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The Chair
Electricity Price Review
Ministry of Business, Innovation and Employment
WELLINGTON

By email: energymarkets@mbie.govt.nz

TRUSTPOWER SUBMISSION: ELECTRICITY PRICE REVIEW'S OPTIONS PAPER

Introduction

Trustpower thanks the Panel for the opportunity to comment on its February 2019 *Options Paper for discussion* (**Options Paper**) and to participate in various workshops to explore the Panel's preliminary views.

We acknowledge at the outset that no regulatory frameworks are perfect and that more can always be done to strengthen the consumer voice, reduce energy hardship, increase retail and wholesale market competition, improve transmission and distribution, improve the regulatory system and prepare for a low emissions future.

In relation to regulatory reform, clearly a balance needs to be struck between improving distributional outcomes in the short term and ensuring that the market will continue to deliver security and reliability, as well as good customer outcomes, as we progress towards ambitious climate change goals. We are confident that this can be achieved if well-researched change is made incrementally and with due regard to transitions, to ensure both investor and consumer interests are protected.

You will find there is considerable common ground between Trustpower and the Panel. In total we support 30 of the Panel's 41 options, in whole or in part.

As you would expect, we have some concerns about how the Panel's proposals to increase competition in the retail and wholesale market will work out in practice and we hope that as the design of some of these options are further developed the focus will be on protecting *competition* not on particular *competitors* or the pursuit of increased fragmentation of the market for its own sake.

We also note that the recommendations to improve the efficiency of the transmission and distribution sector seemed at the lighter end of the scale in view of the issues described in the First Report.

We have different views from the Panel on who should undertake network regulation. We think there is value in transferring this to the Commerce Commission, irrespective of reform to the transmission and distribution pricing methodologies, as to us it makes sense for a single regulator to examine network revenue requirements, investment needs, quality and service standards, and pricing.

We also differ on the value of merits appeals in protecting all stakeholders' (including consumers') interests.

Structure of this submission

Our detailed comments on the options identified by the Panel are set out in Appendix 1 to this letter. These comments are supplemented by more detailed information in the following accompanying papers:

- Attachment 1 – *Market Making Requirements in New Zealand*, an expert report by The Lantau Group;
- Attachment 2 – *Market Making Requirements in New Zealand – Supplementary Paper on the suitability of Trustpower as a Market Maker*, an expert report by The Lantau Group;
- Attachment 3 – *Government Policy Statement on Network Pricing,* along with an explanatory diagram prepared by Law+Policy; and
- Attachment 4 – *Merits Appeals against Electricity Decisions*, a memorandum from Jack Hodder QC.

In making our comments we note that the options supported by the Panel are intended to operate as a package of reform and our comments have been made on the same basis.

For any questions relating to the material in this submission, please contact me on 021 223 4609 or alternatively contact Fiona Wiseman, Senior Advisor – Strategy and Regulation on 027 549 9330.

Best regards,

V.J. Hawksworth

VINCE HAWKSWORTH
CHIEF EXECUTIVE

APPENDIX 1 - TRUSTPOWER RESPONSES TO THE PANEL'S OPTIONS PAPER

Section A – Strengthening the consumer voice

A1: Establish a consumer advisory council

Trustpower supports the establishment of a consumer advisory council to assist in strengthening the voice of electricity consumers. The council should seek to complement rather than replace consumer representation on advisory groups and any consumer panels that may be established.

To ensure the council can be effective it should be set up to directly source consumer views via consumer panels[1] and independent insight communities[2]. It will also need to engage from time to time with the energy hardship group (option B1).

The council should include representatives of small business and residential consumers and will need to be well resourced in order to provide meaningful advice. In our view this will require the council to have:

- its own secretariat and Chief Executive; and
- sufficient funding to enable experts to be engaged to provide advice when required.

This will be more costly than relying on the Ministry of Business Innovation and Employment (**MBIE**) to provide secretariat services but will ensure a truly independent and well-respected consumer voice is established. To address cost considerations the council should be established to also cover the gas sector as there is an increasing overlap between the issues impacting the gas and electricity sectors which would be best addressed collectively. A single voice for energy consumers would support decision making on cross-cutting issues and would align the introduction of a single energy regulator.

We suggest that the council's initial work-plan should include considering the sequencing of the introduction of the proposed changes to reduce energy hardship, the repeal of the Electricity (Low Fixed Charge option for Domestic Consumers) Regulations 2004 (**LFC Regulations**) and introduction of more cost-reflective, service-based pricing to ensure that no individual group of customers is excessively disadvantaged.

We consider that a number of the Panel's recommended reforms (options A1 and B1-B4) should be funded by Government through general taxation. Some initial seed funding for some of the options, particularly the establishment of a consumer advisory council, could be provided by retailers. We do not consider any additional levies on industry should be established for these options.

A2: Ensure regulators listen to consumers

Trustpower does not consider it is necessary for the Electricity Authority and Commerce Commission to be given an explicit statutory responsibility to consult electricity consumers.

We note that both regulators are already required to take into account the long term interests of consumers, consider all stakeholder views, and make reasonable efforts to enable consumers to be able to understand the matters they are consulting on. This is achieved by producing consultation documents that are simply written and making themselves available to talk to consumer interest groups directly.

It is important that when seeking the views of individual consumers and consumer groups, consumers fully understand what is being proposed, along with the broader context, in order to gather informed

[1] We note the work underway in Australia by the Australian Energy Regulator, Energy Consumers Australia and Energy Networks Australia to find innovative new ways of identifying consumer priorities to ensure these are put at the heart of regulatory decisions: https://www.energynetworks.com.au/newreg

[2] For example, Camorra Research is currently establishing its WattsYourOpinion insight community for the energy market through working with a large number of existing electricity retailers to generate a representative sample of household utility decision makers.

feedback. This is not easy for some regulatory matters, as demonstrated by the recent experience of UMR Research, on behalf of the Electricity Network Association, when seeking views of consumers on distribution tariff reform[3]. For this reason we consider that utilising the proposed consumer advisory council to provide an independent view would be preferable.

Section B – Reducing energy hardship

B1: Establish a cross-sector energy hardship group

Trustpower supports the establishment of a cross-sector energy hardship group.

A partnership between Government[4], regulators, and industry will be required to deliver the Panel's recommended package of options to reduce energy hardship. The energy hardship group will play a pivotal role in this through bringing all parties together to provide advice to the Government around how to address energy hardship, including identifying and assessing initiatives, managing the implementation of initiatives and monitoring the success of initiatives.

To ensure that the energy hardship group can be effective in their role, we recommend that:

- the Chair should be a senior staff member from the Ministry of Social Development or another similarly appropriate Government department, this will enable them to draw off resources within that department from time to time;
- the group's governance structure should be being modelled off the Prime Minister's Business Council, with the Chair of the group having a direct reporting line through to the relevant Minister; and
- the scope of the group's role should be extended to gas too (where appropriate), given that energy hardship and overall affordability is also impacted by gas usage for a large number of New Zealanders.

An interim arrangement could draw off the existing working groups that have been established by industry (including Electricity Retailers Association of New Zealand (**ERANZ**)) to consider energy hardship.

B2: Define energy hardship

Trustpower supports a clear definition of energy hardship and a set of related indicators being established as a matter of priority by the cross-sector energy hardship group. This work will be vital for effectively targeting and monitoring the overall success of the recommended package of reforms to reduce energy hardship.

The work undertaken recently by Price Waterhouse Coopers (**PwC**), on behalf of ERANZ, provides a useful starting point for identifying and agreeing on an appropriate definition of energy hardship, along with indicators.

We suggest that the energy hardship group uses the PwC work as a basis for developing a definition and set of indicators for broader consultation. Getting the definition and indicators right from the start of this process will be important for the overall success of the energy hardship group's work, i.e. through enabling correct targeting of households with initiatives. Seeking broader views will add to the depth of discussion and ensure the most appropriate definition of energy hardship is established.

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[3] http://www.electricity.org.nz/news-and-events/news/pricing-reform-workshop-agrees-to-work-together-on-proposed-timing-of-changes/

[4] We note that the energy hardship group will need to bring together representatives from the Ministry for Social Development, Housing NZ, Ministry of Consumer Affairs, the Treasury, Ministry of Health and MBIE.

B3: Establish a network of community-level support services to help consumers in energy hardship

Trustpower supports the establishment of a network of electricity-specific support services for those in energy hardship. We, however, suggest this option should also be expanded to cover gas given the interactions between the supply of both fuel types from an energy hardship perspective, i.e. some households who are suffering from energy hardship may use gas as a heating source.

The EnergyMate pilot programme will provide similar in-home support services for families via a package of support. A package of support is important as a singular focus on switching retailers may deliver a short term cost reduction for customers, but might not be long-lived if they do not learn how to make their house warmer or more energy efficient. For this reason, we are optimistic about the likely success of the EnergyMate initiative and suggest it could be leveraged off by the energy hardship group to enable this option to be progressed more quickly.

On a long term basis the Energy Efficiency and Conservation Authority (**EECA**), in conjunction with the Community Energy Network, could be well placed to take on the role of managing the network of energy-use advisors based on its experience with the Warmer Kiwi Homes initiative.

We support the Panel merging this option with option B4 as there are clear synergies between the two options. In the interim, we understand that ERANZ has agreed to continue funding the pilot project.

B4: Set up a fund to help households in energy hardship become more efficient

Trustpower supports a fund being established to help households in energy hardship become more efficient.

We consider there is significant overlap between this option and the existing functions of EECA. We note that the advice of the energy hardship group would be a vital input into EECA's decision making.

B5: Offer extra financial support for households in energy hardship

Trustpower supports additional financial assistance for households in energy hardship from the Government.

The success of the package of reforms proposed by the Panel to reduce energy hardship, along with any additional options that the energy hardship group may identify in the future, will be dependent on sufficient long term funding.

In designing any additional financial support for those households experiencing energy hardship, the Government should engage directly with the energy hardship group to ensure those households that are most in need will be captured by the new arrangements.

B6: Set mandatory minimum standards to protect vulnerable and medically dependent consumers

Trustpower supports the Panel's proposal for regulated minimum standards to protect vulnerable and medically dependent consumers.

As the number of participants within the industry has increased, this has enhanced the risk that some individual customers may not benefit from the voluntary arrangements that currently guide the industry. It is pleasing that the Panel agrees that a formal, consistent and enforceable regime is now required for dealing with vulnerable and medically dependent customers. This will ensure that trust in the electricity sector continues to be high.

We encourage the Panel to extend the recommendation to include the supporting arrangements developed by ERANZ and consider whether similar arrangements may be necessary for the gas industry.

In our view, this option should be able to be progressed relatively quickly through a change to the Electricity Industry Participation Code (**the Code**).

B7: Prohibit prompt payment discounts but allow reasonable late payment fees

Trustpower supports the Panel's suggestion that prompt payment discounts (**PPD**s) be prohibited, but reasonable late payment fees would be allowed. We, however, caution that there is a risk of unintended consequences arising from extending the proposal to cover conditional discounts.

In our view, the most appropriate manner to introduce this option would be via a change to the Code. The industry is now too large for voluntary protocols to work and it will be important that a suitable enforcement regime is established (as will occur if it's included into the Code). The Code change process will afford an opportunity for further consideration of whether to extend the option to also cap conditional discounts and enable consideration of the process for transitioning to the new arrangements, including making necessary changes to billing systems. PPDs are highly valued by a large number of our customer's so careful consideration of how to manage the transition while not eroding perceived customer benefits will be required.

As an aside, it appears curious that the Options Paper references the Australian Competition and Consumer Commission (**ACCC**'s) recent finding around discounting practices in Australia as part of the rationale for recommending this option. While the ACCC has recommended that advertising of discounts by retailers should be referenced to the default offer rate[5], the current situation in Australia is markedly different to that in New Zealand and there is no evidence to suggest similar discounting practices apply.

B8: Explore bulk deals for social housing and/or Work and Income clients

Trustpower supports the Government actively encouraging agencies such as Housing New Zealand and Work and Income to explore bulk electricity deals for their clients.

ERANZ is currently working on a similar initiative.

Section C – Increasing retail competition

C1: Make it easier for consumers to shop around

Trustpower supports Powerswitch and Whatsmynumber being merged into a single source of information for consumers to identify the best energy deal that may be available for their circumstances.

A merged comparison webpage would be more efficient and practicable from a consumer perspective and support education around switching.

In our view:

- the Electricity Authority should be responsible for the merged comparison webpage (including owning the intellectual property and brand) to ensure ongoing independence of the comparison webpage;
- licensing for the comparison webpage should then be tendered to an appropriate provider, with an ongoing focus on ensuring efficiency and cost-effectiveness of the arrangements; and

[5] Currently discounts within the Australian retail electricity market are off standard offers which are not necessarily retailers market offers.

- transitional arrangements will be required if more automation between retailers and the comparison webpage is required.

We agree with the Panel's assessment that it is unnecessary to expand the information disclosure obligations to cover all price offers made by retailers. In practice, an expanded disclosure obligation would be unworkable unless a clear bright line test could be established.

C2: Include information on power bills to help consumers switch retail or resolve billing disputes

Trustpower partially supports the Panel's suggestion.

In our view, it is important that information provided on bills is useful to consumers and that unreasonable additional cost isn't driven into the industry. Likewise, it is important that these requirements do not stifle innovation occurring in the future.

Information around switching - The Options Paper makes reference to our previous suggestion around enhancing transparency of alternative offers and promoting Powerswitch on bills. Trustpower's suggestion was that annually (not monthly) retailers could be required to include information of their alternative offers (not those of other retailers) along with details of how to access the Powerswitch website to obtain information about competitor offers. This was intentionally designed to ensure loyal customers could annually reassess whether they were on the right plan for their circumstances.

We support a requirement for retailers to promote the merged comparison webpage[6] annually for the next three years being included in the Code, as the industry has too many participants for a voluntary arrangement to be effective. The Electricity Authority should consider whether to extend the requirement in the future, once a broader assessment of the effectiveness of the package of reforms in promoting switching can be undertaken.

Information around disputes resolution services – We support information around the availability of disputes resolution services being annually provided to customers. An advertising campaign similar to that adopted for the broadcasting industry could be run by the Electricity Authority.

We consider that both of these initiatives should also be extended to cover the gas industry.

C3: Make it easier to access electricity usage data

Trustpower supports the policy that customers should be able to easily access their own electricity data.

We note that electricity usage data is already available to customers and agents where informed consent has been clearly provided.

The current industry working group process, which the Electricity Authority is directly involved in, is proceeding well and in our view is likely to deliver appropriate design arrangements to streamline data access in the near term. A key consideration in the process is addressing long-standing concerns around how to appropriately manage privacy considerations. For this reason, it is vital that the Privacy Commission is directly involved in this work.

At the conclusion of the current industry working group process, we consider that the Electricity Authority should mandate the new arrangements within the Code as the industry size is now too big for voluntary arrangements.

[6] We agree with the panel that this obligation shouldn't necessarily just relate to paper bills as increasingly customers are wanting new innovative ways to receive bills, including e-bills.

As an aside we note that it is important that appropriate timeframes for responding to data requests are maintained. A maximum five day access timeframe is not unreasonable once the factors which can drive those timeframes such as Privacy Act requirements and poorly framed data requests are taken into account. It is however worthwhile also noting that most requests are completed much faster.

C4: Make distributors offer retailers standard terms of network access

Trustpower supports the Panel's recommendation that a legislated requirement for distributors to offer common default terms of access to their networks (or embedded networks) should be established.

Refer to our response to option F2.

C5: Prohibit Win-backs

Trustpower does not support a prohibition on win-backs.

Win-back offers have been thoroughly reviewed by the Electricity Authority and Market Development Advisory Group (**MDAG**) as recently as 12 March 2019 and neither identifies win-backs as a barrier to competition or expansion.

We think there is merit in MDAG's latest proposal and encourage the Panel to consider the option of including consumer's experiences of win-back practices in consumer switching surveys.

We acknowledge there are barriers to some consumers switching and gaining the benefits of such a switch but we have not seen evidence that the existence of win-back offers creates such a barrier. Prohibiting win-back offers is not the solution, and may lead to unintended consequences. Instead, Trustpower believes that, through the adoption of a strong package of recommendations that increase consumer engagement, the benefits of competition will be distributed more evenly across consumers. This view is shared by the ACCC. [7]

Some smaller retailers (Electric Kiwi, Flick, Pulse, Vocus) have argued that win-backs are 'unfair' and tilt the playing field in favour of the larger retailers (without providing any real evidence) when in reality it is the largest retailers who acquire the most customers and also lose the highest proportion of their sales to win-backs[8]. All retailers, regardless of size, are attempting to acquire customers, and all are exposed to the competitive pressure win-backs create[9].

The Panel mentions the telecommunications industry's ban on win-backs as an example of what the future framework in electricity could be. As a challenger brand in the telecommunications industry, we have reservations about the validity of this assumption. The industry is not a valid comparison because it does not have a registry, and there is no record on the switch request of who the gaining provider is. Many participants in the telecommunications industry also have 30-day notice periods in their customer contracts, which do not feature in electricity. Retail contracts could emerge that require customers to provide their retailer with 30 days' notice before leaving and would likely defeat the proposed changes suggested by some retailers.

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[7] The ACCC explain in their 2018 Electricity Pricing Inquiry "*that increasing the ability of consumers to compare prices in the electricity market and increasing the transparency of offers available to consumers will assist consumers, including some of these inactive consumers, to engage with the market. Doing so should lessen the efficacy of the retention-focused strategies of the big three, and share the benefits of competition more evenly across all customers.*" Pg.144 available from https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%E2%80%94Final%20Report%20June%202018_0.pdf

[8] MDAG, 2019 Saves and win-backs recommendation paper. pg. 26.

[9] The AEMC's 2018 Retail Energy Competition Review noted that "*A number of smaller retailers indicated their concerns about the prevalence and aggressiveness of win-backs, and the lack of transparency of the practice. However, all retailers interviewed acknowledged that they carried out the practice in their business, including smaller retailers*" available from https://www.aemc.gov.au/sites/default/files/2018-06/Final%20Report.pdf

Constraining the ability to contact a customer following a telecommunication transfer request to find out why they may be leaving, and attempt to keep the customer from leaving, is costly both for the consumer and the retailer. Win-backs provide a method for contacting consumers to validate the switch (ensuring they have not been "slammed" by the gaining retailer), as well as ensuring customers' existing deals, or the benefits of switching, are not misrepresented by acquiring retailers.

Our telecommunications provisioning team receive a number of queries each month from existing consumers who were only intending to get information from an alternative provider but the new service provider interpreted their call as a request to transfer. We then have to request to get the services back, and the consumer is left exposed to potential delay such as slow re-connection times. There have also been instances of services being taken away from a household due to the wrong household being provisioned – leaving consumers frustrated and confused. We sympathise with telecommunication consumers and have been strong advocates of a transparent switching process (including a registry) in telecommunications for a number of years.

Therefore, we advise against the Panel recommending option C5, as we believe that prohibiting win-backs will result in unintended consequences that will disadvantage consumers.

- Prohibiting win-backs will simply shift activity to later in the process, which was shown to be one of the consequences of the save protection scheme. This will in turn increase costs for retailers who acquire new consumers but are unable to keep them long enough to recover establishment costs. It is unclear how this would address the Panel's concerns around the emergence of a two-tier market.
- The Panel has not provided clear details as to how prohibition would work. The incumbent retailer must retain the ability to contact consumers during the switching process and notify them of contract terms, potential exit fees or other changes to any of the services they might retain with their incumbent retailer. It is worth noting that the right to contact exiting customers for these reasons has been retained in the telecommunications industry, but because of the ban on win-backs, there is confusion about whether this right can be exercised.

We would like to bring to the Panel's attention that the potential risk of significant unintended consequences was also identified by the ACCC, who ultimately decided not to limit or prohibit retention activity.

C6: Help non-switching consumers find better deals

Trustpower does not support a "mass-switching" trial being adopted in New Zealand.

The Panel's recommended package of reforms (excluding those to prohibit win-backs) will address concerns around the emergence of a two-tier market. A heavy-handed regulatory intervention like the mass-switching trials in the United Kingdom (**UK**) risks the introduction of unintended consequences.

In our experience engagement levels are higher in the New Zealand market than in the UK. Part of the reason for this is that the regulatory interventions adopted to date have been restrained and generally fit for purpose. In addition, there have been a number of structural barriers to competition in the UK market due to inefficient switching processes and technical limitations on prepayment meters.

There are a number of important elements of the UK trial that we wish to bring to the Panel's attention at this time:

- as outlined above, switching processes in the UK are much less efficient than in New Zealand, and there is a greater risk of poor consumer outcomes resulting from switches in the UK, leading to an overall lower appetite for switching;
- the potential negative impacts on dynamic efficiency have yet to be quantified for the UK trials;

- privacy considerations within the design of the UK trial may not align with expectations in New Zealand (options C3 and E6); and
- smaller retailers have largely not been involved in the UK trials to date, with those who have been limiting their exposure through capping the number of customers they are willing to acquire.

We also note that our bundled product offerings (i.e. including telecommunications services) are not widespread in the UK and other innovative products offered by Trustpower and our competitors mean it is wrong to assume that customers who have not switched have missed out on innovation and the benefits of competition. Many customers do not switch retailers frequently but do change tariffs or plans with their existing retailer – non-price attributes also matter to customers.

The focus of the UK trials has simply been on the duration spent with a retailer rather than the customer's journey with that retailer. We consider that this focus is too narrow in the New Zealand context and it is uncertain that a mass-switching trial could be designed that would not undermine competition and limit innovation in New Zealand.

C7: Introduce retail price caps

Trustpower agrees with the Panel's assessment that the introduction of price caps would do more harm than good.

We agree that the retail electricity market in New Zealand differs significantly from those in both the UK and Australia.

Section D: Reinforcing wholesale market competition

D1: Toughen rules of disclosing wholesale market information

Trustpower partially supports the Panel's recommendations to toughen information disclosure obligations.

We consider that the Electricity Authority already vigorously and effectively enforces the existing disclosure rules. We do however support the Authority identifying any gaps in its current powers, such as around fuel supplies, and progressing a Code change if required.

Information asymmetry in the gas market can have significant implications for outcomes in both the gas and electricity markets in New Zealand. This has been evidenced by the events in late 2018 where an unplanned gas production facility outage had significant implications for the electricity market.

Trustpower has strongly advocated for improvements in gas market transparency (both supply and demand side) for a number of years[10] and is pleased that the Gas Industry Co (**GIC**) is now looking into this important matter.

Our preferred solution for improvements in this area is a regulated arrangement being introduced, noting this will require changes to the Gas Act and the establishment of new regulations. We are however supportive of the GIC considering whether a voluntary arrangement could be agreed in the interim. Any arrangement (whether voluntary or regulated) will need to ensure information around gas supply availability is provided by producers in a timely fashion as they have the best up to date information around any gas supply outage (both planned and unplanned), not thermal generators who are simply intermediaries.

[10] Refer to our submissions on the GTAC development dated June 2017, September 2017, November 2017, submission on the GIC's work programme and levy in FY2019 and FY2020 and submissions to Transpower on adjustments to the Hydro Risk Curves to account for thermal limitations dated July 2018 and January 2019.

