2 November 2023

Consultation: Advancing New Zealand's energy transition
Energy and Resource Markets
Ministry of Business, Innovation & Employment
P O Box 1473
Wellington 6140

By email: electricitymarkets@mbie.govt.nz

Dear team,

RE: Measures for Transition to an Expanded and Highly Renewable Electricity System

The Independent Electricity Generators Association Inc. (IEGA) appreciates the opportunity to provide feedback on the Ministry of Business, Innovation and Employment (MBIE) issues paper "Measures for Transition to an expanded and highly renewable electricity system" (EMM).[1]

The IEGA represents members that operate or are investigating/building renewable generation assets connected to local distribution networks across the spectrum of renewable fuels.

It is timely take stock of the work underway and planned, to consider if there is anything missing, and whether planned work is being prioritised appropriately, resourced and can be completed in time so that the regulatory system supports an efficient transition to a low emissions economy.

The role of distributed generation in the transition

The IEGA supports MBIE's definitions and approach to different forms of distributed energy resources.

MBIE uses "the term 'distributed flexibility' to describe all types of demand side flexibility, demand response and flexibility from distributed generation and batteries. Distributed flexibility can be provided by large scale distributed energy resources (DER), or household-level consumer energy resources (CER)."

> "DER are business-owned assets, and their primary purpose can be either to provide energy system services or to provide business services. They are generally larger in kW/kWh and can be connected at any voltage level on the distribution network. DER can be generation, storage and demand assets. Examples include medium-sized solar farms, wind farms, batteries, commercial EV fleet charging, and industrial and commercial demand-side response from equipment or buildings."

[1] The Steering Committee has signed off this submission on behalf of members

> "CER are (residential) consumer-owned assets, and their primary purpose is to provide a non-energy system service such as heating a home or transportation. However, they can also control their operation to provide energy system services. CER are generally smaller in kW/kWh size and they are connected to the low-voltage distribution network at the consumer's premises. CER can include generation, storage, and demand assets, and common examples include EV charging (including vehicle to gird (V2G)), hot water, heat pumps, heating, ventilation and air conditioning (HVAC), home appliances, small-scale batteries and rooftop solar or small-scale wind." [2]

IEGA members' assets are 'DER' – business-owned generation (including batteries) connected to any voltage level on the distribution network. In our view, the key difference between DER and CER is scale and the increasing requirement for co-ordination with the smaller scale CER.

Everyone is aware that achieving a highly renewable energy system will cost many billions – and this has serious implications for electricity consumers.

Peak demand drives the need for new investment in network and generation infrastructure. Boston Consulting Group's (BCG) recent report noted:

> "Peak loads remain a key driver of network and generation investment costs, with one electrical distribution business (EDB) indicating meeting peak demand accounts for nearly half its costs. Every MW of avoided peak demand is estimated [by Transpower] to save New Zealand $1.5 million in generation, transmission, and distribution investment costs. As such, increasing peak loads have the potential to undermine electricity equity and inhibit electrification efforts elsewhere in the economy." [3]

All types of distributed flexibility can be incentivised to reduce demand or increase distributed generation output during peak demand periods and to use the network more during non-peak demand periods.

BCG estimates that if demand response (from industrial users and aggregating households) - one component of this distributed flexibility - makes a much greater contribution compared with business as usual this could reduce capacity in 2030 by 600MW and save $820 million in network investment during the 2020s.[4] This is a non-network solution – demand response avoiding investment in network infrastructure – this saving is $1.3million/MW.

BCG's preferred Pathway 2 assumes 2GW of demand-side flexibility (EVs, demand response) will reduce peak demand volumes. Despite this assumed demand-side flexibility, BCG forecast $22 billion investment in distribution and $8.2 billion in transmission during the 2020s (the next 7 years). This additional transmission/distribution capacity is required to support an additional assumed new generation capacity of 4,800MW plus 1,100MW of additional peak demand supply-side flexibility (peakers, storage) as forecast.[5]

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[2] This is an interesting description of why Energy Consumers Australia prefer to use CER: https://energyconsumersaustralia.com.au/news/death-to-der-why-we-need-to-change-the-language-we-use-for-the-energy-transition?mc_cid=d8501bccfb&mc_eid=2f0ba19009

[3] Page 52 BCG Report

[4] Ibid Page 91. The IEGA was not part of the group that commissioned the BCG report and has therefore had no input into, or discussion about, the report with its authors.

