A: Strengthening the consumer voice

A1: Establish a consumer advisory council

We support the option to establish a consumer advisory council. However, in order to be effective, this council will need to avoid industry and regulatory capture and will need to maintain a strong focus on consumer, rather than industry, needs. To do this the group will need to be underpinned by strong customer data analytics and evidence and should have a structure which is independent from undue industry or regulatory influence. It should also have strong consumer representation.

We agree with the Panel and that setting up a Consumer Advisory Council to promote the interests of residential and small business consumers is a positive step to help overcome the complexity of the electricity sector and to give consumers a voice in decision-making. However, as noted by the Panel, the complexity of the electricity sector can make it difficult for consumers to engage with industry and regulatory decision making. There is therefore a risk that the proposed Council may simply rely on the views of external consultants to inform their positions and decision making, which could lead to industry and/or regulatory capture of the Council.

Appointing a regulator to act as Secretariat would also raise similar concerns. A number of the options put forward in the Paper signal that the EA has not adequately accounted for consumer interests in its approach. For example, the proposed Government Policy Statement (GPS) on transmission pricing highlights the limitations of a narrow focus on pure economic efficiency at the expense of consumer experience – the impact of price shocks on consumers, and particularly those experiencing energy hardship, has been raised with some concern by the Panel.

It is therefore important for the integrity and influence of the proposed Consumer Advisory Council that it is based on a structure and membership which is free, frank and fearless in critiquing the status quo to create a better future for consumers. This should also include representation of consumers, including Consumer Trusts, to reflect the unique benefits NZ consumers have from a consumer trust ownership models. To affect the change the sector needs we advocate for a more holistic, fresh, evidence-based, approach which includes knowing and responding to the needs of consumers using robust data analytics. To have an impact, the proposed Council needs to do more than consultation – it needs to understand, and be a champion for, consumer interests and trends. Consumer representatives need to be equipped with evidence and data to have influence, and data analytics is also key to ensure that the group is an advocate for transparency. Leveraging the data and tools that are already available is key to ensuring that sector decisions are more strongly informed by actual consumer needs and behaviours, rather than 'hands off' theoretical economic models.

Incorporating rich data into electricity sector discussions would have shed light on many issues affecting consumers in recent years:

- The number of people on the incorrect user tariff (in 2018, 14 percent of total residential ICPs on Vector's network were on the non-optimal tariff, including 23 percent of two retailer's residential consumers being on the non-optimal tariff during this same year).
- Inequitable and/or low uptake of new technology, including smart meters and/or demand response technology
- Inconsistencies between price comparison outcomes on the two government-funded switching websites
- Switching trends (differentiating between genuine switching and moving house)

- Price spikes in the wholesale market, and their connection (or lack thereof) to gas or hydro shortages, comparable to the work undertaken by Dr Poletti.

Vector is already partnering with a number of other EDBs and independent retailers who, as customer owned entities, have a strong drive to put the customers at the centre of the industry and are seeking to strengthen the voice of the consumer in decision-making. We recognise that the industry is on the brink of significant change and want to collaborate across the sector to ensure that the customers of today, and importantly the future, benefit from these new opportunities and innovations as much as possible.

In sum, we support the consumer advisory council, but argue that the above considerations need to be taken into account in its scope and membership, and that actual consumer behaviour and needs be more influential in this group, than the existing views of industry experts and regulators.

A2: Ensure regulators listen to consumers

We agree that regulators should listen to consumers but hold that they are already obliged to do so. The issue of regulators not executing this aspect of their role to the appropriate extent is not a matter that can be solved by legislation, but rather, warrants serious consideration of a regular, independent review of electricity regulators, and in particular, how effectively their current practice, organisational culture and decisions uphold their core purpose of considering, and protecting, consumer interests.

We do not disagree that regulators should have explicit responsibilities to consult with electricity consumers, and our view is that these obligations already exist. As discussed by the Panel, pricing is an area in particular where consideration of consumer impact, as well as economic efficiency, is critical in enabling an outcome which best serves consumers – the core purpose of electricity regulation.

In this context we do not believe that the issue of inadequate consumer consultation can be solved through legislation. To ensure that the regulator appropriately listens to, and takes into consideration, consumers, we agree with the proposal submitted by the ENA, that regulators are subject to regular, independent review with a clear focus on their consumer engagement. This review process should focus on how effectively the execution of electricity regulation translates into positive consumer outcomes.

B: Reducing energy hardship

We strongly support all of the options in B, and we respond specifically to several of the specific options below.

B1: Establish a cross sector energy hardship group.

We support the option to create a cross-sector energy hardship group to address the complex and overlapping drivers of energy hardship. We see strong alignment between this proposal, and that in *G3 – encourage more coordination among agencies*.

We are acutely aware that a significant portion of our consumers in Auckland live in energy hardship. According to data collected by the Household Labour Force Survey, the median weekly income in Auckland in 2018 was $720[1]. According to the New Zealand immigration cost of living calculator, the average weekly spend across Auckland for living costs was $733.[2] Whilst the cost of living calculator is an estimate, and tells us average actual weekly spend, rather than median living costs, these indicators signal, at a high level, that the margin of affordability in Auckland is often slim, and in many cases, non-existent. This is the result of a number of overlapping factors and we subsequently support the Panel's approach to linking up decision makers from government, industry and the community to form a cross-sector energy hardship group. The model proposed in this option recognises the complex and overlapping challenges associated with hardship, which for many consumers, presents the choice of 'heat or eat'. We believe that the work programme of this group should begin with a stocktake of existing initiatives to respond to energy hardship.

A key part of enabling industry to effectively meet the needs of all consumers, is understanding their energy needs, and we support the proposals in *C3 – make it easier to access electricity use data,* and *E6 Ensure access to smart meter data on reasonable terms.* As mentioned above we also think that including robust data analytics as part of the Consumer Advisory Panel is important to ensure that it supports the needs of all consumers.

As mentioned above, Vector is majority owned by customer shareholders through the trust *Entrust.* In 2018 Entrust paid a $350 dividend to 331,000 households and businesses in the Entrust district, which comprises Auckland, Manukau, northern Papakura and eastern Franklin. This equates to two months free electricity each year for the average Aucklander.

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

We support this option and note that the model proposed has strong alignment with the EnergyMate project, which Vector is proud to be partner to. This is being delivered further to the Consumer Energy Efficiency Programme which Vector undertook in partnership with the Auckland Council and Entrust

In 2017 Vector undertook the Community Energy Efficiency Programme (CEEP), in partnership with Auckland Council and Entrust. This project installed 11 Tesla powerwall solar battery systems at schools, kindergartens and marae; developed a supporting school education resource and provided a workshop to educators and delivered over 600 Health Home Checks to owner occupiers within the Takanini Papakura area.

Further to this experience with community focused, energy efficiency initiatives, Vector is partnering with ERANZ and a number of other electricity industry businesses to deliver EnergyMate. and Vector is proud to be a partner of the initiative alongside a number of other businesses in the electricity industry. The project will deliver an in-home visitation service for families living in energy hardship, as referred by retailers, the Healthy Homes Initiative (HHI) and community-based budgeting services. EnergyMate coaches will provide families with energy

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[1] This is across all income categories, including self-employment, wage and salary, and government transfer. http://nzdotstat.stats.govt.nz/wbos/Index.aspx?_ga=2.97504279.90068571.1534118223-1151857897.1526355338

[2] food, clothes, household utilities, health, transport, recreation and culture, and communication; https://www.newzealandnow.govt.nz/living-in-nz/money-tax/comparable-living-costs;

efficiency education, will ensure that they are on the right fixed user charge (in 2018, 14 percent of all residential ICPs on Vector's network were on the non-optimal user tariff) and will undertake checks of families' appliances and lighting to support energy efficiency. Whilst this pilot project is limited in scope (reaching 50 homes on Vector's network), we see strong linkages with the community network of providers supported by the Panel and look forward to seeing how each of these initiatives develop in the future.

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

We support the proposal to prohibit prompt payment discounts (PPDs), as these discounts are inequitable. PPDs do not reflect any real reduction in the cost to serve a consumer but rather, the additional cost paid by consumers who pay outside of this window is a penalty. These penalties are not aligned with cost recovery but equate to pure profit for retailers, most often at the expense of consumers who are the most price sensitive. We recommend that retailers are accountable for the size of their 'reasonable' late payment fees (which should reflect cost recovery) through information disclosure requirements.

PPDs substantially exceed the size of the savings that retailers achieve through an earlier payment, sometimes being a difference of 10-20 percent. As stated by CEO of Meridian Energy, Neil Barclay, in September last year (whilst announcing Meridian's removal of PPDs): 'When we looked at the cost of following up to recover debt, it was a fraction of the value of the discount we were taking away. That makes it manifestly unfair.' At the time, Mr Barclay indicated that the move was expected to cost Meridian $5 million, which he has said would not be recovered from elsewhere in customers' bills. In further months, Meridian reportedly 'Observed no discernible impact on or deterioration in … customers paying their bills late, levels of customer debt, or disconnections.'

These statements confirm that the discounted prices have represented the true standard retail prices and that the disparity between PPDs and later payments has been, for the most part, pure profit. Moreover, as the Panel rightly recognises, this profit has generally been at the expense of the consumers who are the most price sensitive. We therefore note the terminology Meridian has used to describe the removal of the PPDs as a 'guaranteed discount' is misleading – a more accurate description would be that they have removed their later payment penalty.[3]

We therefore support the ban of such discounts, but to allow cost-reflective late payment fees. This should provide sufficient incentive for customers to act in ways that reduces retail costs, whilst ensuring that vulnerable customers are not being penalised disproportionately for outlays that are not, in fact, being incurred. We recommend that retailers are accountable for the size of their late payment fees, through an information disclosure.

C: Increasing retail competition

C1: Make it easier for consumers to shop around

[3] https://www.meridianenergy.co.nz/news-and-events/meridian-to-replace-unfair-prompt-payment-discounts-with-guaranteed-discount-for-all-customers/;

Vector supports the option to make it easier for consumers to shop around and the proposal to combine Powerswitch and Whatsmynumber? into a single switching site. We note that a large number of consumers do not switch retailer, and that evidence shows consumers trust information provided by government, rather than commercially. We recommend that any efficiency gained from consolidating the sites be reinvested to make the switching tool more accessible to all consumers.

As is discussed further in *C6: Help non-switching consumers find better deals,* a large number of consumers have not switched retailer, creating a two-tier energy market whereby non-switching consumers pay more than those who do switch. We also note evidence which suggests that non-switching consumers may be more time poor and price sensitive and that the that rates of switching are not increasing – according to figures provided by the EA, the number of consumers who switched in February 2019 was a four-year low.[4]

One of the key themes to emerge from the Australian Energy Market Commission's (AEMC's) recent retail market review in Australia is that customers are more likely to trust information supplied by governments or regulatory agencies, than by commission-based sites. We therefore agree that the government funded switching sites referred are valuable in encouraging consumers to switch.

We support the proposal to consolidate investment into a single price comparison website that is easier to navigate, better at identifying the best deals for individual customers and offers real-time access to usage data (a matter we return to subsequently). We recommend that any cost savings from consolidating the two platforms be re-invested in tools to improve the accessibility of the site to all consumers, such as making the service available in multiple languages.

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

We support this proposal to include information on power bills on how to switch, or to resolve billing disputes. However, we do not think that this information is adequate in supporting consumers' decisions to switch. Consumers require visibility of what comprises their electricity bill, through itemisation, as well as their own electricity usage through greater access to their smart meter data.

We support providing customers with more information on their power bills, including information to make it easier for consumers to get a better deal or to have a dispute resolved, particularly given the low level of awareness of the Utilities Disputes service. However, we do not think that it is adequate to remind customers that they can switch, without providing them with the information that they need to make this decision. Fully itemised retail bills would provide customers with the data they need to make these decisions in an informed way and we consider that all retailers should be required to clearly set out the various components of a total bill – including itemised energy, transmission, distribution, retail, late payment and regulatory charges. This information should be displayed simply, such as with a graph.

