Orion

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Electricity Authority
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Submitted via email to taskforce@ea.govt.nz

Introduction

1. Orion welcomes the opportunity to submit on the recent consultation papers. Given the interdependencies between these papers, released on 12 February 2025, this submission is combined to cover the following consultations:
   - Package Two initiative 2A – **Requiring distributors to pay a rebate when consumers supply electricity at peak times ("2A")**
   - Package Two initiatives 2B & 2C – **Improving pricing plan options for consumers: Time-varying retail pricing for electricity consumption and supply ("2BC")**
2. Orion owns and operates the electricity distribution infrastructure in central Canterbury, including Ōtautahi Christchurch city and Selwyn District. Our network is both rural and urban and extends over 8,000 square kilometres from the Waimakariri River in the north to the Rakaia River in the south; from the Canterbury coast to Arthur's Pass. We deliver electricity to more than 229,000 homes and businesses and are New Zealand's third largest Electricity Distribution Business (EDB).
3. Orion notes that the Energy Competition Task Force ("Task Force") was explicitly established to address wholesale market volatility and unprecedented spikes in wholesale prices. As stated in its Terms of Reference,[1] the Task Force was formed in direct response to "*fuel scarcity combined with lag in new investment in generation [which] has created conditions leading to unprecedented spikes in wholesale prices*." The Task Force was intended to "*urgently consider the complex factors underlying wholesale prices*."
4. However, Orion observes that the Task Force's Package Two initiatives 2A and 2BC are primarily focused on the retail/distribution side of the market and will have minimal impact on the wholesale market issues that motivated the Task Force's creation. While these initiatives may have merit in their own right, they should be positioned as complementary to, not substitutes for, more direct interventions in the wholesale market. To comprehensively address "*the current issues across the energy system,*" it would be valuable to also consider measures that target the fundamental supply-side issues in the wholesale market.

[1] Terms of reference for the Energy Competition Task Force

5. This misalignment between the Task Force's Terms of Reference and these proposed initiatives is particularly concerning given industry acknowledgment that New Zealand faces immediate challenges with supply adequacy. At the Downstream 2025 conference, Contact Energy Chief Executive Mike Fuge highlighted that the country is "*paying the price for a lack of investment*" and that "*the immediate issue is the lack of development in the gas market and a shortage of fast-start generation capacity*."[2] Similarly, Transpower's James Kilty warned that looking back over the past six or seven years, "*you can see the Swiss cheese slices lining up and all the holes lining up*" to create the current supply challenges.[3] These industry perspectives reinforce initiatives focused primarily on mass-market consumers, while valuable in principle, cannot substitute for addressing the fundamental wholesale market issues that motivated the Task Force's creation.

6. Orion submits that to meaningfully address Aotearoa's energy system challenges, the Task Force should prioritise initiatives that can truly move the dial on security of supply and affordability. The current proposals, though well-intentioned, risk implementing complex requirements with questionable benefits – for both consumers and distributors. Orion recommends that the Task Force focus on more transformative approaches that address fundamental market structures, incentivise investment in flexibility-enabling technologies, and create the regulatory frameworks needed for a more responsive electricity system. Specifically, Orion recommends:

    a. That the Task Force work with the industry to develop standardised flexibility service contract templates for distributors, traders and aggregators. This could create a more liquid market for flexibility services with greater participation than individual rebate mechanisms could achieve.

    b. That the Task Force should prioritise establishing clear regulatory frameworks for Virtual Power Plants that enable aggregation of distributed energy resources across networks, focus on bringing aggregators into the Electricity Industry Act 2010 as Industry Participants, and developing corresponding obligations in the Electricity Industry Participation Code 2010 ("Code"). This would allow small-scale generation assets to collectively provide meaningful network benefits through coordinated operation, rather than relying on the limited impact of disaggregated individual installations.[4]

    c. That the Task Force establish a national register of flexibility service providers and their capabilities to increase market visibility, facilitate competition, and help match flexibility needs with available resources more efficiently than disconnected bilateral arrangements.[5]