[5] See Exhibit 74, page 118 BCG Report

We note there is no transparency about the assumed location of this new generation – worst case the forecasts of new infrastructure investment could be based on all new generation capacity being connected to the transmission grid and all new electrification load being connected to the distribution network. The term 'distributed generation' is used once in the entire BCG report.

The following table highlights the cost per MW of this new infrastructure. These costs per MW can be compared with the cost of building new generation. The forecast required investment in expanding distribution infrastructure is by far the most expensive per MW. Distributed generation is an alternative to this distribution network investment and any distributed generation costing up to $3.7million/MW results in a lower overall system cost.

	Demand response	**Distribution**	**Transmission**	**Generation**
Cost ($million)	820	22,000	8,200	10,200
Capacity (MW)	600	5,900	5,900	5,900
$million / MW	1.37	3.73	1.39	1.73

Distribution networks current load factor or capacity utilisation averages just under 60%. Does the modelling for the BCG report (completed by Concept Consulting) include a marked improvement in the utilisation of existing distribution network assets before modelling new investment? [6] This could be revealed by understanding the assumed growth in demand during peak periods compared with demand during the rest of the day. The range of utilisation factors would suggest that there are networks more vulnerable than others, and/or potentially a range of different utilisation factors across the different areas of a distributor's network system. That would then suggest a targeted investment strategy would be more efficient and reduce total investment costs to consumers. A targeted investment approach requires better information for investors in alternatives, including consumers. We understand this is described by distributors as a dynamic operating envelope (DOE) targeting utilisation improvements.[7]

We suggest that increasing the utilisation of existing distribution infrastructure is far more efficient than investing in new capacity. In our view, commercial distributed generation (including batteries/storage) can play a significant role in increasing the utilisation of existing network assets, increasing two-way flow over lines, by:

- meeting growth in demand during all parts of the day
- investing in areas of the network where there are step changes in demand due to large load electrification
- assisting distributors to manage power quality on their network as investments in CER assets increase.

The IEGA strongly suggests MBIE should model a cost benefit analysis to establish if the overall costs to consumers will be less when generation is built and connected to distribution networks compared with utility-scale generation that requires (a forecast ~$30 billion) upgrades and/or new transmission lines to transport electricity to load centres as well as increased connection capacity between

[6] We note the current ratio of distribution and transmission assets is 73.8% distribution (based on the total Regulatory Asset Base for EDBs of $14.5bn at 31-3-23) and 26.2% transmission (Transpower's property plant and equipment of $5.135bn at 30-6-23). Adding on Concept's forecast investment the ratio is 73.2% distribution / 26.8% transmission - almost exactly the same as currently.
[7] The FlexForum January 2023 Insights paper discusses this issue.

transmission and distribution networks. **What is the optimal mix of distributed generation and network infrastructure investment that results in the lowest overall system costs for electricity consumers?**

The benefits to be assessed in this analysis would include:

- distribution network connected generation and batteries have the same LOCE as utility-scale generation plant
- distributed generation with batteries can be 'firm capacity' to replace the role of fossil fuels in the wholesale market
- shorter construction period
- incremental increase in generation capacity when demand growth can be uncertain
- delaying or avoiding some of the forecast $22 billion distribution networks investment over the 2020s – or annual investment of $3.1 billion in each of the next 7 years. A delay of one year saves electricity consumers $214 million[8]
- delaying or avoiding some of the forecast $8.2 billion transmission over the next 7 years to end of 2029 - investment of $1.2 billion each year. A delay of one year saves electricity consumers $82 million
- avoiding transmission losses – which Transpower assumes at 3.85% in the South Island, 2.85% in the North Island and on the HVDC about 5%[9]
- scale and voltage of the connection likely means lower costs for connecting to distribution network infrastructure
- lower local prices relative to GXP prices when losses are avoided on the distribution network
- the value of distributed flexibility provided by distributed generation (eg generating into peak demand, assisting with planned and unplanned outages) to reduce operating costs
- reducing transmission constraints – the cost of which ends up in wholesale spot prices
- provision of ancillary services that assist real-time dispatch
- operating this generation to assist with operational management of the transmission network, including transmission outages
- potentially lesser environmental impacts
- improved diversity of the location of generation
- increasing resilience of local communities with local sources of electricity

The value of these benefits of distributed generation has to be monetised. At this stage we can estimate the value of the benefit of deferring one year of distribution and transmission investment, assuming BCG's $30bn+ of new investment costs, - this totals almost $300 million – which is the estimated cost of a 200MW /MWh solar/storage facility.

