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By email: taskforce@ea.govt.nz

Tēnā koutou,

Feedback on roadmap for industrial demand flexibility

Thank you for the opportunity to provide feedback on the *Rewarding industrial demand flexibility: Issues and options* consultation paper (the consultation paper)[1]. We would welcome the opportunity to discuss this with you and the team at the Electricity Authority (Authority) and believe the industry would benefit from further dialogue in this area.

Vector is a strong advocate for demand flexibility, and a firm believer in its role in minimising whole-system cost to consumers. Our corporate Symphony strategy has, at its heart, making optimal use of demand flexibility to minimise network investment, thereby maximising affordability for consumers.

Lack of clarity in problem definition

Despite our strong support in principle, we have struggled with aspects of the consultation paper – particularly with regard to the problem definition and some of the solutions proposed.

We found the clearest and most compelling aspect of the consultation package to be the conclusions of one of the supporting expert reports commissioned by the Authority – the survey of international demand-response (DR) schemes by Robinson Bowmaker Paul[2] (RBP Report). We are confused (and concerned) why this report was barely referenced in the consultation paper, and did not appear on the Authority's consultation webpage.

We found the RBP report particularly compelling, and very helpful in forming our conclusions on several of the matters being consulted on by the Authority. As a result, we have quoted from it liberally in our submission.

[1] Available online at https://www.ea.govt.nz/projects/all/energy-competition-task-force/consultation/rewarding-industrial-demand-flexibility/

[2] Available online at https://www.ea.govt.nz/documents/7267/Demand_response_programmes_-_International_scan_-_Robinson_Bowmaker_Paul.pdf

For the benefit of other submitters, we have copied directly the conclusion from page 57 of the RBP Report, noting again this is the direct view of one of the Authority's expert advisors:

4.6 Conclusion

This paper has reviewed a range of DR programmes in gross pool markets around the world. Each of these programmes has been running for several years, providing examples of what has and has not worked to encourage DR participation. We offer five key findings to guide any potential DR participation in New Zealand.

1. Successful programmes have clear goals that relate to power system or market requirements. Programmes which allow DR to provide a standard service in competition with or alongside generation succeed by delivering to the system need. In these cases, DR participation alongside generation increases the pool of potential providers, lowering overall costs. Programmes with a general goal to increase DR participation have been less successful.
2. Today's DR does not provide the same level of flexibility as generation, and this limits its usefulness. DR is currently most effective as a last resort resource used prior to involuntary load shedding, not as an integrated part of regular market trading.
3. DR providers who could currently monetise their flexibility (via commercial or market programmes), but choose not to, likely need additional incentives to make their flexibility available. As such, their participation costs more than the prevailing marginal energy price. and this cost must be borne by other market participants.
4. Extra compensation for DR providers can work in a small-scale programme, or one where a commercial entity is making its own decisions about value. As DR participation scales up, centralised programmes that provide extra compensation to DR resources would become increasingly unfair to other consumers.
5. Off-market programmes, and programmes that leverage existing market processes and functions are simpler to implement. Developing and integrating a new mechanism with existing central market processes can be complex and expensive.

Overview of our submission

We take several key points from these conclusions:

- Demand response (DR) can provide significant competition benefits, but should be pursued only where it is efficient – rather than pursued for its own sake
- DR is currently most effective as a last-resort resource, not as a fully-integrated part of market trading
- Some DR participants would require extra incentives (or 'subsidisation', in our words), over and above avoided marginal prices, to make their flexibility available economically:

    - This means some of the cost of their participation and activity must be borne by other market participants – namely those deemed to ‘benefit’ from their actions.
    - The greater the perceived benefits, the more those participants are paid / subsidised, the more unfair this becomes to the consumers paying those subsidies.
    - It goes without saying how fraught ‘beneficiaries-pay’ is, as a pricing concept
- Off-market mechanisms are simpler to implement than attempting to implement DR mechanisms within central market systems and principles

This has reinforced our existing views on these issues, and informed our key points of submission on the consultation paper:

1. **The Authority should be very wary of implementing payments for BAU demand response**

2. **We support the introduction of a last-resort demand-response scheme, as proposed**

3. **Maintenance of network safety, security and power quality must be a guiding principle**

In the remainder of this submission we expand on each of these points, with reference to the specific consultation questions posed.

