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From: Electricity Engineers' Association of NZ

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Subject: EEA Submission – Issues Paper – *Distributed Generation Pricing Principles*

OVERVIEW

The Electricity Engineers' Association of New Zealand (EEA) welcomes the opportunity to respond to the Electricity Authority's *Distributed Generation Pricing Principles Issues Paper* (February 2025). The EEA represents a broad spectrum of the electricity supply industry, including electricity distribution businesses, engineering and technical service providers, and subject matter experts committed to ensuring a safe, reliable, and efficient electricity system for Aotearoa New Zealand.

This submission reflects the collective expertise and practical experience of our members, who are at the forefront of planning, operating, and integrating distributed energy resources into the distribution network. As New Zealand transitions toward a more decentralised and flexible electricity system, the frameworks that govern distributed generation (DG) pricing must evolve to support innovation, ensure fairness, and deliver long-term value to consumers.

Key Points covered in our submission include:

- **Support for Reform:** The EEA agrees that the current DG pricing framework, particularly the incremental cost limit, is outdated and no longer fit for purpose in a modern, dynamic electricity system.
- **Move to a Principles-Based Approach:** We support transitioning to a more adaptive, transparent, and principle-based pricing framework that reflects the full range of DG impacts—positive and negative—on network planning and operation.
- **Encouraging Efficient Investment:** New pricing principles should enable fair recovery of shared and forward-looking costs, reduce the first-mover disadvantage, and send clearer signals to guide efficient DG uptake.
- **Integration with Broader Reforms:** Revisions to DG pricing must be aligned with distribution pricing reform, emerging flexibility markets, and support for aggregator business models.
- **Preference for Codification:** We recommend the Authority codify revised pricing principles in the Code to ensure consistency, certainty, and timely implementation across the sector.

- **Preferred Path Forward – Option 4 with Components of Option 3:** The EEA supports a comprehensive overhaul of DG pricing principles (Option 4), provided it incorporates key strengths of Option 3—namely a strong emphasis on cost-reflectivity, efficiency, and clear economic signals for investment.

The EEA appreciates the Authority's leadership in initiating this important review and supports continued collaboration with technical experts, industry practitioners, and consumers to ensure the resulting framework is practical, future-ready, and aligned with New Zealand's broader electrification and decarbonisation goals.

Discussion Questions

Q1. Do you have a view on the definition of incremental cost that is contained in the Code? Should it be more tightly defined to include only network costs and to exclude consequential costs relating to factors such as frequency keeping and voltage support? Would this lead to more timely generation build and lower energy costs?

The EEA believes that the current definition of incremental cost lacks clarity and results in inconsistent interpretation and application across distributors. This ambiguity creates uncertainty for all parties—distributors, distributed generators, and other stakeholders—and undermines confidence in the pricing framework.

While tightening the definition to include only direct network costs may offer short-term consistency, we believe that the incremental cost construct is no longer appropriate for a modern and dynamic electricity system. It is increasingly unfit for purpose in an environment with growing levels of distributed generation (DG), diverse connection types, and more active customer and technology participation.

The existing framework artificially constrains distributors' ability to recover legitimate, shared, and forward-looking costs associated with managing DG on the network. It fails to reflect the full range of operational and planning complexities—including voltage management, hosting capacity, and future flexibility needs—which are essential for maintaining safe, reliable, and cost-effective network performance.

Rather than a narrow cost-based definition, we support transitioning to a principles-based framework that enables more adaptive, transparent, and efficient pricing decisions. This approach would allow distributors to consider both near-term and system-wide impacts—while remaining grounded in principles of efficiency, cost-reflectivity, and neutrality between technology types and service providers.

Clarity and consistency in how costs are signalled to DG investors can improve decision-making and contribute to efficient investment outcomes. However, incremental cost definitions alone are unlikely to drive materially faster generation build or lower energy costs. The broader suite of market signals—particularly those from wholesale markets, flexibility services, and access pricing—are more influential in shaping long-term investment and affordability outcomes.

We encourage the Authority to consider a shift away from a rigid incremental cost test toward a more holistic and forward-looking framework for distributed generation pricing that better supports system integration and investment efficiency.

Q2. Do you agree with the problems with the incremental cost limit identified in this section? Why or why not? Do you have a view on the relative importance of the problems identified?

The EEA agrees with the Authority's identification of key problems associated with the incremental cost limit. We support the Authority's effort to modernise the DG pricing principles to better reflect the evolving needs of the electricity system.