Without this bill transparency, many consumers would not be able to weigh up their options adequately enough to switch retailers. This additional transparency would also enhance

[4] https://www.emi.ea.govt.nz/Retail/Reports/R_SwT_C?_si=v%7C3;

consumer confidence by making it clear that retailers have passed-through any reduction in distribution or transmission charges. Ready access to smart meter data which shows consumers their own usage patterns would only strengthen consumers' position in making an informed decision to switch, and on what plan is best suited to their needs. As will be discussed further, we therefore support the option proposed in *C3: Make it easier to access smart meter data.*

C3: Make it easier to access electricity usage data

We support this option as a means of empowering consumers to make informed decisions about their retail plans, including competitive service options, and the Low User Fixed Charge (LUFC). Sharing this data with third parties easily and in real time can provide consumers with even greater efficiencies, including load control device options.

Vector supports this option. As we mentioned in our response to option *C2: Include information on power bills to help consumers switch retailer or resolve billing disputes*, consumers' ability to access this information is necessary for them to choose the best retail plan. Different retailers offer different deals which may benefit some patterns and levels of usage more than others i.e., off peak discounts will benefit a consumer who can avoid heavy usage during peak times but may not offer a better overall deal for a consumer who cannot make the most of this discount. Whilst we recognise (and strongly support) the option to phase out LUFCs, this is unlikely to be implemented immediately. Over the proposed phase-out period, many consumers have the potential to gain cost savings if they switch to the correct tariff. They cannot make this choice if their electricity usage is not visible to them. The ability to share this data with third parties can create further efficiencies for consumers:

- more competitive and dynamic pricing,
- energy efficiency analysis,
- bundled or integrated service options,
- load control device options, and,
- tailored pricing options.

We are consequently strongly in favour of this option. As mentioned earlier, we also think that better understanding the needs and consumption behaviours of consumers is critical for the industry to deliver better services for them. We think that improving access to usage data, starting with the consumer, plays a key role in developing this understanding.

C4: Make distributors offer retailers standard terms for network access

We do not support this option. We have not seen evidence that the current arrangements compromise retailers' entry into the market, particularly when compared with the challenge of gaining a share of the market for new retailers. We acknowledge the recent decision of the Court of Appeal which gives the EA jurisdiction to regulate elements of a Default Distribution Agreement (DDA) and we will work with the EA through this consultation process.

This option proposes to mandate the standardisation of Use of Service Agreements (UoSAs) for retailers' access to distribution networks. This links with a proposal included in *F1 – Give the electricity authority clearer, more flexible powers, to regulate network access for distributed energy services* to give the EA the power to regulate the terms and conditions for the use of transmission and distribution networks. The matter of the EA's jurisdiction to regulate on elements of DDAs has recently been decided by the Court of Appeal – this provides the clarity on this matter which was being sought by the Panel.

We have not seen evidence that the current arrangements regarding UoSAs act as a barrier to entry for new retailers. Vector introduced its Electricity UoSA in 2013, with 12 existing electricity retailers signing up to that contract over the following two years. Since 2013, 26 additional, new to market electricity retailers signed up to Vector's UoSA. The UoSA has seen more new-to-market entrants sign up to the agreement than it has incumbent signatories - it doesn't seem that the requirement for retailers to sign up to a UoSA does act as a barrier for new entrant retailers.

The current arrangements around UoSAs may also offer efficiency to small, new to market, retailers. Under these arrangements, if a better deal is negotiated by a retailer, then the distributor has to make this offer available to all parties who are already subject to an existing UoSA. These parties have 12 months to sign onto this new agreement, if they choose. In this way, a small, new to market, retailer stands to gain from the terms negotiated by other, larger, retailers, without needing to negotiate these terms themselves. For example, the latest service agreement to be offered by Vector is version 1.7 - this is the eighth iteration of the agreement introduced in 2013 and is the version with the greatest number of signatories by far (V 1.6 has the next greatest number of signatories, which is 6). Each existing UoSA-signed retailer has been offered the opportunity to take up the latest version – which a small independent retailer did in 2017 – upgrading from V 1.2 to the already developed V 1.7. However, if a retailer wants to negotiate better terms than are offered by existing UoSAs, then they have the option of doing so.

It is currently in the interests of distributors and transmitters to make these agreements as streamlined as possible. Contractual and operational alignment of our Auckland and Northern networks in Auckland has standardised the services standards, connection processes, outage communications, and mass market pricing across wider Auckland. This approach was intended to enable more retailers to trade on our network and to enable competition and innovation in Auckland's market. The greatest barrier to this currently is the challenge for new retailers to gain a share of the market – despite the large number of new entrants the five large gentailers (Mercury, Genesis, Contact, Trustpower, and Meridian) had over 90 percent of the ICPs on Vector's network in this same year. We appreciate the objective of creating a more competitive retailer market, but do not think that this option would support this outcome.

C5: Prohibit win-backs

Vector supports the option to prohibit win-backs as this practice is a significant barrier for retail market entry and expansion and exacerbates the 'two-tier' market dynamic which costs consumers.

Retailers currently receive a notification if a consumer is leaving to another retailer and have an opportunity to 'win them back' with special deals. As mentioned earlier, MDAG, an advisory group to the EA (which is also appointed by the EA), recently released a report on saves and win-backs, finding that win-backs reduce the transparency of electricity prices and could consequently have an impact on the number of consumers who shop around. This was supported by evidence (of activity on switching websites) which suggests that there is an association between lower rates of switching, and more win-backs. However, the MDAG concluded that 'there is no strong rationale for regulating customer acquisition processes, particularly saves and win-backs in order to promote greater transparency in retail pricing.

Unpublished discounts are not peculiar to saves and win-backs'. Whilst it may be true that unpublished discounts are not peculiar to saves and win-backs, we do not consider this to be a reason in itself to allow this particular market practice to continue - the issue of win-backs obviously came to the attention of the Panel for a reason, and represents one opportunity to strengthen the market. The impact of win-backs on consumers is also not limited to pricing transparency. As such, this should not be the only rationale taken into account when considering their removal (as it seems, was the approach of the MDAG in their analysis on the matter). For example, win-backs also deepen the two-tier energy market and compromise electricity affordability. Large, incumbent retailers who know that they are going to be alerted every time a passive customer finds a better deal have no incentive to proactively offer those customers lower prices in the first place. Rather than offering competitive services by default, the status quo is characterised by complacency which results in some consumers getting a markedly better deal than others – even if receiving the same service from the same retailer. This creates inequity between switching and non-switching consumers, as well as an imbalance between large incumbent retailers, and smaller, market entrants.

If win-backs were banned, incumbent retailers would not be able to wait until customers were on the cusp of switching before offering them lower prices. They would instead have an incentive to offer customers cheaper prices up front. The 'lucrative counter-offers' enjoyed by consumers (which may be framed as the downside of banning win-backs), are red herrings. If win-backs are prohibited, those selectively applied counter-offers would simply be replaced by retailers offering better deals to all customers by default, as well as a more competitive, and efficient, market overall. This is a better outcome for consumers, independent retailers, and for the robustness of the market.

C6: Help non-switching consumers find better deals

We strongly support the option to enable a contracted agent to negotiate a bulk deal for consumers who had not switched retailers for many years. The evidence suggests we currently have a two-tier energy market, whereby passive consumers miss out on better deals (and, are likely to be cross subsidising the cheaper services enjoyed by consumers who do switch). We also note that non-switching consumers are more likely to be time poor and price sensitive. We estimate the potential benefit of such a scheme to be around $15m per year for consumers.

As the Panel has noted, between 400,000 and 750,000 New Zealand households have never switched retailers since records began in 2002. The number of switching consumers is not getting any better with EA figures reporting that switching reached a four-year low in February (the number of consumers who switched in February 2019 is 13 percent less than in the year prior and the lowest February total since 2015).[5]The number of consumers who haven't switched includes consumers who have assessed alternative retail options but decided to stay with their current retailer, or who have started to switch and been 'won-back' (as noted above we strongly support the panel's position to prohibit 'win-backs'). However, based on the EA's most recent research on this matter around 13 percent customers do not even know that they have a choice of retailer and, approximately 16 percent of customers do not know that they can switch

[5]https://www.emi.ea.govt.nz/Retail/Reports/R_SwT_C?DateFrom=20040101&DateTo=20190228&ShowAs=Count&_rsdr=ALL&_si=v|3;

providers. This suggests that approximately 280,000 customers think that retail competition does not exist. In addition to those underinformed customers, there will be more who know they can switch, but have been put off from doing so given the complexity of the market and process. The large number of consumes not switching exacerbates the 'two tier' energy market, as referred by Martin Cave.[6]

As noted by the panel in the first discussion paper, 'there are some indications vulnerable consumers may be over-represented among those who do not shop around and are therefore paying higher prices'.[7] This includes research from the United Kingdom's Competition and Markets Authority, which found that poorer households were less active in switching retailers than wealthier households, as well as research resulting in similar findings in Australia.[8] We therefore support bulk switching as a way of reducing costs for consumers who may benefit the most from the savings. In some cases, this 'loyalty tax' is significant. Disengaged customers who switched as part of Ofgem's recent collective switching trial saved around £300 per year, on average, and, the Panel's analysis of retail billing data suggests that, at a national level, residential customers could save between $240-$280 per year by switching to a cheaper offer.

If the trial was undertaken here and had similar scale to the trial undertaken in the UK, the overall savings to this group could be around $2.7 million. (Assuming 50,000 consumers were identified as disengaged in the trial, 22.4% of whom accepted the new collective offer which included of savings of $240 per year). If this was then scaled up to all disengaged customers, the aggregate saving could be around $15m per year (i.e., 280,000 x 22.4% x $240). The cost of running collective switching over time is also likely to reduce as systems and processes gain efficiency.

New Zealand already has a process for the mass transference of retail customers to alternative providers. When a retailer goes out of business in New Zealand (i.e., when it 'defaults'), the EA oversees a process whereby it notifies the customers of the failed retailer and urges them to choose another. If some customers fail to switch then, after 14 days, the EA begins to assign them to new retailers – first by running a two-stage tender process and then by mandatory allocation. A modified version could be applied to reallocate disengaged customers and the EA's existing guideline could be used as a useful blueprint – particularly when combined with any relevant learnings from the recent UK precedent.

Finally, although this option would constitute a non-trivial intervention, it is still relatively 'market-based'. Retailers would simply be competing to supply a sub-set of the retail market that has, for various reasons, proved inaccessible. If designed well, the process could enable disengaged consumers – including those in energy hardship – to benefit from competition without incurring the costs of searching and switching whilst limiting unintended consequences. As an option, it offers very little downside, but significant potential benefit for consumers.

C7: Introduce retail price caps

We agree with the panel and do not support retail price caps. We think this intervention could have unintended consequences and that other interventions proposed will be more effective in achieving the intended outcome of a more competitive retail market. However,

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[6] Lessons from the UK Electricity Pricing Review, April 2018.
[7] EPR Discussion Document, page 38.
[8] Ofgem, State of Market Report, 2017

we support a review of these initiatives in three years' time, and if these options have not achieved the intended outcome of strengthening competition in the retail market, then further interventions can be considered.

As the Panel will no doubt be aware, both the UK and Australia have taken steps towards re-introducing retail price caps:

- On 19 July 2018, in the UK, the Domestic Gas and Electricity (Tariff Cap) Act 2018 received royal assent and became law. It required Ofgem to place a temporary cap on all standard variable tariffs (SVTs) and default fixed-term tariffs. Ofgem released its decision in November last year and those regulated tariffs came into effect on 1 January 2019.
- In June 2018, the ACCC similarly recommended abolishing 'standing offers' (Australia's variant of the default tariff) and replacing them with a regulated tariff to be determined by the AER. The AER released its draft decision in February which, if implemented, would result in substantial reductions in standing offers throughout the country.

A key motivation for re-introducing retail price caps in both the UK and Australia is to reduce prices for disengaged customers, i.e., to limit the size of the so-called 'loyalty tax', related to the discussion on bulk switching and the two-tier energy market above. We believe that the other options proposed to increase retail competition (prohibiting win-backs, making it easier to switch, and bulk switching) should address this issue. However, if these benefits do not eventuate, then this can be a matter for further consideration at the time of review in three years' time. At that time the 'jury may be in' on the UK and Australian reforms, which will then serve as useful case studies.

Section D: Reinforcing wholesale market competition

Vector supports the package of wholesale market reforms proposed by the Panel. We view these proposals as the absolute minimum steps necessary to restore confidence and transparency in the wholesale market, which is currently performing poorly across the board. However, we are concerned that the proposals do not go far enough, particularly in relation to exploitation of market power, which evidence suggests may be costing consumers upwards of $700m per year. We also note that the EA's enforcement of the existing market rules has been weak and ineffective.