Finally, we support the Authority’s development of a roadmap of activities, and we look forward to further engagement with the sector as the roadmap evolves.

The Authority should be very wary of implementing payments for BAU demand response

(the following should be considered our response to questions 4-7 on problem definition, and questions 8-11 on the vision and making payments for demand flexibility providers)

As the Authority notes in paragraph 2.15 of the consultation paper, its position to date has been that payments should not be made for demand response. Instead, there should be sufficient incentive in industrial consumers, or retailers managing devices, *avoiding high costs of consumption*:

> *“To date, the Authority has not favoured schemes that go beyond offering price avoidance to the demand flexibility provider. This position was informed particularly by the concern that, from an electricity market perspective, paying consumers to not consume would result in their ‘over-compensation.’ This would result in a distortion that could increase demand response above ‘efficient’ levels, which would in turn hinder investment in other forms of peak demand management (ie, peakers and batteries).”*

Later in the document, however, in section 6 the Authority suggests that its position has evolved (our emphasis added):

> *Where the provision of the demand flexibility is efficient, providers* ***should therefore be able to receive some of the value to the overall market of the services they provide****. However, this should be less than the total value to ensure benefits are realised by consumers broadly.*
>
> *We recognise that this vision is a change in the Authority's position on demand flexibility from industrials to date. The focus on long-term benefits for consumers enables consideration of different payment structures for demand flexibility – a short-term incentive may be considered where this is considered necessary to encourage participation, to deliver long-term benefit.*

We find this shift in position concerning. The Authority is effectively saying that its view for the past 15 years, as well as numerous advisory groups (including as recently as MDAG, in 2021-23) has been incorrect.

Ex-post compensation from beneficiaries does not make sense, in practice

Economic theory on these matters has not changed, even if the Authority's statutory objective (or their interpretation of it) has evolved over time. What was once considered inefficient cannot (normally) suddenly become efficient.

At the simplest level, it is unclear where the revenue to support any payments will come from. In markets, those who *do consume*, pay money to those who *do produce*. There is no revenue stream from those who benefit from lower prices to compensate those who choose not to consume.

As set out in RBP's reductio argument (3.4.7), in the limit, the number of non-consumed MWh could exceed the number of consumed MWh. As the number of non-consumed MWh grows, the amount of extra revenue that needs to be found will grow. Those who do consume will have to cover the costs of those who do not, even if the occurrence of DR does not lead to a change in the spot price – in that case it is a simply a wealth transfer.

We note for clarity that we do not think the Authority is proposing to introduce a 'negawatt'-style scheme, where DR providers are paid the prevailing marginal spot price for each unit of non-consumption. However, some readers are likely to make that inference.

In relation to negawatt-style schemes, the RBP report makes the following observation in 4.4:

> When a DR resource is paid an additional amount for having its energy cleared at the same time as generation, the resource saves on the high price, and is also paid for curtailing. This double benefit increases costs for others in the market from whom the payment is recovered. This may work while the volume of DR is low, but becomes distortionary as the volume of DR increases, because the price paid for energy will increasingly depart from the cleared intersection of supply and demand.

To use a more relatable example, it cannot now be efficient for a supermarket shopper to have to compensate a fellow shopper who walks into the supermarket and chooses not to buy their usual dozen tomatoes this week, because they are too expensive. Yes, that single shopper's action might benefit those other shoppers who were happy to pay the current market price, or even more. But it seems reasonably obvious that the grounds for those who *did* purchase tomatoes to pay compensation to those who *did not*, are tenuous at best.

Renowned electricity market design expert Larry Ruff summed this up in a well-known quote way back in 2002[3] (with our emphasis added):

> *"DR can and should be incorporated into [wholesale] markets using standard market concepts and processes, and in particular without trying to treat DR as an energy "resource"* ***or paying anybody for something they might have bought but didn't****. Anybody should be free to sell energy it does not consume* ***as long as it owns that energy****, but buying energy from somebody who might have bought it but didn't is as (il)logical as buying the Brooklyn Bridge from somebody who thought about buying it but decided to sell it instead."*

In other words, if a consumer has a property right to a MWh of electricity – for example because they have pre-bought it through a fixed-price, fixed-volume contract – then they are welcome to reduce their consumption and sell that back at the prevailing market price. For any other consumer, however, paying them for energy that they might otherwise have consumed, but did not, would be as illogical as the tomato example above.