D2: Introduce mandatory market-making obligations

Trustpower does not support the introduction of mandatory market-making obligations.

All markets will go through periods of stress from time to time, and we believe the test of a well-functioning market is that excess profits are not made in the long term[11].

We acknowledge that the Panel holds concerns around the apparent fragility of the wholesale contract market and is seeking to identify improvements to the current arrangements where possible. A similar work programme by the Electricity Authority to enhance the hedge market is also underway which we support.

To assist in considering this matter, we engaged The Lantau Group (**TLG**) who have identified a number of improvements that should be considered prior to adopting a mandatory market-making arrangement:

> *"As with any market there is opportunity for further improvement, but we agree with the Electricity Authority's caution that "before we intervene in the market, we must be confident the benefits of any intervention outweigh the costs which, based on overseas experience, may be considerable. Nothing in our view from the 2017 Winter Review or the Electricity Price Review would suggest that any urgent rectification of current arrangements is warranted"*[12]
>
> *"Enhanced transparency should always be a first consideration for addressing any perceived fragility or unpredictability in current arrangements rather than to move directly to a mandatory obligation. This is especially the case when the EPR rightfully notes that "…**market-makers should not be required to assume undue risks".**"*[13]
>
> "*A "relatively quick" mandatory obligation introduction would only be possible if the extent of the risk and cost imposed on market makers were not adequately considered. The EPR paper itself, elsewhere, would appear to be more circumspect on this point with such suggestions that "new regulation would also include provisions to temporarily relax the market-making obligations when certain conditions were met." and "the level of obligation on market makers could be graduated based on a generator-retailer's size and extent of vertical integration."*
>
> *…*
>
> *A 'relatively quick' approach can often translate as a 'relatively wrong' one.*
>
> *Beginning with a mandated regulatory solution to later unwind it with a less intrusive commercial one is an approach we find difficult to understand. Especially when it is recognized that the later approach will provide "companies best placed to act as market makers". Starting with a "best placed" approach would appear to be the more logical.*
>
> *Our experience would not suggest that a voluntary scheme should take any longer to introduce than a mandatory scheme…"*[14]

TLG also provides the following advice regarding the appropriateness of Trustpower as a market maker which we wish to draw to the attention of the Panel:

> *"… we would be concerned to see Trustpower, as New Zealand's largest net retailer, caught up in an indiscriminate widening of the net under the false impression that it was just another of the larger generators. As we have noted the options to manage a market making book are quite different for a net retailer and would impose higher risks and costs on Trustpower, potentially to the detriment of greater retail competition in general."*[15]

Based on TLG's advice, we suggest that to address concerns around the fragility of market making (whether real or perceived), the Panel recommends that the Electricity Authority pursue the following measures in order of sequence and priority:

1. **Improve transparency of existing market making** - Progress a Code change to improve transparency of market making through requiring:

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[11] We note that the Panel did not identify any evidence to indicate generator-retailer profits are excessive compared to underlying costs in its First Report.

[12] The Lantau Group (2019), Market Making Requirements in New Zealand, Page 4.

[13] The Lantau Group (2019), Market Making Requirements in New Zealand, Page 33.

[14] The Lantau Group (2019), Market Making Requirements in New Zealand, Pages 31-32.

[15] The Lantau Group (2019), Market Making Requirements in New Zealand – Supplementary Paper, Page 3.

- a greater degree of reporting from existing market makers around deviations from the 5% spread requirement and any decisions to relax spreads for a period of time; and
- reporting by the ASX to the Electricity Authority on the level of market making compliance.

2. **Improve market understanding** – Develop and implement enhanced arrangements to better educate market participants around the importance of continuous hedging beyond the short term.
   - In our experience (both our years of operational experience and merger and acquisition experience) there is a real issue with some smaller retailers not having adequate risk management arrangements in place.
   - While the Electricity Authority has been active in ensuring sufficient tools are available for participants to manage their risks and that there is a general awareness of these tools, a more concentrated educational programme would in our view deliver significant benefits. A good measure of success would be well-informed market participants.
   - We also support the Electricity Authority considering the introduction of a hedging requirement for smaller retailers as part of a work programme to improve market understanding.
3. **Investigate an incentive-based scheme** – Investigate implementing a competitive tendering process for the provision of market-making services under normal market conditions, along with other potential initiatives such as:
   - reviewing the bid-ask spread requirements for market makers; and
   - integration of prudential requirements.

A copy of TLG's advice is provided as Attachment 1. TLG's supplementary advice around the appropriateness of Trustpower portfolio in providing market making services is provided in Attachment 2.

D3: Make generator-retailers release information about the profitability of their retailing activities

Trustpower partially supports the Panel's recommendation of segmented reporting for generator-retailers.

Segmented reporting will go some way towards providing a more informed basis to assess the competitiveness of the market. However, unless requirements for segmented reporting are standardised there is a risk that each generator-retailer will report differently, making it difficult to use the information to:

- identify whether cross-subsidisation is occurring within vertically integrated parties;
- help educate smaller new entrant retailers around how the market works and the associated costs of electricity supply that all parties face; and
- enable interested parties to more accurately determine the value contributed from each segment within a vertically integrated business.

Even with standardisation it is unclear that segmented reporting will go far enough to address concerns with a lack of transparency around profitability of the retailing activities of generator-retailers.

In our view segmented reporting requirements for all generator-retailers should be:

- standardised and made mandatory within the Code, subject to a de-minimis threshold (if required);

- conscious of generally accepted accounting principles;
- seek to align with existing disclosure requirements to minimise compliance costs and enable efficiencies through inclusion in existing annual reporting for publically listed companies; and
- complemented by additional disclosure obligations around internal mass market transfer pricing for vertically integrated firms (consolidated with their subsidiaries)[16] to ensure complete transparency of transfer prices.

Additional disclosure obligations could leverage off the existing hedge disclosure arrangements[17] under Part 13 of the Code to include internal mass market transfer pricing (and estimated quantity) of vertically integrated participants. Information could be released annually in arrears. To allow the benefits of information disclosure to be fully realised, information around internal mass market transfer pricing should not be anonymised like other information published on the Electricity Hedge Disclosure System.

The existing hedge disclosure arrangements have the benefit of an established and effective governance framework and would enable the existing systems and supporting processes for providing information to be leveraged. All existing participants are familiar with these arrangements, suggesting that significant additional cost would not be associated with this solution.

Further details of the exact information around internal mass market transfer pricing to be published could be developed by the Electricity Authority in consultation with industry.

D4: Monitor contract prices and generation costs more closely

Trustpower partially supports the Panel's proposal that the Electricity Authority should undertake enhanced monitoring of generator-retailer profits.

It is however important that the state of competition is assessed over a reasonable timeframe in the context of an industry which is subject to cycles of over and underinvestment. It is relatively easy for a new entrant to come in at times of over-investment and undercut the established players. However, the long term interests of consumers are best served by sustainable competition which survives the periods of underinvestment as well as over investment.

We do not think there is any evidence of excess profits being made, and it is too early to say if the surge of new entrants will survive forthcoming periods of tighter supply, so it may be premature to recommend any change to the current work programme of the Electricity Authority. However, if the Panel wants to recommend enhanced market monitoring to provide greater confidence in the wholesale market in the light of stakeholder concerns, then we agree that a comparison of contract prices to new generation costs is the most appropriate tool and could be reported annually, subject to the caveat around investment timing above.

We note that this additional monitoring is well within the Authority's expertise and powers and so would not require legislation to implement.

D5: Prohibit vertically integrated companies

Trustpower supports the Panel's preliminary view that there is no need to prohibit vertically integrated companies.

[16] We do not consider at this time it is necessary for "virtually" vertically integrated firms (i.e. those firms that have achieved vertical integration through contracting arrangements) to disclose information as there is no underlying risk of cross-subsidisation for these parties.

[17] Under the existing hedge disclosure arrangements, information relating to risk management contracts for commercial and industrial customers are submitted to the Electricity Hedge Disclosure System (https://www.electricitycontract.co.nz/) no later than 10 business days after the trade date, or 5 business days in the case of contract for differences or an options contract.

We consider that vertical integration is a pragmatic and effective risk management tool that supports cost-efficiencies, and that vertical integration is not problematic in the New Zealand electricity market. In fact, vertical integration is available at any scale. There are a large number of small generators and retailers in the industry who are already forming partnerships and exchanging contracts. Vertical integration should be seen as an efficient solution to risk management rather than an inefficient problem.

Section E: Improving Transmission and Distribution

E1: Issue a Government Policy Statement (GPS) on transmission pricing

Trustpower supports a GPS being issued which sets out the principles and processes the regulator should follow in developing replacement Transmission Pricing Methodology (**TPM**) Guidelines and approving a TPM prepared by Transpower.

A GPS is a useful vehicle for the Government to provide guidance on how it thinks the Authority's statutory objective (including the objectives of promoting the efficient operation of the industry and the long term interests of consumers) should be interpreted in the context of transmission pricing by expressing its views on:

- the primary purpose of the TPM;
- the respective roles of Transpower and the regulator in developing and reviewing the TPM;
- how the impact on investors and consumers should be factored into the regulator's decision-making;
- the substance of the methodology itself including tariff structure, transmission counterparties, and preferred allocation method;
- the need for adequate transition arrangements to manage price shocks; and
- the process that should be followed in completing this and any subsequent reform.

This would go a long way towards addressing the difficult and contentious issues which the sector has grappled with in the Electricity Authority's TPM reform process.

Trustpower agrees with the Panel that, the extent to which transmission prices should factor in *when and where assets are used*, is one of the issues at the heart of the transmission pricing debate.

This is also an issue at the heart of the debate about distribution pricing as well. The Electricity Authority has adopted the same Decision-making and Economic framework for reform of both transmission and distribution pricing and has recently consulted on a proposal to amend the distribution pricing principles to provide that "prices need to signal the economic cost of service provision by being **time and location specific**" (*emphasis added*).

The Electricity Authority's preferred solution for network pricing is an area of benefit (**AOB**) charge. The aim of the AOB charge is first to allocate costs of individual network investment to areas of benefit (i.e. geographic locations on the network) and then secondly to allocate the costs to customers within those areas based on the private benefits they are said to obtain from those assets.

Once allocated the charges are fixed, so as to prevent customers from changing their consumption behaviour. The concept is that the threat of these charges being levied will provide incentives on parties to change their demand so as to avoid network investment until the last possible point. Thus implicit within these charges is a notion of a price shock when that point is reached.

Trustpower does not think that the AOB charge works to achieve either pricing efficiency or equity. Our reasons are set out in the following table.

Is AOB efficient?	Is AOB fair?
• The modelling complexities, network expenditure approval processes, and actions of other customers could all combine to mean that the price signal is not sufficiently clear, certain or timely to have the desired effect. • The charge does not cater well for entry and exit of network customers or for network build ahead of demand which can be efficient. • There is also a risk that lobbying will result in efficient investment not being made (which may not align very well with the Government's climate change objectives)	• The charge is highly assumption dependent meaning that a range of outcomes is possible for each network customer • The AOB charge results in higher costs for services supplied by new assets rather than old assets. This could mean at the distribution level that customers on the same street receiving the same service face different prices. • AOB charges incorporate rate shock by design which may adversely impact some customer groups more than others. • Transition to an AOB charge is likely to penalise those who have invested based on the current rules.

It follows that we do not support this charge for existing assets, selected assets or assets yet to be built.

We also note that another issue in the transmission pricing debate is who the appropriate counterparties for each charge are. As a general rule we do not support the allocation of additional charges to generators – either existing and/or new - as we think that charging generators will only serve to delay investment in new generation. This is because wholesale prices would need to rise higher than they would otherwise before new investment becomes economic and development occurs. Given that these transmission costs would be passed through to consumers via higher wholesale energy costs, it is more efficient to sheet them home directly to end consumers – and to ensure they are not inflated in the pass-through.

However, we accept that there would be significant distributional impacts for consumers in changing the counterparties who are currently allocated the HVDC charge. Therefore we support Transpower's pragmatic solution that this charge remains allocated to generators but for equity considerations include all generators, not just generators located in the South Island.

As a practical contribution to the Panel's work, Trustpower commissioned Law+Policy Limited (**L+P**) to prepare a GPS which reflects these views. The L+P draft GPS and the accompanying explanatory diagram are provided as Attachment 3. This material has also been shared with members of the TPM Group[18].

As noted in our submission on the First Report (para 29.1.6) we think it should be mandatory for the regulator to give effect to this GPS but note there is no reason why a GPS could not be issued immediately under section 17 of the Electricity Industry Act until the Act is amended to implement a mandatory requirement.

E2: Issue a government policy statement on distribution pricing

Trustpower also supports a GPS on distribution pricing. At the very least we think it is important that the Government signals its support for a shift from the current volumetric pricing to pricing which better reflects the services being provided.

[18] The TPM Group formed in 2016 due to shared concerns around the Electricity Authority's proposed changes to the TPM. The group comprises of organisations from right across the electricity sector including large consumers, stakeholder groups, electricity network companies and electricity generators and retailers. Current active members of the TPM Group include: Counties Power, EMA Northern, Federated Farmers (Northland), Horizon Networks, Norske Skog Tasman Ltd, Northpower, Oji Fibre Solutions, Top Energy and Trustpower.

We also think that there is value in a GPS providing guidance on the timeframes over which reform should occur, how transitions should be managed and relevant stakeholders engaged in the reform process. The L+P draft GPS addresses these issues.

The Government may wish to go further and provide guidance on:

- the preferred degree of standardisation or granularity of cost reflectiveness; or
- how prices should be allocated between urban and rural consumers and/or business and residential consumers.

As noted above, we do not think the adoption of the AOB charge in distribution networks will facilitate the delivery of fair and efficient prices. Instead, such charges are more likely to undo all the other reforms proposed in the Options Paper. This is why we have suggested the Consumer Advisory Council is involved in sequencing these reforms.

E3: Regulate distribution cost allocation principles

Trustpower supports the regulation of distribution pricing principles. This aligns with our view that there should be a mandatory GPS on distribution pricing. Regulation will "cascade down" the GPS requirements (which apply to regulators) to the distributors themselves.

E4: Limit price shocks from distribution price increases

Trustpower supports a policy that distributors would be required to ensure that any price increases did not result in unacceptable price shocks for consumers. This could be one of the regulated pricing principles.

The process described in the Options Paper of approved tariff structure statements is one method by which this policy could be introduced but it may not be needed if the principles are adopted by the distributors without this step. This is something which could be assessed at the proposed three year review.

E5: Phase out low fixed charge tariff regulations

Trustpower supports amendments to the LFC Regulations that would provide for a gradual rise in the fixed prices distributors and retailers must offer to low-use residential customers from 2020 until the advantage currently afforded to low users disappears.

Our reasons for supporting the repeal of the LFC Regulations through a measured transition process are set out in our submission on the Panel's First Report (see paragraphs 30.1.1 to 30.1.3).

E6: Ensure access to smart meter data on reasonable terms

Trustpower supports the policy that distributors should be able to access smart meter data on reasonable terms (as further explained below) to assist them to identify and repair faults and to improve their network planning and operations.

To our mind reasonable terms include:

- pricing which reflects;
    - the risks that retailers have already taken in entering long-term contracts to support the roll out of new meter technology;

   - the benefit that the distributors will receive from the use of data; and
   - recovery of any costs retailers may incur around systems to make data available in the format required;
- protection against unreasonable costs (e.g. where the request relates to real-time information when equipment is unable to provide for this information);
- relief from statutory timeframes where the data request is inaccurate, incomplete or poorly framed;
- robust safeguards regarding all parties' privacy risks, and
- a clear framework and understanding around how the data can be used by distributors.

The current industry working group process is proceeding well and likely to deliver appropriate design arrangements in the near term. However, we do not think it is practicable to implement this access solution by way of voluntary protocol or multilateral agreement given the number of parties who will need to be involved (and the value of having appropriate governance around the rules through the use of audits and suitable enforcement mechanisms etc.). This suggests that a mandatory arrangement (e.g. amendment to the Code) will be required.

E7: Strengthen the Commerce Commission's powers to regulate distributors' performance

Trustpower supports the Panel's proposal to give the Commerce Commission more powers to regulate distributors' performance if that would be better for consumers.

Trustpower is a national retailer and on behalf of its customers is keen to see any initiatives that would act to lower the cost of the distribution service and/or improve quality of supply such as improved asset management practices. The regulator should be empowered to act if that does not occur, or if evidence emerges that there is an outlier non-performer.

We are pleased the Panel supports our suggestion that the Commerce Act be amended to allow the Commerce Commission to benchmark distributor performance in the light of the TDB study[19] but agree that benchmarking should be used cautiously as an input in setting prices. Our view is that it may be better used as a tool to identify where more scrutiny is warranted.

E8: Require small distributors to amalgamate

Trustpower is undecided as to whether it is necessary to regulate for the amalgamation of the smaller distributors whilst still allowing affected trusts to maintain ownership interests and receive and distribute income to local communities.

Trustpower noted in its submission on the First Report the advantages of having fewer but larger distributors (see paragraphs 21.1.16). This would seem to be in the long-term interests of consumers in the relevant districts. We also note it is possible that strengthened powers for the Commerce Commission to regulate distributors' performance may result in more contracting and joint ventures between distributors. This suggests that further consideration of regulated amalgamations should be deferred until the proposed three year review. This would provide an opportunity for small distributors to respond to the concerns which have been raised of their own volition.

[19] TDB Advisory, Estimated Efficiency Gains from Amalgamation of Electricity Distribution Businesses (31 August 2018).

E9: Lower Transpower 's and distributors' asset values and rates of return

Trustpower supports the Panel's decision not to unwind the asset valuations of Transpower and the distributors set when Part 4 of the Commerce Act was introduced. Many elements of these valuations have already been tested in the High Court.

We also support the Panel's recommendation not to lower the rate of return set by the Commerce Commission as suitable for these businesses for the same reason.

However, we do suggest that Panel reconsider our suggestion that the "x" factor be set as a mechanism to *incentivise greater efficiency* rather than merely reflect the *expected long-run demonstrable efficiency patterns*. We acknowledge this will require a change to section 53P of the Commerce Act.

Section F: Improving the Regulatory System

F1: Give the Electricity Authority clearer, more flexible powers to regulate network access for distributed energy service

Trustpower partially supports the Panel's proposal**.** We support a regulator having powers to regulate for default terms of access to distribution networks to constrain monopoly behaviours. Default terms already apply for access to the transmission network and connection of distributed generation to a distribution network. However, as noted in our response to option F2 below, we think that these powers should be with the Commerce Commission, not the Electricity Authority.

Trustpower partially supports the Panel's proposal to amend the provisions in Part 3 of the Electricity Industry Act to provide more flexibility for the regulator to develop and apply restrictions on distributors engaging in contestable activities based on evidence of benefits to consumers.

We think a single regulator should determine whether consumer interests are best served by:

- permitting a distributor to invest in non-wire alternatives in certain circumstances; or
- ensuring a level playing field in relation to contestable activities by, for example requiring the procurement of non-wire alternatives to occur on an arm's length basis.

Our submission on the First Report suggested this function be transferred to the Commerce Commission.

As a consequence, Trustpower does not support the proposal to change section 54V. Under our alternative proposal to transfer all network regulation to the Commerce Commission, it would not be necessary to refine section 54V to ensure the effective coordination of the functions of the Electricity Authority and the Commerce Commission.

F2: Transfer the Electricity Authority's transmission and distribution-related regulatory functions to the Commerce Commission

Trustpower does not support the Panel's decision to retain transmission and distribution-related functions with the Electricity Authority. The current boundary involves a separation of responsibility for revenue adequacy and quality requirements from price and non-price access terms for both transmission and distribution pricing which is inefficient and likely to remain so.

For example, it is not clear to us what assumptions the regulator determining price-quality paths should make about the efficiencies to be achieved from pricing reform when considering requests for accelerated depreciation or approval of asset management plans when responsibility for overseeing or enforcing the relevant price reform lies with another regulator.

Transmission-related functions - We have already outlined some of the problematic features of the current role allocation in relation to the regulation of transmission network in our earlier submissions and so those arguments are not repeated here, but are, we believe, still valid.

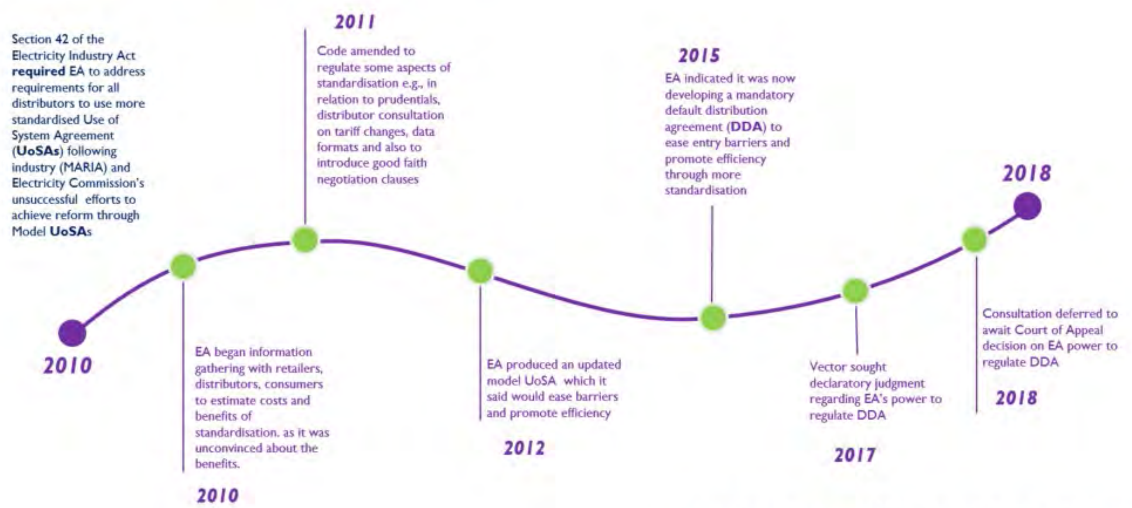
We note the original reason for not transferring the transmission related regulatory functions to the Commerce Commission when the Electricity Authority was established was because these functions interrelate with the operation and efficiency of the market.

We understand the importance of ensuring that any pricing methodology adopted for transmission does not interfere with nodal pricing signals but consider that this can be addressed in the terms of the relevant pricing principles.

Distribution-related functions - The industry regulator has struggled to make effective progress in the regulation of distribution access terms and distribution pricing. This is depicted in the timelines below which show the slow progress of use of system and distribution pricing reform despite these being set as a priority in the last Governmental review.

Relevantly our perusal of the Electricity Authority's Annual Reports shows that in 2015 the Electricity Authority removed its 2014-18 Statement of Intent measures of "*improved efficiency in transmission and distribution networks"* as it was "*unable to measure it at this stage*".

Figure 1: Timeline showing regulatory activities in relation to default distribution agreements



Source: Annual reports and EA's Section 42 report to Government

Figure 2: Timeline showing regulatory activities in relation to distribution pricing principles

Source: Annual reports (and recent consultation document)

As a consequence, we are not confident that the current role allocation is working well for consumers.