D1: Toughen rules on disclosing wholesale market information

Vector supports this option as a matter of priority. In addition to identifying any gaps in the current disclosure rules, it is critical that the disclosure rules already in place are rigorously enforced. There are clear indications that breaches of the disclosure rules have gone undetected and/or unpunished.

As the Panel has rightly noted, there are two distinct elements to the proposal. The first is for the regulator to rigorously enforce the disclosure rules that are in place already, while the second is to identify any gaps in the current rules and/or powers around information disclosure.

With respect to the first issue, there are clear indications that breaches of the existing disclosure rules have gone undetected and/or unpunished by the EA. For example, throughout the period of sustained high prices at the end of last year, a variety of information was not disclosed in a timely fashion. Firstly, numerous plant outages were not disclosed properly. For example, Contact Energy routinely waited until near or after the close of business to declare high impact shutdowns of its gas fired generation in the Taranaki region, despite compelling evidence from bid-offer stacks that the outages were planned and that the company was aware of the outages up to several hours before they were publicised. Genesis Energy also failed entirely to disclose the unavailability of its 5th Huntly generating unit (HLY_5) to the market (via Planned Outage Coordination Protocols or otherwise) on multiple occasions.

In its recent decision on the claim of an undesirable trading situation (UTS), the EA stated that its compliance team was continuing to investigate these potential instances of non-compliance. However, it dismissed this element of the UTS claim on the basis of an analysis that showed there was no evidence that plant owner/operators were using plant outage information to trade on the ASX in any systematic or widespread way. However, generators would be well aware that any competent regulator would swiftly detect such an obvious pattern, and hence would be most likely to employ such tactics sparingly. The UTS claim identified the specific instances listed above as being highly suspicious. The EA's decision to ignore those conspicuously late (or non-existent) announcements on the basis that the behaviour did not appear to be widespread is wholly inadequate.

Secondly, the EA has confirmed that the 'swaption' contract between Genesis and Meridian was activated in late September 2018, but that this was not disclosed to the market. The EA's compliance team is continuing to investigate but, here again, a UTS has been ruled out. The EA concluded that, although the information was withheld, the gap between what the two parties know and what a 'reasonably informed participant' should have known, was limited. Essentially, the EA is suggesting that those not privy to the information could have 'pieced it together' from public sources. Whether or not that is true (which we do not necessarily accept), it does not detract from the fundamental point that the information should have been disclosed and it was not. The rules on this point are clear.

Thirdly, despite the fact that the Pohokura gas field began experiencing problems from 14 September last year, none of the major generators disclosed any changes to their fuel supply situations, despite the impact the outage was inevitably going to have on the wholesale market. It was not until Shell made its first public statement a fortnight later (on 28 September 2018) that the market as a whole was made fully aware of the severity of the problem – and it was not until 12 October that the expected duration of the outage was announced (Genesis had been informed four days earlier on 8 October).

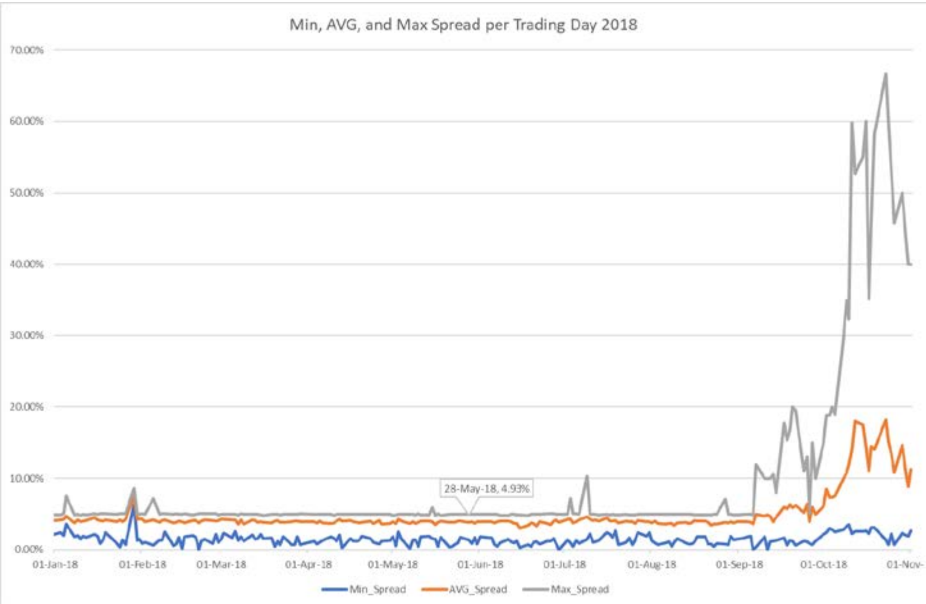
This brings us to the second element of the Panel's recommendation; namely, for the EA to identify any gaps in its powers to require the disclosure of information, such as contract fuel prices. The inference here seems to be that generators may not have been obligated under the existing rules to disclose the impact that Pohokura's problems were going to have on their fuel supplies and, in turn, on wholesale prices. In our opinion, the information disclosure requirements are already very clear in this regard – Section 13.2A of the Code compels market participants to disclose any information they have about themselves that they expect will have a material impact on the prices in the wholesale market if it was to become public. It is difficult to see how information about supply disruptions at the Pohokura field could not meet this criterion. We therefore see no barrier to the EA taking appropriate action against those market participants that failed to disclose information about the outages at the Pohokura field, given the obvious impacts that they would undoubtedly have on the wholesale market. We will consequently wait with interest for the findings of the EA's compliance investigation.

That said, although we do not believe that there are any obvious gaps in the existing rules that would excuse the conduct described above, we see no harm in modifying the Code to remove any possible doubt. The catalogue of troubling events described above suggests that certain market participants have either misconstrued the current rules or have chosen to willingly disregard them – perhaps in the expectation of suffering no repercussions. As such, we favour any option that would significantly toughen the requirements surrounding information disclosure and/or result in more diligent enforcement of the present rules.

D2: Introduce mandatory market-making obligations

Vector supports the Panel's view and considers that mandatory market-making obligations should be imposed on the large vertically integrated generator-retailers as a matter of urgency. Recent experience has revealed that the current voluntary arrangements are manifestly inadequate, and do little to foster confidence in the wholesale contract market.

For extended periods throughout both 2017 and 2018, buy and sell price spreads exceeded the five per cent limit specified in the voluntary undertakings with the ASX. Once again, the period of high prices in October-November last year serves as a prime illustration of the weaknesses in the current arrangements. The following chart shows the percentage difference between buy and sell prices on a daily basis from January to November 2018. The three lines are the minimum spread on the day of all contracts, the average spread of all contracts and the maximum spread on the day.



The chart reveals that, throughout most of the last year, the maximum spread on each day was less than five per cent. However, spreads started to widen on 7 September – initially in the current and next-monthly contracts. This then quickly moved to all the monthly and the first 3 quarterly contracts. By early October, average spreads over all contracts out to 2022 increased to 10%-18%. By the time that information on gas constraints started to hit the market, spreads reached levels bordering on the ridiculous – up to 66% in some instances.

With buy-sell price discrepancies at these levels, purchasers without natural hedges would have had almost no confidence that the contract prices being offered by the vertically integrated firms reflected the real future cost of production. Indeed, as the EA's UTS investigation has confirmed, throughout much of this period, the gentailers were privy to more information about the state of the gas market than other market participants. Independent retailers were hence faced with a no-win situation in which they could choose either to:

- purchase contract cover at what appeared to be unreasonable prices; or,
- remain unhedged and take on the wholesale spot price risk.

Unsurprisingly, many independent retailers opted for the latter, and some were ultimately forced to exit the market when they could not financially withstand the sustained period of very high spot prices that ensued.

Some of the vertically integrated gentailers have argued that spreads of the magnitude observed throughout this period were acceptable in the circumstances. Specifically, they have contended (at least implicitly) that they should not be required to adhere to the voluntary market-making obligations when it would result in them assuming 'undue risks' (however defined). While we accept the general proposition that market-makers should not be forced to take on unreasonable risks when performing their function, the problem with the current voluntary arrangements is that, aside from the four participating generators and the ASX, nobody else knows what the current 'portfolio stress' thresholds actually are and, as a consequence, when the voluntary commitments may cease to apply. For example, it was not until the EA released its UTS claim decision on 28 February that other market participants became aware that the generators relied upon the portfolio stress clauses during the investigation period, and that none of them were found by the EA to have breached their market-making agreements. In our opinion, this lack of transparency undermines substantially the purpose of the obligations.

We also disagree with the suggestion that independent retailers should already have secured firm supply contracts before spot prices started to soar in October and buy-sell spreads began ballooning. The Panel is correct to observe that companies will sometimes need to adjust their position in the middle of a tight supply period – and they should be able to be confident in the observed contract prices. We likewise dispute the claims made by some that retailers trying to buy contract cover when spot prices started to spike was analogous to a houseowner trying to buy insurance for a burning home. A more appropriate analogy is that offering contracts at the prices seen from October to November was akin to an insurance company setting a house on fire (or, at the very least, pouring fuel on the flames), and then offering to insure the home at an exorbitant price. As discussed in our response to D1 above, the gentailers knew that gas supply shortages would have a pronounced effect on the wholesale market, and yet they chose to withhold that vital information from the market for at least two weeks (from 14 September to 28 September 2018). If independent retailers had been warned sooner that 'the house was on fire', then they might have acted more swiftly and with much greater confidence that contract prices were reasonable.

For those reasons, we consider that mandatory market-making obligations and tougher monitoring and enforcement of market disclosure rules go 'hand in glove'. Both are necessary to reduce the now well-recognised deficiencies in the wholesale contract market and restore some badly-needed clarity and certainty. As we set out in our first submission, we consider that compulsory market-making obligations should be imposed on all generators with a share of at least 10% of the transmission-connected generation market. The suite of products that market-makers should be compelled to offer should include baseload, peak period, and cap contracts. Bid-offer spreads should be set at similar levels to comparable markets internationally – 5% at most, and preferably lower.

As we noted earlier, we do not expect market-makers to assume undue risks. Accordingly, we would be happy for any mandatory obligations to contain predefined 'stress provisions' that would be known to all. Finally, strict compliance and enforcement penalties should be introduced. To that end, the regulator should ensure it has sophisticated market monitoring technology so that any irregularities can be identified and quickly dealt with.

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

Vector agrees that far more transparency is needed surrounding the profitability of the vertically integrated retailers' generation and retail activities. At present, segmental reporting is opaque and inconsistent across companies. While separate accounts will go some way to addressing this issue, we think the Panel should go further and recommend operational separation between the generation and retail arms of the large vertically-integrated players.

Lack of transparency an ongoing source of suspicion that undermines confidence in both the wholesale and retail markets – particularly when it is coupled with matters such as the troubling conduct we described in our response to D1 above, and the evidence of significant market power rents in the wholesale market, which we discuss further under D4 below.

However, as we explain in more detail in our response to option D5, we consider that the best way to improve the transparency surrounding the pricing and profits of the vertically integrated businesses is to require operational separation and impose non-discrimination conditions. The gentailers would then be unable to maintain opaque natural hedges that obscure their internal transfer prices. Those separate business divisions would instead need to contract with one another on an arms'-length basis on terms and conditions that would be transparent and, crucially, available to other businesses in equivalent circumstances.

There would then be no need to impose any requirements regarding the specification of transfer prices, since there would not be any. In our opinion, this is likely to be a more effective solution of the problems that have been identified. However, if the Panel does not favour operational separation, then we would certainly prefer the current suggestion of segmental accounts over the status quo.

Regulated segmented accounts should be required to display revenue, cost and profitability metrics for the generation and retail arms separately, calculated on a consistent basis across all vertically integrated companies. Businesses should also be required to disclose the transfer prices that have been applied between their generation and retail segments when calculating revenues and profits. Those transfer prices should be derived using a consistent methodology set out in regulation.

We agree that the Commission's reporting rules for distribution businesses could provide some useful guidance in this regard. Ofgem's Segmental Statement regulations could also be used as a template. For example, the Ofgem regulations specify that the transfer prices adopted by businesses in their segmental accounts must reflect how they actually acquire energy. Companies are required to supply a 'clear and full' explanation of the methodology that they have applied for this purpose.