We highlight the following issues as the most significant:

1. **First-mover disadvantage:** The current approach penalises early adopters of distributed generation by allocating the full cost of upgrades to the initial connection, even when those upgrades benefit subsequent users. This creates a clear disincentive for efficient investment and can delay valuable DG uptake.
2. **Inability to recover shared or anticipatory costs:** The incremental cost limit does not allow for pricing that supports forward-looking investment in shared infrastructure. This undermines long-term planning and can lead to under-sized or piecemeal upgrades, which are ultimately more expensive and disruptive for consumers.
3. **Asymmetry with grid-connected generation:** The current pricing framework results in inconsistent treatment between DG and grid-connected generators. Grid-scale generation can benefit from the allocation of shared costs, while DG providers are restricted, distorting competition and investment signals.
4. **Inflexibility in pricing design:** The strict application of the incremental cost limit discourages distributors from implementing more dynamic or cost-reflective pricing approaches. This hampers innovation, including the development of location-specific or time-varying signals that could improve the efficiency of DG deployment.

These problems are interconnected, and collectively they inhibit efficient distributed generation development. More importantly, they risk driving higher long-term costs for consumers by distorting investment decisions, discouraging innovation, and preventing optimal use of the electricity network.

We consider the first-mover disadvantage and the inability to recover shared or anticipatory costs to be the most pressing issues, as they have significant implications for the efficient development of network infrastructure and DG uptake. Addressing these challenges would enable a more flexible, future-focused, and consumer-friendly approach to DG pricing.

In particular, our members have observed that sub-transmission level upgrades are often significant in cost and tend to occur in large step sizes. When multiple large-scale distributed generators (DGs) seek to connect to the same sub-transmission network, a coordinated and shared upgrade approach has, in their experience, resulted in a more technically robust solution and significantly lower cost per MW connected. This reinforces the importance of enabling cost-sharing mechanisms and removing the first-mover disadvantage, as doing so facilitates more efficient investment decisions, supports long-term planning, and ultimately delivers better outcomes for consumers.

Q3. Do you agree circumstances have changed significantly since the DGPPs were introduced, including that there are now far fewer impediments to distributed generation than in the early 2000s?

The EEA agrees that the circumstances have changed significantly since the Distributed Generation Pricing Principles (DGPPs) were first introduced.

The DGPPs were originally designed to remove barriers to DG investment at a time when small-scale renewable generation was in its infancy, with high capital costs and limited uptake. Today, distributed generation is increasingly modular, scalable, and affordable. Technological advances in rooftop solar, battery storage, inverters, and smart energy systems have made DG mainstream and commercially viable at scale.

These changes have reduced many of the original impediments to DG. In parallel, regulatory and network connection processes have become clearer and more streamlined, and visibility over distribution networks has improved. As a result, the core regulatory concern has shifted from “enabling access” to “managing integration efficiently.”

New challenges now face distribution networks and system planners, including:

- **Voltage management and protection coordination** due to bi-directional flows
- **Hosting capacity constraints** as DG clusters in particular areas
- **Fair cost allocation** for use of the network by all users
- **Efficient integration of flexibility** to manage demand and supply dynamically.

These challenges are not adequately addressed by the existing DGPPs, which were developed under different system and market conditions. As the sector decarbonises and decentralises, there is a clear need to revisit the DGPPs to ensure they enable efficient pricing, support innovation, and reflect the value and costs DG imposes or mitigates on the network.

The EEA supports a comprehensive review of the DGPPs to align them with today's electricity system needs and the long-term interests of consumers.

Q4. Do you agree with the assessment of the current situation and implications of incremental cost pricing? If not, why not? What if any other significant factors should the Authority be considering?

Yes, the EEA and our members agree with the Authority's assessment that incremental cost pricing, as applied today under Part 6, does not fully reflect the economic impact distributed generation (DG) has on the network—both positive and negative. Current arrangements can lead to inefficient investment signals and often fail to recognise either the additional costs of accommodating DG or the potential benefits DG can provide when well-integrated.

