Submission to the Energy Competition Task Force

By email to: taskforce@ea.govt.nz

John Hilhorst

Thank you for the opportunity to participate in this consultation on proposals to empower electricity consumers to better control their energy bills.

I strongly support the aim of providing consumers with more options and believe that flexible, distributed generation can substantially help grow the electricity supply, drive down costs for everyone, and increase energy resilience.

Introduction

In 2022, we completed energy upgrades for our home. This included installing 21 rooftop solar panels and a 20-kW domestic battery, replacing our diesel burner with an air-to-water heat exchange unit to power our hot water supply and in-floor and radiator home heating, and replacing our ICE vehicle with a BEV.

Our primary motivation was to reduce our carbon emissions, and we are now proudly carbon-zero on a net annual use basis despite the relatively high latitude and cold winters of our Queenstown location.

We also greatly value the increased energy resilience for our domestic needs and employment from our two home offices. We stay comfortable, online, and productive while those around us twiddle their thumbs during an electricity outage. This resilience mitigates the risks of the Queenstown Lakes District's challenging weather and topography, which make it prone to power outages. Also, the district will inevitably endure the consequences of an AF8 that is currently overdue, with just a single 110 kV AC branch line supplying it.

We believe an improved financial return on domestic energy upgrades would greatly incentivize and accelerate private household investment in them.

A key issue undermining such investment in New Zealand is the significant delta between the household buy-sell price for electricity. Our solar energy generation cycles are seasonally and daily out of sync with domestic household energy demand. Our solar panels can produce plenty of summer energy, but we have low domestic demand during this time due to mild temperatures and long daylight hours. In winter, we can make less solar rooftop energy, but we have high energy demand to combat the dark and cold when the sun goes down.

This contrasts with, for example, Australia, where home solar production and energy demand are aligned in both the season and daily cycles. Domestic energy consumption peaks during hot summer afternoons as households switch on their air conditioning, while there is less demand for heat during mild winters.

With an Australian household able to directly use its solar energy production as a substitute for grid power, its effective return per kilowatt produced more closely aligns with the market price it would otherwise pay.

It's not so easy for our New Zealand households. We produce substantially more energy during the summer months, when we need it less, than we can in winter. While a battery helps smooth the daily cycle, allowing us to consume at night what we produce during the day, the battery price doubles the investment needed and doesn't help resolve the summer–winter mismatch between production and demand.

In our case, we export most of what we produce during the summer months to the grid, even while powering our car entirely from our solar panels. Yet, in winter, our solar panels produce only 16% of our energy demand because of shortened daylight hours, the sun's low angle, and our increased heating requirements.

Consequently, we still purchase a significant quantity of electricity even though we produce more than we use annually and are a net contributor to the National Grid.

This seasonal solar cycle is no problem from a national or macro perspective. Using additional solar over summer helps the hydro lakes recharge, so there is a national benefit from any increase in household solar production.

However, it does cause problems at the household level, inhibiting investment in rooftop solar.

In our case, parity between the buy-sell prices would encourage us to invest a further $28,333 on additional solar panels, which would more than double our current production. As we pay an average of 38 cents kWh for our shortfall in winter but receive only 7 cents kWh for our surplus in summer, this cyclic effect costs us about $850 each year. From our return on investment perspective, putting solar panels on our roof to save $850 is equivalent to a $28k investment we'd need to produce the cash to pay an annual cost of $850.

> [We don't have a mortgage and target an average 7% nominal return on our investment portfolio, which amounts to a 3% real return after tax and allowing for inflation.]

The enormous potential value of distributed power generation impels us to optimise the policy and financial incentives for households, farms, and businesses to invest in it. This action would support increased sustainable power generation, reduce the need for National Grid investment, and enhance community resilience.