We also note that the regulators are struggling with the role allocation as well. The recent Court of Appeal decision on the Electricity Authority's power to regulate a default distribution agreement gives primacy to the Commerce Commission's power to regulate the service and quality standards which must be supplied by regulated line companies. This leaves the Electricity Authority with a role of regulating some but not all access terms. This decision reinforces our earlier recommendation that all access terms should be governed by the Commerce Commission.

F3: Give regulators environmental and fairness goals

Trustpower supports the Panel's decision not to include environmental and fairness objectives in the functions of the Electricity Authority or Commerce Commission. Our reasons are set out in paragraphs 29.1.1 to 29.1.3 of our submission on the Panel's First Report.

Trustpower does not support the Panel's suggestion that section 16 of the Electricity Industry Act be amended to add another function to the Electricity Authority's existing functions, namely that it make, administer, investigate and enforce the Code, undertake market facilitation measures, and/or undertake industry and market monitoring for the protection of household and small business consumers.

We think this is a potentially very significant and uncertain extension of its functions. We also note that household and small business consumers cannot be bound by the Code which creates a risk of non-reciprocal obligations and/or information flows. However, we would support the inclusion of specific functions such as a power to regulate to set a mandatory minimum standard to protect vulnerable and medically dependent consumers (option B6). Another alternative would be to give the Electricity Authority the power to recommend to the Minister of Energy that she makes regulations on arrangements to protect households and small businesses on certain matters.

F4: Allow Electricity Authority decisions to be appealed on their merits

Trustpower does not support the Panel's view that there is no need to amend the Electricity Industry Act to permit regulatory decisions of the Electricity Authority to be appealed on the merits.

The Panel acknowledges that no entity is infallible and rights of appeal can reduce the risk of regulatory errors or poorly reasoned decisions that undermine confidence and increase investor risk. However the Panel believes:

- appeals are a remedy for those with financial means only; and that
- a better way to promote regulatory accountability is to ensure regulatory objectives (including any implicit trade-offs) are clear and that sound consultation processes are followed.

As noted in our previous submission to the Panel, Trustpower thinks both ex-ante and ex-post accountability measures are required for an entity with the power to amend the Code which governs the sector at any time.

We support increased clarity on regulatory objectives and proper consultation. The L+P draft policy statement contains suggestions on both matters in the context of network pricing. However, this still leaves the situation where a regulator may be operating without sufficient evidence for its views. In such circumstances, we do not think regulated entities should only have recourse to a remedy (judicial review) which is very uncertain in its scope.

Our view is that the "prize" of improved regulatory decision-making, market and investor confidence is simply too big to set aside.

To support this view we have sought advice from a leading QC in this area. Jack Hodder QC's advice highlights the public interest in having high-quality decisions in market and economic regulation and notes that concerns about costs and delays associated with merits appeals can be reduced by a range of design features.

Significantly he notes that:

> *"the ideal of high quality decision-making – impartial, fully informed, and fully defensible on logical grounds – is in the interests of* ***consumers*** *as well as other intended parties. And the availability of a merits appeal* ***incentivises regulators to make high quality decisions*** *in the first place." (emphasis added)*

A copy of Jack Hodder QC's advice is provided in Attachment 4.

F5: Update the Electricity Authority's compliance framework and strengthen its information-gathering powers

Review of compliance framework - Trustpower supports a review of the Electricity Authority's compliance framework. As noted in our submission on the Panel's First Report, we think there should be a clear separation between the functions of rule-maker and rule-enforcer.

As a minimum, we would like to see the compliance functions of receiving complaints, investigating complaints, overseeing settlements and taking enforcement action fully ring-fenced from the regulatory responsibility for market design and performance.

As noted in previous submissions we think there could be economies of scale in having a combined compliance function for both electricity and gas.

Information gathering powers - Trustpower does not support an expansion of the Electricity Authority's information gathering powers.

The Electricity Authority currently has very broad powers to acquire information to enable it to provide advice on any matter relating to the competition in, reliable supply by, or the efficient operation of the industry.

- Under section 46 of the Electricity Industry Act it can require an industry participant to supply information, permit its employees to be interviewed and/or give any other assistance that may be necessary to carry out its functions.

- These functions include the power under section 16 (1)(g) "*to undertake industry and market monitoring, and carry out and make publicly available reviews, studies, and inquiries into any matter relating to the electricity industry*".
- The Electricity Authority's powers currently go well beyond compliance investigations and include all manner of market studies.
- Any exercise of these powers will have compliance costs for the affected industry participants and raise issues in relation to obligations of confidentiality and privacy, and commercial sensitivity.
- However, there is no threshold of public interest before they can be deployed.

Further, the Electricity Authority's current powers appear to be wider than those recently granted to the Commerce Commission. For example under the Electricity Industry Act there is no requirement for any study undertaken by the Electricity Authority to be published (if it falls within the category of industry monitoring), nor is there any statutory obligation to give affected participants the opportunity to comment on a review results before they are made public.

The Options Paper does not explain why the Panel thinks it is desirable for the Electricity Authority to have additional powers to undertake reviews, studies or inquiries on matters outside of the Electricity Authority's objectives such as inquiries in relation to fairness or environmental performance.

We think there is a real risk that this would take the Authority outside of its expertise. There is also no need for this power. The recently modernised Inquires Act 2013 gives the Minister powers to obtain information, order disclosure, and summon persons to give evidence if she wishes to examine a particular element of the industry. This Act also contains appropriate natural justice and public reporting requirements.

F6: Establish an electricity and gas regulator

Trustpower supports the establishment of a combined electricity and gas regulator incorporating the market functions of the Electricity Authority with the market functions of the GIC.

However we think the network regulation functions of the GIC such as its powers to set reasonable terms and conditions "*for access to and use of transmission and distribution pipelines*" or to "*require expansions, upgrades or service quality improvements to gas transmission pipelines*" (as set out in section 43F(2) (c) and (d) of the Gas Act) should also be transferred to the Commerce Commission. This is consistent with our response to option F4.

The benefits of a combined regulator would include:

- greater consistency in the regulation of arrangements affecting consumer outcomes such as model retail contracts and default distribution terms;
- improved interface between the wholesale gas and electricity markets including in relation to information disclosure and critical contingency management;
- greater independence in the gas sector governance (the independent directors of GIC are elected by those they govern);
- more stability in gas governance (as an industry body GIC can be dis-established by either the Minister (by following the process in section 43ZM of the Gas Act) or its shareholders at any time; and
- cost savings from synergies in corporate costs, including in relation to the Board, senior management, premises and statutory reporting requirements.

Section G: Preparing for a low-carbon future.

G1: Set up a fund to encourage more innovation

Trustpower does not support the option of a contestable fund, paid for by industry levies, to foster innovation in the electricity sector. Such innovation should be driven by industry competition with its inherent desire to test emerging technology and implement workable and efficient initiatives.

G2: Examine the security and resilience of electricity supply

Trustpower supports a review of the security, reliability, and resilience of the electricity supply system. It is our opinion that such a review should not be a one-off activity, but a re-occurring one that reflects the pace of technological change, disruption, and growth. It is also plausible that many issues may not be apparent or have shown up in a fixed 12 month period.

To provide a measure of distance from the regulator, this programme should be led and undertaken by the Security and Reliability Council, who would need to receive independent funding and access to resources to carry out this work.

G3: Encourage more coordination among agencies

Trustpower is supportive of more 'joined up' thinking and coordinated action between agencies that regulate or advise on matters relevant to the energy industry.

G4: Improve the energy efficiency of new and existing buildings

Trustpower support amending the building code to strengthen the energy efficiency of new buildings and improve the quality of rental housing. We believe this will go some way to address issues experienced by customers in energy hardship.

Final Paper

Prepared For:

Trustpower

Market Making Requirements in New Zealand

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1. EXECUTIVE SUMMARY

1.1. Objective of this Paper

The Lantau Group (HK) Limited ("TLG") has been appointed by Trustpower to review the current market making situation in New Zealand and to comment on the need for any additional market making requirements. This paper considers:

- The current market making situation in New Zealand;
- International context for market making in electricity markets;
- Whether additional market making requirements are required; and
- Any other market making issues that we believe warrant further consideration.

1.2. Conclusions

Our concluding view is that the current ASX hedge market is working well. In the few isolated instances of spreads widening (the 2017 Winter and the Spring of 2018) this has followed spot prices rising due to supply disruptions (hydrological conditions or gas curtailment). The various Electricity Authority reviews that have followed these isolated instances have generally concluded that the hedge market performed as expected. Parties who hedge before spot prices began to rise had little concern with managing their spot price risk. Further, we observe that participant hedge positions were still being sought and matched during these volatile periods. This is a sure sign of a well-functioning market.

We are also mindful that the ASX hedge platform is just one of several avenues for participants to hedge. However, in providing a transparent forward curve the ASX hedge market facilitates "the increased use of customised OTC hedge agreements, which are likely to remain the predominant hedging instrument for many parties".

As with any market there is opportunity for further improvement, but we agree with the Electricity Authority's caution that "before we intervene in the market, we must be confident the benefits of any intervention outweigh the costs which, based on overseas experience, may be considerable." Nothing in our view from the 2017 Winter Review or the Electricity Price Review would suggest that any urgent rectification of current arrangements is warranted.

Also, nothing we have seen in New Zealand's experience supports expanding market making beyond the current 4 voluntary market makers in place. The 2011 Electricity Authority review supported this view stating that "introducing a tighter code-based market-making obligation is unlikely to yield net benefits if four or more parties are already actively providing these services on a voluntary basis".

International precedent has not been a strong supporter of mandatory market making obligations. The UK's model is in the process of collapsing, Singapore has opted for a voluntary approach and recent events in Australia have seen the ESB recommendations to COAG stall while the AEMC are consulting with the industry on voluntary arrangements.

We were concerned to see claims from smaller retailers that the hedge market fails to provide effective risk management in times of market stress. We concur with the Authority's view that "it is up to participants to be aware of, and manage the risk of, potential high spot prices". We believe that the best and most appropriate response to this claim is for an increased focus on market education around the importance of continuous hedging, combined with the current quarterly stress test arrangements. If this fails to see an improvement in hedge strategies emerging, then we suggest that consideration be given to some form of retail hedging requirement as adopted in Singapore.

We also believe that enhanced transparency around the current voluntary market making arrangements will help to improve general market confidence. Should signs indicate that the current voluntary market makers can no longer sustain the increased risk and cost that market making imposes then we would suggest that an incentivized arrangement be considered with the cost spread over all consumers. As noted by the ACCC "…voluntary market making schemes … have the potential to be implemented in a shorter timeframe than compulsory obligations."

There are also a number of other areas we think the EPR should consider improving current market making conditions. These include more efficient prudential arrangements and balancing market maker spreads with liquidity requirements.

2. CURRENT STATUS OF MARKET MAKING IN NEW ZEALAND

2.1. Current Arrangements

While New Zealand has had a hedge market since 2004 with *EnergyHedge*, over the counter (OTC) contracts for difference (cfd) were being traded well before that time, dating back to ECNZ offering a broad variety of customised contracts[1].

In 2009 a ministerial review into the performance of the electricity market resulted in obligations being placed on the major generator companies concerning the establishment of a more transparent and liquid hedge market. The large generators (over 500 MW of capacity) were requested to put in place an electricity hedge market by 1 June 2010 with the following attributes:

- standardised, tradable contracts;
- a clearing house to act as a counter-party for all trades;
- low barriers to participation and low transaction costs;
- market-makers to provide liquidity.

The Government set a target for this newly formed hedge market to achieve satisfactory market depth by 1 June 2011, expressed as 3,000 GWh of unmatched open interest.

The large generators selected ASX as their preferred exchange and New Zealand electricity futures were listed in 2009. ASX New Zealand Electricity futures and options are standardised and centrally cleared financial contracts, cash-settled against two grid reference nodes (Otahuhu and Benmore).

At the current time ASX offers the following contracts for the New Zealand market[2]:

- Base load futures (Monthly, Quarterly, Strip)
- Peak load futures (Quarterly)
- Average rate options over base load quarterly futures
- Calendar year strip options over base load quarterly futures

[1] M-co (the wholesale market operator) took over settling the ECNZ's cfd hedge book upon its disestablishment in 1999, novating the contracts to the newly formed baby SOE generators.

[2] These were initially traded in 1MW contracts, but moved to 0.1MW contracts in 2015 in order to make it easier for the smaller players to participate.

In addition to the above, ASX is planning to introduce two cap products to the hedge market. The cap products are intended to enable sellers of electricity to gain more stable income for infrequently used plants and will help to underwrite or support new investments[3].

Market making was introduced in 2010. New Zealand's four largest generator-retailers post prices for each day for a 30-minute period. Initially market making was only for quarterly baseload (flat) contracts but now includes monthly baseload contracts. Market making for cap contracts has been identified as a next step. ASX offers a market making incentive scheme to promote liquidity in the Benmore and Otahuhu Base Load Electricity Futures markets in the form of a share of a revenue pool. The incentive is available to each of the appointed market makers when making markets in accordance with the following market making specifications:

Figure 1: Market Making Requirements, Otahuhu and Benmore Base Load Monthly Futures

Minimum Time Requirement	Minimum Liquidity Requirement	Maximum Spread Requirement
Generally required to provide continuous two-way quotes in the front 6 months between 3:30pm - 4:00pm on general business days in Auckland and Wellington.	Minimum volume of 20 contracts per side, with a refresh of 10 contract traded.	If contract price is above NZ$30, each offer must be no more than 5% above corresponding bid. If contract price is below NZ$30, each offer must be no more than 10% above corresponding bid.

Source: ASX website (www.asx.com.au/products/market-maker-arrangements.htm)

Figure 2: Market Making Requirements, Otahuhu and Benmore Base Load Quarterly Futures

Minimum Time Requirement	Minimum Liquidity Requirement	Maximum Spread Requirement
Generally required to provide continuous two-way quotes in all quarters between 3:30pm - 4:00pm on general business days in Auckland and Wellington.	Minimum volume of 30 contracts per side, with a refresh of 10 contract if traded.	If contract price is above NZ$30, each offer must be no more than 5% above corresponding bid. If contract price is below NZ$30, each offer must be no more than 10% above corresponding bid.

Source: ASX website (www.asx.com.au/products/market-maker-arrangements.htm)

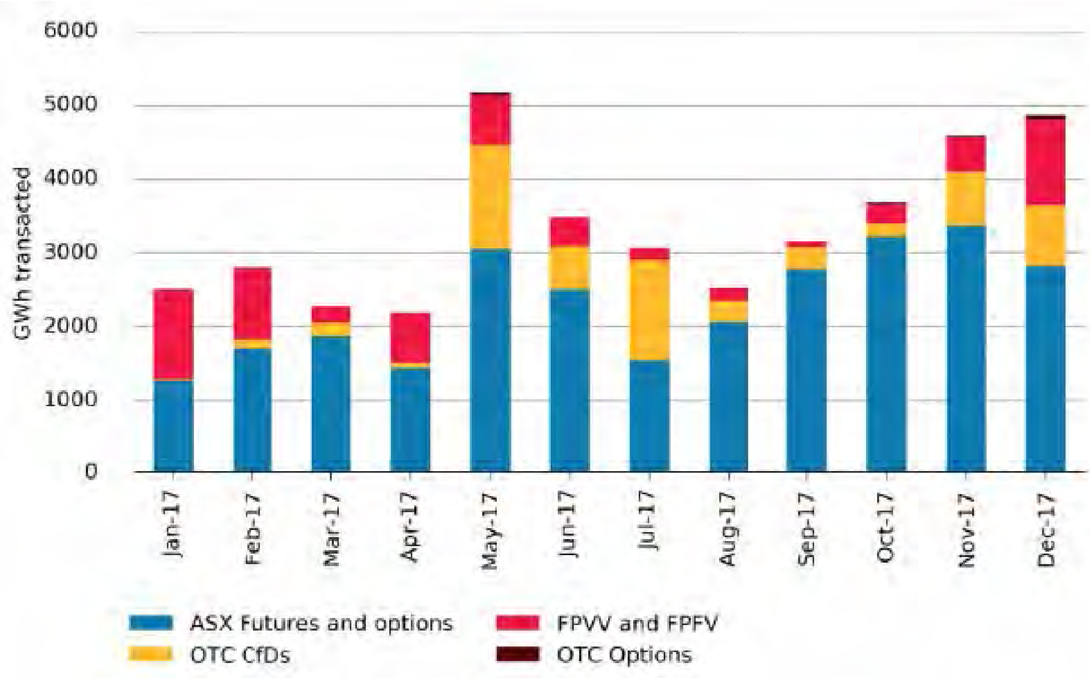
2.2. Benefits of a Liquid Hedge Market

Generally, a liquid and deep hedge market provides opportunities for generators, retailers and large consumers to effectively manage spot price risk arising from the inherent volatility of wholesale prices.

[3] Tim Street, Electricity Authority, Hedge Market Breaks Records,14 December 2017

However, it must be remembered that exchange traded hedge instruments are just one form of hedging available. As well as physical hedging through vertical integration between generation and retail businesses, New Zealand also has OTC trading and large customer contracts (commercial and industrial) with embedded hedging elements (i.e. fixed price variable volume (FPVV) and fixed price fixed volume (FPFV) contracts).

Figure 3: All NZ forward market transactions 2017



Source: Electricity Authority, 2017 Winter Review, Final Report, 18 June 2018

Market making through exchange trades will incur higher working capital costs through the margins to exchange participants, while the trade of OTC cfds will require the rationing of trades with counterparties according to their credit worthiness.

However, one key advantage to market participants of exchange traded products that is often undervalued is the development of a transparent future price curve. Large consumers can use this future price curve to evaluate the competitiveness of fixed price contracts being offered by suppliers. This is consistent with one of the intended objectives of the New Zealand hedge market arrangements "...to provide more transparent and robust forward price signals"[4]. In addition, longer term price signalling assists investment decisions by participants (although this should be balanced with the recovery period of most significant investments extending well beyond the price curves possible from future markets, which in any case get quite thin in the out years).

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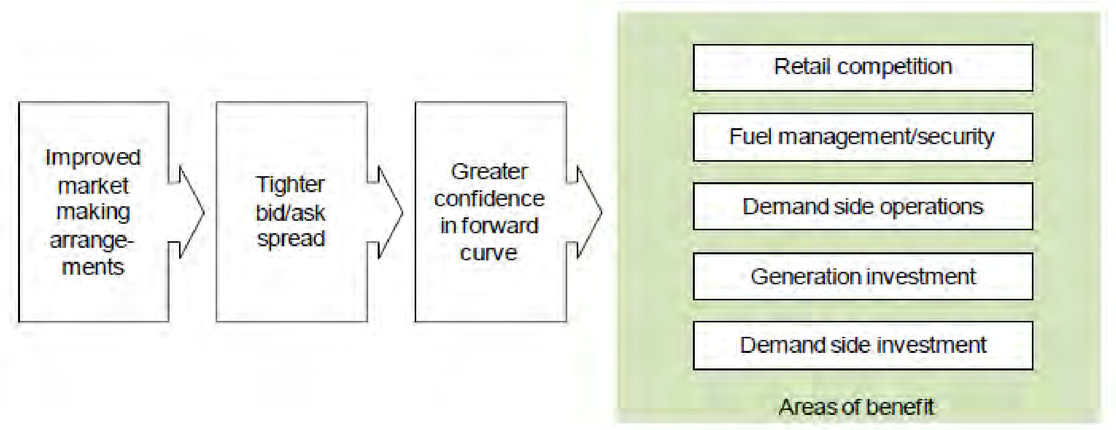
[4] Electricity Authority website, www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development

The Electricity Authority's 2011 report on market making noted in respect of economic benefits that increasing hedging does not, in itself, represent a net benefit (given that hedging constitutes a transfer of cost/risk from one party to another or from one point in time to another). Benefits arise because the presence of more robust hedging arrangements and information about the forward curve allows parties to take actions that they would not otherwise undertake. Moreover, parties do not need to actively trade futures contracts to obtain these benefits. A more robust forward price curve would facilitate ***the increased use of customised OTC hedge agreements, which are likely to remain the predominant hedging instrument for many parties***.

Figure 4: Linkage between market-making and economic benefits



Source: Electricity Authority, Cost Benefit Analysis – Market-Making Obligations, 21 November 2011

Another possible advantage of forward traded products can be in the area of curbing the exercise of spot market power. This is because:

- Contracting volumes forward reduces the ability for dominant generators to influence spot prices – this is similar to the original vesting contract arrangements put in place in 1996, and
- Having a 2nd regulator watching improves market surveillance, especially when manipulating the underlying market to profit in the paper market carries serious criminal penalties in most jurisdictions under relevant financial/security market laws.

However, forward traded products can afford physical players greater flexibility in how they position themselves in the spot market – for example a generator-retailer with forward cover on their retail load could chose to generate less. This can lead to less market predictability and price volatility. In New Zealand's case we note that a large generator swaption is also in place to support market competitiveness.

2.3. 2017 WINTER

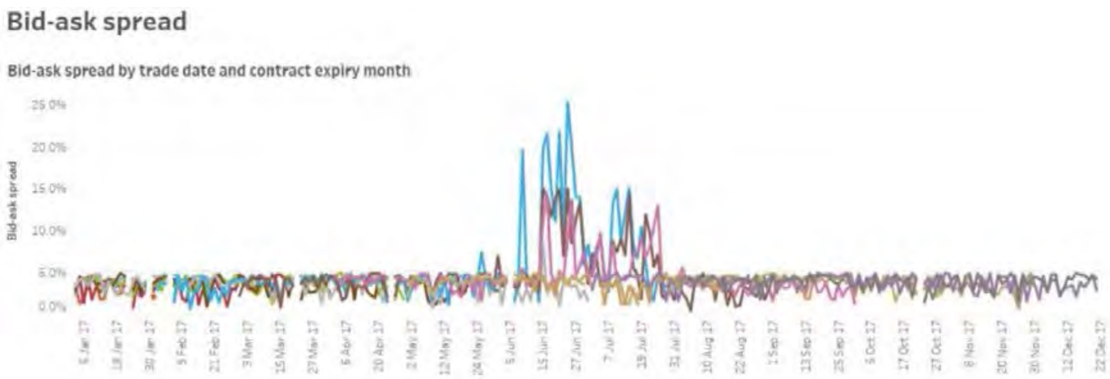
The New Zealand electricity system is prone to the impact of climatic events due to its dependency on hydro generation characterised by limited storage capacity. In 2017 low South Island hydro inflows caused storage to fall to their lowest level since 2008.