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[2] Costs must come down, leaders, Watts say (EnergyNews.co.nz)
[3] Industry failing to deliver affordable transition (EnergyNews.co.nz)
[4] VPP commercialisation a small factor in SolarZero collapse
[5] This aligns with our submission to the Electricity Authority's proposed 'guidance on distributor involvement in the flexibility services market.' Developing this register would allow EDBs to easily and quickly identify flexibility traders operating in New Zealand, and better understand their resources.

d. That the Task Force advocate for MBIE or EECA to implement a targeted incentive programme for technologies that enable flexibility services.[6] This could include capital grants, subsidies, or rebate schemes specifically for battery storage systems, smart inverters, home energy management systems, and other technologies that enable active participation in flexibility markets.[7]

e. That the Task Force advocate for MBIE to update Building Code requirements to include "energy management system" capabilities in new construction. This approach would ensure that all new buildings constructed in New Zealand become valuable "network" assets that enable flexibility rather than passive consumers, creating a foundation for a more responsive electricity system at minimal marginal cost during construction.

Executive summary

7. While we support the overall intent of the Task Force's direction to increase security of supply and lower costs to mass market consumers through more small-scale distributed generation and time-of-use plans, we have significant concerns about the implementation approach, practical feasibility, and potential unintended consequences of the proposals as they are currently drafted.

8. Orion is currently trialling a network-wide two-way power tariff to gauge interest, and to test consumer uptake. Our network-wide approach recognises that consumers should be rewarded for injection where network benefit exists, while balancing implementation practicality with consumer value. This approach provides a consistent, transparent signal that is straightforward to implement, though it necessarily results in a lower tariff than a highly targeted location-specific signal. This balanced approach allows us to test market readiness and consumer response before implementing more complex mechanism.

9. The Task Force's 2A proposal, by contrast, emphasises highly granular, location-specific rebates that potentially deliver minimal consumer benefits, while introducing complexity disproportionate to the value it would create for both networks and consumers. Our key concerns, which we outline in our response, are in the following areas:

   a. **Regulatory concerns**: The proposed Code amendment for initiative 2BC employs an override clause, "despite anything else in this Code or in a distributor agreement," which contradicts the Government's expectations for good regulatory practice. Regulations should be "*well-aligned with existing requirements in related or supporting regulatory systems through minimising unintended gaps or overlaps and inconsistent or duplicative requirements*."[8] Rather than properly assessing the regulatory change required, and properly integrating those changes into the Code, this approach creates challenges by effectively creating a parallel set of requirements that override existing provisions without clear delineation. This may complicate compliance, create uncertainty for distributors and other market participants, and appear to prioritise expedient implementation over enduring, coherent, quality, and navigable industry regulations.

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[6] Orion notes that EECA and Counties Energy have started a project to retrofit "smart" capability into existing consumer devices across more than 500 homes in the Karaka Harbourside subdivision to deliver 1 megawatt of demand flexibility. See here for further details: Energy News, EECA, Counties retrofitting homes for DSO capability.
[7] A local example shows that upfront cost reduction is effective at driving consumer adoption. The end of the Clean Car discount saw EV sales decline, with the market share of new vehicles sold monthly dropping from a high of 50.76% (December 2023) to a low of 5.49% (January 2024). This is despite EVs, in some cases, being cheaper post-rebate.
[8] Government Expectations for Good Regulatory Practice, page 2.

b. **Implementation barriers**: The drafted proposal requiring locational, or asset-specific pricing, would create substantial implementation challenges for distributors and retailers, requiring significant system changes, data processing capabilities, and analytical resources that many participants do not currently possess. Network constraints are dynamic and varied, existing across different network levels (LV, MV, HV), and creating location-specific rebates introduces significant complexity. With approximately 5,800 distribution substations in Orion's network alone, implementing granular pricing would create an untenable number of pricing categories and potential equity issues between consumers. Additionally, the proposal cannot effectively address network constraints in the timeframes needed. Our Lincoln Flex Trial demonstrated that even with substantial incentives (51-cent buy-back rates), customer investment in flexibility resources to enable participation may not be able to scale quickly enough to defer near-term network investment. [9]