In the following submission, I provide specific feedback on the Energy Competition Task Force's initiatives presented in the consultation papers regarding:

1. Requiring distributors to pay a rebate when consumers supply electricity at peak times (Initiative 2A)
2. Time-varying retail pricing for electricity consumption and supply (Initiatives 2B and 2C)
3. Distributed Generation Pricing Principles

I believe these initiatives have the potential to significantly improve how our electricity system functions by better incentivizing efficient investment and operation of distributed energy resources, providing consumers with more options to manage their electricity costs, and supporting the transition to a more renewable and resilient electricity system.

Initiative 2A: Requiring distributors to pay a rebate when consumers supply electricity at peak times

Q1. Do you agree with the problem definition?

I agree with the problem definition outlined in the paper. There is a missing distribution price signal for injection when it provides network benefits. While some prices for using distribution networks include components that signal when consumption contributes to network costs, there is generally no distribution incentive for consumers to inject into the network, even when this would benefit the network by reducing pressure on constrained areas.

The current distributed generation pricing principles (DGPPs) do not appear to create effective signals for mass-market DG. With only Orion and Aurora Energy offering export credits, most distributed generators are not being rewarded for the value they can provide to networks through injection at strategic times.

I agree that the challenges in implementing these price signals relate to the complexity of determining when and where injection provides value versus when it might add costs. However, as more consumers install distributed generation, particularly flexible resources like batteries, having these signals becomes increasingly important for system efficiency.

Q2. Do you agree with these principles?

I support the proposed principles for pricing injection from mass-market consumers. The principles appropriately focus on:

- Identifying locations where injection can provide network benefits
- Enabling payments for injection that provide these benefits
- Sharing the network benefits with consumers
- Considering practical implementation aspects, including uptake incentives and network stability

These principles strike a good balance between prescriptiveness and flexibility, allowing distributors to implement approaches that work for their specific network characteristics while ensuring consumers receive appropriate rewards for beneficial injection.

Q3. Principles for mass-market vs larger consumers?

I believe the principles should initially focus on mass-market consumers as proposed. Mass-market consumers currently face the greatest gap in pricing signals. Larger consumers and generators often have bespoke contractual arrangements that can already incorporate the value of their injection.

However, I also believe that, in the longer term, the principles guiding pricing for all distributed generation should be consistent, regardless of size. This would suggest that the broader review of the DGPPs should align with these principles once implemented. Having fundamentally different approaches for different generation scales could create inefficient investment signals.

Q4. Applicability to all mass-market DG types?

I agree that the principles should apply to all mass-market DG, including inflexible generation. While solar without batteries may not typically provide injection at peak times in most networks, there are circumstances (such as networks with summer irrigation peaks) where even inflexible resources can provide significant value. The key is that rebates should reflect the actual benefit provided, which may be minimal for some technologies but substantial for others.

Q5. Direction of guidance for principles?

The proposed guidance direction seems appropriate and comprehensive. I particularly support:

- Using forecast network constraints to identify where injection can provide benefits
- Providing rebates only during periods that affect future demand forecasts (with some flexibility to increase stability of signals)
- Differentiating rebate levels based on the present value of avoided network costs
- Sharing benefits between consumers and distributors
- Considering how retailers will pass through the price signals
- Addressing potential risks of over-incentivizing injection

Q7. Should principles be in the Code?

Yes, I strongly support incorporating these principles within the Code rather than making them voluntary. Mandating them through the Code will ensure distributors implement them in a timely manner. The history of the distribution pricing principles has shown that some distributors can be slow to respond to voluntary guidance. Given the urgency of establishing these signals as we transition to a more distributed energy system, Code incorporation is appropriate.

Q8. Implementation timeline?

I agree with the proposed implementation timeline for April 2026. This provides sufficient time for distributors to analyse their networks, identify constrained areas, and develop appropriate price structures while still bringing the benefits forward relatively quickly. It also aligns with the distributors' pricing years, simplifying implementation.

Q9. Balance between price-based and contracted flexibility?