In addition, avoiding 5,900 MW of utility scale grid connected generation being transported through transmission and networks, with losses around 7%[10], equates to around 2,000 GWh of potential

[8] Both distribution and transmission savings are calculated using Transpower's Weighted Average Cost of Capital of 6.83%. Source : Footnote 21, Page 74, Transpower's RCP4 Consultation, September 2022

[9] There is a detailed table on losses in either direction for different flows on pages 15-16 of the TPM Assumptions Book

[10] This is a conservative estimate as the average losses on distribution networks was 7.16% in FY22. Source: Commerce Commission Information Disclosure data

energy line losses which at LOCE over $100/MWh is another $200m+ of energy losses that could be avoided or reduced with distributed generation and storage.

This cost benefit analysis would answer the question:

> ***What is the most efficient investment –***
>
> - ***commercial scale distributed generation with storage, OR***
> - ***$30+ billion on distribution and transmission infrastructure over the next 7 years?***

The IEGA suggests this analysis should be undertaken before there is any further work evaluating further measures to support an efficient transition to a low emissions economy.[11]

The results would provide the foundation for the development of distributed generation and simplify/wash away the institutional, economic and regulatory barriers that currently exist as it would be clear it is in NZ Inc's interests to have new distributed generation.

Feedback on the relevant sections of the Electricity Market Measures paper

The remainder of this submission addresses relevant sections of the EMM paper. Appendix 1 includes links to recent IEGA submissions on work that is currently underway by the Electricity Authority and the Commerce Commission, which canvass the same (and other relevant) issues as discussed below.

Part 1: Growing renewable generation; Chapter 2: Accelerating supply of renewables

Overall, we strongly agree that more diversity in generation types, location and ownership will be good for competition in the wholesale market.

The IEGA agrees with MBIE's list of factors[12] that may slow development of sufficient new renewable generation. In priority order from the perspective of a distributed generation investor the barriers are:

i. Resource management legislation and framework –
   - The new resource management legislation and framework is a significant unknown.
   - It is positive all existing distributed hydro generation can now be reconsented for up to 35 years, but a 10 year water permit for new hydro generation is effectively a ban on this technology. As a report for MBIE[13] identified there is significant opportunity for new smaller commercial scale run-of-river hydro. The reason for 'banning' new hydro remains unknown – any project would have to pass environmental tests to get a consent. The IEGA submits this issue must be re-examined so that consumers are assured the least cost new renewables are being constructed
   - The proposed change to the NPS-HPL is a positive and necessary change to enable solar farm construction.

ii. Role of the Department of Conservation (DoC) in 'approving' resource consents – As we have submitted previously[14], the resource management process is duplicated if the project requires

[11] This analysis is long overdue and was not undertaken at the time of other significant regulatory change for distributed generation with the result that peak demand is growing faster than Transpower expected.
[12] Para 47, page 24-25 of EMM paper
[13] See https://www.mbie.govt.nz/assets/embedded-hydro-generation-opportunities-in-new-zealand.pdf
[14] IEGA submission on MBIE's consultation paper on Accelerating Renewables and Energy Efficiency, February 2020

access to land or renewable fuel that is under DoC control. This involves making an identical consent application and awaiting approval for access and information about the concession fee payable for this access. The approach by DoC differs across New Zealand and usually involves lengthy timeframes with highly uncertain outcomes.

The DoC legislation (and framework) has not been updated for the imperative of addressing climate change which seems odd when climate change may be the biggest threat to the things DoC is working to protect. The draft National Policy Statement on Renewable Electricity Generation could provide DoC with strong direction on the government's intentions regarding the imperative to construct new renewable generation.

iii. The IEGA strongly supports work to improve liquidity in risk management products, including the introduction of new products and over a longer time frame – Volatile spot prices results in volatile / unbankable generation revenue for funding existing capacity and, more importantly, new investment. The IEGA disagrees "NZ has a liquid forward contracting market". We do agree that "the range of available hedge products is narrower than in larger markets like Australia and the UK. Thus, the kinds of products needed for a renewable generator to lock in a price for its intermittent generation are currently less likely to be available for the time frame investors might require."[15] MBIE should analyse whether the current pricing of exchange traded hedge products, set by incumbent gentailers, provide a useful benchmark for risk management agreements new entrant generators are looking to sign – this market provides public information about a future price path but the prices are well above the LRMC of new generation.