D4: Monitor contract prices and generation costs more closely

Vector supports the proposal to monitor generator profitability. However, that oversight should be much more extensive than the Panel contemplates. Specifically, comparisons of contract prices with new generation costs should be complemented with assessments of market power in the spot market – such as the recent analysis performed by Dr Poletti at the University of Auckland, which estimated market power rents of up to $6 billion over a seven-year period. Unfortunately, Dr Poletti's analysis and conclusions have been widely misunderstood and misrepresented, mainly based on the false allegation that his results do not make allowances for fixed costs.

In this section, we seek to clear up some of the confusion regarding Dr Poletti's analysis and explain why such modelling should form a central component of any market monitoring framework.

The most common criticism of Dr Poletti's assessment is that because it uses a competitive benchmark of 'short-run marginal cost (SRMC)' it consequently 'ignores fixed costs' and therefore cannot detect market power rents. But that is not the case, and reflects two basic misunderstandings of Dr Poletti's work.

Firstly, in the NZEM (as in other competitive markets), the spot price is set by the SRMC of the marginal generator – i.e. the most expensive plant required to meet demand in any given period. All generation plants with SRMCs below that of the marginal plant will earn 'infra-marginal' rents which contribute to covering their fixed costs. For example, if a gas or coal peaking plant is setting the price, lower cost plant such as hydro and wind will receive significant additional revenue over and above their marginal generation costs.

Secondly, during times of potential supply shortages (e.g. when lake levels are low), the price in a competitive market will rise to whatever level is necessary to ensure that demand matches supply. During these periods, the marginal generator will earn 'scarcity rents' over and above its SRMC, which contribute to the recovery of fixed costs.

Dr Poletti's report clearly sets out that his competitive benchmark prices are based on estimates that fluctuate depending on the level of relative scarcity. In his model, as lake levels drop and the probability of shortages grows, the 'water values' assumed in his competitive counterfactual prices begin to increase. This is precisely what one would expect to observe in a well-functioning competitive market.

During those periods of scarcity, whenever a hydro plant is setting the market price (when it is the 'marginal generator') the competitive benchmark price will consequently include some 'scarcity rents'. These scarcity rents, along with the inframarginal rents earned by lower cost generators during normal periods, will allow all generators to make a contribution to their fixed costs, whilst providing appropriate signals for investment in entry and expansion.

It is therefore wrong to suggest that Dr Poletti's modelling ignores fixed costs. Sufficient compensation for fixed costs should already be factored into the scarcity values in Dr Poletti's competitive benchmarks. Generators do not need even higher prices in order to earn a normal rate of return – prices at those levels are likely to deliver excess returns that indicate significant market power. According to Dr Poletti's modelling, these 'market power rents' could amount to up to $6 billion over the seven-year period he examines, which represent 35-40% of total wholesale revenue, on average. Accordingly, as noted in our response to the EPR's Issues Paper, we think Dr Poletti's results raise very serious questions about the degree of competition in the generation market. It is disappointing that the Panel appears not to have taken these concerns seriously.

Against that background, it is imperative that generator profitability be monitored closely. While we welcome the Panel's proposal to undertake periodic comparisons of contract prices and new generation costs, for the reasons we have set out above, we do not consider this to be sufficient in itself. In our view, the Panel should recommend a full-scale investigation into market power in the wholesale market, led by the Commerce Commission as New Zealand's primary competition regulator. The Panel should also consider much bolder options for improving wholesale market performance, such as reducing concentration in the market by transferring some generation assets to a new SOE; requiring operational separation of the vertically-integrated gentailers so that all contracts are traded transparently via the hedge market; and examining options for wholesale market re-design that have been adopted in other jurisdictions.

Finally, we note that regardless of which options are recommended by the Panel to address issues in the wholesale market, much will depend on regulatory willingness and ability to police the wholesale market more vigilantly. The oversight provided in recent years has been very lax, which has contributed significantly to the current difficulties.

More generally, Dr Poletti's findings serve to highlight the importance of implementing the various wholesale market reforms favoured by the Panel as a package. Put simply, the current market arrangements are not working well. The contract market is fragile and opaque, and suspicions are rife that market power is being exercised by the vertically integrated incumbents. We consequently view the Panel's recommended interventions as the minimum steps necessary to restore confidence and transparency in the wholesale market.

D5: Prohibit vertically integrated companies

While we understand the Panel's reluctance to recommend forced divestiture, there are other options available that could significantly improve market outcomes. The most obvious would be operational separation, whereby gentailers' wholesale and retail arms would be required to function as arms-length businesses. Serious consideration should also be given to undertaking horizontal (rather than vertical) separation to address market power issues in the wholesale market – for example, by transferring some generation assets to a new SOE as was suggested in the previous 2009 review. In our opinion, these more comprehensive reforms are likely to be preferable to the lighter-handed options suggested by the Panel. Even if the Panel is not prepared to support those stronger options today then, at the very least, they should remain 'on the table' for the future if market performance does not show significant improvement.

There are various other options for improving wholesale market performance that go further than those proposed by the Panel but are not as extensive as forced divestiture.

For example, instead of structural separation, *operational* separation requirements could be imposed on the large gentailers. This would involve creating at least two distinct business units within each business, splitting out the wholesale and retail functions, which would then function as arms'-length operations. It would also be necessary to introduce so-called 'equivalence of inputs' (EOI) requirements to prevent the wholesale businesses from discriminating in favour of their own retail divisions, which they would still have an incentive to do in the absence of full ownership separation. EOI requirements typically require equivalent services (in this case wholesale electricity) to be supplied to all buyers on the same terms and conditions.

Under operational separation, gentailers would no longer be able to maintain opaque natural hedges that obscure their internal transfer prices. Instead, the wholesale and retail divisions would need to enter into explicit contracts through the hedging market. Advantages of such a reform would include:

- the prices at which the retail divisions were buying from the wholesale units would be transparent to all parties. It would not be necessary for the businesses to 'construct' a transfer price and report profits in the manner envisaged in option D3 – that information would instead be available for all to see at the time contracts were agreed; and
- the application of EOI requirements, when coupled with this additional transparency, would give independent retailers and generators more confidence that the contract prices being offered were reasonable. It would also facilitate more effective wholesale market enforcement.

There are many examples of operational separation requirements being imposed in industries that were previously vertically integrated. For example, in New Zealand, Australia and the United Kingdom, the integrated providers of fixed line telecommunications services (Telecom, Telstra and British Telecom, respectively) were all operationally separated – and, since that time, all three businesses have also been *structurally* separated to varying degrees. These reforms made it easier for the relevant regulators to clamp down on anticompetitive conduct, such as discriminatory vertical price squeezes, (as exampled by this ACCC response to Telstra over broadband internet pricing)[9].

An even less intrusive option than operational separation would be to leave business structures untouched, but to require the large gentailers to make a defined portion of their generation available (say, 30% or 50%) to third parties via the hedge – thereby increasing the number of contract market transactions and, in turn, the available price data. Under this approach, it would be important to ensure that a business could not comply with the requirement by simply contracting a large part of that generation with itself, as the prices agreed within such 'internal' bilateral contracts would not be meaningful in these circumstances.

The principal potential advantage of such arrangement is, once again, the additional transparency that might be created surrounding contract prices. However, it may not achieve that objective as simply and effectively as operational separation. Accordingly, of the two

[9] https://www.accc.gov.au/media-release/accc-issues-competition-notice-to-telstra-over-broadband-internet-pricing;

alternatives, we favour the former, and consider that it could prove more effective at addressing the problems raised by the Panel than the comparatively 'lighter-handed' options that it has proposed.

One of the reasons we are somewhat sceptical about the 'lighter-touch' options currently favoured by the Panel is that, if the current regulatory arrangements for the sector remain in place, success would depend to a large extent on the willingness and ability of the EA to police the wholesale market vigilantly. The EA's track-record on this matter does little to inspire confidence – oversight has been lax, which has contributed materially to the present difficulties. For example, the EA's handling of three high-profile undesirable trading situation (UTS) claims reveals a troubling pattern:

- When Genesis found itself in a pivotal supplier situation on 26 March 2011 due to a transmission outage, its bidding conduct caused spot prices to reach approximately $20,000/MWh over several hours throughout the Waikato. This was deemed to be a UTS by the EA, but Genesis' conduct was not found to be in breach of any applicable rule or law, and hence was not considered to constitute manipulative trading activity. The EA opted simply to 'reset' spot prices throughout the period to $3,000/MWh. This decision neither fostered confidence in the wholesale market nor provided any meaningful deterrent for future cases. It was analogous to policing a case of shoplifting by asking the thief to simply return the stolen goods with no additional penalty – hardly an incentive for encouraging good behaviour in the future.
- On 2 June 2016, Meridian was facing a peak shortage in the North Island and attendant exposure to its retail load. It responded by submitting bids for its South Island generation units that caused spot prices to reach as much as $4,000/MWh. Despite this, the EA determined that a UTS had not taken place. In other words, the EA considered it was acceptable for Meridian to engage in trading behaviour that took advantage of its pivotal position in the South Island to engineer an artificial shortage in that location to cover its retail exposure in another. It is highly unlikely that this form of manipulation would be permitted in, say, the context of a financial market. Accordingly, it is again difficult to comprehend why the EA felt this conduct was acceptable in the wholesale market, or why it did not feel that a failure to act would compromise the confidence of participants in those arrangements.[10]
- Most recently, last November a UTS claim was lodged following a substantial and sustained increase in wholesale spot and contract prices, and various failures by generators to disclose information in a timely manner. As discussed above, the EA acknowledged that vital information about gas shortages was withheld from the market by some generators for at least a fortnight. However, the EA determined that there was no UTS because the extent of the information asymmetry was 'small' and other market participants could have pieced things together from various public sources. Again, we find this decision difficult to fathom. In our view, it should not be incumbent on market participants – most of whom have far fewer resources than the large gentailers – to hunt out clues when the information in question should have been disclosed. The EA's finding

[10] We note, for example, the advice provided to that effect by Mr Colin Magee (of the Financial Markets Authority) to the EA's Market Development Advisory Board, see: Market Development Advisory Group, Minutes, Meeting number 6 (available: here).

on this claim will increase the cost of participating in the market and is likely to further undermine confidence.

Accordingly, unless there are substantial changes to regulatory oversight and enforcement of the wholesale market rules, then there is a high risk that the options the Panel is currently recommending would not achieve their intended purposes. That risk would be reduced to a substantial extent if the more extensive options we described above were implemented.

Even if the Panel is not prepared to support those stronger options today then, at the very least, they should remain 'on the table' for future reviews. Specifically, if the wholesale market problems described throughout this submission were persisting at the time of the three-year 'health-check', then all of the more intrusive options we have described – including structural separation – should be given serious consideration at that juncture.

E: Improving transmission and distribution

E1: Issue a government policy statement on transmission pricing

Vector strongly supports this proposal. As we discussed in our response to the EPR Issues Paper, the EA's review of transmission pricing has fallen well short of regulatory best practice in almost every respect. While we would prefer to see responsibility for network pricing transferred to the Commerce Commission (as discussed further in our response to F2 below), if the EA is to retain control of the process then clear direction from the Government is needed urgently to bring the process to a resolution.

To assist with this process, Vector has commissioned Pablo Spiller and Marcelo Schoeters at Compass Lexecon in New York to prepare a draft GPS, setting out the key principles that should be taken into account in transmission pricing reform. Their full report is attached at Appendix 1, and their suggested wording for the GPS is reproduced in the box below.

Compass Lexecon's report and draft GPS address what we consider to be the key concerns with the EA's TPM reform proposals to date. Most importantly:

- The EA's insistence on retrospectively reallocating the sunk costs of past grid investments, which would be both inefficient and unfair– in addition to being globally unprecedented; and
- The proposal to reduce transmission charges for generators and major industrial consumers, and increase the proportion paid by EDBs, smaller businesses, and residential consumers (including those in poorer regions like Northland, King Country and Ashburton).

Finally, in terms of process, the EA must be given a clear direction to cease all further work on its TPM review until it is provided with a GPS. This would include halting the production of the CBA that it has commissioned from its external consultants. The reason for this is self-evident. The EA and its consultants plainly cannot undertake further work or make decisions on the TPM methodology until they see what the GPS says, since it is likely that it would necessitate substantial changes to (and possibly even the abandonment of) the key elements of the methodology that has been proposed previously.