The proposal strikes an appropriate balance between encouraging price-based flexibility and contracted flexibility. Price-based flexibility through rebates provides broad signals to the market that can incentivize DG investment and operation in beneficial ways. However, contracted flexibility offers more certainty for network planning and can target specific network issues with greater precision.

By establishing price-based signals while allowing distributors to continue pursuing contracted flexibility solutions, the proposal creates complementary mechanisms that can work together to maximize distributed resource value.

Q10. Wealth transfers?

I agree that the proposal will likely lead to relatively minor wealth transfers in the short term, and will lead to cost savings for all consumers in the longer term. While there may be some redistribution of costs as rebates are offered to those who can inject at valuable times, these will be offset by reduced network investment requirements over time, benefiting all consumers.

The targeted nature of the principles-based approach should limit wealth transfer effects compared to less targeted approaches, ensuring that rebates are only paid where they reflect genuine network benefits.

Initiatives 2B and 2C: Time-varying retail pricing for electricity consumption and supply

Q1. Issues worthy of attention?

The limited availability of time-varying price plans for both consumption and injection is a significant gap in the current market. Despite New Zealand's high smart meter penetration (93%), many consumers do not have access to retail plans that would allow them to benefit from shifting consumption or targeting injection to times that create value for the system.

The combination of factors identified by the Authority—including low awareness, low switching rates, reduced retail competition for specific customer segments, and retailers not facing the true costs of peak contribution—appears to be creating market failures that intervention can effectively address.

Q2. Best option to address issues?

The Authority's proposed four-part approach is the most comprehensive and balanced of the options presented. It appropriately addresses multiple aspects of the problem:

- Ensuring time-varying plans are available from major retailers
- Promoting these plans to consumers who would benefit
- Monitoring outcomes and providing transparency
- Ensuring distributors and retailers use accurate data for billing

Relying solely on the status quo would mean continued slow progress, while more prescriptive approaches risk stifling innovation and creating unintended consequences. Making time-varying plans the default would risk negative impacts on consumers who cannot respond to price signals. The proposed approach balances immediate action with flexibility for the market to continue evolving.

Q3. Combined consumption and injection time-varying plan?

I believe retailers should be encouraged but not required to offer a combined plan with time-varying prices for both consumption and injection. A combined plan would provide the strongest and most coherent price signals to consumers with distributed generation. However, requiring this could unnecessarily constrain retailers' ability to develop diverse offerings that meet different consumer needs. Some consumers may benefit from time-varying consumption prices without having generation capability, and vice versa.

Q4. Design requirements?

The design requirements provide a good framework that balances prescription and flexibility. They appropriately require prices to reflect economic costs and benefits while providing financial benefits to customers proportional to how their patterns reduce retailer costs. The inclusion of "transaction costs, consumer impacts and uptake incentives" provides the necessary flexibility to design plans that will work in practice.

Q6. Which retailers should be captured?

I support the Authority's preferred option of applying the requirements to retail traders with more than 5% market share. This threshold appropriately captures the largest retailers who serve the majority of consumers (83%) while avoiding placing undue compliance burdens on smaller retailers who may already be offering innovative plans or who lack the scale to efficiently comply.

Q7. Implementation timeframe?

I support the proposed implementation date of January 1, 2026. While April 2026 would align better with distributors' pricing resets, implementing the new plans sooner brings forward benefits to consumers. Since this is a new offering rather than a price change, alignment with distributors' pricing cycles is less critical.

Q8. Promotion requirements?

The promotion requirements are an essential part of the proposal. Without active promotion, many consumers who would benefit from time-varying plans might not be aware of or consider them. The requirements to advertise the plans prominently, provide personalized information about potential benefits based on consumption history, and follow up after one year are appropriate and proportionate.

Q10. Sunset provision vs. review provision?

I support including a sunset provision rather than a review provision. A sunset provision after five years provides certainty about the temporary nature of the intervention while still allowing sufficient time for the market to develop. This avoids the risk of regulatory inertia that can occur with review provisions. The Authority can always extend the arrangements through a further Code amendment if the review shows continued need.