The IEGA suggest it would be useful for MBIE to publish a list of generation and transmission projects categorised as: announced; seeking consent; consented; decision to invest has been made; commissioned. It would be useful to monitor the date these announcements are made – whether the timeframe between each announcement indicates barriers to progressing the project, an intent to construct or maybe announcements that are made to 'crowd out' other potential projects / investors.

Question 2*: If you think extra measures are needed to support renewable generation, which ones should the government prioritise developing and where and when should they be used? What are the issues and risks that should be considered in relation to such measures?*

As well as addressing the issues listed above, the IEGA suggests other urgent issues for distributed generation include addressing:

i) distributors being more transparent about the opportunity for new generation capacity (including close to new load) that reduces/eliminates any need for new network investment
ii) delays in connection of this generation
iii) how distributors recover network investment in anticipatory capacity, ie, when it is more economic / efficient (due to economies of scale) to invest in an upgrade of capacity that exceeds the needs of the connecting party that initiates this upgrade. First mover disadvantage for connecting distributed generation is significant.

The IEGA supports government **issuing a Government Policy Statement** to provide clear direction on its expectations of how industry regulators and participants can work together to achieve the

[15] Paragraph 66, page 61 of EMM paper

objectives of the New Zealand Energy Strategy. From our perspective, this should facilitate investment in distributed generation and distributed flexibility if this is the most efficient outcome for the long-term benefit of consumers.

Part 1: Growing renewable generation; Chapter 3: Ensuring firm capacity during the transition

Question 4: *Do you think measures could be needed to support new firming/dispatchable capacity (resources reliably available when called on to generate)? If yes, which kind of measures? What needs do you think those measures could meet and why?*

As discussed above, the IEGA recommends the government reconsider the 'ban' on constructing new hydro generation capacity. A project cannot be financed with only a 10 year water permit. It's not clear what issue this approach is trying to address (given hydro generation is a non-consumptive use of water which is available for other uses downstream). Instead of limiting access to the renewable fuel there could be a limit to the height of any dam built. Smaller scale or run of river hydropower stations can have a limited impact on the river and local environment and can be operated to provide firming resources (or incorporate a small amount of storage).

Considerable work is required to realise the potential for distributed flexibility, including distributed generation, to provide firm capacity, in particular the financial incentives required.

Part 1: Growing renewable generation; Chapter 5: The role of large-scale flexibility

IEGA members are or will be offering the form of large-scale flexibility MBIE describes as 'behind the meter' injection or battery dispatch to reduce grid-presented demand without affecting operation'.[16] Any measures developed to encourage large industrial users, distributors and/or retailers to support large-scale flexibility must also apply to distributed generation.

Part 2: Competitive Markets; Chapter 6: Workably competitive markets

MBIE discuss central procurement of flexible resources. The IEGA does not support a single buyer market. However, IEGA members own distributed flexible generation. We support progressing with pace development of a 'market' and standard contracts for flexible resources.

Transpower and distributors are already required to assess these non-network solutions as alternatives to poles & wires investment.

Further work is required to determine if central procurement is the most efficient outcome. Could this central procurement body be an 'Independent System Operator' responsible for co-ordinating both transmission and distribution. Co-ordination of flexible resources across the demarcation of distribution and transmission networks is essential for ensuring reliable electricity supply to all consumers.

Part 3: Networks for the future; Chapter 8 Distribution networks for growth

Question 29: *Do you agree we have identified the biggest issues with existing regulation of electricity distribution networks?*

Overall, MBIE's focus (and that of the Authority) appears to be on connecting new <u>load</u>. As importantly, officials should look to understand the issues facing connecting generation to distribution

[16] Paragraph 126-127, page 49 of EMM paper

networks. If both generation and load are considered at the same time it's more likely consideration will be given to distributed generation being able to supply new load on a distribution network, avoiding the need for distribution and transmission investment.

The following is feedback on three of the four issues highlighted by MBIE in the EMM paper[17]:

Issue: "Removing barriers to connection for new demand (such as industrial decarbonisation and public EV chargers) – barriers to connection of new customer load can arise from inconsistent distribution business policies, processes and capacity, and constraints imposed by regulation."

Feedback: These same issues apply to connection of new distributed generation. There is the opportunity for distributed generation to be located close to new demand to reduce the need for new distribution network capacity.

