Genesis Energy Limited
Level 6
155 Fanshawe Street
PO Box 90477
Victoria St West
Auckland 1142
New Zealand

T. 09 580 2094

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To: The Energy Competition Taskforce
Email: taskforce@ea.govt.nz

Genesis submission on proposal to requiring distributors to pay injection rebates

Genesis Energy Limited **(Genesis)** welcomes the opportunity to comment on the Energy Competition Taskforce's **(the Taskforce)** *Requiring distributors to pay a rebate when consumers supply electricity at peak times* consultation paper. Genesis agrees there are potential system and consumer benefits from distributed generation and are supportive of pricing principles that efficiently encourage greater utilisation. We agree that consumers who can export electricity should be fairly and efficiently incentivised and rewarded.

Genesis agrees with the Taskforce about the potential benefits of demand side flexibility and distributed generation resources. As part of our Gen35 Strategy, we aim to achieve 150 MW of demand-side flexibility in our customer book by the 2028 financial year. This reflects the fact we see significant benefit (under existing market settings) in attracting customers with demand side flexibility capability. We are already progressing towards this target. Genesis is New Zealand's largest distributed energy retailer with 29,100 household solar customers and 26,900 EV customers. Genesis is now purchasing c77GWh p.a. of solar export from customers. January was a record month with 5% of Genesis's total energy supply coming from customer exports. Peak customer solar generation is now around 226MWp. We expect mass-market consumer adoption of solar and batteries will continue to grow rapidly driven by decreasing technology costs, improving functionality, and increasing consumer understanding and acceptance. This will occur even without the proposed regulatory intervention.

We do not believe the case for regulatory intervention has been clearly established. We note there is nothing stopping distributors from offering rebates for injection now and indeed some are starting to offer this. Distributors are best placed to identify where distributed generation can create net benefits on their networks, and we agree with the Taskforce that any option needs to provide a certain level of flexibility. As stated in our submission on options 2B and 2C, the market for demand side flexibility and distributed energy resources in New Zealand remains relatively nascent, and regulatory intervention at this stage risks prematurely 'freezing' the market by codifying a prescribed set of requirements. Therefore, if any of the options are progressed, we would support the principles-based approach, as this strikes the best balance between setting minimum requirements and giving distributors flexibility to design approaches that best suit their networks.

There is a material risk that mandating time-varying tariffs will have distributional impacts that may not be considered optimal. As noted by the Australian Energy Market Commission (AEMC) in its consultation on its review of electricity pricing in Australia, "Tariffs designed to efficiently reflect the costs of consumer decisions should result in more efficient network use, and therefore, more efficient investment in and operation of the network. This has the potential to lead to lower overall network bills for consumers. However, these tariffs may impose higher costs on those households and businesses least able to respond to these tariffs."[1] We understand this risk was also identified by some submitters to the consultation. Without being definitive as to the best settings for New Zealand, the Australian experience does demonstrate that mandating time-varying distribution tariffs is complex and hard to get right. This complexity is likely to be increased by the fact retailers will need to operationalise this requirement in coordination with 29 different distribution businesses. We urge the Taskforce to draw on lessons learned from Australia and apply as relevant to New Zealand.

Even with a principles-based approach, regulatory design will be challenging. We note there is potentially a tension between ensuring rebates reflect network benefits and the objective of incentivising greater uptake using export rebates. A certain minimum level of rebate certainty and stability is likely to be necessary to materially impact consumer investment decisions, while as noted the benefits from injection are likely to vary depending on variable network demand. We also note the proposal requires retailers to pass-through rebates to consumers. While we support the objectives of this proposal (as we agree consumers should be fairly and efficiently rewarded for injection), as noted in our submission on Options 2B and 2C, this package of regulatory interventions will not succeed in achieving the Taskforce's objectives (and indeed may be distortionary) unless incentives are efficiently allocated among all parties, retailers, distributors, and consumers. If retailers are required to pass-through the full benefits from injection, there is no incentive for retailers (other than the compulsion of regulation).