Compass Lexecon Draft GPS on Transmission Pricing

1. It is Government policy that transmission prices should:

    a. Be simple, practicable and understandable to a wide range of sector participants, by setting prices in a way that avoids continuous disputes.

    b. Reflect the costs of transmission and allow for the recovery of existing sunk costs while minimizing distortions to production, consumption, location and investment decisions, by means of a postage-stamp charge evenly spread across a wide base of network users which includes loads and generators.

    c. Make beneficiaries of new transmission investments internalize the cost of such investments, promoting efficient choices between relying on the existing assets or expanding the network, by charging the cost of new investments to beneficiaries based on the net benefit they obtain from those investments.

    d. Introduce regulatory changes incrementally to:

        i. minimize regulatory uncertainty, without altering the rules of the game for existing investments in network or other assets; and

        ii. avoid creating price shocks that may threaten affordability of end-users or have material distributional effects.

2. In conducting the TPM reform process, the Electricity Authority (EA) should be mindful of the adverse effects of delaying the resolution of the process. The EA shall provide clear guidance consistent with the principles stated in this Policy Statement. Transpower, in conjunction with user groups, should take the principal responsibility for development, implementation and ongoing review of the TPM.

E2: Issue a government policy statement on distribution pricing

We are broadly supportive of the Government issuing a GPS on distribution pricing. Although distribution pricing reform has not proved as contentious or protracted as the TPM review, there are signs that the EA's thinking on this issue may be similarly rigid. A distribution pricing GPS does not need to be as prescriptive as the transmission pricing GPS, but it should set out the Government's support for pricing reform that is customer-centred and takes account of factors such as simplicity, fairness, and limiting bill shock in addition to economic efficiency. It should also specify that all users of the distribution grid need to pay a fair share of the costs – this is increasingly important in the context of distributed generation and the increase in two-way flows on the grid.

While we see merit in a high-level distribution pricing GPS, we consider that it would be counterproductive to adopt a 'one size fits all' approach to distribution pricing, given that there are currently 29 EDBs across New Zealand all operating in different circumstances. Moreover, if each distributor remains free to tailor a pricing methodology to its own conditions then this will create 29 'natural experiments'. Those methodologies that work well are likely to be quickly mimicked – provided the local circumstances are conducive – and those that do not are likely to be avoided. A distributor-driven approach could consequently deliver substantial efficiencies. Those benefits could be stymied by a GPS that mandated the universal application of a particular pricing approach.

E3: Regulate distribution cost allocation principles

Vector does not support prescriptive regulation in this area. The analyses presented with the Panel's first report did not provide clear evidence of concerns about the current allocation of distribution costs across business and residential customers. However, Vector (along with other non-exempt EDBs) will continue to transparently report its cost allocation methodology, and will review this methodology as part of our wider consideration of distribution pricing reform.

As we explained in our first submission, the Panel's analyses of cost allocation were incomplete, since they failed to account for the dividends paid back to customers via trust ownership. In Vector's case, Entrust provides a fixed dividend amount to each ICP in the Entrust district. This means that households receive the same dollar amount as commercial customers. Our effective distribution charges to residential customers are therefore much lower than the headline rates would suggest.

In addition, while the Panel's assessments indicated that residential customers tend to be allocated a greater share of distribution costs than business customers based on MWh consumed, as the Panel itself acknowledged the costs of distributing electricity are not primarily driven by consumption volumes. The majority of EDBs network costs are fixed, while incremental costs are driven primarily by peak demand. Since residential customers' demand tends to be 'peakier' than business customers', it is reasonable for the former to pay proportionally more for their usage.

Finally, the analysis in the Technical Paper indicated that the present allocation of costs to residential customers is 'subsidy-free' (i.e., they are not paying less than incremental costs or more than stand-alone costs). From the perspective of pure economic efficiency there are therefore no obvious problems with the basic mechanics that most distributors are using to allocate costs to their residential customers. Any changes to the cost allocation methodology would therefore be motivated chiefly by notions of fairness, i.e., as a means of reducing prices for residential customers and assuaging the affordability problems that some are experiencing. While we support measures to alleviate energy poverty, a cost re-allocation between business and residential customers would be a poorly targeted mechanism as it would not focus specifically on residential customers experiencing affordability problems.

E4: Limit price shocks from distribution price increases

As a majority consumer-owned company, Vector is highly attuned to the risk of price shocks from distribution price changes and takes this issue very seriously. We also consult regularly and widely with our stakeholders prior to making changes to our prices. However, we do not support introducing detailed regulations of the type discussed in the Panel's options paper. Instead of introducing additional regulations, we suggest that mitigating risks of bill shock could be included as a high-level principle within a distribution pricing GPS.

The Commerce Commission already regulates network companies' prices (from 1 April 2020 this will move to a revenue cap methodology rather than a price cap), which limits the scope for annual bill increases. As the Panel acknowledges, introducing an additional layer of pricing regulation would significantly increase compliance costs for distributors. Moreover, if this additional regulation were administered by the EA as the Panel suggests, this would create another area of potential regulatory overlap and inconsistency between the two regulators. We also note that at present it is the EA's single-minded focus on cost-reflectivity over other objectives that is creating the greatest risk of bill shock in relation to both distribution and transmission prices.

E5: Phase out low fixed charge tariff regulations

Vector supports the phasing out of the LUFC regulations. As the Panel has recognised, although these were originally intended to protect low-usage consumers (particularly low-income households) and encourage energy conservation, they have several widely acknowledged drawbacks.

The issues with the LUFC regulations have been well-canvassed by the industry and include:

- they make it much more difficult for EDBs to move away from the 'legacy' model of predominantly volumetric pricing (i.e., a rate per kWh) to more innovative charging structures that could improve both efficiency and equity; and,
- they provide windfall benefits to (typically high-income) households that can afford the up-front costs of energy efficiency and distributed generation technologies to reduce their consumption, as well as to holiday homes that are used only part of the year. This increases the residual network costs that must be recovered from other customers – a problem that is likely to increase over time as uptake of new energy technologies increases.

However, we agree that it will be important to examine how much fixed charges might increase once the LUFC regulations are repealed and, if necessary, to phase in any changes in order to mitigate price shocks – particularly for low income customers. That transition might commence in 2020 when regulated distributors enter the next default-quality price path period, which is currently under consultation.

E6: Ensure access to smart meter data on reasonable terms

Discussions on data access should be based on the premise that consumers own their data and must have the final decision rights over how it is used. A host of new opportunities exist once consumers can more easily access their own data or authorise the sharing of that data with third parties of their choice. This would allow data to flow to parties who need it to provide new and innovative services that benefit consumers.

As part of this, we agree with the Panel's view that metering data should be readily available to EDBs on reasonable commercial terms so that they can properly manage their networks. Effective use of data has the potential to lead to lower network costs, as obstructions to the transfer of data has cost implications for EDBs. Removing these barriers will lower costs. However, Vector considers that it is preferable for these terms to be negotiated commercially rather than imposed by regulatory fiat.

Implementing the EA's proposals around Additional Consumer Choice of Electricity Services (ACCES), formerly Multiple Trading Relationships (MTR), will enable multiple parties to simultaneously access smart metering data. In addition, the ENA-Smart Technology Working Group will be undertaking work on data access issues as part of its Network Transformation Roadmap project which will be launched in April this year. Vector recommends that these processes be allowed to take their course before any regulatory decisions are made on smart meter data access.

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

We do not support the proposals in this section. The Commission already has extensive powers to regulate EDBs. Instead, what is needed is clearer guidance on the Commission's decision-making process for enforcement action.

The Commerce Commission has a variety of tools available to regulate EDBs' performance, for example via:

- Information disclosure requirements
- Price-quality regulation (for non-exempt EDBs)
- Court proceedings to enforce breaches of the above requirements
- Reviews of Asset Management Plans
- Market Studies
- General consumer protection legislation.

We are strongly opposed to raising the maximum penalties for breaches of the price-quality regulations and do not accept that the current maximum penalties are insufficient to deter large EDBs. Raising the penalty threshold would be premature given that there has yet to be a single court penalty awarded. The Commission itself did not mention any need for higher penalties in its submission on the Panel's first report. Instead, it said that the "fundamental market and regulatory mechanisms of the electricity sector are working relatively well".

Rather than higher penalties, Vector would like to see greater clarity on expectations for price-quality trade-offs within the current framework. There are a range of possible interventions that could reduce the number and duration of interruptions for customers, but not all of these are within the price limits set for distribution price paths (DPPs). For example, Vector has estimated the cost of undergrounding our remaining overhead network to be in the vicinity of $5 billion. This would significantly reduce the incidence of outages but at a high cost to consumers, likely leading to breaches of the price component of the DPP. We have seen regions in Australia where more rigorous quality standards prescribed by law makers were the catalyst for significant network expenditure programmes. These have improved reliability but have also been criticised for not being supported by customers and for driving increased electricity costs.

The much delayed Enforcement Guideline by the Commerce Commission should prescribe the model behaviours it anticipates from EDBs even where environmental conditions are adverse. This would make it clearer to all stakeholders the consequences of non-compliance to quality standards, given the influence environmental factors have on annual statistics. It would also ensure that enforcement action in response to price-quality breaches is applied evenly across EDBs, which we do not believe is the case at present.

Overall, we believe that the metrics and administration of the price-quality regime need to be more strongly connected with the consumer and consumer experience. For example, quality thresholds should reflect the impact of breaches on consumers accounting for the location of an outage, rather than just understanding breaches at an aggregate level. A more customer focused regime would also compensate affected consumers directly, rather than paying penalties for quality breaches to the Crown. We also note that in many cases price-quality breaches do not reflect factors which EDBs can control – such as climate change or vegetation management regulation. Connecting the breach resolution process more clearly to EDB practices by leveraging EDBs' own internal accountability frameworks – for instance, by requiring EDBs to immediately report any breaches to their Boards – would be more likely to contribute to better quality outcomes, rather than simply increasing penalties. As described above, we believe that the proposed approach is likely to create perverse outcomes which are more likely to impact negatively on consumers in the long term.

E8: Require small distributors to amalgamate

We agree with the Panel's view that small EDBs should not be forced to amalgamate via legislation. However we believe there are opportunities to gain efficiencies for consumers through greater collaboration and coordination in the sector.

Amalgamation would impose significant restructuring costs and is likely to be opposed by local communities, while the evidence of efficiency gains from greater scale – once network density is controlled for – is weak. Whilst we believe that amalgamation would ultimately be inefficient, we think that there are opportunities to effectively gain efficiencies through collaboration and coordination – with both other EDBs and, across vertical market segments. As mentioned above in our response to *A1: Establish a Consumer Advisory Council*, Vector is already partnering with a number of other EDBs who share the objectives of strengthening the voice of energy consumers in industry and government decision making; and of ensuring that the customers of today, and the future; benefit from new innovations and technology. As has also been mentioned, Vector is partnering with ERANZ in support of the EnergyMate project. Vector will sit alongside gentailers, government agencies, retailers and community organisations to deliver energy efficiency education and support for families in energy hardship. As many of the challenges and opportunities experienced by our sector cut across market segments (and in some cases, sectors), we think it is critical to that we take a broad view to gain efficiencies for consumers through collaboration and coordination. As is discussed further in *F1: Give the Electricity Authority clearer, more flexible powers to regulate network access,* we believe that the opportunities for consumers presented by greater coordination are great.

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

We strongly agree with the Panel's view on this option. There is little to be gained from devoting significant resources to re-litigating matters such as asset valuation and rates of return that have already been subject to extensive review.

Over the past decade, foundational aspects of the regulatory arrangements for Transpower and EDBs have been scrutinised closely by government departments, regulators and courts. Moreover, the weighted average cost of capital (WACC) for EDBs is subject to periodic review by the Commission as part of the Input Methodologies (IM) and DPP processes.

Making changes to input methodologies outside of the standard regulatory processes would create significant regulatory uncertainty and undermine incentives for investment at a critical time in New Zealand's transition to a new energy future.

F: Improving the regulatory system

F1: Give the EA clearer, more flexible powers to regulate network access for distributed energy services

We do not support the proposal to restrict the relationships that EDBs can have with distributed energy services. Enabling industry to meet the new challenges facing the energy sector requires a regulatory approach which proportionately responds to the actual risks to competition, whilst weighing up the opportunities of coordination and innovation (and the need for greater optionality with investment given greater uncertainty). This cost benefit analysis needs to consider the new challenges and opportunities we face today, and in the future, rather than carrying forward assumptions based on the past and rhetoric. Having undertaken this analysis at a high level, we do not see how the risk to competition currently outweighs the opportunity cost of disenabling the uptake of distributed generation technology, and the critical role of EDBs in this.