We agree there should be more transparency about connection costs and more consistency in capital contribution policies. Also connecting parties should be able to use distributor approved 3rd parties to do the connection work.

The IEGA does not support developing a new process in Part 6 of the Code for larger distributed generation (or load). It is more important to support distributors in terms of capability and capacity to cope with the rate of new connection applications. The IEGA recommends a centre of excellence that distributors can call on to help complete the required studies (instead of numerous (could be 29) consultants becoming competent in this topic).

Barriers to new connection of generation is essentially the same as the distribution sector being unprepared to contract for non-network solutions / flexibility.

The IEGA agrees more information on network capacity and congestion would be very useful. As discussed above, the use of dynamic operating envelopes would inform distributors as well as network alternative investors (Including consumers) about where opportunities / capacity exists.

Distributors could also provide public information about their connection enquiry queue (both load and generation), similar to Transpower, with enough location detail so that potential connecting parties can assess the likely impact of their request on the distribution network (and therefore the success or speed of processing the application). There should be visibility across the entire supply chain because investments made in distribution networks can have consequences for the transmission grid.

Issue: "Cost allocation to support network investment ahead of immediate need – the cost of anticipatory capacity or network upgrades that provide for future growth can be allocated to the initial connecting customer. This can add a barrier to connection of both distributed generation and new demand, or result in inefficient investment."

Feedback: Recovering the cost of anticipatory capacity is a major issue (and could be impacting the pace of investment in new load and generation). The IEGA believes there is a role for the government or NZ Green Investment Finance to fund the 'excess capacity' and be paid back as the capacity is used up (by other new connections or by the distributor as overall demand increases).

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[17] At para 218, page 74 of EMM paper

Issue: “Pricing signals to provide efficient use of networks – current distribution pricing may not adequately incentivise changes to retail pricing, or the provision of distributed flexibility, needed to support more efficient use of networks.”

Feedback: Distribution sector has to be prepared to contract for non-network solutions / flexibility. A standardised approach to contracts and valuing the range of services across NZ is most efficient.

Part 4: Responsive demand and smarter systems; Chapter 10 Increasing distributed flexibility

As discussed above, the IEGA totally supports MBIE’s terms for distributed flexibility, DER and CER. It is very useful and important to make the distinction of resources located at the consumer premises where the resource is much more dispersed. The CER resource owner is more likely to require or engage with an aggregator / retailer and can’t be expected to be an actual registered market participant.

IEGA is engaged in the FlexForum and acknowledges government’s support. We suggest MBIE investigate the UK approach to flexibility and whether this can be lifted and dropped into NZ. Institutional changes may be required, including maybe an Independent System Operator.

Progress on a digital platform for trading flexibility (as well as standard contracts / valuing flexibility services etc) is getting more urgent.

Question 45: *Would government setting out the future structure of a common digital energy infrastructure (to allow trading of distributed flexibility) support co-ordinated action to increase use of distributed flexibility?*

The IEGA supports MBIE working with the FlexForum to set out the future structure of a common digital infrastructure for trading distributed flexibility. Industry learning-by-doing can continue alongside development of infrastructure.

The EMM paper provides an accurate description of the barriers to investment in distributed flexibility and non-network solutions.[18] These issue have been known for years and there has been limited progress. We are not aware of any work currently underway that addresses these challenges.

If the use of dynamic operating envelopes (DOEs) make distributors more open to non-network solutions then they have an obligation to provide quality data about network DOEs / capacity / constraints to enable non-network solutions.

As discussed above, any central procurement of non-network solutions should be by an Independent System Operator who has visibility across the transmission and distribution networks. Alternatively a ‘centre of excellence’ for distributors could advice distributors about how the non-network solutions meets the distributor’s investment or operational need.

The focus is on whether stronger regulatory requirements are needed to accelerate provision of pricing which rewards flexibility without stifling competition or encouraging behaviour which increases congestion on networks.[19] In our view the issues are wider than this. A mechanism is needed to value flexibility and enable providers of flexibility to realise components of the value stack.

[18] Pages 94-95 of EMM paper
[19] Paragraph 341 of EMM paper

The paper discusses supporting the uptake of batteries or solar pv coupled with batteries.[20] MBIE may be referring to installations at consumer premises. The IEGA submits that storage in a range of capacities within local distribution networks has substantial benefits (eg Victcoria is trialling funding of batteries at distribution feeder / subzone station level to aggregate output from multiple household solar installations).