Figure 5: New Zealand controlled storage and hydro risk curves in 2017

Source: Electricity Authority, 2017 Winter Review, Final Report, 18 June 2018

The Electricity Authority noted that the market broadly performed as expected during the 2017 winter, with prices rising to signal increasing risk and participants making decisions to mitigate spot price risk exposures. However, bid-ask spreads on the ASX futures market widened (refer Figure 6 and Figure 7) and to levels that meant very high price volatility and a consequent high cost to trading in and out of positions.[5]

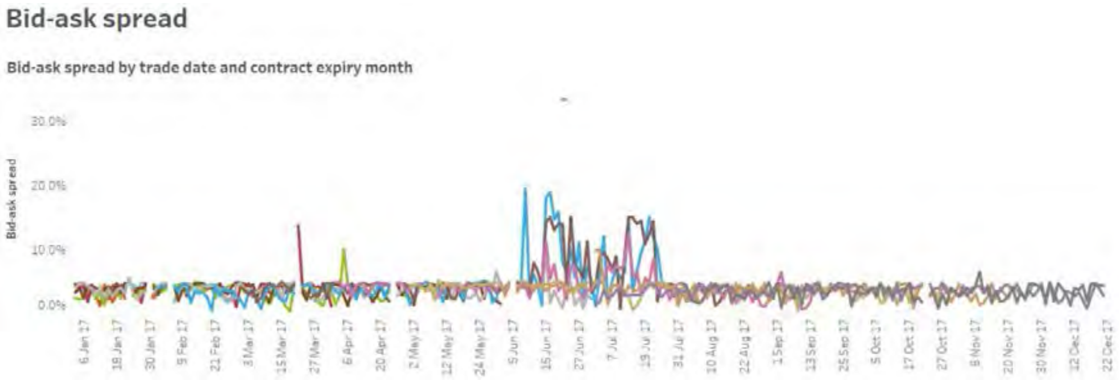
Figure 6: Bid-ask spreads at Benmore 2017



Source: Electricity Authority, 2017 Winter Review, Final Report, 18 June 2018

[5] Electricity Authority, 2017 Winter Review, Final Report, 18 June 2018

Figure 7: Bid-ask spreads at Otahuhu 2017



Source: Electricity Authority, 2017 Winter Review, Final Report, 18 June 2018

The increased bid-ask spreads mostly related to the front monthly contracts (not quarterly or out months). This would indicate that those parties seeking hedge coverage in advance of the spot market experiencing stress would not have been adversely impacted.

This view was confirmed by the Electricity Authority's review which noted that electricity purchasers were hedged well in advance of the winter of 2017. This meant that ***purchasers were not adversely affected when the spreads for exchange traded futures widened during the winter***. However, the Authority commented that;

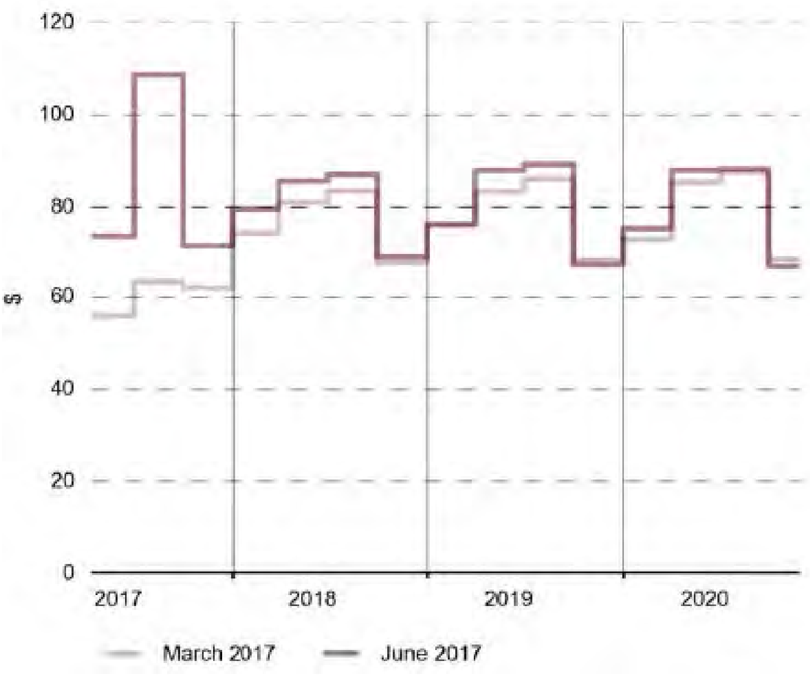
> ***"…widening of spreads signalled that the market making arrangements are more fragile than anticipated and these should be reviewed to ensure that problems do not eventuate in more severe circumstances"***.

One reason offered for the widening bid-ask spreads was that market makers were suffering portfolio stress and began to offer wider bid-ask spreads (contrary to their market making obligations). The Electricity Authority defined portfolio stress as;

> ***"…market makers found it financially distressing to continue to market make, either because of the cost of doing so, or because risk limits were constraining their ability to do so".***

This stress on market makers resulted in a large increase for the September quarter contracts (see Figure 8). It is important to note however, that it is not uncommon for ***exchanges to offer some form of relief to market makers in the event of abnormal market conditions*** e.g. fast market situations. This is discussed more in Section 3.4, the UK case study.

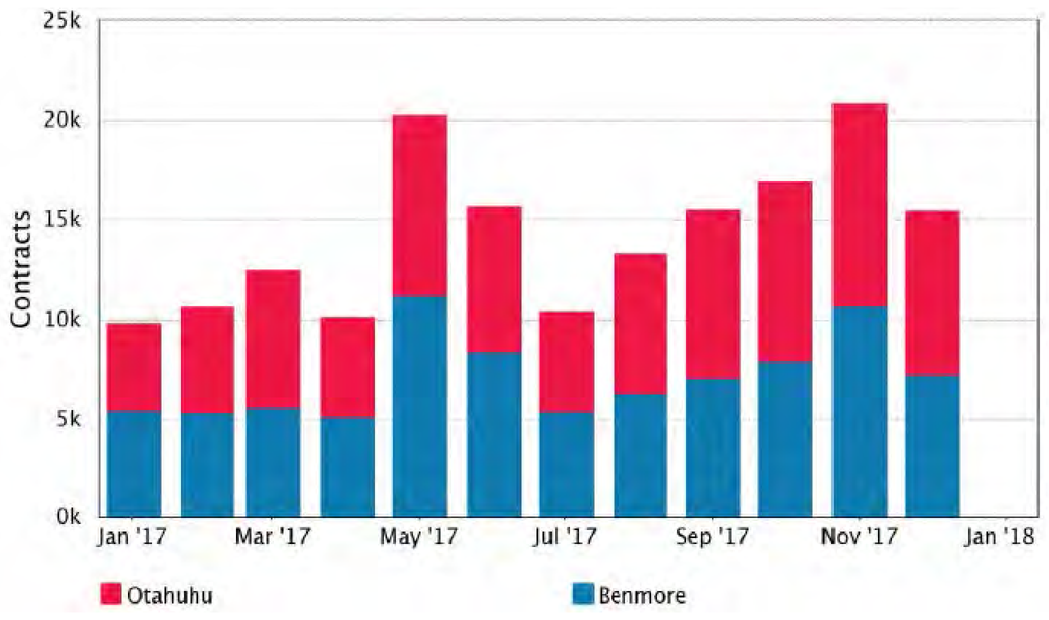
Figure 8: Forward curves as at March and June for ASX quarterly contracts, NZ



Source: Electricity Authority, 2017 Winter Review, Final Report, 18 June 2018

As the hydrological shortage was signalled to the market, monthly trading volumes on the ASX showed increased volumes (see Figure 9), demonstrating that hedge cover was being sought and matched (May). Volumes fell in June and July coinciding with the increased bid-ask spreads (Figure 6 and Figure 7). Volumes then recovered to high levels in November as the period of winter stress ended.

Figure 9: Monthly ASX trading volumes 2017, NZ



Source: Electricity Authority, 2017 Winter Review, Final Report, 18 June 2018

Following the 2017 winter events, the Electricity Authority engaged Concept Consulting to survey hedge market users to discover their experiences during the winter. In summary, the survey found that[6]:

(a) Although most hedging was done well in advance of the periods with wide spreads, there were **some examples of particular participants having problems obtaining cover**. However, judging by trading volumes during the winter, ***these were isolated examples***.

(b) Hedge prices are used in a variety of ways by different businesses. Physical market participants use the long-term prices as guides for decision-making rather than the short-term prices. This is because the important decisions they make are long-term decisions like investment choices. This meant that the ***short-term price volatility caused by wide bid ask spreads didn't necessarily undermine the value of the forward price curve***.

2.4. ELECTRICITY PRICE REVIEW (EPR)

In 2018 the NZ Government embarked on a review of electricity prices in New Zealand following concerns that "…household electricity prices in New Zealand have risen much faster than in countries to which we compare ourselves"[7].

In respect of the hedge market, the EPR's comments[8] were;

> *"The New Zealand contract market had been **developing well and has been on a trajectory of steady improvement since 2010**. However, events during the winter of 2017 highlight the fragility of current arrangements. For this reason, we consider improving the depth and resilience of the contract market should be given high priority".*

This conclusion appears to be a simple repeat of the Electricity Authority's earlier comments from its 2017 Winter Review as commented on earlier.

Further views expressed in the review that;

> *Some aspects of the contract market's performance have faltered recently. We were told of a "steady decline in market-maker performance," as evidenced by buy-sell price spreads **routinely wider than 5 per cent**, and the absence at times of any quoted prices for some contracts during parts of the 2017 winter.*

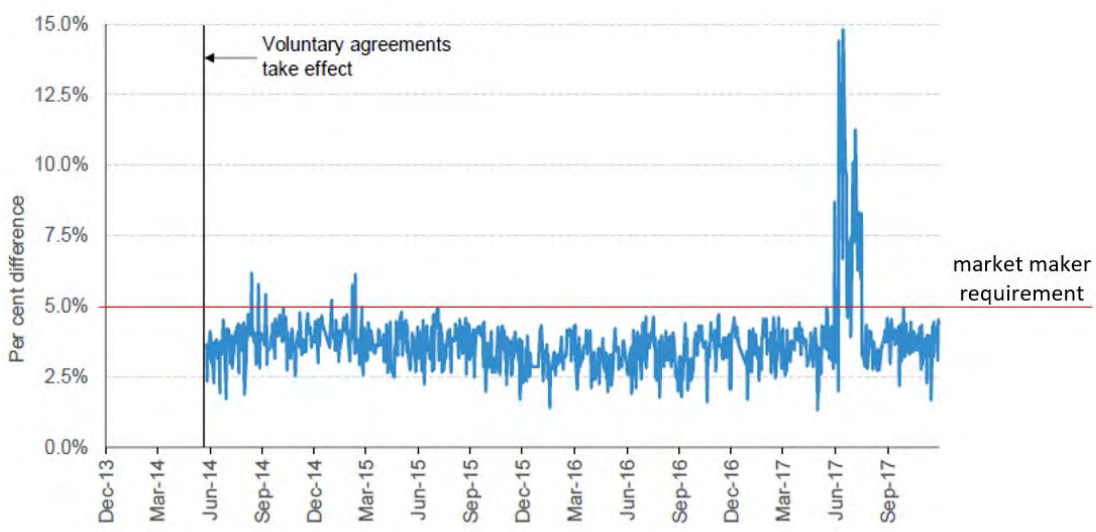
appear to be contradicted by the evidence presented. As shown in Figure 10, outside of the initial period of voluntary market makers agreements taking effect (which can be attributable to a bedding in period) the buy-sell price spreads have not exceeded the minimum of 5 per cent other than when the market was stressed during the winter of 2017 (as discussed earlier) – this directly contradicts the "routinely wider than 5 per cent" claim.

[6] Electricity Authority, 2017 Winter Review, Final Report, 18 June 2018

[7] Hon Dr Megan Woods, Minister of Energy and Resources, Electricity Price Review, 30 August 2018

[8] Electricity Price Review, First Discussion Document, 30 August 2018

Figure 10: Spread between contract buy and sell prices, NZ



Source: ASX. Note: average spread at the end of each trading day for the nearest three-monthly futures contracts for Benmore on the ASX (Electricity Price Review, First Report for Discussion, 30 August 2018)

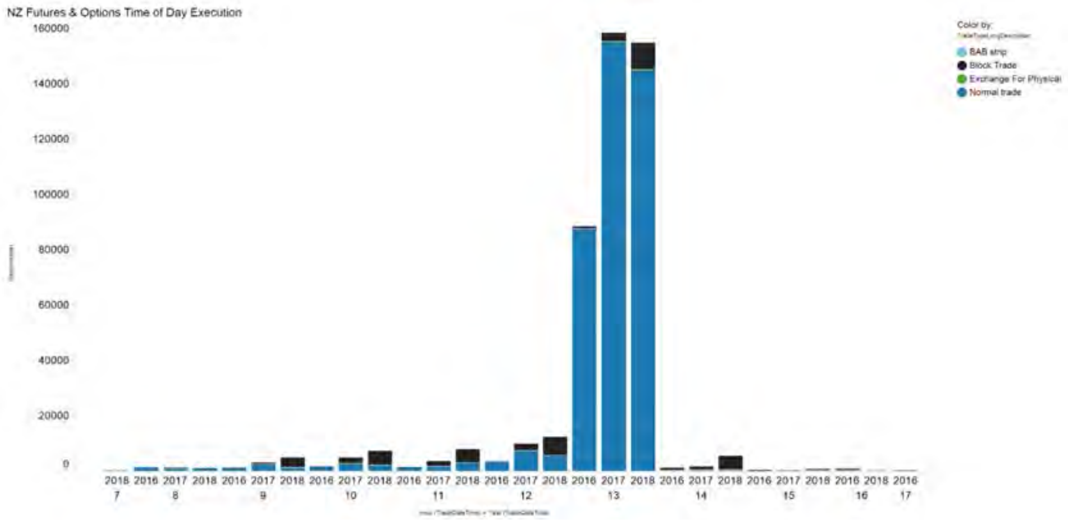
It would be far more reasonable to conclude that the NZ hedge market has been performing as intended, other than when placed in market stress such as the winter of 2017. And as highlighted previously from the Electricity Authority's investigations of that time, and concluded by Concept Consulting's support of that exercise;

- purchasers were not adversely affected when the spreads for exchange traded futures widened during the winter,
- some examples of particular participants having problems obtaining cover. However, judging by trading volumes during the winter, these were isolated examples, and
- short-term price volatility caused by wide bid ask spreads didn't necessarily undermine the value of the forward price curve.

We also note that in some areas the NZ hedge market is well in advance of its regional counterparts. The recent ACCC review (discussed in more detail in Section 3.3, Australia case study), recommended more information be published about the prices of wholesale contracts negotiated directly between parties. New Zealand already requires disclosure of the key terms for such contracts.

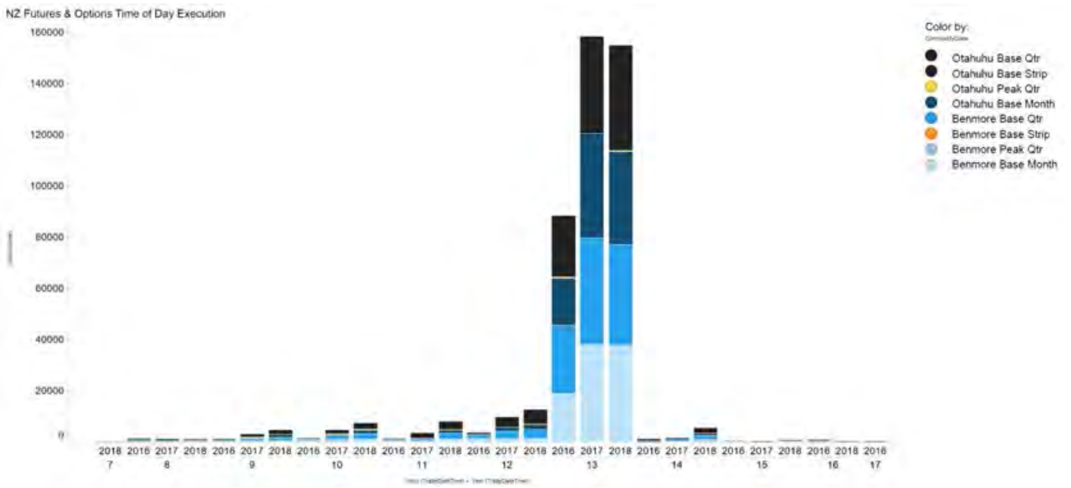
We do however note that recent experience (subsequent to the 30 August EPR Report being released) may be more indicative of wider spreads occurring, associated with higher than normal prices. However, we also note that this often coincides with volume going through the market during the pre market maker session, normally consisting of strip products, and sometimes a profile shape (refer Figure 11 and Figure 12). From discussions with brokers we understand that these trades are often for smaller volumes (up to 1MW) which implies that small retailers are hedging before the market making window to get the volumes they need. We also understand from brokers that there are approximately 7-8 trades pre-window each day (often for options/delta hedging). These are all signs of a well-functioning market in times of increased volatility and higher prices.

Figure 11: Time of day execution NZ Futures & Options (Australian time used)



Source: ASX, NZ Electricity Energy Trader Forum, Wellington, February 2019

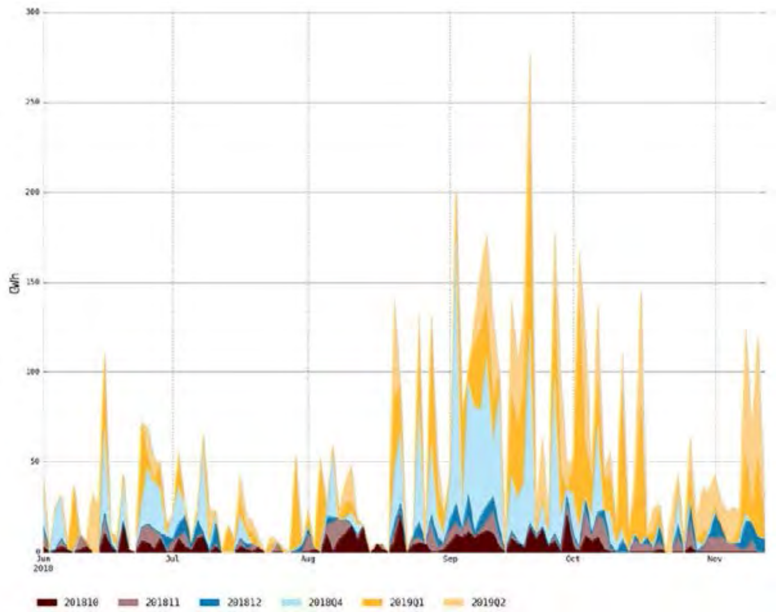
Figure 12: Time of day execution NZ Futures & Options (Australian time used)



Source: ASX, NZ Electricity Energy Trader Forum, Wellington, February 2019

Looking at short dated contract trading over the Spring 2018 period highlights that participant hedge positions were still being sought and matched during this volatile period. This is a sure sign of a well-functioning market.

Figure 13: ASX short dated trading volumes, Spring 2018



Source: The Authority's decision on claim of an undesirable trading, 28 February 2019

The Electricity Authority have also reviewed recent events[9] and concluded that;

> ***It is up to participants to be aware of, and manage the risk of, potential high spot prices*** *(or low spot prices if they are generators). In general, it is also up to participants to determine how much risk to take on, and how to manage that risk. Our focus is on ensuring participants have tools available to manage their spot price risk, such as the hedge market.* ***The claimants allege that the hedge market failed to provide effective risk management to participants. However, our investigation found that the hedge market performed as expected and that parties who hedged before spot prices began to rise had little concern with managing their spot price risk.*** *Nonetheless, we are aware of issues with liquidity in the hedge market. Our investigation highlighted these issues again.*

We acknowledge and agree with the Electricity Authority's note of caution in respect of any market intervention;

> *We regularly consider whether the voluntary arrangements could be improved or are the most appropriate way to ensure liquidity. Our indicative 2019/20 work programme includes a project to enhance the hedge market. The project will consider a number of potential improvements, including whether market making can be made more robust.* ***However, before we intervene in the market we must be confident the benefits of any intervention outweigh the costs which, based on overseas experience, may be considerable.***

9 The Authority's decision on claim of an undesirable trading situation; Claim submitted 8 November 2018 by Electric Kiwi, Flick Energy, Pulse Energy, Switch Utilities (Vocus), and Vector; Decision made 14 February 2019; Decision paper released 28 February 2019

3. INTERNATIONAL CONTEXT

3.1. Overview

A number of countries have and/or are reviewing the need for some form of market liquidity obligation. This paper considers the cases of;

i. Singapore – where rather than mandating market making obligations, the spot regulator (the Energy Market Authority) sought to attract market makers through incentives called forward sales contracts. These incentives began on 1 April 2015, however due to the way they were structured they had unexpected financial costs to the consumer. Consequently, the incentive scheme moved to a tender based market maker procurement model in 2018 (still on a voluntary basis), attracting commercials as market makers.

ii. Australia – where the June 2018 ACCC Retail Electricity Pricing Inquiry Report recommended that the AEMC should introduce market making obligations in South Australia, requiring large, vertically integrated generator-retailers to market make to boost liquidity. This recommendation has received much criticism from participants for failing to recognise the underlying issues specific to South Australia.

iii. The UK – where market making obligations were introduced on 31 March 2014 for the six largest vertically integrated companies as part of the Secure and Promote (S&P) licence conditions. This scheme was reviewed in 2017 and the consultation that took place highlighted concerns about the increasing costs on licensees from complying with the market obligations. Recommendations followed to reduce the financial burden placed on mandated market makers.

3.2. Singapore

Singapore's electricity market regulator, the Energy Market Authority (EMA), in conjunction with the Singapore Exchange (SGX), launched electricity futures on 1 April 2015. Modelled on the experience in Australia and New Zealand, the new futures market was, according to the EMA's objectives, to provide a robust price discovery process for future supply of electricity, while enabling efficient transfer of risk between participants. In addition, the electricity futures market was to enable the entry of independent electricity retailers.

A prerequisite to launching the futures market was obtaining a sufficient number of participants to make market. It was recognised that because of Singapore's small market size (approximately the same as New Zealand), market liquidity would be an issue from the outset. This was further exacerbated by Singapore's largely homogenous gas fired generation which meant that fuel curves were already providing a reasonable form of hedging.

The initial attempt to attract voluntary market makers was to offer incentives to the existing generator licensees in the form of a Forward Sales Contract (FSC). The FSC was to be a cfd between generators and contestable retailers, intended to proxy current vesting contract arrangements by offering generators the margin (positive or negative) between the vesting contract price (based on LRMC) and the market pool price. It was thus intended to support generators by smoothing pool price volatility. However, as the pool price in Singapore collapsed to SRMC (due to an oversupply of generation and an over-contracting of fuel) the margin between pool price and vesting price grew materially, turning the FSC into a significant windfall.

However, despite the size of the FSC incentive generators banded together to decline to take up market making citing that because the FSC incentive would be a cost imposed on their vertically integrated retail affiliates it was a zero-sum gain to them (unless they tried to pass the FSC cost onto their commercial and industrial customers which was an unpopular proposition).

Following this standoff, the EMA revised the FSC incentive scheme by opening it up to retail licensees, including a number of new entrant retailers waiting in the wings. Six voluntary market makers were found on this basis (including at least 1 generator who 'broke ranks' and a number of stand-alone retailers, including some who outsourced market making to commercial trading houses). During this protracted renegotiation period spot prices continued to collapse, the value of the FSC incentive continued to increase, and the incentives were finally capped by the EMA. Although the final cost of this incentive has not been disclosed it reached at least S$204 million[10] by 31 March 2018 in respect of the initial market making period of 1 April 2015 to 31 July 2018.

