Chairman: Ben Gibson, [redacted]
Secretary: David Inch, [redacted]

25 June 2025

Electricity Authority
P O Box 10041
Wellington 6143

By email: decentralisation@ea.govt.nz

Dear team,

Re: Decentralisation green paper

The Independent Electricity Generators Association Inc. (IEGA) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) discussion about the opportunities and challenges of a more 'decentralised' electricity system in New Zealand.[1]

The IEGA comprises about 30 members who are either directly or indirectly associated with predominantly small-scale power schemes connected to local distribution networks throughout New Zealand for the purpose of commercial electricity production. Members' own and operate the full range of renewable generation technologies: hydro, wind, geothermal, solar and biomass and energy storage. We are price takers in the electricity market – the majority of our members do not have the financial or human capacity to operate 24/7 dispatching into the wholesale market.

IEGA members are small, entrepreneurial businesses, essentially the SMEs of the electricity generation sector, who have made significant economic investments in renewable generation plant and equipment. Combining the capacity of member's plant makes the IEGA the sixth largest generator in New Zealand.[2] We have 21 members whose existing 48 individual generation stations are already essentially 'decentralised' being connected to distribution networks supplying electricity to distribution network connected consumers. Numerous new distribution network connected generation projects are also under consideration by members.

[1] The Committee has signed off this submission on behalf of members.
[2] Or fifth after the Contact Manawa transaction is completed

Defining decentralisation

The IEGA notes that the Green Paper describes decentralisation in the electricity sector as "shifting from large scale electricity generation at a small number of sites across the country to smaller scale renewable and other 'distributed energy resources' closer to consumers".[3]

We agree with this description but suggest that it is also useful to be more specific about the definition of 'distributed energy resources'.

MBIE's Electricity Market Measures discussion paper[4] used "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."
>
> "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." [5]

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.

The IEGA recommends a common language / definitions be used in this area. FlexForum has already published useful information on this topic. Definitions might reflect who owns the resource, the primary location of the resource (at / not at a load customer site), scale and capability to 'participate'. This will also influence the purpose and value of regulation - it is critical that the benefits or need for regulation exceed compliance costs.

[3] Paragraph 2.1

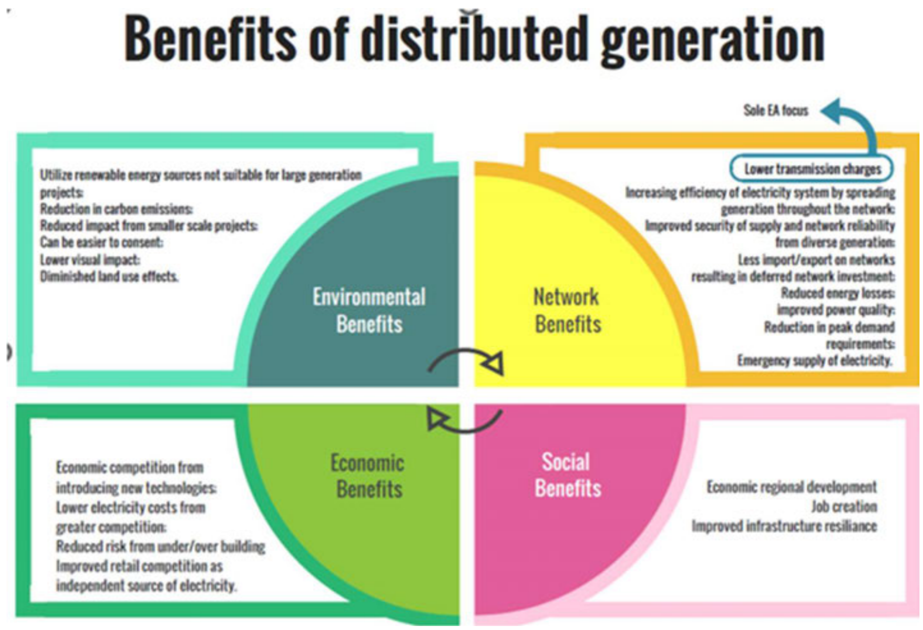
[4] See Section 10 pages 285 - 359 https://www.mbie.govt.nz/dmsdocument/26909-measures-for-transition-to-an-expanded-and-highly-renewable-electricity-system-pdf August 2023

[5] 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

Benefits of a decentralised system

The purpose of the IEGA's regulatory engagement across the board is to ensure the benefits of distributed generation are maximised for electricity consumers and the whole electricity system, and enabling supply security and resilience.

We often refer to a 2007 report by the Federal Energy Regulatory Commission[6] which summarised the benefits of distributed generation in the following diagram:



Realising all of these benefits requires input from a range of regulatory agencies, including the Authority.

It is useful the Authority is considering a future state of the electricity system – and what changes might be required to facilitate consumer and investor trends towards a decentralised state.

The Green Paper asserts that "By 2040, decentralisation can unlock more affordable, clean, secure, and resilient energy for Aotearoa".[7]

It is also the IEGA's view that more distributed generation can result in lower overall system costs for consumers. The IEGA's submission to MBIE on the Electricity Market Measures discussion paper suggested there would be value in analysing the whole of system costs faced by consumers associated with a focus on, essentially, a decentralised system versus more of a transmission grid connected scale generation system. That section of our MBIE submission is included in Appendix 1.

If the Authority's view remains (after this consultation) that decentralisation can unlock more affordable energy for consumers, the **IEGA suggests the Authority should be publicly committed to promoting and implementing regulation that supports or facilitates this outcome**. This regulation must apply consistently across different providers / participants who provide essentially the same

[6] See https://www.ferc.gov/sites/default/files/2020-04/1817_study_sep_07.pdf

[7] The IEGA agrees with the Green Paper's list of factors (paragraph 5.6) that will enable this outcome – in particular: making full use of our existing system; and creating a network of flexible, locally optimised energy systems, which connect to a strong grid.

service within a decentralised system. For example, regulation to ensure compensation is paid to incentivise behaviour change that reduces peak demand or reduces congestion on a distribution network should apply equally to consumer-owned and business-owned distributed energy resources.

We would welcome the opportunity to discuss this submission with you.

Yours sincerely

Ben Gibson
Chair

Appendix 1 – Extract from IEGA submission on MBIE's Electricity Market Measures discussion paper

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." [8]

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.[9] This is a <u>non-network solution</u> – 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.[10]

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.

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[8] Page 52 BCG Report

[9] 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.

[10] See Exhibit 74, page 118 BCG Report

	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? [11] 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.[12]

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 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

[11] 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.

[12] The FlexForum January 2023 Insights paper discusses this issue.

- 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[13]
- 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%[14]
- 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%[15], equates to around 2,000 GWh of potential 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?***

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[13] 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

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

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

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.[16]

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.

[16] 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.