Yours sincerely,

[redacted]

Mitch Trezona-Lecomte
Senior Advisor, Government Relations and Regulatory Affairs

[1] See page 23 of the AEMC's Consultation Paper: https://www.aemc.gov.au/market-reviews-advice/pricing-review-electricity-pricing-consumer-driven-future

Consultation Questions – Genesis Energy response

Problem Definition Q1. Do you agree with the problem definition above? Why, why not?	We agree there are potential system benefits from distributed generation and are supportive of pricing principles that efficiently encourage greater utilisation. We agree that consumers who can export electricity should be fairly and efficiently incentivised and rewarded. However, we note there is nothing currently preventing distributors from paying rebates to customers where this creates net benefits for the network (for example, we understand Orion has already started offering this).
Proposed solution: principles-based rebates Q2. Do you agree with these principles? Why, why not?	As noted, we do not agree that the case for regulatory intervention has been established. However, if regulatory intervention is to be progressed, we would support a principles-based approach, as this is likely to be the best way to balance the need for consistency with the need to give EDBs a degree of flexibility reflecting the specific circumstances of their network. EDBs are best placed to identify where distributed generation can create network benefits, and a more prescriptive approach risks adverse consequences.
Q3. Do you agree that the principles should only apply to mass-market consumers, or should they apply to larger consumers and generators also? Why, why not?	We understand that the barriers are most acute for mass-market customers, and therefore the proposed regulations may not be necessary for large industrial customers.
Q4. Do you agree the principles should apply to all mass-market DG, including inflexible generation (noting that the amount of rebate provided will still be based on the benefit the DG provides)?	Yes, if progressed, the principles should apply generally to all mass-market distributed generation, including inflexible generation as this can still provide network benefits in certain circumstances. Consistent with the Taskforce's proposal, consumers with inflexible generation should be rewarded proportionate to the benefits they provide.
Q5. Do you agree with the direction of the guidance that would likely accompany the principles? Why, why not?	We agree with the direction of the guidance and that rebates should be aligned to benefits i.e. should aim to incentivise injection at times and in locations that create net benefits for networks (and therefore consumers). As noted, there may be a tension between the principle of rewarding injection where it benefits networks and the stated objective of incentivising consumers to install distributed generation. For example, consumers may not be incentivised by truly benefit-reflective tariffs where the benefits are highly variable and dependent on relatively infrequent demand peaks. This becomes even more so when you consider a cold winter's night is when consumers are least likely to be able to export their power – due to no solar generation and high demand in their own household. Flexibility should be afforded to distributors to spread rebates over a longer time period, to give consumers stability and certainty. However, doing so will necessarily dilute the efficacy of tariffs as a peak demand signal. Another related issue is that potential benefits may be highly variable across different locations (networks) and times. For example, the benefits of injection may be highly concentrated in relatively few large

	demand peaks. These issues are canvassed by the Energy Consumers of Australia in a 2024 report titled *"Analysis: Cost-reflective network tariffs aren't very cost-reflective"*.[2]
Q6. Are there any additional issues with the principles where guidance would be particularly helpful?	As noted, there is a tension between the principle of aligning incentives to network benefits and the stated objective of incentivising consumer uptake of distributed generation. Consumers are likely to need a certain level of rebate certainty and stability over a period of time for this to materially influence their investment decisions. However, achieving this rebate certainty would require distributors to 'artificially' spread rebates in a way that may undermine the objective of incentivising injection at times that create network benefits. Another potential risk is where network conditions change, for example if congestion points are alleviated through network upgrades (poles and wires), with the result that rebates in following years decrease or are removed altogether. Consumers who have invested in solar and battery systems may feel aggrieved, particularly if they have factored rebates into their decision-making and given the fact it usually takes multiple years for such systems to pay-back.
Q7. Do you agree the principles should be incorporated within the Code, rather than being voluntary principles outside the Code? Why, why not?	If the EA progresses with the proposed intervention, we support a voluntary principles-based approach. This is most likely to strike the best balance between creating a minimum requirement while giving distributors flexibility to define the most suitable approach for their network. Moreover, defining the requirements in the Code carries the risk regulations will become outdated, particularly given the market for demand side flexibility / distributed energy resources remains relatively nascent. Voluntary guidelines will be easier to update and adapt to changing circumstances, which is appropriate at this stage of the flexibility market's development.
Q8. Do you agree with the proposed implementation timeline for this proposal? If not, please set out your preferred timeline and explain why that is preferable. "We are proposing that the Code amendment would come into effect on 1 April 2026 to align with the start of the 2026–2027 pricing year for distributors. As such, their pricing methodologies for that year would need to be compliant with these principles."	If progressed, aligning implementation to distributors' annual pricing timelines appears sensible.
Q9. Do you agree the proposal strikes the right balance between encouraging distributors to pay a rebate when consumers supply electricity at peak times, price-based flexibility and contracted flexibility? Why, why not?	We expect that EDBs are best placed to strike the right balance between price-based flexibility and contracted flexibility.