Under the FSC scheme market makers were required to quote all quarterly contracts with an initial spread of 10% (which was directly copied from New Zealand's experience). This spread was subject to periodic review and tightening each time if liquidity objectives were not being met.

Following the unintended blowout of the FSC incentives the EMA renamed the scheme as the Futures Incentive Scheme (FIS) and will continue under this arrangement for a further 3 years (divided between 2 phases; 1 August 2018 – 31 January 2020 and 1 February 2020 - 31 July 2021). Following which, EMA will re-assess the market's performance and review the need for further intervention.

A Request for Proposal (RFP) to provide Market Making Services for the first phase period to 31 January 2020 was issued, and to better assess the prevailing market readiness for tighter spreads, EMA requested for two price bids based on two indicated spreads; (i) $1/MWh or 2% of bid price whichever is lower, or (ii) $2/MWh or 2% of bid price whichever is lower.

[10] "On 21 June 2016, the Authority also granted … a loan facility of $250 million to fund the settlement of payments, collections and associated costs relating to the Forward Sales Contract Scheme. … As at 31 March 2018, net loan amount drawn down was $204 million after amortization of upfront fee …", EMA Annual Report, 2017/18 (Note: SGD$204million = NZD$215million using exchange rates as at 31 March 2018)

Six applicants were selected as market makers at a spread of $1/MWh or 2% of the bid price, whichever is lower. The RFP Price was settled at S$218,000 per month. While two of the six market makers have links with spot market participants through ownership, all are trading operations in their own right;

- DRW Singapore Pte Ltd
- ENGIE Global Markets, Singapore Branch
- Epoch Energy Solutions Pty Ltd
- Fenix One Asia Pte Ltd
- Liquid Capital Australia Pty Ltd
- RCMA Asia Pte Ltd

Figure 14: Market making obligations in Singapore

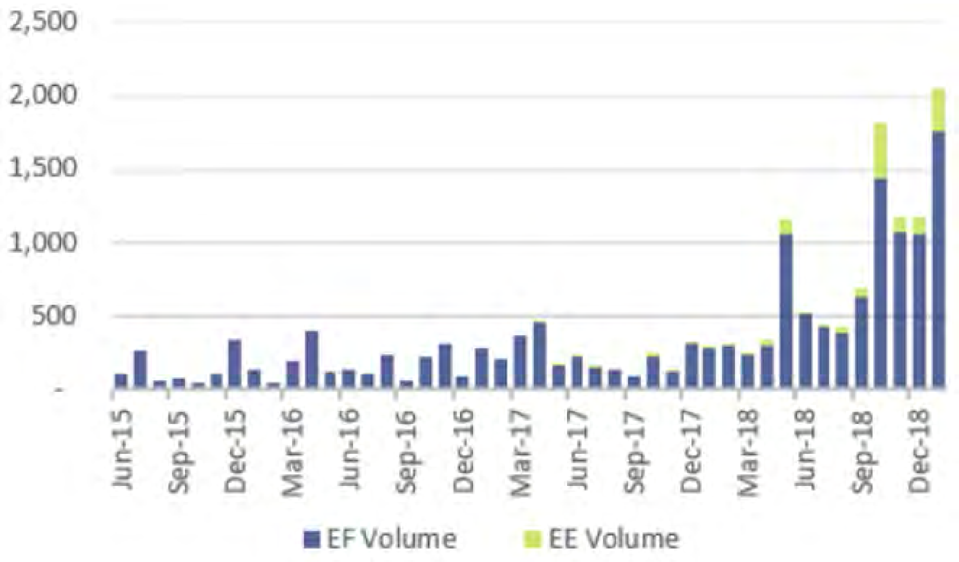
	Requirement
Product parameters	Quarterly: MMs are required to put up (i) 6 lots of 0.5MW contracts (totalling 3 MW) for each side, for each of the first 5 listed quarterly contracts; and (ii) 4 lots of 0.5MW contracts (totalling 2 MW) for each side, for each of the next 4 listed quarterly contracts Monthly: MMs are required to put up 6 lots of 0.5MW contracts (totalling 3 MW) for each side, for each of the 4 – 6 listed monthly contracts
Spread	Quarterly: August to December 2018: $2/MWh January 2019 onwards: $1/MWh or 2% of bid price whichever is lower Monthly: Prevailing quarterly contract two-way price making spread + $1/MWh
Refresh period / Quantity	Old (FSC): Quarterly and Monthly: Not less than one reload Refresh of quotes needs to be as soon as technically or operationally feasible and at most within a 60 second grace period New (FIS): Quarterly and Monthly: August 2018 to January 2019: Not less than 2 reload February to July 2019: Not less than 3 reloads August 2019 to January 2020: Not less than 4 reloads No grace period for refreshing of quotes

Source: EMA, Enhancing the development of the electricity futures market, final determination paper, 13 February 2018

The EMA have stated that they will assess market performance from the first phase and reserve the right to revise the market making obligations for the second phase from 1 February 2020 to 31 July 2021, at which time a separate RFP will be launched.

The change to FIS incentivised market makers also coincided with Singapore's rollout of full retail competition. This has had a significant impact on the need for hedging, especially from independent retailers, and consequently on the volumes traded through the futures market. In December 2018 the combined electricity futures volume crossed the 2,000 GWh level for the first time, representing 50% of the underlying spot market on an annualised basis.

Figure 15: Traded Volume (GWh), Singapore



Source: SGX (Note: EF – base load quarterly contract, EE – base load monthly contract)

Figure 16: Average Open Interest (GWh), Singapore

Source: SGX (Note: EF – base load quarterly contract, EE – base load monthly contract)

Singapore demonstrates that with appropriate bid-based incentives it is possible to attract commercial market makers, and at relatively tight spreads. It is interesting to note that the bid-based cost of S$218,000 per month is broadly in line with the costs imposed on industry market makers as quoted in the recent OFGEM review, with the exception of 2017 where imposed industry costs blew out (this is discussed in more detail in Section 3.4, UK case study).

3.3. AUSTRALIA

The Australian Competition & Consumer Commission (ACCC) has recently undertaken an inquiry into retail pricing in Australia's electricity sector. On June 2018 the ACCC released its final report which made two recommendations concerning the hedging market;

Figure 17: ACCC Recommendations, Australian Hedge Market

Recommendation 6
The NEL should be amended so as to require the reporting of all OTC trades to a repository administered by the AER. Reported OTC trades should then be disclosed publicly in a de-identified format that facilitates the dissemination of important market information without unintentionally revealing the parties involved. The requirement should be implemented to align with (or be eligible for) any OTC reporting requirements under the NEG. The AER, AEMC and AEMO should have access to the underlying contract information, including the identity of trading partners.
Recommendation 7
The AEMC should introduce market making obligations in South Australia, which require large, vertically integrated retailers to make offers to buy and sell specified hedge contracts each day, in order to boost hedge market activity. The parameters of a market making obligation should have regard to: • the size of the South Australian market • the distribution of generation ownership in the region • the benefits to market liquidity and efficiency of regular trading activity • the burden of the requirements on obligated entities • any impact on the incentives of intermittent generators to invest in firming technology. After an appropriate period of time (for example, after two years) the mechanism should be assessed for its effect on market activity, liquidity and risk to determine if it should be continued, amended or removed in South Australia and, potentially, extended to other NEM regions.

Source: ACCC, Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report, June 2018

As already commented on in Section 2.4, Electricity Price Review, implementing recommendation 6 would serve to bring the Australian hedge market on par with similar arrangements already in place within New Zealand.

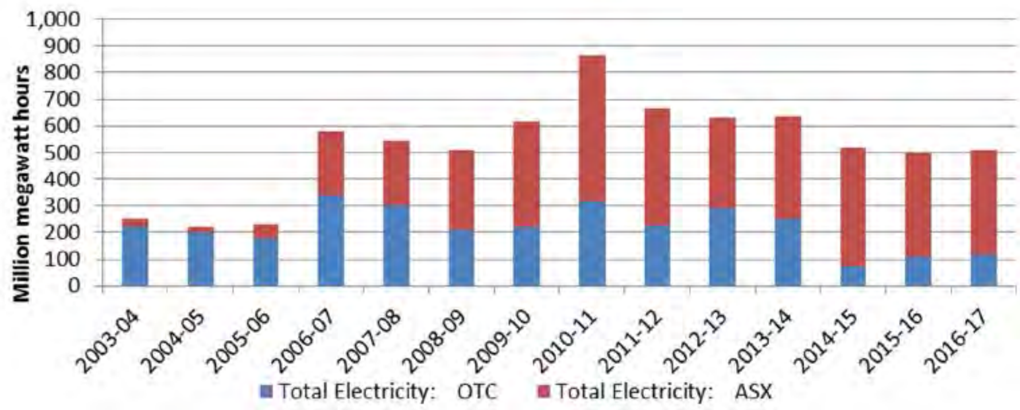
Recommendation 7 would serve to accelerate for South Australia an existing and more general work stream being undertaken by the Energy Security Board's (ESB) - the National Energy Guarantee (NEG). NEG is a market liquidity obligation intended to apply to some large vertically integrated generator-retailers "… proposed to promote liquidity, transparency and competition in the event the Reliability Obligation is triggered".

The ACCC Report noted that in a relatively small and concentrated (in both wholesale and retail markets) region like South Australia, market making obligations would likely enhance contract market liquidity and reduce risk management costs for non-obligated participants. Improving retailers' access to risk management products would likely boost competition in the retail market.

However, the report also identified that such an intervention would involve risks. The burden of market making would likely fall on the few owners of dispatchable generation capacity in South Australia. South Australia's wholesale prices are particularly volatile and market making costs may be substantial during periods of volatility.

The concerns raised by the ACCC in respect of South Australia are not typical of the NEM as a whole, which enjoys fairly high levels of liquidity in all regions (except South Australia).

Figure 18: Australian Electricity Futures Market Turnover



Source: AFMA Electricity Derivate Turnover Survey

Following ACCC's recommendations 6 and 7, the ESB was tasked with providing their advice to the COAG Energy Council, and released a further consultation paper in September 2018, market making requirements in the NEM.

The proposal for introducing market making obligation in South Australia has been heavily criticised by a number of market participants who claim that it fails to recognise the underlying structural issues of the South Australian Market. Two typical examples of these claims are;

EnergyAustralia[11]:

> EnergyAustralia believes the case has not been made to warrant the need for the market making requirements … South Australian specific issues include:
>
> - The small size of the market, compared to other regions
> - It is a very volatile physical market which is highly sensitive to weather patterns and single asset contingencies
> - There is low accountability for market impacts when scheduling transmission outages and interconnector constraints

[11] EnergyAustralia submission to Market Making Requirements, 19 October 2018

- There is significant market intervention by system operator.

These factors all contribute to the lack of liquidity and enforcing market making over the top of these issues will not paper over these structural problems.

ENGIE[12]:

ENGIE does not support the ACCC's assessment because they have not effectively diagnosed the South Australian market conditions nor made a link to conclude market making as proposed will solve the challenges some suggest are present in South Australia.

Hedging in the South Australian market needs to be assessed in comparison to other jurisdictions on the basis of its unique characteristics: a small market with a high penetration of renewables, reliant on gas generation to provide firmness, and with important inter-connection with Victoria.

Importantly, the ASX is currently looking to introduce a voluntary market making in the Australian Electricity Futures, Caps & Options contracts market. This voluntary mechanism is a far preferable way to explore any consideration of expanding market making obligations beyond SA as it provides the necessary flexibilities to ensure market makers are not locked into loss making positions by regulatory obligations.

ESB were due to provide their advice to the COAG Energy Council in December 2018. This has yet to occur.

3.4. UK

Concerned that poor wholesale electricity market liquidity was posing a barrier to effective competition and entry in the generation and supply market, the UK introduced market making obligations (MMO) on the 6 largest vertically integrated companies on 31 March 2014 (through the Secure and Promote (S&P) licence condition).

These obligations required market making across the following product set during two separate liquidity windows from 10:30 to 11:30 and 15:30 to 16:30;

Figure 19: MMO Product Set, UK

Baseload	Month +1 Month +2 Quarter +1 Season +1 Season +2 Season +3 Season +4
Peak	Month +1 Month +2 Quarter +1 Season +1 Season +2 Season +3

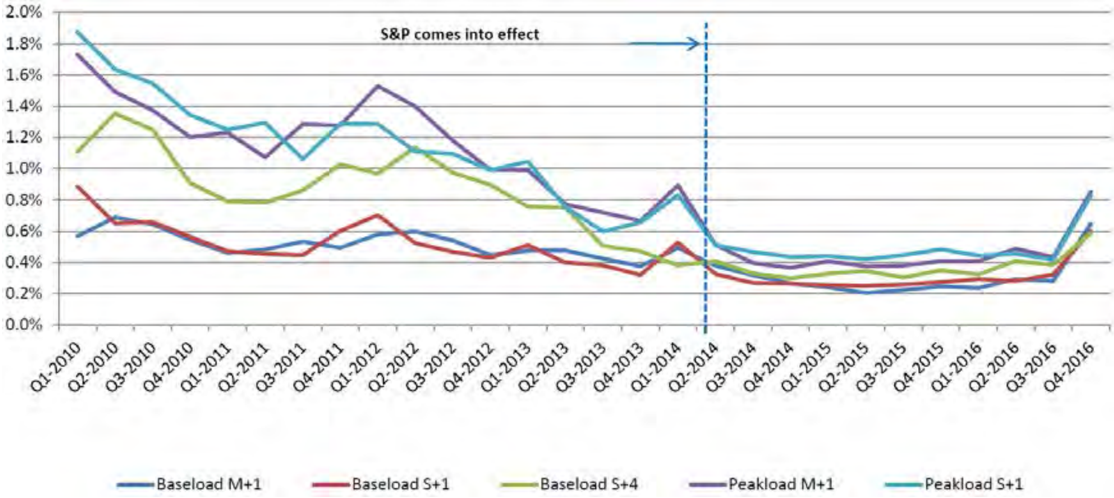
Source: S&P Licence Conditions, Schedule A

12 ENGI submission on ESB Consultation Paper: Market making requirements in the NEM and Notification of intention to lodge a proposal to amend the National Electricity Rules, 19 October 2018

In the UK there is no nominated platform for posting market obligations and in at least one case an OTC broker has been used as the 'qualifying trading platform'[13].

Bid-offer spreads were already narrow across the product range and reduced further following the introduction of MMO through the new S&P licence conditions (refer Figure 20). However, spreads increased in the final quarter of 2016, and in some cases over product-specific requirements mandated under S&P licence conditions (refer Figure 23).

Figure 20: Bid Offer Spread of selected S&P products, UK



Source: Secure & Prompt Stakeholder Workshop, 2 May 2017

As part of introducing the Secure and Promote (S&P) policy in 2014, OFGEM committed to undertaking a review after three years of the new licence conditions. This review commenced in July 2017 with OFGEM seeking stakeholder views on the impact of the policy to date.

OFGEM's observations from the review were that;

- Respondents supported the high levels of liquidity, although they found the benefits difficult to quantify and could not agree whether they could be attributed to S&P.
- Respondents generally observed robust prices and a good availability of products. This had enabled them to better hedge their activities, and robustly price their supply contracts and power purchase agreements (PPAs).
- Licensees reported their compliance costs increased over 2016. They attributed this to the volatility in quarters three and four of 2016. Licensees explained that this was a result of market making at the prescribed bid-offer spreads when prices were moving significantly and rapidly.

13 "ScottishPower quotes bids and offers to trade standard bilateral forward contracts via the OTC brokers in all trading windows," said a spokesperson to ICIS, 26 June 2017

Comments were also received around the criteria used for selecting those to discharge the MMO, and whether these need to be revisited. This is on the back of several large market participants having (or being in the process of) restructuring their businesses following the Competition and Market Authority (CMA) findings on vertical integration not being a significant barrier to wholesale power market liquidity.

OFGEM accepted concerns about increasing costs on licensees from complying with the MMO. Licensees provided evidence that these costs were increasing beyond the original estimates during periods of market volatility. These costs broadly arise from restrictions on bid-offer spreads during volatile market periods making price discovery more difficult.

Figure 21: MMO costs per licensee (£m), UK

	costs provided by licensees (£m)			
	2014	*2015*	*2016*	*H1 2017*
Fixed costs	~ 0.5	~ 0.5	~ 0.5	~ 0.5
Variable	0.2 – 0.7	~ 0.5	3.0 – 8.0	0.3 – 0.7

Source: licensees

Source: OFGEM, Secure and Promote review: Consultation on changes to the special licence condition, 13 December 2017

OFGEM has proposed two measures to help mitigate these costs:

- A soft landing period of ten minutes at the beginning of each market making window with wider bid-offer spreads
- A new fast market rule to widen bid-offer spreads in the market making windows when the price moves by ±1% from the first trade of the window

3.4.1. Soft landing

Market participants commented that prices often move significantly around the beginning of market making windows. This was supported by OFGEM analysis which showed this was particularly evident in the first 10 minutes of the window.

OFGEM proposed to widen the bid-offer spreads during these first ten minutes of market making windows up to 1% across all Products. This was intended to facilitate a more natural process of price discovery while helping to reduce avoidable costs for licensees.

3.4.2. Fast market rule

The current S&P licence condition contains a ‘fast market’ rule designed to reduce the risk of making significant losses in periods of volatility. It allows licensees to withdraw from posting bids and offers in the remainder of the designated market making windows if prices for a product increase or decrease by 4% compared to the first trade in the window.

Feedback from licensees suggested the threshold had been hit too infrequently, and it was insufficient in preventing licensee costs from escalating during market volatility. OFGEM analysis showed the current threshold had only been triggered in 0.7% of windows between the beginning of 2015 and July 2017. This was well below the 'couple of percent' of windows initially intended.

Figure 22: Proportion of windows incurring fast markets at various thresholds, UK

Proportion of windows where a fast market would be triggered, by fast market threshold, 2015 – 30 Jun 2017

	Month+1	*Month +2*	*Quarter +1*	*Season +1*	*Season +2*	*Season +3*	*Season + 4*
1% threshold	7.1%	5.1%	5.7%	2.2%	1.8%	1.3%	2.2%
2% threshold	2.8%	1.9%	2.1%	0.5%	0.2%	0.3%	0.3%
3% threshold	1.3%	0.9%	0.8%	0.2%	0.0%	0.0%	0.1%
4% threshold	0.7%	0.4%	0.3%	0.1%	0.0%	0.0%	0.1%

Source: Ofgem analysis of ICIS transaction data

Source: OFGEM, Secure and Promote review: Consultation on changes to the special licence condition, 13 December 2017

However, rather than relaxing the current 4% fast market threshold, OFGEM instead proposed to allow licensees to widen their bid-offer spreads to a 1% threshold when a lower 1% price movement threshold was reached. OFGEM were concerned that a complete withdrawal from the window at a lower threshold would be an extreme provision as this would impact smaller suppliers accessing the market during times of volatility.

Figure 23: Proposed bid-offer spreads for fast markets and soft landing, with the current spreads in brackets

	Baseload	Peak
Month+1	1.0% (0.5%)	1.0% (0.7%)
Month+2	1.0% (0.5%)	1.0% (0.7%)
Quarter+1	1.0% (0.5%)	1.0% (0.7%)
Season+1	1.0% (0.5%)	1.0% (0.7%)
Season+2	1.0% (0.5%)	1.0% (0.7%)
Season+3	1.0% (0.6%)	1.0% (1%)
Season+4	1.0% (0.6%)	N/A

Source: OFGEM, Secure and Promote review: Consultation on changes to the special licence condition, 13 December 2017

3.4.3. Market Maker Obligation to end?

The UK market is going through a period of structural reform with several of the large obligated market makers selling down their generation assets. As market makers are relieved of their obligations the burden falls to the remaining market makers with a cascading effect.

OFGEM consulted with the industry in August 2018 on whether to suspend market making and although they decided not to proceed with this at the time, they warned the industry that this could be inevitable by 2019;

"…market participants should prepare for the suspension of the MMO if both the SSE/Npower merger and the acquisition of Scottish Power's thermal generation units by Drax complete. The public announcements on these transactions suggest this is likely to be by the end of the first quarter of 2019."[14]

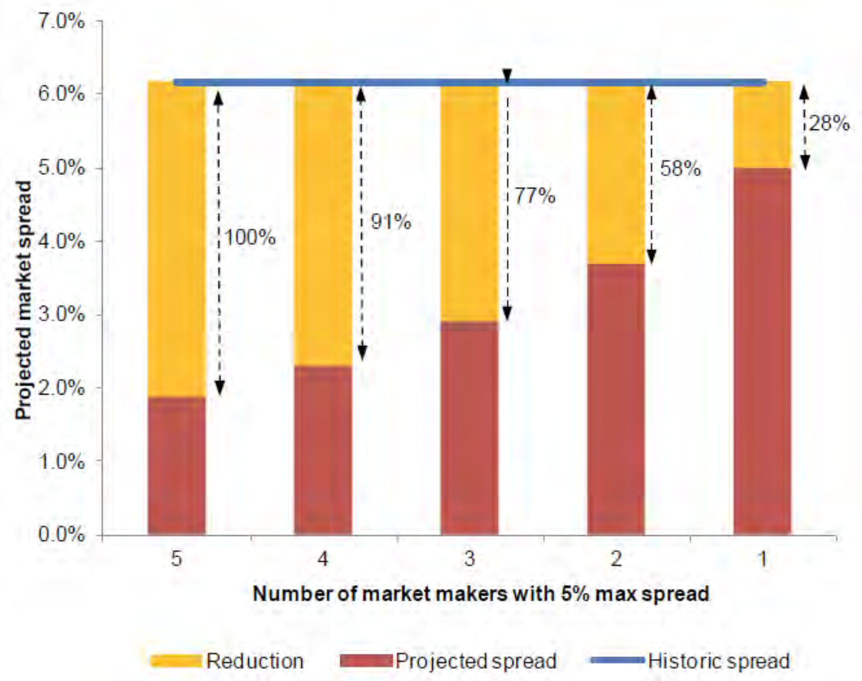
[14] Letter to all stakeholders, OFGEM, 6 November 2018

4. ARE TIGHTER MARKET MAKING ARRANGEMENTS REQUIRED IN NZ?

On 21 November 2011 the Electricity Authority released an analysis of the costs and benefits for tighter market-making arrangements in the New Zealand electricity futures traded on the Australian Securities Exchange (ASX)[15].

The analysis indicated that bid-ask spreads of 5% or lower (at the time of the analysis required spreads were 10% with effective spreads of 6%) would increase confidence in the forward prices and create more robust hedging arrangements, which in turn would provide a number of benefits to the electricity market. Required bid-ask spreads have subsequently reduced to 5% (refer Figure 1 and Figure 2) with effective spreads in the 2-4% range (refer Figure 10).

