs. However, the transition from one market design to another would risk short-term disruption to investment and associated negative consequences for consumers. These potential transition and disruption costs should be kept in mind as MDAG progresses the project.
9.	Do you agree that these are the key issues in relation to demand-side flexibility with 100%RE? If you disagree, what is your view and the reasoning for it?	The market features necessary to fully realise the benefits of demand side flexibility include: • The physical ability to easily shift or curtail load, especially for hot water or V2G or roof-top solar and battery systems. • The technology to automate and easily manage load shifting for consumers so that it is as painless as possible. • Ability to scale via aggregation or similar. • Clear ownership structures for those that can call on the flexibility option and ownership by a diverse range of parties with different use cases. • Consumer agency in load management decisions so consumers can switch to the aggregator or manager of their load that delivers them the most value while still meeting energy needs. • The beneficiaries of flexibility (be they network companies, wholesale purchasers, or other parties) actively consider the value delivered and develop clear pricing, tariffs, or other commercial arrangements so people can see how they would benefit from flexible load. MDAG and the Authority could consider ways to promote and facilitate markets for demand side flexibility. However, Meridian considers it best that markets for demand side flexibility emerge organically and that they are consumer driven. Consideration may need to be

		given to the role of regulated monopolies to ensure demand side flexibility does not become part of an expanded regulated service. Competitive markets deliver better innovation and long-term benefits to consumers.
10.	Do you agree that these are the key issues in relation to contracts markets with 100%RE? If you disagree, what is your view and the reasoning for it?	Meridian believes the necessary features of the contract market are likely to develop naturally and be present as the shift to 100% renewable electricity occurs. Therefore, regulatory actions will not be required. Meridian agrees that access to competitively priced risk management products will continue to be critical in an increasingly renewable future. Contracting needs should be driven in the long-run by the unavoidable risk and engineering realities of the power system. In an ideal world this would be left to the free exchange of value and risk between willing buyers and willing sellers. We agree with Steve Batstone's observations that risk management has evolved and improved substantially since the commencement of the market, and especially over the past ten years. We expect that evolution to continue in future. In time, new technology driven consumer agency should also begin to provide products back to the power system (either individually or via aggregators), further increasing competition for risk management contracts. A variety of different risk management products can be traded now through bilateral agreements including shaped products like caps or peaks. Generators (at least for Meridian's part) are open to these bilateral conversations and willing to transact on a commercial basis. However, as MDAG notes, there may be "a material gap between what sellers and buyers believe the risk management value of the product is worth". That is a commercial problem, not a liquidity problem for MDAG or the Authority to solve. Increased OTC transparency may have merit to monitor willingness to trade and ensure there are no attempts to foreclose competitors. However, such monitoring is already the responsibility of the Commerce Commission and regardless will not be able to overcome commercial gaps between the prices at which buyers are willing to buy and sellers are willing to sell.

		Anecdotal concerns about any gap between what buyers and sellers believe risk management products to be worth is not evidence of a market failure or lack of liquidity. If retailers were prepared to pay reasonable premiums for short-lived peak capacity cover or extended dry year cover it is highly likely generators would be very keen to agree those products. There are many potential counterparties with which risk management contracts could be negotiated and these options are expanding as more generators enter the market. The option also exists to self-manage risk through PPAs or direct investment in generation, retail, or demand side flexibility. If risk management products do not evolve as anticipated it could be due to any number of issues, including the small scale of some parties and their inability to meet associated credit or prudential requirements. The point being, that MDAG and the Authority should not jump to the conclusion that regulated contracting or market-made products are required, as that may not solve the underlying costs of market participation. Generators are strongly incentivised to close the price gap of risk contracts where a contract aligns with their own physical risk profile due to engineering – i.e. they have a risk exposure that the contract can help to address. Many companies have invested in generation and retail together to mitigate such risks. They are never perfectly self-hedged and still have strong incentives to contract to balance their risk positions. Any forced contracting required of integrated firms is effectively disincentivising generation investment and self-hedging by forcing those that have made high capital investments in generation to share the benefits with those who have chosen not to do so. As the experience with ASX market-making has proven, it is extremely difficult to establish whether the benefits outweigh the significant costs when mandating contract specifications and liquidity providers. There would be considerable debate regarding the product set, scale of offering, who pays, and whether the complexity did in fact strengthen resilience for the future power system (as opposed to high prudential requirements that exclude many retailers leaving speculators as the primary beneficiaries of market-making at the expense of market-makers and New Zealand consumers).