Q12. Half-hourly data use requirement?

I strongly support Part 4 of the proposal to require that consumers are assigned to time-varying distribution charges where available and that retailers provide half-hourly data to distributors for settlement. This is a critical foundation for efficient pricing throughout the electricity system. Without accurate data flows, time-varying price signals cannot function properly. This requirement will ensure retailers face the true costs of their customers' consumption patterns, creating appropriate incentives to manage demand.

Distributed Generation Pricing Principles

Q1. Definition of incremental cost

The definition of incremental cost in the Code is overly broad and should be more tightly defined to include only network costs and exclude consequential costs relating to factors like frequency keeping and voltage support. The current definition creates uncertainty and allows for inconsistent application across distribution networks.

Limiting the definition to network costs would provide greater clarity and certainty for distributed generators, likely leading to more timely generation build and lower energy costs. Network costs are more directly attributable to specific connections, whereas system-wide costs like frequency keeping are more appropriately addressed through wholesale market mechanisms or ancillary services.

Q2. Problems with incremental cost limit

I agree with the problems identified with the incremental cost limit. Particularly concerning is how it:

- Discourages efficiently sized investments that could accommodate future demand
- Creates first-mover disadvantage that can prevent efficient investment
- Provides weak incentives for distributors to dedicate resources to DG
- Prevents cost-reflective pricing approaches that use approximations

These issues can lead to inefficient investment decisions and higher long-term costs for consumers.

Q4. Assessment of incremental cost pricing

The assessment of current incremental cost pricing is accurate. The rule may have been appropriate when DG was relatively uncommon and there were significant barriers to entry, but circumstances have changed dramatically. Now, with the improved cost-effectiveness of technologies like solar and battery storage, DG is becoming more widespread and developers face different challenges.

The learning and resource constraints faced by distributors in managing new DG are now bigger impediments than asymmetries in bargaining power. The incremental cost rule is increasingly becoming a barrier to efficient network development rather than a protection for DG.

Q9. Best option for distribution cost recovery

Option 4 (Comprehensive overhaul of DG pricing principles) would best support efficient pricing for recovery of distribution costs from DG. A principles-based approach allows distributors to develop pricing methodologies that reflect their specific network circumstances while ensuring they adhere to economic efficiency principles.

The approach should draw on the existing distribution pricing principles for load customers, which have proven effective in guiding more cost-reflective pricing. This would provide consistency across load and generation pricing while allowing necessary flexibility.

Q10. Authority's tentative view

I agree with the Authority's tentative view on a comprehensive overhaul of the DGPPs. Specifically:

- Efficient price signals should be sent through a revised set of pricing principles that maintain flexibility while ensuring economic efficiency.
- Codifying these principles in the Code would be preferable to voluntary guidelines. The experience with distribution pricing principles suggests that having binding requirements results in faster, more consistent implementation.

The approach should be consistent with the principles being developed for mass-market consumers with DG, creating a cohesive framework across all scales of distributed generation.

Q12. Market incentives for DG reducing transmission costs

I agree that current market and regulatory settings generally provide efficient incentives for DG reducing or avoiding transmission costs. The wholesale market properly prices locational value through nodal pricing, and DG that reduces grid reliance already benefits from this pricing structure.

Conclusion

The initiatives proposed by the Energy Competition Task Force represent significant progress toward a more efficient, consumer-focused electricity system. Together, they will help establish appropriate price signals for distributed energy resources, enable consumers to better manage their electricity costs, and support New Zealand's transition to a more renewable, resilient, and distributed electricity system.

The principles-based approach to distribution rebates for injection, combined with requirements for retailers to offer time-varying plans and improvements to data use for billing, create a comprehensive package that addresses key gaps in current market arrangements. These changes will help unlock the full potential of distributed energy resources to benefit all electricity consumers.

I support the implementation of these initiatives with the refinements suggested in my responses to the specific consultation questions.