Figure 24: Projected change in average market spread



Source: Electricity Authority, Cost Benefit Analysis – Market-Making Obligations, 21 November 2011

The quantitative cost–benefit analysis (CBA) indicated that introducing a tighter code-based market-making obligation is unlikely to yield net benefits if four or more parties are already actively providing these services on a voluntary basis. The report was also critical of the efficacy of mandated spreads;

[15] Cost Benefit Analysis – Market-Making Obligations - the Electricity Authority, 21 November 2011

> ***"As compared to a broadly equivalent voluntary approach, a regulatory solution will tend to be less flexible and responsive, and less supportive of innovation. The Authority estimated that Code-driven arrangements would deliver between 60% and 90% of the benefits derived from an equivalent voluntary approach …"***

Further, the report specifically stated that:

> ***"… there is unlikely to be a net economic benefit from introducing Code-based market-making obligations that would obligate Trustpower (the only generator of the big-five not currently providing market-making services on the ASX) to provide tighter market-making services. "***

The Electricity Authority stated that "If circumstances change, and in particular if observed spreads were to widen because the number of active market-makers were to decline… the Authority would reconsider its position".

Given all four original market makers remain, this review trigger has yet to be met, however we note that when new quarterly peak and option products were added to the ASX product set in 2014 the Electricity Authority wrote to the six larger generator retailers[16] to "understand what barriers were inhibiting voluntary market making in the [new products] and map out a path for voluntary market making in those products… The Authority is starting work on the mandatory approach now to minimise lost time if voluntary measures prove unsuccessful …".

This would appear to us to be an implied threat of mandatory intervention to prompt a preferred voluntary approach.

Imposing obligations on spot market participants to trade contracts they would otherwise not wish to trade due to additional costs or risks is a significant change to the New Zealand market design and one we would caution be considered carefully. ***Nothing in our view from the 2017 Winter Review or the Electricity Price Review would suggest that any urgent rectification of current arrangements is warranted***.

4.1. A FURTHER MARKET MAKER CAN INCREASE RATHER THAN REDUCE MARKET VOLATILITY

If we assume a market maker already has a balanced hedge portfolio and doesn't wish to hold positions on their market making activity, then when a market maker offer is lifted, they will seek to hit another market maker's offer to close out their position (incurring the cost of the higher offer price to do so). The market maker that has been hit in this process will similarly seek to immediately lift the offer of another market maker, and so on.

[16] 5 June 2014 letter to six generator retailers from Carl Hansen, Chief Executive of the Electricity Authority

Concurrently, a market maker may seek to reload their offer at a higher price to reduce the likelihood of being lifted again (by hiding behind another market maker's offer), however, their bid price will also need to be raised to maintain mandated spreads, increasing the likelihood of it being hit. The greater the number of market makers the more likely they will bump into each other.

This activity can increase the cost for some market makers, increase market volatility, drive up initial margin costs and place markets under stress which in extreme cases could trigger fast market conditions and suspend market maker activity altogether (thus removing liquidity from the market).

4.2. MARKET MAKERS HAVE PHYSICAL LIMITS

A market marker's business model is to profit from the buying and selling from the (other) market participants. The market maker provides the market liquidity with the intention of profiting between the buying and selling prices. In the context of an energy market, what is being bought and sold is a finite resource. Creating a market marking obligation will not automatically increase the hedges available to the market.

A market making obligation will have additional and considerable costs e.g. IT and associated costs with developing algorithms to set suitable prices. Additional risks also arise in a market maker holding a net position contrary to their underlying position. A forced obligation may lead to parties trading at a loss in order to provide an obligated market making service. Whether implicitly or explicitly, these costs will find their way to consumers.

5. EPR OPTIONS PAPER – 18 FEBRUARY 2019

In their 18 February paper the EPR have gone further to "in the first instance … favour a mandatory obligation, with provision to move to an incentive-based scheme later." This view appears to be premised on a number of points made in their report:

- Mandatory market-making happens in Britain and is being introduced in parts of Australia.
- A mandatory market-making obligation could be introduced relatively quickly.
- A mandatory market-making obligation could be replaced later by an incentive-based scheme whereby companies best placed to act as market makers could be paid to take on that responsibility.
- Singapore's experience suggests an incentive-based scheme would take several years to develop.

As already discussed in this paper, much of these premises may not hold true when examined with greater context;

- The mandatory market making in Britain is in the process of collapsing even though the scheme was relaxed following the 2017 review that concluded that existing obligations were too onerous. In Australia the ESB has yet to provide their advice to the COAG Energy Council on a mandatory requirement and in the meantime AEMC have issued a consultation paper[17] to propose the alternative arrangements of a voluntary market maker approach (refer Section 6.1).
- A "relatively quick" mandatory obligation introduction would only be possible if the extent of the risk and cost imposed on market makers were not adequately considered. The EPR paper itself, elsewhere, would appear to be more circumspect on this point with such suggestions that "new regulation would also include provisions to temporarily relax the market-making obligations when certain conditions were met." and "the level of obligation on market makers could be graduated based on a generator-retailer's size and extent of vertical integration."

  Introducing a 'fast market' condition is certainly advisable and normal. However, as noted in Section 3.4, the UK case study, their first attempt did not work as intended and had to be later revised. As for recognizing the extent of vertical integration, we would suggest this also be extended to recognize the difference between net-retailing vs net-generating as the options available to support a market making book will vary depending on the level of net long generation available.

  A 'relatively quick' approach can often translate as a 'relatively wrong' one.

[17] AEMC Consultation Paper, National Electricity Amendment (Market Making Arrangements in the NEM) Rule 2019, 20 December 2018

- Beginning with a mandated regulatory solution to later unwind it with a less intrusive commercial one is an approach we find difficult to understand. Especially when it is recognized that the later approach will provide “companies best placed to act as market makers”. Starting with a “best placed” approach would appear to be the more logical.

- Our experience would not suggest that a voluntary scheme should take any longer to introduce than a mandatory scheme. We see that the ACCC have also expressed a similar view in respect of the Australian market **-** “The ACCC notes the voluntary market making schemes proposed by the ASX and ENGIE **have the potential to be implemented in a shorter timeframe than compulsory obligations.**”[18]

  The example quoted of Singapore taking “several years to develop” an incentive-based scheme is simply incorrect. The January 2012 to April 2015 period referred to in the EPR paper footnotes, was the time it took to design and develop the futures market in its entirety. This included consultation with the industry, selection of the exchange, developing the initial product set, attracting independent retailers, Monetary Authority regulatory approvals and incentivising market makers. Admittedly, the first attempt to incentivise market makers under the FSC based scheme (refer Section 3.2, Singapore case study) left a lot of room for improvement. The new FIS scheme was developed relatively quickly, being initiated on 31 August 2017 with the release of the Energy Market Authority’s consultation paper “Enhancing the Development of the Electricity Futures Market”[19]. This progressed to the 9 March 2018 release of an RFP to invite interest from commercial market makers with the new market making arrangements taking effect on 1 August 2018 with 6 incentivised market makers (an implementation period of less than a year from the initial consultation paper being released).

5.1. MARKET MAKING TRANSPARENCY

The EPR options paper states that;

> *Some submitters argued wider price spreads were acceptable during increased uncertainty about supply.* ***We acknowledge this view has merit, and market-makers should not be required to assume undue risks.*** *However, individual market-makers currently decide whether to take part in this activity.* ***Nothing is made public about the criteria they use to arrive at decisions, or even whether they have withdrawn from market-making.*** *Once one withdraws, the likelihood is others will follow. This arrangement renders market-making fragile and unpredictable.*

We would concur that one of the weaknesses of the current arrangements is a lack of transparency. The simplest approach to resolve this would be to require a greater degree of reporting from market makers and from ASX. All exchanges will have their own internal market making compliance monitoring tools and reporting arrangements.

[18] ACCC response to the AEMC consultation on market making arrangements, 7 February 2019

[19] This paper proposed revised commercial market maker terms as well as enhancing the product portfolio

Placing a requirement on market makers to report to the Electricity Authority any deviation from the 5% spread requirement, and any decision to withdrawal from market making, together with reasons, would be to us an obvious first step. This should also be complemented with ASX reporting to the Electricity Authority on the level of market making compliance, if this is not already taking place (we note that there is a requirement in Singapore for SGX to report to the Energy Market Authority on market making compliance).

Enhanced transparency should always be a first consideration for addressing any perceived fragility or unpredictability in current arrangements rather than to move directly to a mandatory obligation. This is especially the case when the EPR rightfully notes that "…***market-makers should not be required to assume undue risks".***

6. OTHER MARKET MAKING ISSUES THE ELECTRICITY PRICE REVIEW SHOULD CONSIDER

6.1. ATTRACT COMMERCIALS AS MARKET MAKERS

As discussed in the Singapore case study (refer Section 3.2), commercial market makers were introduced under the original FSC based incentive scheme (1 April 2015) through outsource contracting by spot market licensees. With the move to FIS arrangements (1 August 2018) market making moved entirely to commercial market makers through voluntary incentivised arrangements.

We accept that in New Zealand's case additional attention will need to be placed on the underlying market volatility with no fuel market to proxy electricity price (Singapore's forward electricity curve is correlated with dated Brent and HSFO 180).

ENGIE (one of the six selected Singapore market makers) is also active in the Australian market and went so far as to submit a rule change to the AEMC to effect similar tender based arrangements in Australia in response to ACCC recommending a move to mandated market making[20]. ENGIE claimed that;

- Forced participation of physical players seems contrary to appropriate risk allocation which is an underpinning driver of the NEM design and ignores the important role that financial intermediaries play in the market for derivatives.
- Likewise, the existing financial markets could be used to encourage parties to take upon market making obligations for a fee, as is the case in Singapore which deserves closer attention
- A tender is the most appropriate method for identifying parties who have the sophistication and appetite to take on additional risk that cannot be readily managed by physical participants at this time.
- There is no strong rationale for limiting market making to physical participants. Arguably, there is a case that specialists who do not own physical generation may be best placed to tender for the services.
- A successful tenderer will look for ways to offload risk. This may include sub-contracting physical generators or others to provide specific services. This is a very efficient way for the market maker to act.

[20] Engie rule change submission to the AEMC, 25 October 2018

- By having the successful tenderer perform this function they can sculpt contracts and hedges with other market players in a way which matches their risk profile, which has been determined based on the tender conditions and subsequent bid. This is a more effective and efficient way of parties managing risk than government centrally determining what each party's obligation should be.

ENGIE believed that such commercial arrangements, as opposed to mandating physical players, would deliver the following benefits to the market:

- An economically efficient allocation of risk occurs between parties in the NEM including management of new entrant retailers without placing unmanageable risk on selected physical participants.
- Commercial drivers underpinning individual market participants hedge positions and trade in risk management instruments are not distorted.
- Services that are provided outside the normal course of market conditions are provided in a transparent manner with appropriate cost recovery.
- Shareholders and investors' expectations are not undermined by potential compulsory market making obligations so as to avoid placing a further risk premium on investment in specific or all regions of the NEM to account for unmanageable risk and unrecoverable costs.
- Encourage entrance of specialist providers who may be better placed to support market making services.
- Minimises need for interventions which will directly impact existing businesses based on centralised decision-making.
- Minimise the potential for entities to provide financial risk management services beyond their capability to do so (e.g. obligations to provide hedges that exceed the financial capability of the underlying generation asset).

While we note that it was likely in ENGIE's own interest to submit this rule change we acknowledge that ENGIE has voluntarily entered into such arrangements in Singapore where it is both a major shareholder in a physical generator-retailer and has a significant global commodity trading operation.

6.2. REVIEW SPREADS

Generally narrower bid-ask spreads serve to increase market efficiency through;

- Improving liquidity,
- Building confidence in the forward price curve,
- Reducing the cost of closing out positions for market makers and other participants, and
- Reducing margin requirements and use of capital.

Both Singapore (under the new arrangements) and the UK (even after recent relaxation) have significantly tighter market maker spreads than New Zealand (even though original Singapore spreads were modelled on New Zealand's experience).

However, in respect of market makers, if spreads are too tight this can serve to increase their costs and risks significantly as discussed in Section 4.1. This was the dilemma faced in the UK which lead to the relaxation of bid-ask spreads through the soft landing and fast market rules.

We would recommend that bid-ask requirements for market makers be re-examined on the basis of balancing market liquidity requirements with market maker costs.

6.3. MORE EFFICIENT PRUDENTIAL ARRANGEMENTS

Allowing positions to be netted between the physical spot market and the futures markets (ASX and OTC) has been raised as a way of improving market efficiency and of reducing the costs to market participants.

> ***"To assist small retailers who trade futures, and to partly offset the costs of market-making, the Authority should investigate how a net futures position could as of right be taken into account in calculating prudential requirements …"[21]***

At present, participants can lodge OTC trades with the NZEM Clearing Manager as Hedge Settlement Agreements (HSAs). HSAs provide a way to have the hedging effect of OTC derivatives reflected in prudential security requirements with the clearing manager. Despite attempts, HSAs have not been extended to recognise the hedging effect of exchange-traded derivatives.

> ***"It is important to note that the current prudential arrangements are a barrier to entry that is higher for small players than large players."[22]***

As recently as 2018 the Electricity Authority has again reviewed netting positions for exchange traded hedge contracts concluding that "after a thorough investigation, we have decided at this time not to pursue further developments in this area". This review conclusion seems to be taken largely from the Australian experience where the Australian Energy Market Operator (AEMO) and ASX, undertook a similar study concluding that net benefits from integrated clearing and settlement were unlikely in that market.

The 2017 NZX submission to the Electricity Authority outlined a potential solution to allow prudential offsets between exchange traded hedge contracts and spot market arrangements. We believe this proposal warrants further investigation to reduce costs of trading to market makers and other participants.

[21] Evaluation of Hedge Market Liquidity, Prepared by Energy Link for The Electricity Authority, June 2011

[22] NZX submission to the Electricity Authority's Treatment of prudential offsets in the wholesale market – Issues and options paper, 31 October 2017

6.4. FURTHER MARKET EDUCATION

The anecdotal claims that smaller retailers find difficulty in accessing the hedge markets at times of market stress is concerning and is not supported by Electricity Authority investigations (refer Section 2.4).

As noted at the beginning of the paper, New Zealand is characterised by its hydrological dependency to maintain generation supply. This means that in the event of a dry year the system is placed under stress and requirements to hedge become more acute. Such events occur fairly frequently, with 2007, 2008 and 2017 presenting problems. This is not to suggest that dry years present the only requirement for hedging.

Figure 25: New Zealand Daily Hydro Storage

Source: NZX Hydro

While the hedging strategy of each retailer will vary depending on many factors such as risk appetite and the portfolio and nature of customer contracts, one factor remains constant and that is that parties need to hedge themselves in advance of unexpected events occurring. ***Remaining unhedged or attempting to hedge in the midst of such an event, when the market is stressed, should not be resolved (nor entertained by regulators or officials) through playing the moral hazard card in hindsight***.

Hedged retailers are exposed to the cost of the hedge when the spot price is below the hedge price. Its only in the event when the spot price exceeds the hedge price that the hedged retailers realise the benefit of the hedge. If retailers are able to hedge against a high spot price during a market stress event then there is less incentive to hedge earlier. This claim by smaller retailers may lead to a less liquid market as it doesn't reward early and prudent hedging.

Smaller retailers, especially during their start up phase, may find the financial requirements to access exchange traded contracts prohibitive, or such contracts may not provide sufficient granularity. Such retailers will typically rely on bilateral arrangements with larger players.

However, regardless of how hedging is undertaken it should be a deliberate process that takes place over a long period of time, as described below.

Figure 26: Retail hedging strategy

Most retailers start hedging for a particular period about two years in advance of that period commencing. However, prudently managing forward exposure to prices is a balancing act, with benefits and costs to hedging too far in advance or not far enough. For example, a retailer would not want to enter into hedges to cover their entire (forecast) load two years in advance of a particular period because:

- their load might change in the intervening two years
- in two years' time, contract and spot prices might be lower (and competing retailers may set lower retail prices based on those lower spot/contract prices).

In this sense, contracting too much load too far out might increase the retailer's exposure to risk.

Similarly, a retailer would prefer not to hedge their entire load just before a particular period commences because such a strategy would mean they are completely exposed to the prevailing spot and contract prices. Their retail prices for the period will be largely locked in already, so any wholesale price increases will negatively impact the retailer's margins.

By building up a portfolio of contracts over time, a retailer is best able to balance these different risks.

Retailers that pursue this hedging strategy generally do not own generation, or only own small amounts of generation that do not provide adequate protection from wholesale price volatility.

Source: ACCC Retail Electricity Pricing Inquiry—Final Report, June 2018

We believe that further education of market participants is important and should be conducted as part of the regular stress test arrangements currently taking place.

6.5. RETAIL OBLIGATION TO HEDGE

New Zealand has a stress test regime requiring certain industry participants in the wholesale electricity market to apply a set of standard stress tests to their market position and report the results to their Board and to an independent registrar (NZX). These tests are intended to increase awareness of participant exposure to spot price risk.

To similarly increase participant awareness of spot price risk, and with a view to increasing market liquidity, Singapore sought to copy the NZ stress test arrangements when they launched their hedge market in 2015. However, with the current rollout of full retail competition, and the entry of new stand-alone retailers, Singapore has gone one step further, to require hedging for all retailers participating in the Open Electricity Market rollout.[23] Although not publicly disclosed we understand that this requirement is based on a 50% VAR coverage.

As shown in Section 3.2, the Singapore Case Study, this step has had a significant contribution to market liquidity as shown in volume traded (see Figure 15) and open interest (see Figure 16).

[23] "In addition to fulfilling existing requirements for an electricity retailer licence, retailers who wish to serve households and small business consumers in the Open Electricity Market are required to fulfil additional requirements such as hedging their contracts to mitigate market volatility and enhance their business viability," EMA said. Channel News Asia, Red Dot Power exit, 7 January 2019

7. ABOUT THE AUTHORS

Dave Carlson

Dave Carlson is a senior advisor to The Lantau Group. He is an experienced energy market operator, designer and change manager with a track record spanning Asia, Africa, Australia and New Zealand.

Before returning to New Zealand in 2016 he was a Senior Vice President at SGX, responsible for new initiatives in the gas and power sectors. Prior to that he served for 10 years as the COO and CEO of the Energy Market Company, EMC, the national electricity market operator for Singapore.

Dave has served on and chaired many industry and governance panels in Singapore to further liberalise energy markets including market rule evolution, the implementation of retail contestability, developing gas trading and introducing electricity derivative products.

Dave continues to work with a number of national utilities, regulators, market operators, private generator-retailers, and government clients in South East Asia and the Middle East. He has a BSc in Mathematics from Victoria University in Wellington and passed the Associate Examinations of the Institute of Actuaries, London.

Mike Thomas

Mike Thomas, is a founding partner at The Lantau Group with 30 years of consulting experience, focussing mainly on the energy sector. He advises clients on market design and development; regulatory matters; commercial transactions and disputes; and business and regulatory strategies.

Within the Asia Pacific region, he has led seminal projects on energy-only and capacity market design issues; advised on cost-benefit analysis of transmission expansion; provided crucial expert testimony in a number of commercial contract disputes; served as market advisor on around 50 GW of transacted or commissioned capacity across Mainland China, Hong Kong, Taiwan, Malaysia, Philippines, Singapore, Vietnam, Australia, and New Zealand; advised on regulatory and policy developments concerning cost of capital, cost of service, tariff design, and market power mitigation; and worked extensively with numerous stakeholders to identify opportunities or mitigate risks arising from technology and fuel market shifts, policy developments, and regulatory uncertainty. He has worked extensively with commercial stakeholders, financing entities, regulatory bodies, policy ministries, and end users, maintaining a balanced and coherent perspective on the challenges and requirements of the regions complex and dynamic energy sector.

He started his career in 1988 as an Associate at Putnam, Hayes & Bartlett, in the United States. In 1997, he transferred to the Asia Pacific region. Prior to co-founding The Lantau Group in 2010, he headed the Asia Pacific Energy & Environment practice of a global consulting firm. Mike has an MPP from Harvard Kennedy School and a BA in economics from Carleton College.

John Culy

John is a specialist in energy and utility economics with over 25 years' experience in energy for both the Government and private sectors. He is widely recognised as a leading adviser to the electricity industry in New Zealand and has also undertaken numerous energy consulting assignments in Australia.

John has specific expertise in the analytic techniques of hydro/thermal power system modelling, system security analysis, operation and planning. He also has an extensive background in the theory and practice of electricity and transmission spot pricing, and the economics of energy companies.

John was Senior Economist at the New Zealand Institute of Economic Research for over 10 years. In 1998 he joined Morrison & Co, the management arm of utility investor Infratil, where he advised on energy asset valuation and due diligence, competition analysis, regulatory reform and energy market design in the NZ and Australian markets. John now works with Concept Consulting Group as an Associate on a variety of projects. John has a BSc in Physics and Mathematics and has a Diploma in Statistics and Operations Research.

Final Paper

Prepared For:

Trustpower

Market Making Requirements in New Zealand

Supplementary Paper on the Suitability of Trustpower as a Market Maker

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Date: 12 March 2019

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1. EXECUTIVE SUMMARY

1.1. OBJECTIVE OF THIS PAPER

The Lantau Group (HK) Limited ("TLG") has been appointed by Trustpower to review the current market making situation in New Zealand and to comment on the need for any additional market making requirements. The initial paper considered:

- The current market making situation in New Zealand;
- International context for market making in electricity markets;
- Whether additional market making requirements are required; and
- Any other market making issues that we believe warrant further consideration.

This supplementary paper considers the suitability of Trustpower as a market maker.

1.2. CONCLUSIONS

Our initial paper concluded that the current ASX hedge market is working well, with participant hedge positions being sought and matched, even during the periods of market stress associated with the Winter of 2017 and the Spring of 2018. We also noted that the ASX hedge platform is just one of several avenues available for participants to hedge. Nothing in our view from the 2017 Winter Review or the Electricity Price Review suggested that any urgent rectification of current arrangements was warranted.

Isolated claims from smaller retailers that the hedge market fails to provide effective risk management in times of market stress have not been supported by recent Electricity Authority investigations. The most appropriate response to this claim should be an increased focus on market education around the importance of continuous hedging.

Also, nothing we have seen in New Zealand's experience supports expanding market making beyond the current 4 voluntary market makers in place. The 2011 Electricity Authority review supported this view stating that "introducing a tighter code-based market-making obligation is unlikely to yield net benefits if four or more parties are already actively providing these services on a voluntary basis".

However, despite this we note that Trustpower is questioned from time to time on whether it would be willing to take up market making, and more recently, appears to be included in the consideration by the EPR to introduce a mandatory market making obligation on New Zealand. Our initial paper is not supportive of this move in general.

More specifically, we would be concerned to see Trustpower, as New Zealand's largest net retailer, caught up in an indiscriminate widening of the net under the false impression that it was just another of the larger generators. As we have noted, the options to manage a market making book are quite different for a net retailer and would impose higher risks and costs on Trustpower, potentially to the detriment of greater retail competition in general.

This view is supported by earlier expert opinions that were received by the New Zealand Electricity Commission and The Electricity Authority in 2010 and 2011 respectively but appear not to have been acted upon.