Troubling precedent for pricing of other services, across the sector

Our particular interest in this workstream is from the perspective of a distributor attempting to inform consumers' purchasing decisions on the basis of cost-reflective network pricing.

In this regard, the Authority has never given any indication that we may need to compensate consumers for foregone consumption on the distribution network – in contrast, avoiding higher time-of-use prices has always been seen as efficient, and sufficient. How would such payments to non-consumers fit in with the Commerce Commission's revenue limits? Will EDBs be able to recover

[3] Ruff (2002), Demand Response: Reality versus "Resource", *The Electricity Journal*, Volume 15 (10), Pages 10-23.

those payments under their regulation? Many distribution transformers on our networks serve only a small handful of consumers – will those consumers who choose not to respond to price signals be required to make payments to those who do? If a new customer chooses *not* to connect to a particular transformer because it would precipitate an upgrade, leading to a cost increase for all customers connected, should the existing customers be required to make a payment to the non-connecting customer? How many non-connecting customers would such payments apply to?

We would appreciate further guidance from the Authority on how its new position impacts how distributors should address price-setting, for both use-of-system and connection charging.

Relatedly, through nearly a decade of consultation on the Transmission Pricing Methodology, (TPM) the Authority promoted nodal pricing as being both efficient and sufficient in terms of its ability to signal to consumers of the value of consumption or demand response. Again, we would appreciate the Authority elaborating on how its new position – that supplementary payments may be both required, and efficient, to signal to consumers the true value of load shifting – aligns with the TPM that took so many years to implement.

Evidence of how industrial demand flexibility has been stimulated, to date

The Authority, and the RBP Report, both note that the existing price-avoidance incentive has been sufficient to stimulate some notable examples of both on- and off-market demand response in the New Zealand market, including from the Tiwai smelter, Norske Skog mill at Kawerau, and, potentially, NZ Steel's mill at Glenbrook. Norske and Tiwai had found sufficient incentive in avoiding high prices, whereas more recent contracts have contained some extra payment by a third party (namely their energy supplier) – effectively an option fee – implicit in their energy purchase contract.

In contrast to shifting hot-water load, or (in future) EV charging loads, it can be extremely costly for a major industrial consumer to change their consumption profile. These costs need to be considered in any decision whether or not to shift consumption to avoid high energy prices – or in other words, energy prices need to be *very* high to justify shifting load. New Zealand typically has less short-term wholesale price volatility than overseas, thermal-based systems, but, on the flip-side, much greater price volatility month-to-month. As we become more reliant on wind generation, the predictability of spot prices is likely to become even less (again, compared with overseas markets where demand is still the primary driver of price levels, rather than supply). On the surface, given the high costs, low value and difficult predictability, it may therefore not be surprising that levels of industrial demand response in New Zealand are lower than other jurisdictions.

Relatedly, as the Authority notes in conclusion in paragraphs 5.3 and 5.4, "*Historically, however, electricity prices have been relatively stable in real terms and represented a low proportion of costs for many commercial consumers. As a result, the potential savings from demand response have been modest and may not be enough to incentivise significant volumes of industrial demand flexibility.*" The RBP Report notes further that levels of industrial demand response are generally still very low in overseas markets, even where ex-market payments have been in place to provide an extra incentive over simply avoiding high prices.

Referencing question 4 specifically, both internationally and in New Zealand, 'flexible connections' are growing in profile and importance as a mechanism for network businesses to connect customers more rapidly, and at lower cost – especially if it means avoiding high-cost upgrades further up the network. Arrangements like Vector has with Auckland Transport's e-bus charging depots provide for a degree of predictability in when demand response is or might be required, and are only appropriate for loads which can be shifted seamlessly – for example bus or EV charging, or other industrial processes which benefit from some storage. Again, these arrangements are being stimulated solely on the basis of avoiding cost, rather than through payments. Hence we are not at all sure there is a missing incentive.