c. **Consumer and network value proposition**: The Task Force's own analysis indicates that residential consumers would receive minimal monthly rebates ($0.00 – $0.72).[10] Given that residential consumer solar and battery systems typically range from $22,000 to $37,000, or more, these rebates are likely insufficient to meaningfully influence investment decisions or provide sufficient real value for flexibility suppliers to package alongside their wider offerings. Additionally, this creates a challenge where meaningful network benefits only materialise when sufficient distributed generation penetration is achieved within constrained network areas, yet this penetration is unlikely to develop in response to minimal rebates.

d. **Flexibility market impacts**: The rebates proposed in initiative 2A risk undermining the development of more sophisticated flexibility services markets that could deliver greater network benefits at scale through aggregation and targeted response mechanisms. Flexibility Stakeholder research during the Resi-Flex project revealed a desire for commercial mechanisms from EDBs to reflect real network needs and desired responses, and the importance of flexibility stakeholders in packaging those signals into simple solutions of the end customer, rather than expecting direct EDB-to-consumer price signals.[11] Creating consumer expectations of rebates for all exports during peak times may hinder the development of more efficient, and effective, aggregator models. The size of the forecasted rebates suggests that aggregation and coordination through flexibility service providers would be better positioned to capture higher value, but the Task Force's proposal may inhibit the development of this market by fragmenting incentives across individual consumers rather than enabling coordinated responses at scale.

10. We have reviewed the consultation paper, and our specific responses to the questions posed by the Task Force as well as other feedback we consider appropriate to the consultation are set out in Appendix A (2A) and Appendix B (2BC).

11. Orion supports the ENA's submission in principle.

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[9] EnergyNews - Economy challenged Lincoln non-network solution

[10] 2A Consultation Paper, paragraph A.9, page 40.

[11] https://www.oriongroup.co.nz/assets/Your-energy-future/Resi-Flex-Public-Report-Release-2023.pdf

Response to initiative 2A – Requiring distributors to pay a rebate when consumers supply electricity at peak times.

12. The Task Force should be aware that the proposal, as drafted, is unlikely to deliver significant system or network benefits at the current penetration levels of consumer distributed generation. Orion submits that it recognises the Task Force's intent to reward consumers, and agrees that consumers should be rewarded for injection where there is network benefit. Orion sees value in signalling that we will reward consumers for export at a network-wide level. However, we recommend that this initiative is not progressed as drafted by the Task Force for the reasons detailed below:

Problem definition and approach

13. The Task Force asserts that fixing "*missing price signals*" would yield considerable benefits in reducing distribution network investments, referencing Boston Consulting Group's estimate that "*more than $20 billion will need to be invested in distribution networks every decade until 2050*."[12] While Orion acknowledges that pricing reform can optimise existing infrastructure use (e.g. by reducing peak demand and shifting demand into other periods), they cannot fully eliminate the need for capacity expansion. Even with perfect price signals, until sufficient penetration of mass market consumer distributed generation is achieved, the fragmented nature of individual consumer decisions cannot effectively coordinate to address network constraints at the scale or timing required to meaningfully defer major infrastructure investments. This indicates there may be a more complex relationship between small-scale distributed generation and network investment than has been fully explored in the consultation document.[13]

14. Furthermore, Orion submits in support of a recent report from Boston Consulting Group, which found that to deliver "*the infrastructure needed for the energy transition, grid* [and distribution network] *companies must substantially increase spending on their networks*." The report found that to align with the International Energy Agency's Net Zero Emissions scenario, "*average annual investment worldwide in transmission and distribution networks needs to be 88% higher from 2020 to 2030 than it was from 2012 to 2021*." Investment is needed not only to help "*grid* [and distribution] *compan*[ies] *cope with more renewable energy sources and great electrification on the demand side, but also to enable them to replace and upgrade ageing infrastructure*."[14] Growing electrification of transport, heating, industry, and new data centres, hydrogen plants, and other future needs, will substantially increase demands on distribution networks across Aotearoa, requiring capacity expansion regardless of mass-market consumer distributed generation penetration.