- This option proposes that current provisions which restrict the relationships that EDBs can have with a generator and retailer which are not at 'arms' length', are able to be expanded by the EA in future, 'if necessary'. The Panel holds that such necessity would stem from competition risks posed by EDBs' involvement in distributed energy services. Specifically, these risks are described as the potential for EDBs to offer distributed energy services at discounted rates by recovering losses through lines charges (cross-subsidisation), or that EDBs use household consumption data which is not available to competitors to gain an unfair advantage in selling distributed energy services (information asymmetry). We believe that the proportionate response to these risks already exists in current, or proposed, mechanisms in our market.

- Mitigations to competition risks

Regarding cross-subsidisation, the Commission's cost allocation rules ensure that only those costs that are genuinely attributable to the regulated service are recovered through lines charges. The Commission's related parties rules impose disciplines on procurement of services by the regulated supplier from related parties. There are, consequently, already constraints in the regulatory framework – actively monitored by the Commerce Commission – that address this concern of the Panel. The risk of cross-subsidisation only exists where there is scope for the distributor to earn supernormal returns from its regulated network services, or to inefficiently allocate assets that provide competitive services into the Regulatory Asset Base for monopoly services. The current regulatory framework, which closely monitors both returns and cost allocation, already provides a mitigation to this risk.

Regarding the risk of information asymmetry, we note that any unfair information advantage in relation to customer data is currently enjoyed principally by retailers rather than by distributors.

We note the panel's support for the options to make it easier for consumers (or their agents) to access electricity usage data (C3), and to ensure access to smart meter data for EDBs on reasonable terms (E6). As noted earlier, we support these options and believe that customers should have ownership of their own data and the ability to understand their own usage and power costs. If implemented, these options would enable efficiencies across the whole electricity market, not just for distribution, eliminating the risk described by the panel here, that EDBs gain an anti-competitive information advantage through the use of this data. The potential impact of these data-related proposals on the risks described here, shows how quickly new developments can impact on perceived risks and opportunities in the sector. Regulation cannot be future-proofed – we recommend that any decision to regulate in this area is therefore delayed until there is more certainty to assess the potential costs and benefits of this regulation.

- If this analysis found that there was a case for change, that change should be implemented through primary legislation, as was the case with the provisions in Part 3 of the Electricity Industry Act in the first place. The Part 3 arrangements were imposed via legislation following an extensive and transparent policy process that assessed the benefits and detriments associated with structural separation of the supply chain. It was appropriate that that was done via primary legislation given the significant interference in commercial freedom, the implications for existing investments, and the risks to competition and innovation (detailed further below) associated with excluding suppliers from participating at multiple levels of the supply chain. In our view, extending those provisions should similarly be done by primary legislation, supported by evidence and a proper policy process, and at the point at which the problem is clearly defined.

We are also concerned that affording regulatory discretion to extend the Part 3 provisions will chill potentially welfare-enhancing investment now, even if the regulator is not currently proposing to exercise those powers. Any supplier that is considering investment in distributed energy services will have to price in the risk of future regulatory intervention. That chilling effect should be avoided given that any alleged competition problems have yet to materialise.

Regulatory segmentation and coordination failure

The proposal reflects a wider regulatory approach of market segmentation, which seeks to hold the natural monopolies in the market (distribution and transmission) to account for the price and quality of their services, whilst maximising the benefits of competition in the competitive segments (generation and retail). This has promoted a siloed understanding of the market, which seeks to achieve optimal outcomes for each vertical segment rather than understanding the market as a whole. The cost of this approach is coordination failure; transaction costs across the value chain; and of the unquantifiable opportunity cost to market efficiency and innovation which could have occurred between market segments (i.e, spill-over benefits of R&D). In some cases, the risk to competition outweighs this cost. The key point, however, is that this cost benefit analysis ought to be applied throughout the electricity sector, and account for the complex and changing challenges and opportunities of the present and future, rather than carrying forward the assumptions and approaches of the past by default.

Distributed energy services and our transition to a zero-carbon economy

An example of such a consideration is our transition to a zero-carbon economy. As we anticipate higher demand peaks associated with an increased reliance on electrical, rather than combustion, sources of power (such as through the electrification of transport and uptake of electric vehicles), the cost of network capacity expansion and investment will be significant – as reported by the Panel, one study anticipates this cost to be around $2.1 billion to meet the target of a net zero carbon economy by 2050.[11] As further reported by the Panel, one distributor attributes up to 50 percent of their overall costs to the need to accommodate peak demand. As these peaks are projected to increase in proportion to overall demand, these costs will only increase – as will the 'dry year problem' of how to meet demand peaks when we rely more on intermittent sources of renewable generation.[12]

In both reports, there has been discussion of the role of cost-reflective pricing in recovering the cost of this investment. We support the panel in highlighting the potential risks to consumers of cost-reflective pricing, and we do not believe that using price as a lever to reduce demand peaks is an adequate solution by itself - this is because electricity demand is, for the most part, currently inelastic. Whilst some demand response technology (such as smart chargers) can enable consumers to avoid peaks, for most consumers there is little they can currently do to avoid using electricity at 6:30pm in the middle of winter – and we do not think it responsible to incentivise consumers experiencing energy hardship to attempt this. To avoid this we need to use technology and innovation to meet increasing demand affordably – such as through distributed energy services.

Benefits of innovation

Given the role that EDBs currently have in maintaining costly network infrastructure, we have a clear and unique incentive to enable the uptake of this technology and to realise these benefits.

Large incumbent gentailers may have the capital to invest in this innovation but lack the incentive - a distributed energy future where consumers can leverage the generation potential in their own backyard; are less beholden to wholesale price volatility; and where they can sell surplus power back to the grid; undermines the current imperative of gentailers - to centrally generate electricity

[11] Page 55, EPR Discussion Document.
[12] ICCC panel workshop on findings from modelling on a transition to renewable generation.

and sell it to consumers. There are not many firms in NZ which have both the capacity and incentive to invest in disruptive energy innovation. Allowing EDBs to invest in these areas is not likely to squeeze other players out – particularly given the mitigations outlined above. What is more likely, is that disallowing EDBs to make these investments would severely reduce innovation in our market. The cost of this would be affordability and our just transition to a zero-carbon economy.

As well as the benefits described above, innovation has benefits for the wider economy. As a Small Advanced Economy (SAE), innovation plays a key role in our economic growth. In the absence of economies of scale, and given our small domestic market, we are driven to gain efficiencies and to stand out in global markets through innovation. The agility of the NZ economy makes us well placed to act as 'fast followers' of new distributed energy innovation and technology – such as the Local Energy Market (LEM) pilot in Cornwall. This large scale project is designed to defer distribution costs resulting from the increased load on Cornwall's network, caused by the amount of wind and solar power generated in support of the UK's carbon reduction targets.[13] We do not have the scale of capital to take major risks, however, we need to do things differently, and better, to maintain reliability of electricity into the future and to ensure that we are meeting consumers' needs affordably. We recognise that currently cost-saving innovation and technology, such as distributed energy services, is mostly available to consumers who can afford it. However, a system level transition to greater distributed energy services, supported by distributer investment, rather than relying on consumer investment, would benefit all users of the system.

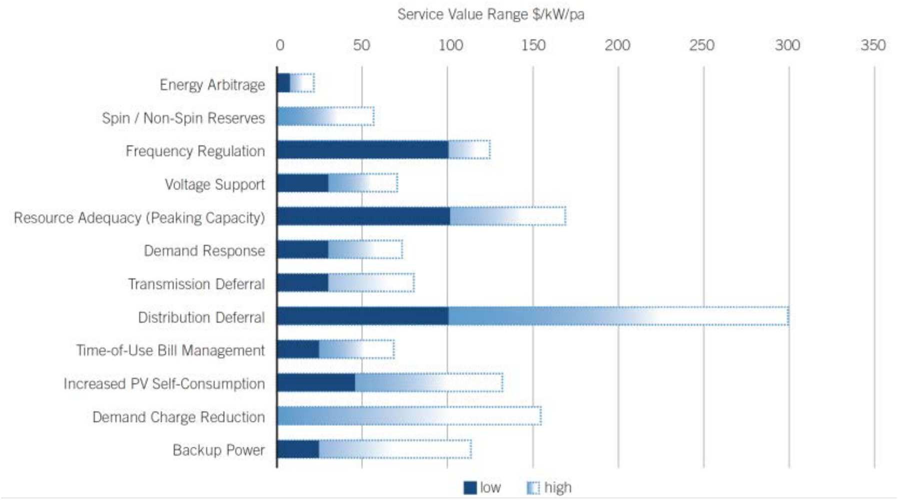
[13] https://www.centrica.com/innovation/cornwall-local-energy-market;

Case Study 1: Distribution deferral benefits

Recent work by Transpower sought to estimate the value of the benefits that batteries can bring when deployed for 12 services that batteries can provide across all segments of the electricity sector. The below shows the estimated value of each of these services considering the value of each service separately (without taking into account how a battery owner might get paid for that service or how they may seek to optimise the deployment of the battery between these services to maximise the value the owner extracts). The figure also usefully demonstrates the wide range of values for individual services, as these can vary materially depending on the circumstances.

This analysis indicates that distribution investment deferral (the value gained from managing distribution network peaks to help defer network investment) is by far the biggest potential benefit to the sector, a battery can provide.

Value of different battery services



Source: Transpower

We can also estimate the extent to which distribution network benefits may be realised depending on whether battery storage is operated by a distributor, or another party.

Using Transpower's point estimate for the distribution deferral benefit of $150 per kW[8] and the assumptions of Transpower's Energy Futures work that 5.5 GW of distributed battery capacity is available nationwide in the long term to help manage peaks, the retailer led scenario results in $165 m in annual benefit, compared with $413m in the distributor led scenario (and this is the conservative distributor led scenario which assumes 50 percent battery capacity is made available to manage peaks, as opposed to 80). 20 percent of battery capacity is made available to manage demand peaks under the retailer-led scenario.

Battery benefits under retailer vs distribution led scenarios

Scenario	Annual Benefit ($M)	10 year NPV benefit ($M)
Retailer-led scenario	165	$1,015
Distributor-led 50%	413	$2,535
Distributor-led 80%	660	$4,055

The cost of coordination failure is most evident in relation to the introduction of new technology, which tends to cut across the boundaries of artificial market segments. As is shown by the case study of ripple relays, this segmentation risks stunting the uptake of new technology and innovation.

<u>Case study 2: Ripple relays</u>

Ripple relay systems (often called ripple control) are an old technology for load control set up extensively around New Zealand from the 1950s. Under ripple relays, a specific electrical frequency to an area turns off hot water cylinder elements (or swimming pool pumps), saving the user electricity. New Zealand was a world leader in load control technology for a time as a result of ripple relays.

When these technologies were installed, New Zealand had integrated retailer/distributors with strong incentives to manage network peaks, as well as a direct relationship with end users. After New Zealand structurally separated distribution from retail, the direct relationship between most distributors and end users ceased, as did the incentives on retailers to control load .

While distributors continued to face incentives to control the load on the network, their ability to utilise ripple control has been reduced. This partly reflects the split ownership of ripple control equipment in many parts of the country, whereby distributors own signal transmission equipment, and retailers own receiving equipment at the customer's premise. Although the Auckland ripple relay network is still mostly effective from a technical standpoint, it is not used to its full potential (or original intention). Fewer customers are opting in to controlled plans. The share of customers on controlled tariffs declined from 80.5% in 2012 to 74% in 2018.

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

Vector supports this option. As stated in our previous submission, the current division of responsibilities between the EA and the Commission is flawed and causes unnecessary conflict and confusion. Moreover, this problem is only likely to get worse as emerging technologies continue to blur existing network boundaries.

While we accept that regulatory restructuring will incur some time and cost in the short term, this needs to be set against the significant delays on network regulation issues that have been incurred (and in our view are likely to continue) under the current regime. The most obvious example is of course the EA's TPM review, which has now been in train for 7 years. While we support the Panel's proposal to introduce a GPS to guide the EA in this area, this in itself will take time – and, even then, it is unclear whether the EA would be capable of bringing this matter to a satisfactory conclusion, given the process to date.