We are also seeing rapidly-increasing interest from retailers in managing fleets of devices in consumers' homes, such as hot water and EVs. These retailers are doing so primarily to avoid high wholesale and network prices, to reduce the bills they pay to both the Clearing Manager and their host EDBs. We have not heard any concerns from them that avoiding high prices do not create enough of an incentive for them to bother making the investments in systems, products and services required to be able to make use of that flexibility. Obviously, the costs to these consumers whose household devices are being managed are very low, relative to industrial consumers, and so it makes sense that lower-cost resources are engaged well before higher-cost industrial loads.

In summary, we are struggling with the idea that the existing incentives may be insufficient to stimulate efficient levels of flexibility in demand, when these same incentives are already demonstrably stimulating response across the New Zealand market.

Alternative commercial arrangements generally provide a fee for loss of flexibility / autonomy

The Authority's analysis appears to overlook the fact that where additional payments have been made to consumers for demand flexibility, they have been to cover either *availability* (as in the case of interruptible load reserves in New Zealand), and/or the *loss of autonomy / flexibility* that comes from selling the right for another party to call on that flexibility when it suits them (as in the case of the recent Tiwai and Glenbrook arrangements).

These payments should not necessarily be considered an additional incentive, over and above the benefit of avoiding high spot prices – indeed, the call by a third party for a consumer to drop their load could come at a time when the consumer would otherwise have been very happy to pay the prevailing spot price. As such, these payments should be considered primarily as *option premia*, rather than extra incentives to supplement value from cost-avoidance. In other words, the consumer is choosing to provide a service to the third party – whether it is the SO for reserves, or their retailer – and this premium is the price at which they are happy to trade that service.

The RBP report notes this in section 4.3, in its discussion of why centralised DR programmes have been less successful than off-market, bilaterally-negotiated agreements:

Despite the continuous efforts to improve these programmes, it remains a challenge to incentivise DR to participate, because flexible load can often achieve the outcomes it wants without joining a programme.

Demand response programmes lack participation because prospective providers can just as easily implement their own off market arrangements without giving up control of their operations, and prefer to do so unless there is an additional carrot. They always have the option of monitoring market prices, and adjusting their consumption if it makes sense to do so. They can do this without giving control of their operations to the system operator, and without facing penalties or sanctions. Just being a part of central dispatch does not give sufficient additional benefit compared to what they can do outside the market processes. This is why successful DR programmes (both commercial and centralised) have to offer additional compensation. The prevailing electricity sector paradigm is that demand has the right to consume whatever it wants, whenever it wants, and generation will be adjusted to meet it. Generation is held to strict standards of performance and compliance, demand is not.

In addition, getting DR resources to give up control of their own flexibility requires relaxed compliance requirements. Nearly all of the programmes discussed treat DR differently to generation:

- DR is not always required to follow dispatch;
- DR is not required to have real-time telemetry;
- DR is dispatched on a reduction basis rather than receiving an absolute MW dispatch target, meaning baselines have to be used to determine what reduction was actually delivered.

In the long run, it may be that demand can be held to the same standards of forecasting and dispatch compliance as generation in a two-sided market, but that will require a fundamental change in the way electricity demand is treated – for retailers, if not for end-consumers.

We therefore agree that there is a good case for option premia to be paid to the sellers of demand-response services, but these should not be confused with supplements to potentially inadequate incentivisation from avoided spot prices, or any form of benefit-based reward for reducing prices.

Authority's logic for intervention could apply equally to generation

Finally, there seems no reason why the same logic used by the Authority in 5.5 – 5.10 to justify its shift in position on paying for DR would not also apply to generators who produce electricity, thereby avoiding the need for more expensive generators to be dispatched. Like consumers, they "*face upfront costs (e.g. control systems, operational process enhancements, telemetry)*" (ref 5.6), to ensure they can respond to market signals. These costs may not be able to be recovered under trading conduct rules, which tend to require offers to be made with reference to short-run marginal costs (including scarcity). If *unoffered* (i.e. participating outside of the market, but in response to prices), they may also cause the price to fall when they respond to what might otherwise have been a high price. If the price settles at the generator's offer price, they are not receiving any net benefit at all for their service.