		The ASX New Zealand electricity futures market has grown significantly with many records set for open interest and traded volumes in recent years. The volumes traded are many times the volumes bought and sold on the physical market. While this is positive, the significant costs of providing this liquidity are carried by the four companies that provide market-making services. The Authority should continue its project to move towards fully commercialised market-making arrangements, so the beneficiaries of market-making (other than non-participant speculators) collectively fund the service. We believe this would provide a more durable basis for exchange based contracting in any future scenario and should be a precondition for any expansion of market made products (if levy payers agree to the added costs that result from any increase in the scope of market-made products).
11.	Do you agree that these are the key issues in relation to transition to 100%RE? If you disagree, what is your view and the reasoning for it?	The scope of MDAG's work was to consider the operation of the market in a 100% renewable electricity future. How fast that transition occurs should ideally be determined via market process as that will achieve the most efficient outcome for consumers. Meridian is confident that the current market design will move New Zealand very close to the 100% renewable goal within the next few years. Consistent with the Climate Change Commission's final recommendation, MDAG should not be considering regulatory options to speed the transition to a fully 100% renewable electricity market. The Minister of Energy and Resources has signalled the development of an Energy Strategy that will consider transition issues and the New Zealand Battery Project has been established to contemplate what if any role there might be for Crown investments in the supply side during the transition. **Strengthen market process for retirement** A regulatory focus on the private retirement decisions of plant owners (and in particular thermal baseload plant owners) seems unnecessary. The owners of the relevant plant are best placed to determine what constitutes "premature retirement". They will be acutely aware of the risks and that decisions like this involve more than a simple assessment of earnings, cost and profit at risk. Brand, carbon emissions, and lack of system flexibility are also important and will impact on closure decisions.

		Thermal plant owners are already subject to wholesale market information disclosure obligations to inform the market if they hold any information that, if known to the market, might affect wholesale prices. The Authority is also party to such information (or should be) as a result of the recent amendments to the wholesale market information disclosure provisions requiring quarterly disclosure of information to the Authority where information qualifies as disclosure information by exceptions to the disclosure requirement are relied upon.
12.	Are there any other 'lumpy' issues that warrant specific consideration in the transition to 100%RE?	Not at this stage. The Electricity Authority is already considering large industrial contracts like the smelter contract as part of the review of competition in the wholesale market. MDAG should not duplicate that work.
13.	Do you agree that we should analyse how competition in the wholesale market is likely to be affected by a shift to 100%RE, in particular, in competition for seasonal flexibility services? If you disagree, what is your view and the reasoning for it?	MDAG may struggle to analyse competition in a hypothetical future market. We do not know how the market will evolve over the coming years. If seasonal flexibility services are highly concentrated, then the issue could be considered as and when it arises. The regulator should remain mindful of this as the market evolves but it would not make sense now to analyse (or attempt to solve) an unspecified problem that may or may not arise in future. As an example of how the market might evolve in unexpected ways see Dr Richard Meade's white paper *Preparing Electricity Regulation for Disruptive Technologies, Business Models and Players – In the Long-Term Interests of Consumers* which discusses the potential for digital disruption in electricity markets by the likes of Amazon, Google and other data giants. Such developments would dramatically alter the nature of competition in the market. Aggregation of consumer load, particularly vehicle to grid flexibility is one area to watch out for. The ability to freely switch aggregators would ideally be a feature of this evolving market. That would mitigate the risk of a first mover locking in consumers for less than fair value in long-term contracts. Any attempts by regulated monopolies to expand the scope of the regulated lines service into other areas like the aggregation of demand flexibility should also be closely monitored. Competition will deliver better

		consumer outcomes in the long term than expansion of the scope of operation of monopoly service providers.
14.	What other key areas of opportunity or challenge (if any) will arise in the wholesale electricity market with 100%RE that are likely to have a significant impact in relation to achieving the statutory objective of the Authority, which is to “promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers”?	We have not identified any other key areas at this time. However, as a procedural matter it would also be helpful if MDAG and the Authority were explicit about the process that will be followed in the next steps of this project, including the deliverable that is expected of MDAG and at what point the Authority would itself consider the issues and options raised. Recent examples have indicated that the Authority is willing to pass difficult regulatory issues to MDAG and then rubber stamp recommendations. However, MDAG is not a representative group and is not a statutory decision-maker. The Authority needs to behave as a thought leader itself on matters that have a significant impact on the operation of the market and the long-term interests of consumers and must also be careful not to effectively cede its responsibilities to consider and decide on fundamental market changes.