We therefore support all aspects of the economic regulation of networks being placed under the umbrella of the Commission. That would include revenue determination and service quality (for which the Commission is already responsible), pricing methodologies and access terms and conditions. Under this approach, the EA could then have a narrower remit that focussed primarily on the operation of the 'non-network' elements of the supply chain; namely, wholesale and retail.

F3: Give regulators environmental and fairness goals

We understand the Panel's concerns regarding the risks of giving regulators multiple objectives. However, as stated in our previous submission, we believe that both carbon considerations and resilience considerations should be incorporated within the regulatory framework. We also support the Panel's proposal to give the EA an explicit consumer protection function.

Electricity has a disproportionate influence over the environment, and this is likely to increase over time due to increasing electrification of the economy. We therefore believe that carbon considerations should be included in the regulatory framework for electricity, as is the case internationally, for example Ofgem in the United Kingdom. We are not prescribing how carbon should be reviewed by energy regulators, simply that it should be a consideration in the decision-making process.

Resilience considerations are also currently missing from the regulatory framework, which is focused on reliability (security of supply) rather than resilience, based on historical benchmarks. This does not recognise the exponential changes that are occurring due to new technology and climate change. As we noted in our previous submission on the EPR Issues Paper, a renewed focus must be given to developing:

- an agreed upon concept of resilience;
- an appropriate framework for measuring resilience to assess industry participants' success; and
- regulatory recognition of the resilience framework, to ensure there are appropriate incentives for action

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

We strongly support amending the Electricity Industry Act 2010 to allow EA decisions to be appealed on their merits. The checks and balances applied to the EA are currently very limited, which is of particular concern given its broad powers and historic processes that have been called into question and decision-making on key issues such as the TPM review and enforcement of wholesale market rules.

Allowing the Commission's input methodology (IM) decisions to be reviewed by the High Court has enabled industry participants to test the efficacy of critical building blocks of the regulatory framework and provided clarity on statutory powers. We consider that this has improved the quality of the Commission's decisions and enabled the Part 4 framework to bed-in more quickly.

The EA's decisions have significant impacts on businesses and consumers. We therefore consider that a subset of 'reviewable' EA decisions should be identified and subjected to merits review.

In our opinion, the arguments presented by the Panel against introducing appeal rights are not persuasive. Clear statutory objectives and principles and comprehensive stakeholder consultation can help improve regulatory accountability, but that does not mean that there should not also be appeal rights. These regulatory mechanisms are complements rather than substitutes.

The Panel's observation that appeals may best serve the interests of those with the financial resources to afford such legal action is also not compelling. All stakeholders – including companies, shareholders and consumer groups – benefit from stronger accountability, protection against regulatory errors and clarity on statutory purpose.

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

We support undertaking a review of the EA's compliance framework, in particular the consideration of ways to separate rule-making from monitoring and enforcement functions. We also strongly support strengthening the EA's information-gathering powers in relation to the generation and retail sectors – as the Panel itself found in the course of its investigation, the current regime relies heavily on the 'goodwill' of gentailers to provide relevant data.

We are less convinced of the merits of enabling the Minister of Energy and Resources to direct the EA to undertake reviews and inquiries outside of its statutory objectives. This proposal risks overlapping with the Commission's recently introduced market study powers and introducing additional regulatory conflict and confusion.

F6: Establish an electricity and gas regulator

As discussed above, the major structural issue that needs to be addressed at present is the overlapping responsibility for network regulation between the EA and the Commission. If the Panel does not support this option, then we do not see a strong case for establishing an integrated gas and electricity regulator, as the current gas industry company (GIC) is functioning well. However, we would support the Panel's suggestion of undertaking a preliminary investigation into the merits of establishing a combined regulator if the investigation also considered network regulation issues.

We stated earlier that serious consideration should be given to placing all aspects of the economic regulation of networks under the umbrella of the Commission. That would include revenue determination and service quality, pricing methodologies and access terms and conditions. Under this option, all matters sitting on the periphery of network regulation – such as those arising from emerging technology – would become the unambiguous responsibility of the Commission, thereby eliminating the costly duplication of regulatory roles. However, the Panel does not support this option at present.

We do not see a strong case for combining the GIC with the EA unless other changes are also made to the regulatory framework. However, we would support undertaking an investigation into the merits of establishing a joint regulator if the investigation also considered the question of combining markets and networks regulation (i.e. a structure similar to Ofgem's in the UK).

G: Preparing for a low-carbon future

G1: Set up a fund to encourage innovation

We do not believe that the provision of funding by itself will enable innovation and R&D to occur at a level that will most benefit consumers, the economy and the sector, without adequate regulatory certainty. The proposal in F1 to expand the jurisdiction of the EA to restrict EDBs from investing in distributed energy services, is at odds with the panel's intention of supporting greater innovation expressed in this option.

Innovation and Business Expenditure on R&D (BERD) also has benefits for the whole economy. As noted earlier, an economy which is the size of New Zealand's, and which has our geographic isolation, relies on innovation to retain a competitive position in global markets in the absence of economies of scale and easy physical access to global markets.

BERD also generates 'spill over benefits' – or benefits which cannot be captured by a single firm when it invests in R&D. When a new technology or innovation reaches the market, competitive pricing pressure quickly narrows the commercial benefit to be gained by a single firm. However, consumers gain better services more efficiently; developments can be applied to other sectors and technologies; and NZ firms can increase their capture of global markets, strengthening NZ Inc.

Given the inherent risk of R&D, and the fact that single firms cannot capture all the benefits, there is an under incentive for businesses to invest in R&D. Alongside this market failure, the scale of NZ's economy means that businesses rely on external sources of funding (such as the proposed innovation fund) and overseas capital investment, including human capital. Attracting overseas skills and investment is critical to the development of an 'ecosystem' which supports BERD, innovation and overseas market access.

Vector supports these overseas linkages through our partnership with MPrest, a global provider of industrial Internet of Things (IoT) systems, to develop the Internet of Energy (or, 'system of systems'). This provides us with the ability to manage complex energy systems of distributed generation and two-way flows of electricity. The IoE will help us manage and coordinate our customers' energy use and assets in real time using AI. This will enable our customers to more easily access lower energy costs and to enable automation to streamline energy use and cost.

However, supporting the development of an ecosystem which enables innovation in our energy sector also requires the right regulatory settings. Funding will not encourage EDBs to invest in innovation if they do not have clarity around their ability to do so within the scope of the regulatory regime. The option of allowing scope to expand existing regulatory restrictions on EDBs in future 'if necessary', does not provide this clarity or certainty. Other jurisdictions, including Australia, have recognised the importance of providing EDBs with this certainty, and have introduced a 'regulatory sandpit', which provides EDBs with certainty that regulatory expansion, such as that proposed in F1, will not be advanced by the government within a ten-year time frame. This provides EDBs with the certainty that they need to invest in the distributed generation innovation which our future energy sector will rely on.

G2: Examine security and resilience of electricity supply

We support a review of the security, reliability and resilience of electricity supply. However, this review needs to take a holistic approach to resilience and reliability, which takes into account developments across the electricity supply chain.

This option proposes that the EA conduct a thorough review of the security, reliability, and resilience of electricity supply, in the context of developments which have the potential to profoundly impact the way the sector works. We agree that the sector is facing significant change, including a transition to more intermittent and climate-dependent sources of renewable generation, alongside greater demand for electricity through the electrification of transport. Auckland is also facing significant growth, and with it, increasing strain on infrastructure. Auckland's population is projected to increase from 1.6 million in 2016 to 1.9 million in 2025 – this will be 36 percent of the projected population of New Zealand.[9] Vector currently provides, on average, 99.7% reliability. However, as electricity plays a greater role in people's everyday lives, and as comparable network services (such as telecommunications services) advance, we anticipate our consumers will expect better. In parallel to these changes, the impact of climate change increases the likelihood of adverse weather events[14], such as the storms experienced by Auckland in April last year. The increase in temperature is also likely to have demand side ramifications – the extent of which are still unclear.

Technology and innovation will play a critical role ensuring security, reliability and resilience of electricity in this context. As noted earlier, technological change tends to cut across different vertical segments in the electricity market, just as the transition to renewable generation will have ramifications which go beyond generation to also impact on transmission, distribution, retail, and consumption. In this context, and given the interconnectedness of the electricity supply chain, (whereby an issue in any one segment could disrupt the entire flow of power), we need to take a holistic view of the whole energy system when it comes to strengthening security, reliability and resilience of electricity supply.[15]

For example, distributed energy services cut across vertical market segments to reduce consumers' dependency on both centrally generated sources of electricity, and the centralised distribution network and transmission grid. Distributed energy services could also enable Peer to Peer (P2P) trading of electricity, impacting on the consumption and retail of power. These services could have a significant impact on communities' resilience. Some communities on Vector's network are currently connected to the network through a single feeder. If this feeder goes down, the whole community is unable to access power. The Vehicle to Home (V2H) trial at Piha is an example of how distributed energy services can strengthen the resilience of these communities. The V2H trial which enables power to flow between a users' electric vehicle and home, can act as an emergency power source and can supplement a home's electricity storage capacity. The eventual integration of EV's storage capacity into the grid (V2G) can help flatten demand peaks and V2H systems installed by Vector can also act as a back-up generator. This project is supported by government and private co-funding from the Low Emission Vehicles Contestable Fund, and, as with the LEM in Cornwall, is an example of how collaboration between government and industry helps to meet changing infrastructure needs. Grid scale batteries are also likely to play a critical role in ensuring security of supply as we transition to more intermittent sources of renewable generation. The key point is that an examination of security, reliability and resilience of supply needs to consider new technology and innovation in the context of the whole supply chain. As noted by electricity sector commentators in the United States, traditional models of building resilience, which involve increased investment into the network and grid to manage

[14] The Physical Effects from Climate Change, Report of Findings for Vector Limited, EY November 2017
[15] These themes are discussed further in Vector's report "Working Together on Resilience", released in September 2018.

demand peaks, is "...like shopping mall parking lots — with enough capacity for Black Friday shoppers, but a sea of empty spaces the rest of the year. As electricity customers, we all pay the price."[11]Technology and innovation can enable us to ensure reliability and resilience without this inefficiency and will be critical to a just transition to renewable generation and a zero-carbon economy in the future.

As well as understanding the macro picture of resilience, which accounts for technological, policy and environmental disruption, we also need to account for the micro impacts on resilience. An example of a micro factor which impacts on resilience would be vegetation management regulation. For example, a key source of the outages experienced in Auckland during the April 2018 storms, were trees falling on Vector's network. Many of these trees were compliant with current regulation, which prescribes a 'cutting zone' - the distance that a tree's branches must be from the lines. Current regulation does not however account for the height and distance of trees which could fall on the lines during a storm (the 'fall zone') - many of which did. Current regulations also do not prescribe tree planting practices which could prevent the need to cut down dangerous trees in the first place. The scope of lines' companies to legally manage trees which are not in violation of the regulation, but which do pose a threat to the network, is limited. A preventive approach to vegetation management, which responds to risk, and which strengthens partnership between lines' companies, local authorities, and communities, would significantly improve resilience. We understand that the Electricity (Hazards from Trees) Regulations 2003 are to be reviewed by MBIE this year. We hope that this issue is understood in the wider context of resilience, reliability and security of supply.

We agree that the Terms of Reference (TOR) of the Security and Reliability Council (SRC) be included as part of this review. This should include an examination of the SRC's scope and role, to reflect an holistic approach to security, resilience and reliability of supply. This approach should account for the impacts of technological, environmental and policy change on the whole electricity supply chain, and should outline clear workstreams which account for both the macro and micro view of resilience.

G3: Encourage more co-ordination among agencies

We support the option to encourage more coordination among agencies, and understand the issues of a just transition to a zero carbon economy and reducing energy hardship as key examples of where a coordinated approach across government and sectors is required. We do not support the proposal to use the Council of Energy Regulators for this purpose as we believe this forum needs to be broader in terms of membership (to include more than energy sector regulators), but more clearly defined in terms of the issue it seeks to address. We note that the State Services Commission's plans to reform the State Sector Act propose to create different leadership arrangements whereby senior leaders are brought together across government to address complex, overlapping, issues. An example of this is the establishment of the new Ministry of Housing and Urban Development. We therefore propose that the establishment of a new Ministry of Energy be considered, alongside the other potential leadership arrangements proposed by the SSC to achieve coordination between agencies to address complex issues in the energy sector.