In an exact parallel with consumers that choose not to consume, the generator also does not receive a payment that reflects the benefits they provide to other consumers through their actions. Their payment instead reflects the marginal value of generation. For example, imagine a generator that offers to generate 10 MW at an offer price of $1000/MWh, when the next most expensive generator in the stack costs $10,000/MWh. By generating, and setting the price at $1000/MWh rather than $10,000/MWh, that generator has saved the entire demand side from paying an extra $9000 for each MWh. The generator's compensation in no way reflects that benefit – and again, as noted above, their net compensation could be $0 if the price settles at their SRMC.

The RBP report makes the same observation in section 3.7.6:

> The same argument could be made for peaking generation. If demand side response is compensated based on the market wide saving it produces, why is a peaking generator any different? Rather than paying generators the marginal market clearing price, we could move to pay-as-benefit, where each offer tranche is paid based on the difference from market prices in the counterfactual where it is not present. This approach is not used in any electricity market – generators are paid based on the marginal price of getting a unit of energy from somewhere else, not based on the total change in consumer or producer surplus. In situations where the market price does not represent the actual marginal cost of energy (e.g. because it has hit a cap or a floor), then it may be relevant to pay based on some other calculation, but ideally that could still be related back to the marginal cost.

If the Authority is attempting to make the case for an ex-market payment to industrial response, it needs to be very careful to treat demand and supply with an even hand.

In summary, and for absolute clarity, we are far from convinced that such an ex-market payment is required, or can be introduced without setting precedents across all the pricing overseen by the Authority.

We support the introduction of a last-resort demand-response scheme

(response to question 16 on ERS)

While we made clear in the previous section our position on 'negawatt' style schemes in the wholesale energy market, we do, however, support availability payments for demand-response ancillary services (action 1). Again, these payments should be cost-based, though, not benefit-based, reflecting the fee required to justify the availability and performance requirements of the resources in question.

As the RBP report notes in its conclusion, "*DR is currently most effective as a last resort resource used prior to involuntary load shedding, not as an integrated part of regular market trading.*"

We see merit in the design detail in the Australian Reliability Emergency Reserve Trader (RERT) scheme, as set out in section 3.2 of the RBP Report:

> RERT contracts are negotiated directly between AEMO and the provider – there is no rule defined market mechanism. AEMO can only procure a reserve contract if the region is declared to have either a low reserve condition[13] or a lack of reserve (LOR)[14] condition at some time in the next 12 months. AEMO cannot contract RERT at a cost greater than the assessed value of customer reliability (also referred to as the value of lost load, or the value of unserved energy) for the region.
>
> RERT is contracted differently for three different timeframes.
>
> - Long notice situations – between 12 months and 10 weeks from projected reserves shortfall.
> - Medium notice situations – between ten weeks and seven days from projected reserves shortfall.
> - Short notice situations – less than seven days from projected reserves shortfall.
>
> For long notice situations, AEMO will issue an RFP for prospective suppliers to respond to. For medium and short notice situations, AEMO has pre-qualified a RERT panel from whom to request

Again, we would not limit participation in such a scheme to DR from consumers. We are aware of tens of MW, if not over 100 MW, of standby backup generation connected to our network alone, that could be of use to the system operator in managing grid emergencies. We would support some form of availability payment to these generators, as and when their availability is required. This generation would show up at the GXP as a reduction in demand.

It is worth the Authority being mindful of this advice in the RBP Report:

> ### 3.2.7 What are the potential weaknesses of the programme?
>
> RERT is a programme of last resort only. It was never intended to function as a mechanism to encourage large volumes of DR into the market.
>
> As an out of market programme, the RERT is not subject to the same level of competition as standard market processes.
>
> Because potential returns are higher than regular market processes, there is incentive for participants to withhold capability from market processes in order to participate in the RERT scheme. The Australian Energy Council (the industry body for generators and retailers) noted in 2018 that:
>
> > *"AEMO is limited to recruiting for the RERT reserves which did not intend to participate in the market, and are therefore additional. In practice it is impossible to be sure. Energy Council members anecdotally report being outbid by AEMO in their springtime DSR recruitment drives."*[16]

Maintenance of network safety, security and power quality must be a guiding principle

(response to question 12 on guiding principles)

Industrial load exercising flexibility could be connected either to the grid or to a distribution network. We have noted for several years now that there is a gap in the regulatory framework requiring parties managing load on EDBs' networks, regardless of whether they are offering services to EDBs, to follow 'good electricity industry practice'. At a minimum, expectations on these parties need to include that they enter into and comply with a Load Management Protocol with their host EDB(s).