[2] https://energyconsumersaustralia.com.au/publications/analysis-cost-reflective-network-tariffs-arent-cost-reflective

Q10. Do you agree the proposal will lead to relatively minor wealth transfers in the short term, and will lead to cost savings for all consumers in the longer term?	We believe there is a material risk of wealth transfers associated with this proposal and that these are likely to favour typically wealthier consumers who are able to benefit from injection tariffs. We strongly encourage the Taskforce to consider distributional impacts as part of a cost-benefit analysis. As noted earlier, the Australian Energy Market Commission (AEMC), time-varying network tariffs may impose higher costs on those households and businesses least able to respond to these tariffs. Moreover,"…network tariffs could also be designed to incentivise greater connection of users and technologies which reduce future network costs. For example, a technology whose use of the network leads to reductions in future investment requirements could be incentivised to connect with an offer of negative or zero-cost tariffs. In these cases, such technologies may not contribute to the immediate recovery of network costs, meaning higher short-term tariffs for other consumers."[3]
Alternative option: prescribed rebates Q11. Do you agree that more prescriptive requirements to provide rebates will be less workable than a principles-based approach, and therefore should not be preferred? Why, why not?	Yes, as noted we believe a more prescriptive approach will be more likely to have unintended consequences. Distributors are best placed to make decisions about how to align incentives to benefits from distributed generation on their networks.
Alternative option: consumption-linked injection tariffs Q12. Do you agree that a consumption-linked injection tariff would not be sufficiently targeted, and therefore should not be preferred? Why, why not?	We agree that the pricing structure of distributed generation injection should be reflective of network benefits, rather than artificially mirror consumption charges.
Q13. If this approach was progressed, do you think: a) injection rebates should perfectly mirror consumption charges? b) there are sufficient safeguards in place that would allow distributors to avoid over-incentivising injection to the extent that it incurs additional network costs?	We do not agree that injection rebates should perfectly mirror consumption charges. Consumption charges currently reflect more than just the value of the energy. Injection rebates should reflect the value that they provide to the system, but the design must also consider human behaviour recognising that tariff design must be appealing and deliver value to all parties in aggregate (i.e. all fixed and variable charges, rebates and any other incentives).
Regulatory statement Q14. Do you agree with the objective of the proposed amendment? If not, why not?	No further comment.
Q15. Do you agree the benefits of the proposed amendment outweigh the costs?	We strongly encourage the Taskforce to conduct a full cost benefit analysis and intervention logic for Package 2A, B and C as a coherent, combined set of regulations. This is consistent with the Government's expectations for regulatory agencies as outlined by The Treasury, specifically:[4]

[3] See page 23.
[4] https://www.treasury.govt.nz/sites/default/files/2015-09/good-reg-practice.pdf

	• Undertaking systematic impact and risk analysis, including assessing alternative legislative and non-legislative policy options, and how the proposed change might interact or align with existing domestic and international requirements within this or related regulatory systems. • Making genuine effort to identify, understand, and estimate the various categories of cost and benefit associated with the options for change.
Q16. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Taskforce's statutory objectives in section 15 of the Electricity Industry Act 2010.	We believe the status quo is preferable to the proposed amendment, for the reasons stated above. There is a risk the proposed approach forces distributors to offer rebates where they do not believe this to be the most efficient way to manage periods of high demand. This may increase system costs and costs for consumers.
Proposed Code Amendment Drafting Q17. Do you have any comments on the drafting of the proposed amendment?	No further comment.