Question 56: *Is a regulatory review of critical data availability needed? If so, what issues should be looked at in the review?*

IEGA supports a regulatory review of critical data availability if it means that distributors will be more informed about the current and future state of their network and more prepared to procure non-network solutions / flexibility.

Part 5: Whole-of-system considerations

The IEGA supports one government agency being responsible for energy policy, rules, and market operation. Alternatively MBIE should be responsible for Policy and instruct the Electricity Authority to develop/implement Code that achieves that Policy.

As discussed above, significant new investment is required in the near term – at a higher rate than seen in living memory.

Some change is needed to resource whatever agencies exist to a level that enables timely regulatory intervention. The Authority Chair recently said "The Authority is struggling to keep up, let alone support the future".[21]

The industry must have confidence the regulatory settings support an efficient transition to a low emissions economy – confidence is low at the moment.[22]

Chapter 11 Setting priorities and improving co-ordination

The IEGA does not support a new coordination function that would extend to making decisions about what investments can or cannot be made.[23]

The IEGA does not support the development of Renewable Energy Zones for New Zealand.[24] Our submission to Transpower is here. As a representative body of generators looking to connect to local distribution networks we hope to be engaged in any further development of this concept.

Q60: Should MBIE regularly publish opportunities for generation investment to enable informed market decision-making?

Rather than MBIE "regularly publish[ing] opportunities for generation investment" it would be very useful if MBIE maintained a constantly updated central public record of the location and size of new generation investment categorised as potential (announced), seeking consent; consented; made Final Investment Decision and likely commissioning date; partly or fully commissioned.

[20] Paragraph 343-359 Page 106-109 of EMM paper
[21] Message from our Chair, Anna Kominik, 10 October 2023
[22] See results of the Electricity Authority's 2022 market participant perception survey
[23] Discussed in paragraphs 362-366 of EMM paper
[24] Paragraph 367-376 Page 112-116 of EMM paper

Concluding remarks

The IEGA's recommendations for MBIE are:

1. Undertake a detailed cost benefit analysis to establish the most efficient investment
    - commercial scale distributed generation with storage, OR
    - $30+ billion on distribution and transmission infrastructure over the next 7 years?
2. Issue a Government Policy Statement to provide clear direction on its expectations of how industry regulators and participants can work together to achieve the objectives of the New Zealand Energy Strategy. From our perspective, this should facilitate investment in distributed generation and distributed flexibility if this is the most efficient outcome for the long-term benefit of consumers.
3. Ensure the environmental regulatory settings support existing and new distributed generation, including hydro.
4. Progress addressing the institutional (capacity, capability and culture) barriers for distributed generation as well as economic and regulatory barriers.
5. Work with the FlexForum at pace to establish a standard contract, values for flexibility services (including services already provided by distrusted generation) and the appropriate 'platform' for enabling procurement.
6. Review institutional arrangements for energy policy to: eliminate duplication of effort and unnecessary regulatory uncertainty due to different approaches or interpretations; ensure the regulatory system is well resourced; and enable timely decisions that give confidence to private sector investors who will be instrumental in NZ's transition to a low emissions economy.

We welcome the opportunity to discuss with you the questions we have raised in this submission.

Yours sincerely

[unsigned as sent electronically]

Chair

APPENDIX 1 RECENT RELEVANT IEGA SUBMISSIONS

The IEGA has canvassed the same issues as discussed above in the following recent submissions on work that is currently underway by the Electricity Authority and the Commerce Commission:

Electricity Authority:

Updated regulatory settings for distribution networks, September 2021

Refreshed guidance on distribution pricing, November 2021

More efficient distribution pricing, February 2019

MDAG – Pricing under 100% renewable electricity supply Issues Paper, March 2022

Commerce Commission :

Targeted ID Review (2024) draft decision - EDBs – cross submission, October 2023

Cross submission on Transpower Capex and Input Methodologies, August 2023

Cross submission on EDB draft Input Methodology Determination, August 2023

Expenditure incentives EDB workshop, December 2022

EDB Targeted ID Review – cross submission, May 2022

The following older submissions are also included as the same issues regarding non-network solutions and flexibility are discussed (ie. haven't been resolved):

EDB DPP3 reset draft decision, July 2019

Supplementary feedback on issues raised at Spotlight on emerging contestable services workshop, June 2019

Spotlight on emerging contestable services terms of reference, April 2019