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[12] 2A Consultation Paper, paragraph 4.10, page 13.

[13] In addition, our understanding of Australia's experience with integrating significant amounts of mass-market distributed generation suggests that while it can contribute to deferring some traditional network investment, they also necessitate new types of investments to manage grid stability and integration. For example, the Australian Energy Market Operator had to increase grid interventions from 6 in 2016 to 321 in 2020, partly due to the impact of variable generation and distributed energy resources (Integrating distributed energy resources in the electricity grid (Engineers Australia)).

[14] Delivering the Energy Transition Will Come Down to the Wires, Boston Consulting Group, pages 4-5.

15. Orion submits that the Task Force's statement that "*even if more injection from mass-market consumers only reduced or deferred a small proportion of this investment, it would still result in substantial savings*" overlooks the practical realities of network planning and investment decisions. As demonstrated in our Lincoln Flex Trial, achieving even modest levels of participation required substantial incentives far beyond what is contemplated in this proposal. The scale required to actually defer network investments would necessitate participation rates and response capabilities that are simply not achievable through the proposed rebate mechanism.

16. Orion submits that the Task Force's emphasis on the August 2024 high wholesale prices as justification for this proposal[15] appears to create a false equivalence between distribution-level rebates and wholesale market issues. The flexibility required to address gas shortages and low lake levels operates at a fundamentally different scale and timeframe than what residential solar and battery systems can provide through distribution pricing signals. This suggests an opportunity to more comprehensively address the interventions that will meaningfully address New Zealand's energy challenges.

Consumer and network value proposition

17. Orion submits that the Task Force's analysis shows minimal monthly distributor rebates to consumers ($0.00 - $0.72, an average of $0.43).[16]

18. Orion submits that as solar + battery systems cost between $22,000 and $37,000 (based on recent quotes gathered by Orion staff from three providers), these rebates likely will not meaningfully influence investment decisions by mass-market consumers. The apparent disconnect between the scale of investment required, and the proposed reward, undermines the Task Force's assertion that "*customers will generally choose the size of their DG investment in response to price signals*."[17] A monthly rebate that amounts to less than $1 per month cannot reasonably be expected to influence a $22,000+ investment decision.

Flexibility services market development

19. Orion submits that the size of the forecasted rebates suggests that aggregators, or other similar flexibility services market providers, would be better positioned to capture higher value by coordinating responses across multiple consumers. The current approach could be strengthened by more explicitly recognising that the future of distributed energy resources should lie, not in fragmented individual consumer responses to minimal price signals but be enabled through sophisticated aggregation platforms that can deliver coordinated, reliable responses at scale. Consideration of how the proposed rebate mechanism might interact with the development of more effective market solutions would be valuable.

20. Orion submits that our experience with flexibility trials demonstrates the practical challenges in this space. As part of our Lincoln Flex Trial, we sought to unlock 500kW of residential consumer demand response via solar + batteries injecting during peak times. Despite offering significant incentives, we saw relatively slow uptake, and Ecotricity were only able to recruit approximately 0.72% of households in the target area.

[15] 2A Consultation Paper, paragraph 4.13, page 14.
[16] 2A Consultation Paper, Table 5, page 40.
[17] 2A Consultation Paper, paragraph 4.9, page 13.

21. Orion submits that if these rebates were deployed to mitigate real constraints and attempt to defer network investment, a tension would arise between two distinct objectives that require different approaches. Similar to our time-of-use consumption pricing that provides network-wide signals, network-wide injection pricing has value. However, the Task Force proposal appears to conflate two separate objectives:

   a. targeted deferral of specific network investments through non-network solutions (which typically requires location-specific flexibility services), and

   b. establishing broader price signals to incentivise export (which is best achieved through pricing).