We obviously need to ensure that any available distributed resources are used to their maximum extent in a national (grid) emergency, including turning off load in response to high spot prices, but how those resources are used still needs to be coordinated by, and through, the distributor on whose network the resources are operating. Failure to do so has the potential to create, or exacerbate, local emergencies.

This is less of a concern for how dispatchable load is turned *off*, and more to do with how load is *restored* following a period of control. Neither the System Operator, nor the consumers themselves, has any visibility of what rate of load restoration can be accommodated on local networks following a period of control. It is simply not the case that all resources turned off for a period of an hour or more can safely be turned on again at the same time, at the conclusion of a grid emergency. We refer to this as "*the forgotten side of load management*". The same applies to the injection from batteries to alleviate a grid emergency – it is critical that this is limited to what can be contained within the thermal limits of network infrastructure, to avoid risks to public safety, outages, consumer assets or network assets.

As we have discussed in submissions in relation to the Load Management Protocol, it needs to be clear that:

a) At all times, controllable load operates within the physical and power quality limits of the distribution network; and
b) EDBs must have the ability to coordinate response of distributed assets to grid emergencies, and will also need the ability to instruct response to Network Emergency Events on their networks. This coordination must trump any other arrangements in place – in a similar vein to how grid emergency arrangements give Transpower the power to orchestrate response by grid assets to emergencies when other mechanisms have failed, to avoid more widespread issues.

Given how critical responsible load management will be to maintaining network safety and security in a future with many more flexible resources, we therefore request that the Authority adds a further guiding principle, and/or outcome, to its list that '**Network safety, security and power quality must be preserved as demand response is exercised**'.

We support the development of a roadmap for industrial demand flexibility

(response to question 17-20 on the roadmap)

Publication of a multi-year roadmap is useful to signal to the sector the direction in which the Authority wants to head in this space. However, we agree with the Authority's current view in 7.35 that "*more evidence is required before we should decide to establish additional market mechanisms or platforms, significantly increase regulatory incentives, or make further incremental modifications to existing market arrangements for industrial demand flexibility*."

We are happy to support the design of a standardised, intra-day demand flexibility product (action 2), to the extent that one is needed over and above the new super-peak product – which was also designed in part to value and elicit intra-day demand response on an ongoing basis. We would note, however, that it may be hard to standardise a product with sufficient depth of both buyers and sellers (which was a criterion of the previous design group), given how different each consumers' process is. Consumers and their agents will be able to offer and informed view.

In relation to action 6, the Authority should not introduce Code to enable third-party, non-retailer load managers until and unless it requires those parties to enter into a binding Load Management Protocol with their host network companies. To do otherwise would be entirely irresponsible. The same situation would not be countenanced on the transmission grid.

As noted above, flexible connections are becoming a growing feature of power systems internationally, and in New Zealand. We have recently introduced flexible connections as a standard use-of-system tariff offering for larger consumers who have an element of demand flexibility, and can shape their load within a dynamic operating envelope with which we issue them. We would be happy to brief the Authority on its implementation and uptake. This could inform the Authority's development of actions 7, 8 and 9. We note in 2022 we provided the Authority with a full briefing on the outcomes of our Warkworth request for third-party flex services, and documented it in a subsequent submission[4].

We are also shortly to embark on a scaled flexibility pilot on our network, with the support of EECA, and will engage the Authority on its progress (supporting action 9).

Thank you for considering this feedback. As noted above, we would appreciate further opportunities to engage with you and the team on the development of this guidance.

Ngā mihi

[redacted]

James Tipping
GM Market Strategy / Regulation

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[4] See pages 31-36 of our February 2023 submission: https://blob-static.vector.co.nz/blob/vector/media/vector-2023/vector-submission-issues-paper-updating-the-regulatory-settings-for-distribution-networks_1.pdf