In reviewing the pricing principles, we encourage the Authority to consider the following additional factors to ensure any future framework supports efficient, fair, and future-ready outcomes:

1. **Interaction with Flexibility Services and Dynamic Pricing:** The evolution of flexibility services markets—including dynamic export pricing—has the potential to incentivise or disincentivise DG behaviours in ways that either support or hinder network efficiency. Pricing signals should work in concert with emerging flexibility mechanisms, not in isolation. There's an opportunity to better coordinate DG pricing with services that support peak demand management, voltage control, and congestion relief.
2. **Distribution-level Congestion and Network Planning:** Incremental cost pricing must increasingly account for localised network constraints and congestion at the distribution level. Without this, the costs of accommodating additional DG in constrained areas may be understated, potentially leading to inefficient connection decisions or deferring more cost-effective network investments.
3. **Support for Aggregator Models and Coordinated DER:** The future electricity system will depend on more sophisticated coordination of distributed energy resources through aggregators and market platforms. Pricing principles should support the emergence of innovative aggregator business models that can efficiently pool and manage DG and other flexible devices to deliver system benefits.
4. **Dynamic and Long-term System Integration Costs:** DG impacts are not always static or immediate. Pricing mechanisms should consider the long-term and evolving costs of system integration—such as the need for greater monitoring, protection upgrades, and operational complexity under high DER penetration scenarios.

   Many of the earlier DG investments were made with relatively long payback periods in mind. Rapid or significant shifts in pricing arrangements risk negatively impacting these existing investments and undermining investor confidence in future DG development. Maintaining regulatory certainty is key to supporting long-term investment decisions.

5. **Fairness, Certainty, and Practical Implementation:** Any pricing reforms should be transparent, feasible to implement, and designed with a fair transition pathway. Many consumers have made DG investment decisions based on existing arrangements, and the sector must maintain trust and provide long-term certainty while transitioning to more efficient pricing.

While we support the Authority's assessment, we urge a broader framing of incremental cost pricing—one that recognises the need for coordination with flexibility markets, enables dynamic congestion management, and supports innovative aggregator-led solutions. This approach will ensure DG pricing principles remain fit for purpose as the system transitions.

In addition, the current incremental cost regime results in a structural cross-subsidy between distributed generators (DGs) and load customers. DGs are not required to contribute to core network costs—such as system operations, business support, and Transpower interconnection charges—that are instead borne entirely by load. This creates an uneven playing field and incentivises large-scale DGs to connect at the distribution level specifically to avoid Transpower connection charges that would apply if they connected directly at grid exit points (GXPs). This creates distortions in cost allocation and increases the financial burden on load customers. At a principles level, DGs and load customers should be treated equitably, with both contributing appropriately to shared and system-level costs.

Q5. Do you agree these are the appropriate options to consider?

The EEA agrees that the four options outlined by the Authority provide a clear and useful framework for assessing the future of distributed generation (DG) pricing. We support the inclusion of a comprehensive overhaul (Option 4) as an important part of the spectrum of potential reforms. This full range of options allows for a thorough examination of both incremental improvements and more transformative changes.

We appreciate the Authority's transparency in presenting the options and their implications, and we welcome the balanced consideration of efficiency, fairness, and implementation practicality. This approach supports informed decision-making by stakeholders and enables robust discussion on the trade-offs involved.

We support the evaluation of options that:

- Improve the alignment of DG pricing with locational and temporal system value,
- Reduce cross-subsidies and encourage efficient investment decisions,
- Enable more consistent and principle-based application across networks, and

- Complement broader regulatory initiatives, such as distribution pricing reform and the development of flexibility services.

As the role of distributed energy resources grows, it is increasingly important to ensure pricing mechanisms are forward-looking, technically sound, and supportive of innovation while maintaining system reliability and fairness. We encourage the Authority to continue engaging with technical experts and industry practitioners to test the feasibility of each option and ensure any reforms are practical, proportionate, and future ready.

Q6. Are there other options the Authority should consider for improving rules about costs that can be recovered from distributed generators?

The EEA welcomes the Authority's focus on ensuring that cost allocation frameworks for distributed generation (DG) remain fit for purpose in a rapidly evolving electricity system. Our members—who work across the electricity supply chain—are seeing increasing volumes of DG seeking connection and are committed to ensuring the regulatory settings support efficient investment, system security, and consumer value.

In addition to the options outlined in the Issues Paper, we encourage the Authority to explore the following areas:

1. **Tiered or staged pricing approaches:** A differentiated approach based on the size and nature of DG—distinguishing between small-scale, mass-market installations (such as rooftop solar) and utility-scale generation—would allow for more proportionate and practical cost recovery mechanisms. These tiers should reflect differences in network impact, connection complexity, and the potential for system service contributions.
2. **Mechanisms for co-investment or cost-sharing in infrastructure upgrades:** Where network upgrades provide long-term shared benefits to both DG and load customers, the Authority could explore frameworks that enable equitable co-investment or cost-sharing. This could help unlock efficient generation in constrained areas and ensure that investment decisions consider the wider system value.
3. **Encouraging cost-reflective and service-based pricing:** Cost recovery should reflect the specific services a DG uses or benefits from—such as export access, voltage support, or use of shared network capacity—rather than applying uniform charges. This supports more efficient decision-making and helps DG proponents understand the actual costs associated with their use of the network.