22. A single mechanism cannot effectively serve both purposes simultaneously: location-specific flexibility services offer precision for investment deferral but creates implementation complexity, while network-wide pricing is simpler to implement but provides less targeted investment signals. Greater clarity around these distinct objectives would enable more effective mechanism design that appropriately addresses each need. As drafted, the Task Force proposal would effectively require distributors to pay twice: once for an incomplete response from mass market consumers, and again for the network build that would need to proceed (and perhaps sooner than forecasted).

23. Orion submits that for location-specific network needs, continuing to develop the flexibility services market may be a more effective, and enduring, solution. Distributors should signal where we have constraints worth pursuing, and then support the development of a flexibility market to meet these needs when and where they occur, until we can no longer defer network build investment. The Task Force should ensure that creating a new payment mechanism that targets mass market consumers does not dilute emerging flexibility services market solutions.

Implementation challenges

24. Network constraints are dynamic and varied. Orion submits that the location-specific requirement could cause unintended issues:

   a. Constraints could be due to harmonics, voltage, congestion, or thermal limits.

   b. Generation can fix thermal constraints, but may create or exacerbate voltage constraints. For example, solar generation in a residential area may reduce loading on a transformer during summer (beneficial), but simultaneously cause voltage rise issues that may require additional network investment to manage (detrimental).

   c. Constraints could also exist across different network levels (LV, MV, HV), and addressing issues at one level could create or exacerbate problems at another level. For example, consumer exports that help relieve congestion on an 11kV feeder may simultaneously create harmonics issues at the LV level that require installation of mitigation measures.

25. The proposed Guidance states that "*rebate levels [should be set] based on the amount of network benefits the injection provides. For example, where injection occurs on a part of the network that is likely to face constraints in the next few years, it should be rewarded more than injection that occurs where constraints are only likely later in the future*…"[18] Orion submits that this approach conflates two different mechanisms with different purposes:

[18] 2A Consultation Paper, paragraph 5.7(c), page 17.

a. Network-wide pricing signals (such as TOU pricing or general export rebates) function effectively as broad market signals that provide consistent investment signals across the network. Orion supports this approach and has implemented a two-way tariff accordingly. However, these pricing mechanisms necessarily involve simplified structures to maintain consumer understanding, assist retailers with implementing it, and assists with revenue recovery under the Commerce Act.

b. Targeted constraint management requires precision in both location and timing that pricing signals alone cannot effectively deliver. Our experience demonstrates that addressing specific network constraints is more effectively accomplished through contracted flexibility services rather than pricing mechanisms. This enables distributors to precisely target resources where and when needed, with appropriate certainty and verification.

26. The Task Force's proposal creates implementation challenges by attempting to achieve both objectives through a single mechanism. For effective constraint management:

a. When constraints are 1 – 2 years away, contracted flexibility provides the necessary certainty for network planning that general pricing signals cannot, as network upgrades are already planned, or underway, to mitigate the constraint. Paying consumers a targeted injection tariff at this stage would make the eventual solution more expensive for all consumers. This also creates significant consumer risk, as homeowners may make substantial capital investments based on high rebate expectations, only to find their anticipated returns diminished or eliminated when the tariff is removed after network upgrades are completed – effectively stranding their investment.

b. The Task Force's proposal cannot effectively incentivise new solar + battery installations to benefit the network in time to address these near-term (1 – 2 year) constraints. Our Lincoln Flex Trial provides direct evidence of this challenge. Despite our trial partner, Ecotricity, offering a substantial 51-cent buy-back rate for peak demand periods (significantly higher than any rebate contemplated in the Task Force's proposal), we found that scaling residential participation to the required levels to resolve a potential constraint to be a real challenge. While we successfully achieved our initial target of 100kW in the first year, we could not scale to the full 500kW needed for the second winter. This demonstrates that even with strong financial incentives, distributors and flexibility providers, may not attract sufficient participants quickly enough to defer network investment.[19]

c. Conversely, for constraints that are only "*likely later in the future*", that are "*forecast network constraints in [our] asset management plan*", granular pricing signals risk incentivising consumer investments in areas where constraints may ultimately not materialise. This creates two significant risks: potential stranding of consumer assets when anticipated network needs evolve differently than forecasted, and inefficient resource allocation across the electricity system. Network constraints frequently resolve through changing demand patterns, operational measures such as network reconfiguration, or more cost-effective non-network solutions – rendering the consumer investments stimulated by location-specific rebates unnecessary or suboptimal from a system perspective.