We support the proposal to encourage more coordination among agencies. As noted above, some of the options proposed in this paper have clear implications for our just transition to renewable generation and a zero-carbon economy. For example, the option proposed in *F1, Give the Electricity Authority clearer, more flexible powers to regulate network access for distributed energy services* could seriously compromise the uptake of distributed energy services which are critical to ensuring the resilience and affordability of distribution services as we transition to electric, rather than combustion, sources of energy – particularly through the electrification of transport. As described, the greatest anticipated benefit from battery technology is the deference of distribution costs. Without this deference, the network investment required to meet increased demand peaks will be significant and borne by consumers – impacting in particular consumers experiencing energy hardship. This is directly at odds with the Government's objective of a just transition to a zero-carbon economy. We think it is critical that the policy agenda being advanced by the Interim (and in future, Independent) Climate Change Commission is strongly linked with the work being advanced through this Electricity Pricing Review, and future work undertaken by the Electricity Authority, Commerce Commission, or other Government department, which could impact on the electricity sector's ability to adjust sustainably to New Zealand's climate agenda. Another example of where 'joined up thinking' across government is required, is reducing energy hardship – as noted above, we are strongly supportive of the option to establish a cross-government working group to address this issue.

We think that cross-sector, or cross-government forums, should be mobilised with the issue at the centre. We do not think that the Council of Energy Regulators is the appropriate forum for this purpose, given its narrow focus on energy regulation. As noted above, coordination needs to occur across sectors and policy agendas, but, should be clearly targeted on the issue at hand. We note that this approach links with the work proposed by the State Services Commissions' Public Sector Reform Act, which proposes to create different leadership arrangements whereby senior leaders' across the Public Sector are mobilised around complex, overlapping, issues which require a joined-up approach.[16] An example of where public sector leaders and policy thinkers have mobilised around such an issue, is the establishment of the new Ministry of Housing and Urban Development. This brings together key parts of the Ministry of Social Development; Ministry of Business, Innovation and Employment; and Housing New Zealand to ensure a joined-up approach. We believe there are parallels between the public housing supply chain and the electricity supply chain, whereby artificial segmentation discussed above (or a 'siloed' approach) has the potential to create unnecessary inefficiencies and complexities, at a cost to consumers, or clients. Similar to the approach taken to address housing issues, we believe that the establishment of a new Ministry of Energy which brings together parts of the Ministry for the Environment, Ministry of Civil Defence and Emergency Management, Ministry of Transport, and MBIE, warrants serious consideration to address the issues of a just transition to a zero-carbon economy, energy hardship, and resilience.

Another issue that could be addressed through the new Ministry of Energy is the improvement of the energy efficiency of new and existing buildings, as proposed in G4. We support this option, and note that consultation is already underway for the Healthy Homes Guarantees Act, which will strengthen regulations governing the quality of rental housing proposed in this option.

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[16] Information on the consultation for the State Services Commission State Sector Reform Act: https://www.havemysay.govt.nz/state-sector-act-1988-review-short-form/leading-better-outcomes-and-services/;

Appendix 1: Compass Lexecon Report on Transmission Pricing GPS

Transmission Pricing Government Policy Statement*

Prepared for Vector Ltd.

by

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Marcelo A. Schoeters

March 22, 2019

* This paper was commissioned by Vector Limited. The opinions expressed here are exclusively those of the authors, and do not reflect the opinions of Vector Limited, Compass Lexecon or the University of California, Berkeley.

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I. BACKGROUND

1. Since 2007, the cumulative investment in New Zealand's transmission network reached approximately $2.1 billion. This process is likely to continue, as an increasing degree of electrification to reduce carbon emissions is expected to drive demand growth.

2. The extent of these investments poses challenges related to how costs should be spread across users of the network through transmission charges.

3. The Electricity Authority (EA) is responsible for defining the Transmission Pricing Methodology (TPM).

II. KEY CONSIDERATIONS FOR THE DEFINITION OF THE TPM

4. Network investments involve large sunk costs that, once incurred, cannot be avoided or scaled down. The benefits of these sunk costs are common to multiple users. The way that common costs are allocated across users is a key aspect of the TPM and has implications for network usage and the incentives to invest both in the network and in assets connected to the network. The allocation of costs also raises issues surrounding the fairness and the affordability of prices.

5. For the TPM to benefit consumers in the long term, it needs to generate the correct incentives to both promote efficient new investment, and to make an efficient use of the existing grid, avoiding unnecessary costs.

6. Investments in the transmission network are efficient when the value of the expected benefits to users outweighs their incremental costs, and such benefits cannot be obtained by means of a less costly investment. Advances in technology and the decreasing costs of computational power mean that more sophisticated methods for measuring transmission services and identifying who is receiving those services are available. This can drastically improve the ability to provide adequate investment signals through pricing over time, and to delegate decisions on new investments to users. A TPM that makes users pay for the costs of new

investments based on their net benefits promotes efficient choices on users' location and on whether to use the existing network or to invest in expanding it.

7. Decisions on past investments, however, cannot be changed, and thus there are no efficiency gains in making retrospective changes in the TPM to increase the extent to which sunk costs are allocated to beneficiaries. Instead, the TPM should focus on promoting the efficient use of preexisting assets, by not distorting current user choices and location decisions and by discouraging inefficient bypass. This is best achieved when the individual burden of the sunk cost on each connected user is relatively low, and unlikely to affect their decisions.

8. TPM should also evolve in a way that is not perceived by investors and users as unfair or entailing unexpected change in the rules of the game. Significant modifications in the way sunk costs are allocated creates regulatory uncertainty which could undermine investors' confidence.

9. Users should be able to understand and internalize price signals. Hence, complex pricing schemes may fail to convey the information that they contain, even when they are based on sound theoretical considerations.

10. Finally, changes in the TPM should not create price shocks significantly affecting the affordability of end-user's bills and sizeable or sudden distributional effects.

III. GOVERNMENT POLICY STATEMENT

11. Based on the considerations outlined above, a suggested draft of a Government Policy Statement (GPS) on transmission pricing is as follows.

12. It is Government policy that transmission prices should:

    a. Be simple, practicable and understandable to a wide range of sector participants, by setting prices in a way that avoids continuous disputes.

b. Reflect the costs of transmission and allow for the recovery of existing sunk costs while minimizing distortions to production, consumption, location and investment decisions, by means of a postage-stamp charge evenly spread across a wide base of network users which includes loads and generators.

c. Make beneficiaries of new transmission investments internalize the cost of such investments, promoting efficient choices between relying on the existing assets or expanding the network, by charging the cost of new investments to beneficiaries based on the net benefit they obtain from those investments.

d. Introduce regulatory changes incrementally to:

   i. minimize regulatory uncertainty, without altering the rules of the game for existing investments in network or other assets; and

   ii. avoid creating price shocks that may threaten affordability of end-users or have material distributional effects.

13. In conducting the TPM reform process, the Electricity Authority should be mindful of the adverse effects of delaying the resolution of the process. The Electricity Authority shall provide clear guidance consistent with the principles stated in this Policy Statement. Transpower, in conjunction with user groups, should take the principal responsibility for development, implementation and ongoing review of the TPM.

IV. QUALIFICATIONS

IV.1. PABLO T. SPILLER

14. Pablo T. Spiller is a Senior Consultant at Compass Lexecon. He is also the Jeffrey A. Jacobs Distinguished Professor (Emeritus) of Business and Technology at the Haas School of Business, and Professor of Graduate Studies, University of California, Berkeley; Research Associate at the National Bureau of Economic Research; and the former President of the International Society for New Institutional Economics. He was previously at LECG since 1993, where he was the co-chair of the International Arbitration Practice Group.

15. Dr. Spiller has written extensively on regulatory, antitrust, and institutional issues, having published more than 100 academic articles and several books on those issues. Dr. Spiller has extensive consulting and expert testimony experience. He has consulted on issues of regulation and antitrust for private businesses, governments and international organizations, and testified as expert in more than 120 international arbitration cases, involving both treaty and contractual disputes rendering opinions on damage assessment, contract interpretation and regulatory conduct in a variety of sectors, including the electricity sector.

16. Dr. Spiller has contributed to the design and implementation of public utility regulatory reforms in Argentina, Bolivia, Brazil, Colombia, Costa Rica, the Commonwealth of Dominica, Ecuador, El Salvador, Guatemala, Hungary, Jamaica, Malaysia, Mexico, Norway, New Zealand, Panama, the Philippines, the United States, Uruguay, and Venezuela.

17. Regarding the electricity sector, Dr. Spiller participated in regulatory reform projects in Argentina, Bolivia, El Salvador, Mexico, Peru, United States, Uruguay and New Zealand. He is the co-author of "Transmission pricing mechanism in New Zealand", a paper prepared during the TPM consultation process in 2015. He also provided advice in New Zealand on various issues, including competition in the transmission services, determinants of optimal quality of distribution and transmission services, the design of contracts for electricity distribution companies, and the design of pool operations procedures. Additionally, his

regulatory experience in the electricity sector includes auditing of bidding practices by an Argentine generator and an analysis of electricity regulation and practice for the government of the same country. In El Salvador, he provided advice on a reform of electricity regulation, on the drafting of electricity legislation and development of industry and regulatory reform, and on other regulatory policies in the electricity sector. He also advised on transmission pricing for a major electricity distribution company in the United States.

18. Dr. Spiller was the Editor-in-Chief of the Journal of Law, Economics, and Organization, and Associate Editor of the Journal of Applied Economics, the Regulation Magazine, and the Journal of Comparative Economics. He was also the Chair of the Business and Public Policy group at the University of California, Berkeley for five years. Dr. Spiller has also been a Special Advisor to the Director at the Bureau of Economics of the Federal Trade Bureau. Dr. Spiller was also an elected member of the Board of Directors of the American Law & Economics Association.

IV.2. MARCELO A. SCHOETERS

19. Marcelo Schoeters is a Senior Vice President at Compass Lexecon. He specializes in economic and regulatory analysis; valuation of businesses and other assets; and the assessment of damages in the context of international and commercial arbitration cases.

20. Mr. Schoeters has provided written and oral expert testimony or advice in more than 45 cases. His experience involves treaty disputes between private investors and governments on topics related to damage valuation and regulatory standards. He also has substantial experience in commercial arbitrations, shareholder disputes and political risk insurance claims. His experience involves cases in several industries in Argentina, Bahrein, Bolivia, Chile, Colombia, Ecuador, Guatemala, Panama, Peru, Trinidad and Tobago, Turkey, Ukraine, Uruguay and Venezuela under ICSID, ICC, PCA, UNCITRAL and IACP rules.

21. Mr. Schoeters has served as key economic advisor to Argentina's Secretariat of Energy on the energy sector reform that took place in the 1990s. He was also an Executive Consultant

at Mercados Energéticos, where he completed more than 50 cases in the electricity sector. He worked in several cases in the electricity transmission sector of Argentina, Panama and Peru and in the electricity distribution sector in Argentina, Brazil, Colombia, Italy, Panama, Paraguay, Peru, Spain and Venezuela. In particular, in Brazil he worked with the Electricity Regulator, ANEEL, on different projects, which involved the X Factor revision (price cap regulation), the creation of the alternative regulatory mechanisms for the treatment of extra concession revenues and the determination of the cost of capital for the 64 electricity distribution companies in Brazil. He also participated in cases involving the design of strategies to develop rural electrification using renewable energies in Bolivia and Ecuador.

22. While working in Compass Lexecon, Mr. Schoeters completed projects in the electricity transmission sector of New Zealand and Turkey, in the electricity distribution sector of Argentina, Colombia and Guatemala; and in the electricity generation sector in Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador and Uruguay.

23. As it relates to electricity transmission, Mr. Schoeters worked in the assessment of the economic reasons for unbundling of electricity transmission services in the context of the electricity sector reform in Turkey. He also worked in the design of an alternative regulatory procedure based on the identification of beneficiaries for capacity expansion projects on electricity transmission in Argentina. He conducted the tariff setting and compensation charges of the secondary system of electricity transmission project (2005), which implied the tariff calculation for 27 carrier companies in Peru. In addition, he is the co-author of "Transmission pricing mechanism in New Zealand" (2015), which was prepared for Vector in the context of the consultation process for reforming the TPM.

24. Mr. Schoeters obtained his BA in economics at the National University of Cordoba (Argentina) and is now a PhD candidate in economics at the same institution. He is a regular speaker at conferences on damages issues. He has been recognized over nine years among the world's top arbitration expert witnesses by *Who's Who Legal*.