4. **Incentives or rules that support flexibility-based revenue models:** The Authority could consider enabling pricing mechanisms that reward distributed generators for providing flexibility, such as agreeing to export constraints in exchange for price incentives or connection fee reductions. This approach could support better utilisation of the network while avoiding unnecessary investment.
5. **Allowing regional or network-level flexibility in pricing design:** Given the diversity of network conditions across New Zealand, distributors may require the flexibility to tailor DG-related cost recovery frameworks to reflect local constraints, demand profiles, or asset conditions. A principles-based framework could provide consistency while allowing for regional adaptation.
6. **Clarifying the boundary between connection-related and ongoing operational costs:** Greater clarity around which costs can be recovered upfront at connection (e.g. dedicated assets) versus those that should be recovered through ongoing charges (e.g. shared use or congestion management) would improve transparency and reduce the risk of disputes.
7. **Standardised methodologies or templates:** The Authority could support the development of standardised cost allocation methodologies or templates, co-designed with industry, to improve transparency and consistency in how charges are applied—especially for smaller DG participants.
8. **Alignment with broader flexibility and distribution pricing reforms:** The treatment of DG should be considered alongside related reforms aimed at enabling flexibility and pricing innovation. A consistent and integrated approach can help reduce regulatory friction and better unlock the value DG can provide to the wider system.

The EEA and our members support a future-focused, technology-neutral framework that encourages innovation, efficient investment, and long-term consumer value. We welcome the opportunity to continue engaging with the Authority as it considers reforms in this important area.

Q7. Will new aggregator business models emerge to solve the problem?

Aggregator business models have strong potential to help address the challenges and opportunities associated with distributed generation (DG), particularly by unlocking value from distributed energy resources (DER) and enabling more dynamic and flexible system operation. However, these models are not currently emerging at scale under the existing regulatory settings.

Without pricing and access frameworks that appropriately recognise and reward the flexibility and capacity contributions of DG, business models for aggregators and virtual power plants (VPPs) are unlikely to thrive. Current market signals do not provide meaningful or predictable revenue streams for the value-added services that aggregators can offer—such as load shifting, peak demand reduction, or local network support. Reform of DG pricing principles is essential to unlock these services and support the development of innovative aggregator-led offerings.

While aggregators—whether operating independently or in partnership with retailers, technology providers, or network businesses—could play a significant role in a more distributed, responsive energy system, they cannot fill the gap created by weak or misaligned pricing structures. Emerging business models will need to be underpinned by transparent, efficient, and consistent economic signals that reflect the true system value of DER services.

Furthermore, the role of aggregators needs to be explicitly recognised and supported in the Code. This includes clarity around their obligations, rights to access data and networks, and participation in relevant markets. Without this recognition, there is a risk that aggregators remain marginal players, limiting competition, innovation, and the overall efficiency of the energy transition.

In summary, the EEA considers that aggregator business models will likely emerge as part of the solution—but only if they are enabled through targeted regulatory reform, including revised DG pricing principles and formal recognition of their role within the electricity industry framework.

Q8. Are distribution price signals alternative to, or complementary to contracting?

The EEA considers that distribution price signals and contracting are complementary mechanisms for enabling efficient outcomes from distributed generation (DG). Each plays a distinct but mutually reinforcing role.

Efficient price signals reduce transaction costs, support scalability, and provide broad behavioural incentives — particularly important in mass-market contexts where individual contracting would be impractical. Through well-designed, cost-reflective pricing structures (such as time-of-use or capacity-based pricing), distributors can influence the investment and operational decisions of many customers in a consistent and transparent way.

Contracting, by contrast, is well-suited to more targeted or bespoke arrangements, such as those involving utility-scale DG, large commercial participants, or specific non-network alternatives. It enables distributors to address localised network constraints, voltage support needs, or outage mitigation services that cannot be efficiently managed through pricing alone.

A strong, well-signalled pricing framework enhances the effectiveness of contracts by establishing a common economic baseline that informs investment decisions and negotiations. It also ensures that contracts are layered on top of – rather than in place of – fair and efficient price signals, helping to avoid distortions and cross-subsidies.