[19] https://www.oriongroup.co.nz/our-story/the-latest/lincoln-flex-update

27. Orion recommends that the Task Force clearly distinguish between these two distinct objectives—broad market signalling through simplified pricing structures versus targeted constraint management through contracted flexibility services—rather than attempting to serve both purposes through a single, highly complex pricing mechanism.

28. Orion submits that implementing truly cost-reflective injection pricing requires sophisticated systems and processes that are developing but do not exist at scale yet, across the sector:

    a. Distributors would need enhanced capability to identify constraints, and to determine fair value for constraint mitigation.

    b. Distributors would require mechanisms to signal these constraints dynamically (e.g. DERMS).

    c. Distributors would need to implement systems to measure the response from consumers, and calculate charges/rebates accurately.

    d. Retailers would need to implement the systems to manage highly granular pricing structures at scale. Through Orion's experience in working with retailers, we have observed some retailers explicitly request to minimise the number of time-of-use tranches for customers due to system constraints. This indicates that even as distributors develop the capability to design granular, location-specific rebate structures, some retailers lack the ability to effectively implement and pass through these complex signals to end consumers (and this will drive cost into this part of the supply chain). The Task Force's proposal assumes retailer systems can manage and communicate potentially hundreds-to-thousands of distinct location-specific pricing categories across multiple networks. Additionally, retailers' appetite to offer customised or location specific offerings to customers is not well understood which could limit the effectiveness of these signals and the benefit of more granular pricing structures.

29. Orion submits that the Task Force's proposal would also create an asymmetry between consumption and injection pricing, and introduce **significant** complexity:

    a. Orion's pricing methodology applies consistently to consumption pricing across our entire network, and we do not use location-specific price signals.[20]

    b. Creating location-specific rebates, or requiring location-specific consumption pricing, introduces significant complexity for both retailers and distributors. For example, even if distributors implemented location-specific rebates only at the GXP-level, with approximately 180 GXPs in New Zealand, this could mean that retailers would then need to accommodate potentially an additional 180 new pricing categories.[21]

    c. However, the proposed Guidance suggests that rebates should target areas with specific network constraints, which often exist at much more granular levels. Orion has 52 zone substations and approximately 5,800 distribution substations.[22] If a constraint exists at an LV or MV level, and location-specific pricing is implemented at that level, the number of potential pricing categories would become untenable for both distributors and retailers to implement. This is exacerbated when considering the number of zone and distribution substations across Aotearoa.

[20] https://www.oriongroup.co.nz/assets/Our-story/Pricing/Orion-schedule-of-delivery-prices-2025.pdf
[21] https://en.wikipedia.org/wiki/Electricity_sector_in_New_Zealand
[22] Orion's Asset Management Plan, pages 151-152.

30. Orion submits that it is currently trialling a network-wide two-way power tariff to gauge interest and test consumer uptake. Mandating immediate changes before market testing is complete risks implementing solutions that don't align with consumer preferences or market readiness. The Task Force should allow distributors to continue these trials and implement approaches that work for their specific network and customer base rather than imposing a Code mandated solution prematurely.[23]

31. Orion submits that we also observed consumers outside of our Lincoln Flex Trial target area expressing concerns about being unable to benefit from the trial. This highlights potential equity issues with location-specific pricing signals, as consumers may perceive it as unfair that their neighbours receive financial benefits, while they do not, based solely on which side of a network constraint boundary they happen to live on.