In New Zealand's case, access to controllable generation (controlled storage hydro and thermal) is a distinct advantage for market making. We note that this is not a feature of Trustpower's portfolio which is run-of-river and short storage hydro. This would place Trustpower at a distinct disadvantage vis-à-vis the existing four voluntary market makers, which are normally long generation and have a much larger degree of control over their generation portfolios.

2. SUITABILITY OF TRUSTPOWER AS A MARKET MAKER

2.1. OVERVIEW

As noted previously four of the five larger generator-retailers in New Zealand provide voluntary market making for the base-load monthly and quarterly futures contracts listed on ASX. The question has arisen from time to time as to whether Trustpower may also wish to voluntarily take on market making obligations. It is important to note that while Trustpower may not be a market maker at present, it is an active trader for ASX futures contracts and therefore plays an important role in adding market depth.

The question of Trustpower's involvement dates back to the 2009 Ministerial Review which requested that the 5 generator companies over 500MW put in place an electricity hedge market which included (inter alia) market makers. Also dating back to this time has been the observation that of the 5 large generators Trustpower may not be well suited for market making;

> ***"The 500 MW capacity limit for generators to be market makers is likely to be onerous for a participant like Trustpower. The degree to which different generators have different liquidity requirements is something that we presume will be worked through as part of the EnergyHedge Limited development of the hedge market***."[1]

> ***"The combination of narrower bid-ask spreads and consistently available competitive bids and offers near to, and at the closing of trade each day will help lower the initial margins and help to ensure that daily settlement prices (against which contracts are valued each day) are competitive and efficient. As these requirements are more onerous than those presumed to exist at present, the Authority should consider increasing the threshold for mandatory market-making to 1,000 MW of capacity (up from 500 MW), with additional requirements around net position, i.e. large net retailers might also need to be excluded."***[2]

The 500MW limit imposed by the 2009 Ministerial Review would appear to be entirely arbitrary. It is largely based upon being placed in this original grouping of the 5 larger generators that further justification for including Trustpower as a potential market maker has arisen;

> ***"If a Code obligation were to be introduced, it would be important to ensure that similar entities were treated on a similar basis. This would help to ensure a level playing field which is important for competition and dynamic efficiency"***.[3]

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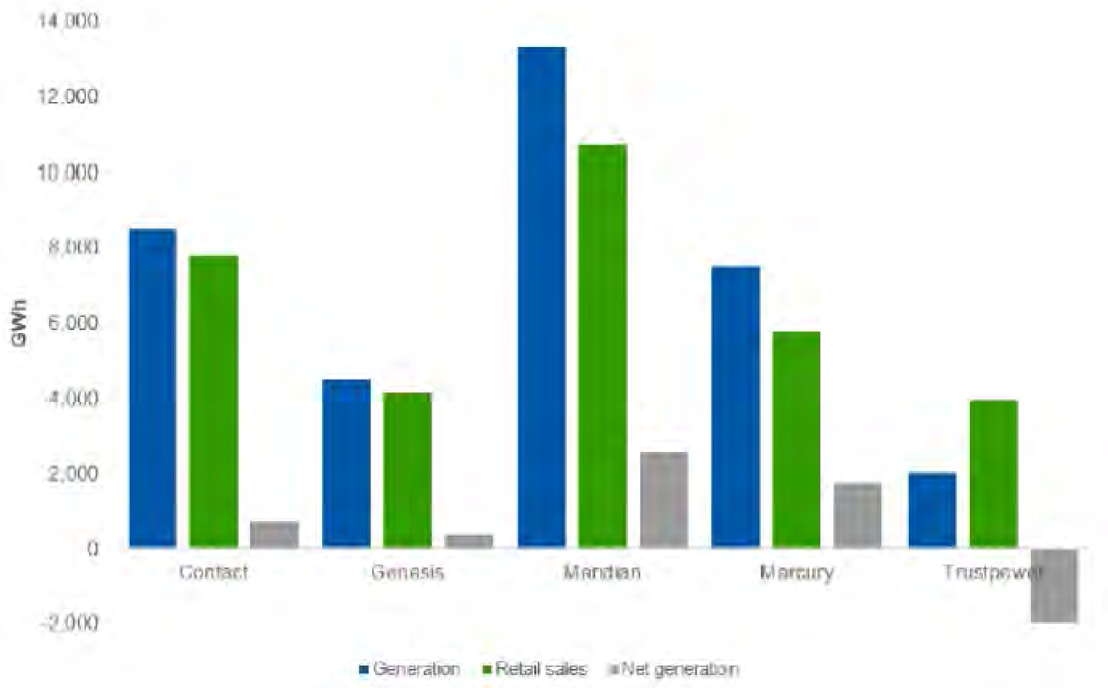
[1] The Development of a Liquid Electricity Hedge Market in New Zealand, A paper prepared for the New Zealand Electricity Commission, Cybele Capital, January 2010

[2] Evaluation of Hedge Market Liquidity, Prepared by Energy Link for The Electricity Authority, June 2011

[3] Cost Benefit Analysis – Market-Making Obligations - the Electricity Authority, 21 November 2011

What differentiates Trustpower from the other four large generator-retailers in New Zealand is that it is a) the only net retailer of the five and b) has a significantly smaller generation portfolio.

Figure 1: New Zealand Generation/retail Sales Balance (FY2017)



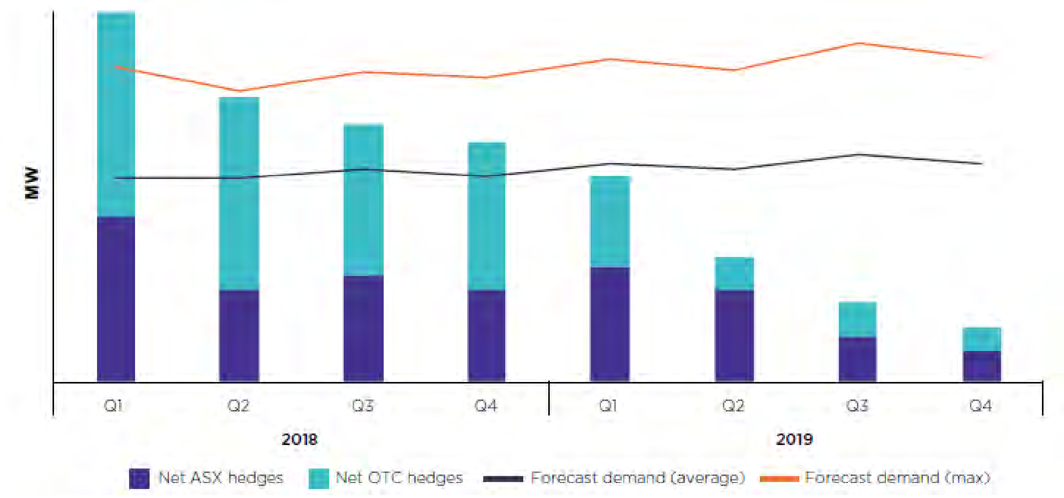
Source: NERA Report under Meridian submission to EPR Panel October 2018

2.2. NET RETAILER HAS FEWER OPTIONS TO MANAGE THEIR PORTFOLIO

As a vertically integrated generator-retailer, Trustpower has the opportunity to hedge a proportion of its retail load with its physical generation (subject to any mismatch between load and supply points in a constrained nodal priced electricity system). However, even if all generation could be matched with load, Trustpower would still have approximately 50% of its load (refer Figure 1) exposed to spot market volatility. In this way its net exposure is no different to that of a stand-alone retailer, in fact because of its size Trustpower is the most exposed retailer in New Zealand.

The ACCC provides the following net profile position for a stand-alone retailer;

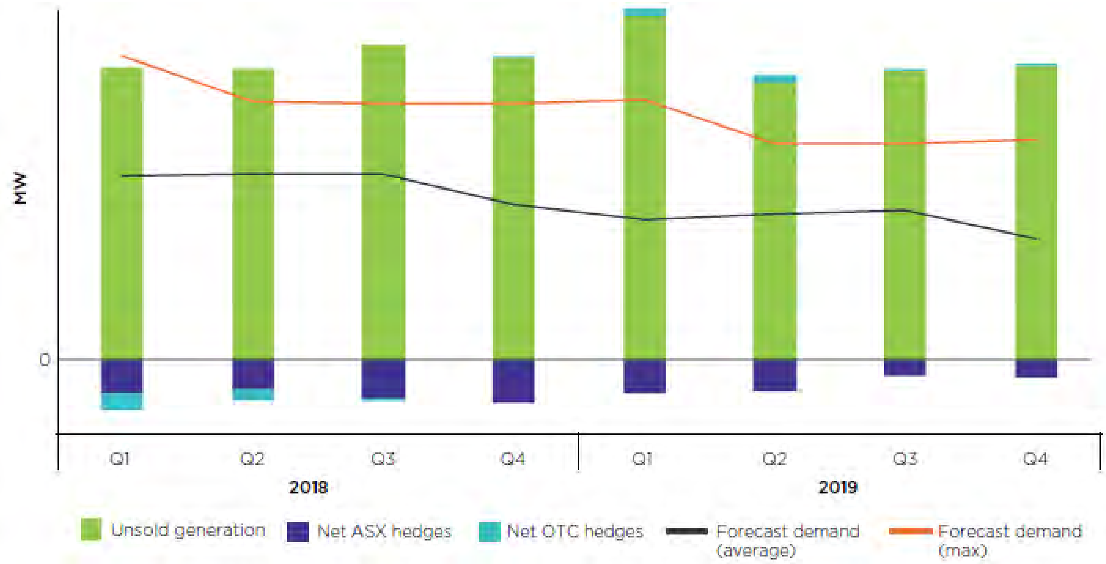
Figure 2: Representative average net position of a stand-alone retailer, Q1 2018 to Q4 2019



Source: ACCC Retail Electricity Pricing Inquiry—Final Report. ACCC analysis of retailers' information. To better preserve anonymity, the chart has been compiled by averaging the net position of multiple retailers with similar hedging strategies, and across separate NEM regions.

Compare this with a participant who is a net generator reveals the additional flex provided by having unsold generation.

Figure 3: Representative average net position of a vertically integrated retailer, Q1 2018 to Q4 2019



Source: ACCC Retail Electricity Pricing Inquiry—Final Report. ACCC analysis of retailers' information. To better preserve anonymity, the chart has been compiled by averaging the net position of multiple retailers with similar hedging strategies, and across separate NEM regions.

Simply put, generators can use their physical ability to generate to honour a position they post in the futures market should it prove too costly to close out the position financially. This is not possible in the case of a net retailer. Also, in New Zealand's case, access to controllable generation (controlled storage hydro and thermal) is a distinct advantage for market making[4]. We note that this is not a feature of Trustpower's portfolio which is run-of-river and short storage hydro (refer Appendix A).

2.3. NET RETAILER WILL TRANSFER RISK IF FORCED TO MARKET MAKE

Without this unsold physical generation position if a net-retailer is forced to take on additional risk as a market maker that they don't have an appetite to hold, they will seek to rebalance their operations or contract in other areas to maintain a similar overall risk exposure.

For example, if mandated to market make, Trustpower may change its internal risk management approach, holding back generation sales (to that extent possible given that the majority of Trustpower's generation is uncontrollable), even if this means requiring its integrated retail affiliate to purchase and hedge additional volumes through the market. This will lead to a loss of efficiency. In the case of a retailer without a generation portfolio it may seek a bilateral arrangement with a market generator to help cover its market making trading positions in the event it cannot immediately close out of its positions in a volatile market.

In the most extreme case, Trustpower will seek to reduce their retail exposure to become long in generation, or even exit the retail market. This is potentially anti-competitive at the margin (the incremental gain from adding Trustpower as a market maker is less than the loss incurred in reducing the overall level of retail competition). Unless one believes that pulling Trustpower out of retailing and into market making will make a substantive improvement for other retailers to enter the market, or expand their activities, then one would have to conclude that this will be overall detrimental to the health of the market and at odds with an implied government policy objective to enhance retail competition. Given that Trustpower is the largest net retailer in New Zealand this is not a gamble that we would advise playing out.

2.4. ADVANTAGE TO MARKET MAKE FOR LARGER DOMINANT PLAYERS

Contracting volumes forward (through such instruments as vesting contracts) is a typical way that markets address potential market power concerns in concentrated markets and that a futures market may assist in curbing market power or at the least, increase confidence in spot market price formation. This was discussed in more detail in our initial report.

Should players find themselves in dominant spot market positions they may be more willing to voluntarily act as a market maker given that this would reduce their uncontracted volumes being sold into the spot market, thereby serving to support market confidence, and thus reduce unwarranted surveillance activity or scepticism. As a net retailer with very little control over its generation (which is run-of-river and short storage hydro) Trustpower is not in this position.

[4] In the case of a commercial market maker entering the market it is likely that they will seek a bilateral arrangement with one or more flexible generators to provide a physical option to hedge positions taken

2.5. MARKET MAKERS HAVE PHYSICAL LIMITS

A market marker's business model is to profit from the buying and selling from the (other) market participants. The market maker provides the market liquidity with the intention of profiting between the buying and selling prices. In the context of an energy market, what is being bought and sold is a finite resource. Creating a market marking obligation will not automatically increase the hedges available to the market.

A market making obligation will have additional and considerable costs e.g. IT and associated costs with developing algorithms to set suitable prices. Additional risks also arise in a market maker holding a net position contrary to their underlying position. A forced obligation may lead to parties trading at a loss in order to provide an obligated market making service. Whether implicitly or explicitly, these costs will find their way to consumers.

3. ABOUT THE AUTHORS

Dave Carlson

Dave Carlson is a senior advisor to The Lantau Group. He is an experienced energy market operator, designer and change manager with a track record spanning Asia, Africa, Australia and New Zealand.

Before returning to New Zealand in 2016 he was a Senior Vice President at SGX, responsible for new initiatives in the gas and power sectors. Prior to that he served for 10 years as the COO and CEO of the Energy Market Company, EMC, the national electricity market operator for Singapore.

Dave has served on and chaired many industry and governance panels in Singapore to further liberalise energy markets including market rule evolution, the implementation of retail contestability, developing gas trading and introducing electricity derivative products.

Dave continues to work with a number of national utilities, regulators, market operators, private generator-retailers, and government clients in South East Asia and the Middle East. He has a BSc in Mathematics from Victoria University in Wellington and passed the Associate Examinations of the Institute of Actuaries, London.

Mike Thomas

Mike Thomas, is a founding partner at The Lantau Group with 30 years of consulting experience, focussing mainly on the energy sector. He advises clients on market design and development; regulatory matters; commercial transactions and disputes; and business and regulatory strategies.

Within the Asia Pacific region, he has led seminal projects on energy-only and capacity market design issues; advised on cost-benefit analysis of transmission expansion; provided crucial expert testimony in a number of commercial contract disputes; served as market advisor on around 50 GW of transacted or commissioned capacity across Mainland China, Hong Kong, Taiwan, Malaysia, Philippines, Singapore, Vietnam, Australia, and New Zealand; advised on regulatory and policy developments concerning cost of capital, cost of service, tariff design, and market power mitigation; and worked extensively with numerous stakeholders to identify opportunities or mitigate risks arising from technology and fuel market shifts, policy developments, and regulatory uncertainty. He has worked extensively with commercial stakeholders, financing entities, regulatory bodies, policy ministries, and end users, maintaining a balanced and coherent perspective on the challenges and requirements of the regions complex and dynamic energy sector.

He started his career in 1988 as an Associate at Putnam, Hayes & Bartlett, in the United States. In 1997, he transferred to the Asia Pacific region. Prior to co-founding The Lantau Group in 2010, he headed the Asia Pacific Energy & Environment practice of a global consulting firm. Mike has an MPP from Harvard Kennedy School and a BA in economics from Carleton College.

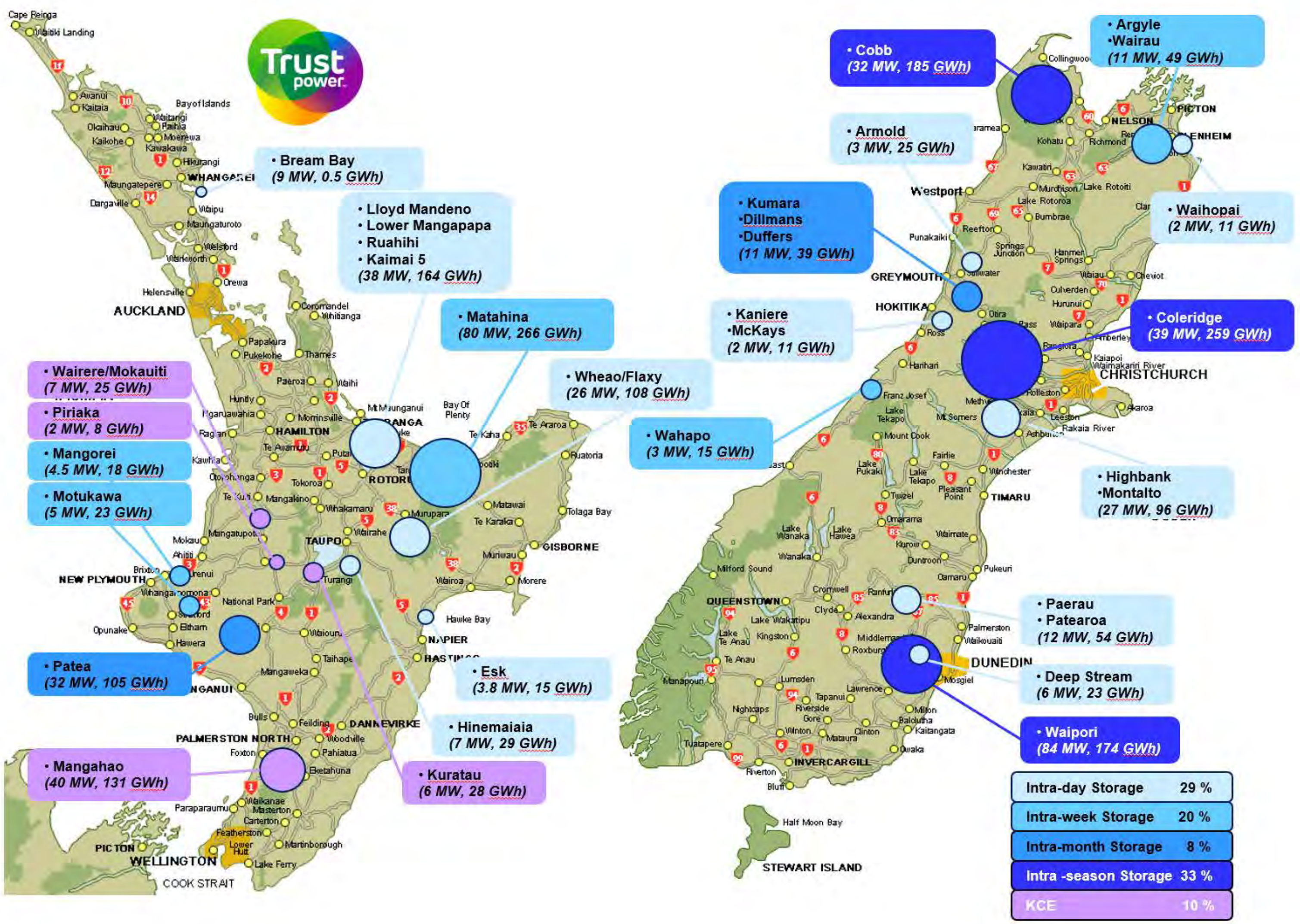
John Culy

John is a specialist in energy and utility economics with over 25 years' experience in energy for both the Government and private sectors. He is widely recognised as a leading adviser to the electricity industry in New Zealand and has also undertaken numerous energy consulting assignments in Australia.

John has specific expertise in the analytic techniques of hydro/thermal power system modelling, system security analysis, operation and planning. He also has an extensive background in the theory and practice of electricity and transmission spot pricing, and the economics of energy companies.

John was Senior Economist at the New Zealand Institute of Economic Research for over 10 years. In 1998 he joined Morrison & Co, the management arm of utility investor Infratil, where he advised on energy asset valuation and due diligence, competition analysis, regulatory reform and energy market design in the NZ and Australian markets. John now works with Concept Consulting Group as an Associate on a variety of projects. John has a BSc in Physics and Mathematics and has a Diploma in Statistics and Operations Research.

APPENDIX A: TRUSTPOWER'S GENERATION PORTFOLIO



Government Policy Statement on Network Pricing

To the Commerce Commission and the Electricity Authority:

This statement is given to:

1. the Electricity Authority by the Minister of Energy pursuant to section 17 of the Electricity Industry Act 2010 as a statement of government policy concerning the electricity industry; and
2. the Commerce Commission by the Minister of Commerce pursuant to section 26 of the Commerce Act 1986 as a statement of the economic policy of the Government on the electricity industry.

1. Background to this Government Policy Statement

1.1.1. A well-functioning electricity sector is essential for the well-being of all New Zealanders.

1.1.2. Across the sector new investment is likely to be required to accommodate an expansion of renewable energy and new energy technologies.

1.1.3. Transmission and distribution networks have strong natural monopoly characteristics and have an important role in the delivery of competitive, efficient, affordable and reliable electricity.

1.1.4. The way in which transmission and distribution services are provided and priced has an impact on all parts of the industry as well as the broader economy and the environment.

1.1.5. This makes it important that the Government sets out its policy expectations as to how these services should be provided and priced.

2. Government's future intentions in relation to the regulation of network pricing

2.1.1. The Government believes it is important that a single regulator is responsible for the way in which network services are provided and priced.

2.1.2. This will ensure a consistent and cohesive approach to regulatory decisions about each network company's:

a. regulated revenue requirements and how those revenue requirements are turned into prices for its customers;

b. network investment including its efficient deployment of alternative technologies;

c. desired network reliability, quality and service levels; and

d. network access arrangements including the obligations imposed on its customers.

2.1.3. The Government intends to pass new legislation which will:

a. transfer responsibility for the regulation of networks to the Commerce Commission with effect from [1 April 2020]; and

b. replace the processes and principles which currently apply for the regulation of network pricing with the processes and principles set out in this statement of government policy.

3. Government's views on the interests which need to be taken into account when determining network pricing

3.1.1. The Government considers that the Commerce Commission when making regulatory decisions about network pricing should take into account (and demonstrate how it has taken into account):

a. [the incentives to innovate] and the risks faced by investors in long life investments; and

b. distributional effects on end users of electricity service[1].

OR if the Government decides not to transfer the network functions to the Commerce Commission

3.1.2. The Government considers that it is both consistent with (a) the efficient operation of the industry and (b) the long term interests of consumers that the Electricity Authority when making regulatory decisions about network pricing should take into account (and demonstrate how it has taken into account):

a. [the incentives to innovate] and the risks faced by investors in long life investments; and

b. distributional effects on end users of electricity services.

4. Government's view on the need for sound transition arrangements in cases of significant network pricing reform

4.1.1. The Government's view is that the Commerce Commission when making regulatory decisions about network pricing should require:

a. Appropriate transitional arrangements where a revision of a network pricing methodology leads to large increases or decreases in current charges[2].

OR

b. That any significant change should be introduced incrementally, in a way that avoids price shocks, is sensitive to the impact on vulnerable regions or groups of consumers, and limits the potential for unintended consequences[3].