Both mechanisms play essential but distinct roles in managing the evolving electricity system. Price signals provide the foundation for scalable, cost-reflective incentives across the mass market, shaping investment and operational behaviour at scale. Contracting offers the flexibility to address specific network needs that price signals alone may not capture. When used together, they create a more adaptive and efficient framework for integrating distributed generation while maintaining network reliability, affordability, and fairness.

Q9. Which, if any of the above options, do you consider would best support efficient pricing for recovery of distribution costs from DG?

In principle, the EEA supports Option 4 – Comprehensive Overhaul of DG Pricing Principles as the preferred approach. This option provides a robust foundation for the efficient recovery of distribution costs from distributed generation (DG), while enabling flexibility and supporting the ongoing evolution of the electricity system.

Option 4 strikes an appropriate balance between flexibility and regulatory clarity, enabling distributors to tailor pricing to local network conditions, while aligning with the broader direction of distribution pricing reform for load customers. It also removes the outdated incremental cost cap, which is increasingly incompatible with modern network planning and the growing role of distributed energy resources. Importantly, it retains consumer protections through clear pricing principles and regulatory oversight, ensuring fairness and transparency.

We also recognise the strengths of Option 3 – Cost-reflective network charges, particularly its focus on efficiency and economic signalling. These principles are essential to guide long-term investment decisions by DG owners and network businesses alike.

We encourage the EA to consider an approach that merges the desirable aspects of both Options 3 and 4—incorporating Option 3's emphasis on cost-reflectivity and efficiency into the broader, more flexible and future-proof framework proposed under Option 4. This could help enable consistent and efficient pricing signals across the system while maintaining practical adaptability.

In summary, the EEA supports a move towards a more comprehensive, principle-based framework that enables cost-reflective, service-based pricing, supports innovation and system optimisation, and maintains confidence in the regulatory framework for all stakeholders.

Q10. Do you agree with the Authority's tentative view on a solution? In particular:

- Should efficient price signals be sent through a revised set of pricing principles?
- Would voluntary guidelines or mandating through the Code be the best approach?
- Should we rely on the distribution pricing principles outside the Code or codified new pricing principles for DG? Why?

The EEA agrees with the Authority's direction that revised pricing principles are essential to support more efficient distributed generation (DG) pricing and integration. A clearer framework is needed to send accurate price signals that reflect both the costs DG can impose on networks and the potential benefits it can provide.

1. Efficient price signals through revised pricing principles: Yes, the EEA supports the use of revised pricing principles that better reflect efficient cost allocation and system value. These should:
    - Recognise that DG can have both positive and negative impacts on the network and wider electricity system,
    - Enable technology-neutral, location-specific, and scalable approaches where feasible,
    - Provide a consistent basis for pricing distributed energy resources (DERs) more broadly, including batteries and flexible load.

    Clear, fit-for-purpose principles will guide electricity distribution businesses (EDBs) and stakeholders toward more transparent and economically efficient pricing outcomes.

2. Voluntary guidelines vs Code-based approach: We recommend that the revised principles be codified in the Code, rather than maintained as voluntary guidelines. Our view is that codification:
    - Supports consistency and sector-wide accountability,
    - Provides regulatory certainty to investors and stakeholders, particularly in a rapidly evolving DER environment,
    - Ensures that all EDBs prioritise and allocate resources to implement reforms in a timely and coordinated manner,
    - Builds on the positive experience with the codified distribution pricing principles for load, which have provided a more effective foundation for change than earlier voluntary approaches.

While we acknowledge the benefits of flexibility and innovation, the current pace and variability of progress in DG pricing across the sector suggest that a non-binding approach may not deliver the outcomes or momentum required.

3. Single set of pricing principles or separate DG-specific ones: The EEA supports building from the existing codified distribution pricing principles rather than creating a wholly separate set for DG. A single, coherent framework ensures alignment across pricing for both load and generation, avoids unnecessary complexity, and reflects the reality that many customers will both import and export energy.

   However, we would welcome supplementary guidance or explanatory material tailored to DG pricing – including case studies, practical approaches, and worked examples – to support consistent and efficient implementation.

In summary, the EEA supports the Authority's proposed direction and recommends:

- Codifying revised DG pricing principles in the Code to ensure consistency, certainty, and timely reform
- Retaining a single integrated pricing principles framework that applies to both load and DG, with targeted guidance where needed
- Prioritising clear and efficient price signals that reflect DG's true costs and benefits to the system.

We look forward to collaborating with the Authority and sector participants to refine and implement these changes effectively.