Orion's Resi-Flex Project learnings

32. Orion submits that our Resi-Flex project (in partnership with Wellington Electricity) has provided valuable insights into the complexities of the flexibility ecosystem and consumer engagement barriers that the current proposal does not adequately address. The trial examined the entire flexibility value chain, including distributors, flexibility stakeholders (aggregators, retailers, and technology providers), and residential consumers. Our findings revealed several challenges:

    a. **Upfront cost barriers**: The most significant barrier to consumer participation is the high upfront capital cost for battery adoption. Our research explicitly identified that "*removing the challenge of high upfront costs for customers*" is a key enabler for market development.

    b. **Complex stakeholder ecosystem**: The flexibility market involves multiple stakeholders with different objectives and business models. The Task Force's proposal oversimplifies the ecosystem by focusing primarily on direct EDB-to-consumer price signals, bypassing the role of intermediaries in understanding market signals, packaging and delivering simple and attractive consumer offerings.

    c. **Consumer segment diversity**: Not all consumers are motivated by the same factors. The research demonstrated that while some consumers are motivated by financial incentives, others prioritise simplicity,[24] environmental benefits, or energy independence. The current proposal assumes a predominantly financial motivation that does not reflect the diversity of consumer preferences observed from this research. The Task Force's problem definition appears to rely on the assumption that consumers act with perfect economic rationality and respond proportionately to even minimal price signals. Our research revealed that consumer behaviour is influence by a complex mix of factors depending on their motivations, capability and opportunities to flex. The assumption that consumers will methodically calculate and respond to a $0.43[25] monthly rebate when considering a multi-thousand dollar investment is not supported by our learnings.

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[23] For further details about Orion has implemented the two-way power price category for mass market consumers, please see these links: https://www.haveyoursay.oriongroup.co.nz/pricing-strategy-update and https://www.oriongroup.co.nz/assets/Our-story/Pricing/Orion-schedule-of-delivery-prices-2025.pdf

[24] We refer the Task Force to research conducted by Energy Consumers Australia, which found that most households (54%) said they just wanted a simple and reliable electricity service at a good price.

[25] This is the average monthly rebate, as identified by the Task Force in Table 5, page 40 of the 2A Consultation Paper.

d. **Value stacking requirements**: Our research highlighted that to stimulate the flexibility services market, "*commercial mechanisms additional to distribution pricing should enable open market that can attract a liquid pool of resources*" and "*EDB value must be sufficient for flexibility suppliers to package alongside their wider offerings*." As outlined in paragraphs 19 - 22, a more targeted approach through flexibility markets could better address specific network needs than the proposed network-wide rebates, which may not effectively signal locational value or the timing of network constraints. While the Task Force's proposal represents a step towards recognising consumer value, flexibility markets could potentially offer more precise signals and create stronger incentives for coordinated responses.

33. For further detail on these findings, we refer the Task Force to our Resi-Flex project report, which provides in-depth analysis of consumer and flexibility stakeholder requirements to inform flexibility market development.[26]

Recommendations for initiative 2A

34. Orion submits that the Task Force should not progress the initiative in its current form and reconsider their approach. Orion recommends:

    a. That the Task Force clearly distinguish between the two distinct objectives outlined in the consultation paper: broad market signalling through simplified pricing structures versus targeted constraint management through contracted flexibility services – rather than attempting to serve both purposes through a single, highly complex pricing mechanism.

    b. Implementing a sunset clause, if the proposal is added to the Code, to allow future flexibility for distributors to integrate or replace mass-market consumer rebates with emerging flexibility services markets.

    c. Remove prescriptive, location-specific requirements that may create unintended consequences.

    d. Consider the learnings from the Resi-Flex project regarding the complexity of the flexibility ecosystem, and the barriers to mass market consumer participation.

Response to initiative 2BC – Improving pricing plan options for consumers

35. Orion submits that while we support the intent to provide consumers with more pricing options, we strongly oppose the Proposal Part 4, and the obligation for distributors to use half-hourly data for billing purposes. The proposed change introduces significant confusion and complexity into the Code and distributor agreements, and the outcome that the Task Force seeks can be obtained by an alternative method.