OR if the Government decides not to transfer the network functions to the Commerce Commission

4.1.2 The Government's view is that it is both consistent with (a) the efficient operation of the industry and (b) the long term interests of consumers that the Electricity Authority require:

a. Appropriate transitional arrangements where revisions of a network pricing methodology lead to large increases or decreases in current charges.

OR

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[1] NB The transfer of network functions role to the Commerce Commission will require consequential amendments to the Commission's statutory objectives.
[2] Adapted from current clause 19 of TPM Guidelines.
[3] Transpower proposal in its draft GPS.

b. That any significant change should be introduced incrementally, in a way that avoids price shocks, is sensitive to the impact on vulnerable regions or groups of consumers, and limits the potential for unintended consequences.

Transmission pricing

5. Government's view on the purpose of network pricing principles

5.1.1. The Government's view is that Transpower's individual price quality path and information disclosure regulation under Part 4 of the Commerce Act will ensure that the overall costs of transmission services will be consistent with outcomes produced in competitive markets.

5.1.2. As a consequence the Government considers that the principal purpose of the transmission pricing methodology is to provide for the efficient and fair recovery of the Transpower's regulated revenues and to promote the nationally efficient use of the transmission network by grid users and consumers.

6. Government's view on respective roles of Transpower and the regulator in relation to the development and review of the transmission pricing methodology

6.1.1. The Government intends to amend the Commerce Act to provide that Transpower will:

a. have the principal responsibility of developing, for the approval of the Commerce Commission, any amendments to the current transmission pricing methodology required to implement the provisions of this Government Policy Statement;

b. be able to initiate operational reviews of the approved transmission pricing methodology if it identifies amendments which could subsequently be made to an approved methodology that would better achieve the purposes set out in this Government Policy Statement; and

c. be required to report to the Ministers of Energy and Commerce and the Commerce Commission every ten years on whether it thinks the principles in this statement of government policy need to be changed in any manner to achieve the Government's overarching objectives for the sector.

OR if the Government decides not to transfer the network functions to the Commerce Commission

6.1.2. The Government's view is that it is that it is both consistent with the efficient operation of the industry and the long term interests of consumers that:

a. the Electricity Authority permits Transpower to take the principal responsibility for the development, implementation and ongoing review of the current transmission pricing methodology in accordance with high level transmission pricing guidelines developed and published by the Electricity Authority having regard to this Government Policy Statement; and

b. following completion of the current transmission reform process the Electricity Authority should review the process currently set out in the Code to ensure that the process and decision-making criteria which apply to transmission pricing reform appropriately reflect the contents of this Government Policy Statement.

7. Government's views on transmission pricing principles

7.1.1. The Government considers that:

a. the transmission pricing methodology should allocate costs in accordance with the types of assets used, and in particular should provide that:

- the costs of connection assets should be recovered from those connected to them;
- charges for interconnection assets should be recovered from distributors and directly-connected load on a national postage-stamp basis; and
- charges for the HVDC link (as defined in Part 1 of the Electricity Industry Participation Code) should be recovered from generators who inject into the grid in the manner Transpower determines will least interfere with nodal prices;

b. the overall pricing structure should include a variable element that signals the impact of peak usage on transmission costs. This will promote the greater utilisation of existing assets by flattening demand and deterring peak demand growth, delaying or avoiding the need for further grid investment; and

c. the transmission pricing methodology should:

- be simple, understandable to a wide range of sector participants and readily able to be implemented; and
- take into account practical considerations, transaction costs, and the desirability of consistency and certainty.

OR if the Government decides not to transfer the network functions to the Commerce Commission

7.1.2. The Government considers that the following transmission pricing principles comply with the objectives in section 15 of the Electricity Industry Act:

a. the transmission pricing methodology should allocate costs in accordance with the types of assets used, and in particular should provide that:

- the costs of connection assets are to be recovered from those connected to them;
- charges for interconnection assets are to be recovered from distributors and directly-connected load on a national postage-stamp basis; and
- charges for the HVDC link (as defined in Part 1 of the Electricity Industry Participation Code) are to be recovered from generators who inject into the grid in the manner Transpower determines will least interfere with nodal prices;

b. the overall pricing structure should include a variable element that signals the impact of peak usage on transmission costs. This will promote the greater utilisation of existing assets by flattening demand and deterring peak demand growth, delaying or avoiding the need for further network investment; and

c. the transmission pricing methodology should:

- be simple, understandable to a wide range of sector participants and readily able to be implemented; and
- take into account practical considerations, transaction costs, and the desirability of consistency and certainty.

8. Government's views on the process which needs to be followed when reviewing transmission pricing

8.1.1. The Government's considers that changes to transmission pricing reform need to follow best practice regulatory processes.

8.1.2. For substantial changes to the transmission pricing rules the Government would expect that the decision-maker:

a. supports its views on the problems with the current arrangements and preferred solutions with those of independent experts and/or to the extent practicable empirical evidence;

b. avoids setting its reform objective in a manner which excludes any meaningful options analysis;

c. adopts a staged approach to consultation with separate consultations on problem definition, the evaluation of alternatives, implementation issues and risks, and rule drafting;

d. uses an independent firm to conduct cost benefit analysis of various preferred options to guard against the risk of confirmation bias;

e. uses advisory groups or workshops to assist it to both develop and test options and implement reform;

f. incorporates in its consultation processes:

- a cross-submission process so stakeholders have the opportunity to comment on the others views and refine their own views, and
- hearings so stakeholders have the opportunity to engage first hand with decision-makers; and

g. provides ongoing feedback to stakeholders on how their submissions have fared in the development of the decision-makers thinking.

Distribution pricing

9. Proposed repeal of LFC regulations on a phased basis

9.1.1. The Government has received advice from a number of stakeholders, including the Electricity Price Review Panel, that the New Zealand Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC regulations) are hindering the ability to change distribution pricing structures to more accurately reflect the costs of distribution networks.

9.1.2. As a consequence the Government proposes to amend the LFC regulations so the fixed prices distributors and retailers must offer low-use residential consumers would gradually rise over a specified period until the advantage enjoyed by those consumers compared with those on other tariffs is gone.

10. Government's views on distribution pricing reform

10.1.1. The Government expects distributors will reform their tariff structures to introduce more service-based pricing and reduce the current reliance on consumption based pricing.

10.1.2. This transition should occur in parallel with the removal of the price cap in the LFC regulations.

10.1.3. When distributors reform their tariff structures, they will:

a. Actively engage with consumers, retailers and other stakeholders and take into account their feedback on their proposals;

b. Ensure an efficient and fair allocation of network costs across all users of the network, acknowledging stakeholder views;

c. Take into account practical considerations, transaction costs, and the desirability of consistency and certainty for consumers; and

d. Manage transitions in a manner which complies with clause 4.1.1 of this policy statement.

BACKGROUND: The Minister of Energy has appointed an advisory panel (the **Panel**) to advise her on how regulatory frameworks could be improved to facilitate the delivery of fair and efficient electricity prices. The Panel is now consulting on a paper (**Options Paper**) which address the problems it identified in its First Report. Included in the package of reform options is a proposal to issue a government policy statement (**GPS**) on transmission pricing (**Option E1**) and on distribution pricing (**Option E2**). The Panel have invited stakeholders to, comment on a GPS Transpower drafted "for discussion purposes", and make suggestions on the content of a policy statement that would provide enduring guidance on distribution pricing. The Options Paper does not support a transfer of network rule-making functions to the Commerce Commission (**Comcom)** (see **Option F2**).

Trustpower supports Option E1 and Option E2 and disagrees with the Panel on Option F2. Trustpower is a member of a group of diverse stakeholders (**TPM Group**) who are concerned about the TPM reform which has been undertaken by the Electricity Authority (**EA**). The TPM Group support Option E1 and E2 and agree with Trustpower on Option F2. Trustpower is also aware that there are other companies outside the TPM Group that share its views. Therefore it asked Law+Policy Ltd **(L+P)** to draft a GPS on network pricing which could be endorsed in whole or in part by submitters on the Options Paper. This diagram accompanies that draft GPS and records L+P's advice. It has been prepared for Trustpower.

Legislative change will be required to implement a transfer of network rule-making functions and to make a GPS binding on the relevant regulator. Currently both the EA and Comcom are required to have regard to a GPS, but this obligation does not preclude them setting aside its guidance if they consider the GPS is incompatible with their interpretation of their statutory objectives. Nevertheless, a GPS under current legislation could be useful vehicle to (a) signal an intention to transfer network rule-making if the Panel changes its mind (b) set out how the Government thinks the EA should interpret its statutory objective in the context of transmission pricing and its preferences on the next steps in the TPM reform and (c) outline the Government's intentions in relation to the LFC regulation and expectations on distribution pricing reform including in relation to the desired degree of cost reflectivity, timeframes and how distributional impacts should be managed.

The annual reports of the EA (and its predecessor) show that attempts to reform price and non-price network access terms have been underway since industry regulation commenced and are still ongoing. There is also growing evidence of border issues between the EA and Comcom.

In the period from 2012 to 2017, the EA has developed nine different versions of an asset based beneficiaries pay TPM but no other options. A further option is on its way despite strong opposition to its proposals on economic, equity and workability grounds. At the heart of the EA's approach is its view that a more granular allocation of the cost of each transmission asset best aligns with its statutory objective. A GPS setting out the Government's views on how it interprets the EA's statutory objective could clarify if socialized or individualized pricing best aligns with the EA's operational efficiency objective and provide timely guidance on the next stages of the current reform process. It could also address the need for fair transitions for both investors and consumers and outline the respective roles of the regulator and Transpower in TPM reform.

Originally the focus in DPM refom was increased standardisation. More recently the focus has shifted to the lack of benefits based pricing. Distributor's ability to reform tariffs has been impacted by the LFC regulation. There are also concerns about the degree of rate shock associated with the EA's pricing preferences. A GPS providing guidance on these matters could avoid DPM becoming as costly and contentious as TPM reform.

Transfer of network regulation should be in the GPS

- The Panel think a transfer of network rule-making functions to Comcom would be complex and time-consuming to implement and could delay the resolution of transmission and distribution issues.
- However, the EA continuing down its present pathway is also likely to result in a multi-year delay (for the reasons noted on page 50 of the First Report).
- DPM reform may also prove problematic as the EA is seeking to deploy the same approach.
- A transfer to the Comcom will ensure that there is a consistent and coherent approach to the establishment of price-quality paths and price and non-price access terms.
- A GPS could:
  (1) Set out the Government's transfer intentions ahead of the legislation
  (2) mitigate risks of TPM/DPM delay by providing clarity on the desired methodology and implementation timeframes.

GPS should clarify TPM roles

- The EA's TPM reform process has involved very specific direction to Transpower about how the TPM should be structured.
- This direction appears to go beyond the "guidelines" provided for in the Code and has in effect involved the EA developing the TPM itself.
- Trustpower's experts have advised Transpower should have the primary role as it knows its assets and customers best.
- A GPS could clarify the respective roles of Transpower and the regulator so Transpower does not end up having to implement a methodology it considers impracticable and unworkable (which took the EA 6.5 years to design!)

GPS should require fair transitions

- The EA's (a) ability to change the Code at any time (including after long life investments have been made) and (b) view that it need not consider transition or distributional issues do not sit well with the Government's desire to electrify the economy whilst safeguarding the interests of consumers.
- A GPS could address these matters directly by (a) setting an intervention thresholds based on robust benefit assessment and (b) providing that the regulator was required to provide for appropriate transitions in the cases of significant reform.

GPS should set TPM pricing principles

- The EA believes its preferred cost allocation will improve investment efficiency (including in relation to network upgrades) and usage
- There are disputes about whether (a) network investment efficiency can be improved over and beyond existing processes administered by the Comcom and (b) the proposed approach will provide a clear enough price signal to impact other investment and usage decisions.
- There are also concerns about the equity of (a) providing price shocks each time the grid needs upgrading (b) applying the methodology to a selection of existing assets rather than just to new upgrades.
- Government's view on how a regulator's statutory objective should be interpreted in the context of transmission pricing would provide guidance on these issues.

GPS should outline preferred TPM process

- The Panel's First Report and Options Paper contain a number of references to the poor process which has been followed in TPM reform to date (see pages 49-50 of the First Report and page 22 of the Options Paper)
- Yet surprisingly the Panel's option did not include any suggestions as to how the EA might improve its rule-making processes in the future.
- Process is a very important *ex ante* accountability measure for a regulator with as wide a power as the EA and so it is recommended that the GPS sets out the Government's expectations on how TPM reform should be carried out.

GPS should confirm LFC intentions

- The First Report and Options Paper acknowledge that the regulated price cap on fixed charges for low users is impeding distribution reform.
- The EA believes reform can occur without repeal of the LFC regulations, but many in the industry disagree including those with legal obligations under the regulations.
- A GPS could provide clear guidance on the Government's future intentions and note that it would be consistent with the efficient operation of the industry if distribution pricing reform occurred in parallel with the phased removal of the LFC regulations.

GPS should set out DPM reform preferences

- Some distributors are concerned that the EA's preferred cost allocation is complex and will lead to difficult "bright lines" and equity issues.
- The Panel is presently undecided about whether it will recommend principles for a fair allocation of distribution costs between household and business consumers. Another equity issue is the allocation between urban and rural (which seems to have received less focus from the Panel but is of concern to some distributors).
- In this context we think it would be helpful if the Government expressed its views on the need for (a) more service based pricing and (b) distributors to engage with stakeholders, take into account practical considerations, and manage transitions when reforming their network tariffs.

Memorandum

JACK HODDER QC

To: Briony Davies/Emma Peart
Minter Ellison Rudd Watts
Barristers & Solicitors
Wellington

Date: 8 March 2019

Subject: ELECTRICITY PRICE REVIEW (*EPR*) – OPTIONS PAPER (FEBRUARY 2019) – MERITS APPEALS AGAINST ELECTRICITY DECISIONS

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1 You have requested concise comments from me on the EPR's discussion of merits appeals as an option for improving the regulatory system for the electricity sector. The comments below reflect several decades of experience of civil court processes, advising or litigating in relation to a range of regulatory regimes, and a longstanding interest and involvement in law reform.

2 In formulating my comments, I start from the premises that no regulatory regime can be designed and operated perfectly, that economic/market regulation involves large costs (including in relation to investment incentives), and litigation processes have many unsatisfactory elements (not least delays and costs).

3 In summary, it is my view that:

(a) there is a strong public interest in economic/market regulatory decisions that are high quality: impartial, fully informed and fully defensible on logical grounds;

(b) the human factors involved means that there is an inherent risk of errors or reduced quality in any major decision, including on economic/market regulation;

(c) an independent "second look" – relevantly by the courts – is an established and generally well regarded means of reducing such risks and reinforcing high quality in relation to such decisions;

(d) the EPR paper does not suggest removal of judicial review rights, but a judicial "second look" by means of modern judicial review is of uncertain scope: the boundaries have expanded in modern times, albeit inconsistently. And the same is true of appeals on "questions of law";

(e) such uncertain boundaries undermine the purpose of the independent second look, and favour the availability of a merits appeal;

(f) concerns about costs and delays (and gaming by major players) can be reduced by a range of design features in a merits appeal regime for the electricity industry.

The Options Paper

4 The EPR's Options Paper is helpfully clear in indicating (at page 32) that it does *not* favour the option of allowing Electricity Authority (*EA*) decisions to be appealed on its merits. This option is one of six discussed in Section F of the paper, headed "Improving the regulatory system". Of those options, the EPR favours three:

- the EA having clearer, more flexible powers to regulate network access for distributed energy services;

- the EA having a consumer protection function;
- updating the EA's compliance framework, and strengthening its information-gathering powers.

5 The EPR paper also records that it is undecided about another option, establishing a replacement regulator for gas as well as electricity.

6 Perhaps stating the obvious, I note that the merits appeal option is *not* inconsistent with any of the EPR's favoured options. Rather the EPR paper suggests that regulatory accountability can be "better" achieved by clear statutory guidance and requirements for comprehensive consultation.

7 The direct criticism of the merits appeal option is stated in a single but important sentence:

> But appeals can be costly and may best serve the interests of those with the financial means to afford such legal action.

8 The "but" in that sentence to the EPR's preceding (and similarly important) sentence:

> No person or organisation is infallible, and rights of appeal to a second decision-maker can reduce the risk of regulating errors that undermine confidence and increase investment risk.

9 In those two sentences, the EPR paper succinctly identifies the two poles of a longstanding debate over regulatory design. However, as the discussion below seeks to explain, there is more to be said about purposes and processes between those poles.

10 Of relevance for my comments below, I have seen no suggestion that the EPR is considering any removal of the scope for seeking judicial review (principally, now, under the Judicial Review Procedure Act 2016).

Forms of Access to the Courts

11 In the context of decisions by statutory regulators, the relevant statutory framework generally involves dissatisfied parties invoking the courts by one or more of the following processes:

(a) an application for judicial review;

(b) an appeal limited to questions of law;

(c) a general appeal, including on the merits.

12 In my experience, and relevant to comments below, the boundaries of "judicial review" and "questions of law" are uncertain. While judicial review is often spoken of as being about "procedural errors" by a first instance decision-maker, that is no longer a useful description. The modern availability of challenges based on irrelevant considerations, errors of fact and unreasonableness (in varying intensities) can be extensive. But some judges will take a narrow view of the judicial review role while others have a more expansive view, producing unpredictability.

13 As one leading text has explained the modern evolution of judicial review, which tends to match the increased reach of economic/market regulation, there has been a "spectacular" expansion of the circumstances in which the courts may grant remedies. There has also been a shift from a culture of jurisdiction (ie, is the decision-maker acting within its powers?) to a culture of *justification* (ie, can the decision-maker explain that it has proper and coherent reasons for its decision-making?): Woolf et al, *De Smith's Judicial Review* (8th ed, 2018), [1-007], [1-037], [4-050], [11-001].

14 I would add that, based on relatively modern judicial review recognition of the role of enforceable "rights" as having "constitutional" significance, and associated suggestions that the courts have a role akin to partnership with the legislature in interpreting and applying legislation, the trend favours an increasingly expansive approach to judicial review by New Zealand judges.

15 In short, the force and elasticity of the usual descriptions of judicial review grounds – legality, procedural propriety and rationality ("proportionality" remains an open question) – should not be underestimated.

16 Somewhat similarly, the legal distinction between a "question of law" and questions of fact or of mixed law and fact is elusive in many circumstances. Lawyers can readily find cases to suggest a restrained or an expansive approach to what amounts to a question of law.

17 On a "merits appeal", while modern courts exercising appellate functions dislike the language of "deference" to a first instance decision-maker, they consistently recognise the advantages that such a decision-maker has (usually including more time to absorb the arguments). And this places a significant onus on an appellant to show that the original decision was actually "wrong", and not merely debateable. This is more pronounced when the original decision involved the exercise of a discretion.

18 In short, the boundaries of and between the usual procedures are imprecise. This might suggest that judicial review above provides sufficient scope for correction of "regulatory errors". I disagree. In my view, the very uncertainty of scope associated with judicial review would be undesirable. Accordingly, I see the key questions as being whether an appeal regime can be designed to provide a clearer framework for challenge to alleged regulatory errors.

Merits Appeals: countering the concerns

19 If we stand back to ask "Why not just trust the regulators to get it right the first time?", the cogent answer is that provided in the EPR paper, and quoted earlier (see [7], above). In short, an independent "second look" is a means of reducing concerns about the risks inevitable in any decision-making by a person or organisation. The independence of judicial decision-making is real and, I consider, publicly accepted.

20 At the heart of these concerns is the general point that the ideals of a public interest regulatory decision should be met. Such a decision should be impartially, fully informed and fully defensible on logical grounds.

21 In recent years, many regulators have taken considerable trouble to make themselves fully informed, not least through iterative consultation processes. However, having once reached conclusions on a range of issues, there is also the separate and ongoing risk of entrenched thinking – sometimes called "confirmation bias": see Mark Seidenfeld "Cognitive Loafing, Social Conformity, and Judicial Review of Agency Rulemaking", 87 Cornell Law Review 486 (2002).

22 In my view, such confirmation bias was a real influence in several regulatory decisions I have encountered. This is an example of the departure from the ideal of decision-making outlined above, best addressed by an independent "second look" *not* confined within "process" or "question of law" boundaries.

23 If that be accepted, a merits review appeal would seem well justified, *provided* that it is not overwhelmed by costs, delays and asymmetric access to the appeal process.

- ***Potential design features***

24 In addressing that proviso, I do not attempt to fully design a bespoke or model appeal regime. However, there are several design features which, in my view, would mitigate the concerns:

(a) *An agreed or appointed expert*: In the event that an appeal raises specialised issues, and the general intelligence of the court (assisted by counsel and evidence) is thought insufficient to achieve a necessary understanding of such issues, a relevant specialist can be appointed to assist the Court. The specialist's opinions should be available to all parties (unlike the contribution of lay members of the High Court in, say, Commerce Act appeals). Such an appointment might be subject to, and preceded by, an invitation for relevant parties to submit an early joint expert statement on specialist issues.

(b) *Case management/defined issues/limited issues*: Appeals from regulatory decisions are entirely amenable to active "case management" by the courts. Such judicial conferences can and should require early identification of the issues and avoidance of irrelevant evidence. There can and should be rigorous hurdles before new evidence (ie, not considered by the first instance decision-maker) is permissible, especially oral evidence and/or cross-examination.

(c) *Counsel assisting the Court*: Insofar as the position of general consumers is concerned, the early appointment of *amicus* to represent their interests – particularly as a cost of proper indemnity appellants – seems likely to be appropriate in many cases.

(d) *The consumer's voice being heard*: In any regulatory regime, the interests of the consumer will be forefront in the regulator's decision-making. It is likely that major industry players are the most likely appellants if merits appeals are available, but the regulator can be explicitly authorised to defend its decisions and, if an *amicus* process is not favoured, articulate pro-consumer arguments at any appeal. Further, the ideal of high quality decision-making – impartial, fully informed, and fully defensible on logical grounds – is in the interests of consumers as well as other intended parties. And the availability of a merits appeal incentivises regulators to make high quality decisions in the first place.

(e) *Leave/criteria*: One means of curbing tactical or frivolous appeals would be to impose a legal requirement. This would involve a short hearing, on limited submissions, to establish the existence of truly arguable grounds for any merits appeal.

(f) *Time limits*: The avoidance of delays, including the complexities of clawbacks is of obvious importance in relating to regulatory appeals – and ties in with the case management point. I can see no reason why in some form (statute, regulations, High Court Rules, practice statements) the expectation of rigorous timetable to the hearing of, and judgment on, an appeal cannot be clearly articulated. And it might be made clear that the availability of specific counsel of choice – a major delay factor in civil litigation – is not a decisive consideration.

(g) *Special leave for further appeal/questions of law*: The spectre of delays (and costs) expands with the prospect of appeals to the Court of Appeal and (with leave) the Supreme Court. This is inherent in judicial review applications. For a merits appeal, where the objective is *a* "second look", I see no sound reason why further appeals should not require the leave of the higher Court *and* be limited to "questions of law" (albeit recognising the imprecision of that description, as noted earlier).

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