Q11. Are there any unintended consequences from removing the existing DGPPs?

- Do you agree with the risks we have identified, and our assessment of them?
- Do you think there are any other risks we should consider associated with the removal of the DGPPs?
- Do you have any information that would allow the Authority to better assess such risks?

The EEA agrees with the Authority's assessment that the risk of perverse or distortionary outcomes from removing the existing Distributed Generation Pricing Principles (DGPPs) is low—particularly if the removal is accompanied by the introduction of updated, codified pricing principles that better reflect the current and emerging electricity system context.

Mitigating Transitional Risks:

While the DGPPs may no longer be widely relied upon in pricing methodologies, their removal could create transitional uncertainty. These risks can be effectively mitigated by:

- Providing clear implementation timelines and transitional protections for existing distributed generation customers, especially where pricing arrangements were developed under the DGPP framework.
- Encouraging greater pricing transparency across distributors to support consistent application of cost-reflective principles and avoid regional disparities.
- Supporting dispute resolution mechanisms during the transition period to manage any disagreements that arise from changes in pricing methodologies.
- Publishing draft pricing principles well in advance of the DGPPs' removal to provide clarity on regulatory intent, allow time for industry feedback, and ensure continuity of investment confidence.

Additional Risks to Consider:

In addition to those noted in the Issues Paper, the EEA encourages the Authority to consider:

- The potential for regulatory uncertainty in the transition period between the removal of the DGPPs and the full adoption of new principles. Clear communication and phased implementation can help avoid uncertainty for distributed generation investors and network planners.
- Loss of reference guidance for smaller or less-resourced distributors, who may still find value in the existing DGPPs as a foundation for applying pricing methodologies in line with good regulatory practice.

The EEA is currently undertaking initiatives such as Flextalk and the National and International Scan of Flexibility Projects as well as engaging with members and other stakeholders such as Flexforum. These provide insight into how distributed generation and flexible demand resources are being integrated into network planning and operations. The lessons emerging from these pilots can inform more contemporary pricing principles that support efficient investment, fairness, and system flexibility.

In conclusion, the EEA supports the removal of the existing DGPPs, provided this is managed alongside the introduction of updated principles that reflect the modern electricity system and facilitate a smooth transition. Doing so will maintain investment confidence, support pricing consistency, and advance New Zealand's electrification and decarbonisation goals.

Q12. Do you agree market and regulatory settings provide efficient incentives for DG reducing or avoiding transmission costs? What, if any, other significant factors or options should the Authority consider?

Yes. The EEA agrees with the Authority that the existing wholesale market arrangements, including nodal pricing and scarcity pricing, provide efficient and technology-neutral incentives for distributed generation (DG) to contribute at the transmission level. These mechanisms help ensure that DG is rewarded when it delivers genuine value in relieving transmission constraints or deferring grid investment. On that basis, we do not believe further intervention at the transmission level is currently warranted.

However, we consider that more attention is needed at the distribution level, where price signals and integration frameworks remain underdeveloped. The lack of clear, consistent locational signals, combined with limited transparency on hosting capacity and network constraints, makes it difficult for DG providers to identify where their investments can offer the most system value. This limits the potential for efficient and scalable DG adoption that supports both local and system-wide outcomes.

To support the ongoing evolution of DG and other distributed energy resources, the Authority may also wish to consider the following:

1. **Monitoring Grid Support Contracts:** Transpower's use of Grid Support Contracts may increasingly interact with emerging DG and flexibility markets. We encourage the Authority to maintain a watching brief to ensure these arrangements complement broader market development and do not distort incentives.
2. **Distribution Pricing Reform:** Continued focus on reforming distribution pricing and improving cost reflectivity will be critical to providing meaningful investment signals to DG and enabling more efficient integration.
3. **Flexibility Services and Future Access Regimes:** As New Zealand moves toward a more dynamic and distributed electricity system, pricing frameworks should evolve to support flexible, service-based models for network access and optimisation.
4. **Planning Coordination and Information Transparency:** Improved alignment between transmission and distribution planning—along with enhanced visibility of local constraints—will support better decision-making by both DG developers and network operators.

Transmission-level incentives appear to be operating effectively, and we support maintaining the current approach in that part of the system. The more pressing opportunity is to strengthen distribution-level arrangements to better support the efficient integration of DG. By improving price signals, transparency, and coordination across system levels, we can unlock greater value from distributed resources and ensure they contribute meaningfully to resilience, decarbonisation, and long-term consumer benefit.

Contact

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