Mandating half-hourly data use

36. Orion submits that from 1 April 2025, all of our residential connections, small, medium and large general connections, and irrigation connections on our network will be charged for electricity delivery services using a time-of-use (TOU) pricing methodology.[27]

[26] https://www.oriongroup.co.nz/assets/Your-energy-future/Resi-Flex-Public-Report-Release-2023.pdf
[27] https://www.oriongroup.co.nz/assets/Our-story/Pricing/Orion-schedule-of-delivery-prices-2025.pdf

37. Orion submits that we have created TOU bands, within the EIEP1 files that we receive from retailers, that are aligned to our TOU price schedule. We require retailers to submit data to us in this format. If a retailer chooses to not submit consumption data within these TOU bands, all consumption for the ICP is billed at our shoulder rate (*note: the end consumer is not directly impacted by, nor pay this "penalty")*.

38. Orion submits that this approach allows cost-reflective pricing that achieves the **same outcome** as the Task Force's desires, but without the mandated requirement to use half-hourly EIEP3 data.

39. Orion submits that by mandating the use of EIEP3 files, there will be an increase in data processing and storage costs, and create a substantial increase in data volumes shared between retailers and distributors, which complicates the billing process. For example:

    a. If using an EIEP3 file, each retailer will send approximately 1,344 to 1,488 rows of data, per month, per ICP for billing.

    b. For a distributor with ~200,000 residential ICPs, this equates to approximately 3.57 billion lines of data annually. Orion retains data for 14-months to align with the reconciliation process, which means maintaining approximately 4.1 billion lines of data for the 14-month period.[28]

Regulatory approach concerns

40. Orion submits that the proposal represents poor regulatory practice, with its use of override clauses like "*despite anything else in this Code or in a distributor agreement*." This approach:

    a. Creates significant uncertainty about which specific Code provisions and distributor agreement clauses are being overridden, as the amendment provides no clear delineation or mapping to affected sections. This creates potential for unintended consequences and conflicts with other provisions that may not have been fully considered during drafting.

    b. Makes compliance unnecessarily complex as distributors and retailers must effectively maintain parallel understandings of the regulatory framework – one based on the existing Code structure and another based on these override provisions. This may lead to inconsistent interpretation and application across different parties.

    c. Contradicts the Government's expectations for good regulatory practice, which specify that regulations should be "*well-aligned with existing requirements in related or supporting regulatory systems through minimising unintended gaps or overlaps and inconsistent or duplicative requirements*."[29]

    d. Fails to properly assess the regulatory change required and integrate those changes coherently into the existing Code.

[28] This substantial increase in data volumes will likely create challenges in meeting both parties meeting Code and DDA mandated timelines, which are: 5 Working Days for retailer data submission; 10 Working Days for invoice submission, and 20th day of the month for payment.

[29] Government Expectations for Good Regulatory Practice, page 2.

e. Prioritises expedient implementation over enduring, quality industry regulations that market participants can understand and apply with confidence. This continues a concerning pattern that has been raised in submissions to the Electricity Authority's ("Authority") Network Connections project, where multiple submitters urged the Authority to "*please slow down. It is being implemented with undue haste. Mistakes and missteps will only be borne by our existing customers in the form of higher prices and increased risk*."[30]

Recommendations for initiative 2BC

41. Orion submits that the Task Force should not progress Proposal Part 4 in its current form, as alternative approaches can result in the same outcome.
42. Orion submits suggested drafting changes:

12A.4 Distributors must calculate charges using appropriate time-based methodologies

*Where available, **distributors** must calculate **distribution** services charges payable by a **retailer** using either information provided by **retailers** under clause [00.4], or an alternative time-based methodology that achieves an equivalent time-of-use cost-reflective pricing outcome.*

Concluding remarks

43. Orion submits that we urge the Task Force and the Authority to focus on higher-impact initiatives that will make a meaningful difference to security of supply and affordability, rather than introducing complex requirements with questionable benefits. The current initiatives may have merit in their own right, but they should be positioned as complementary to, not substitutes for, more direct interventions in the wholesale market. Without addressing fundamental issues, the Task Force is unlikely to achieve its stated objectives.
44. Orion thanks the Energy Competition Task Force and the Electricity Authority for the opportunity to provide feedback on these consultations, and we look forward to working constructively and developing practical solutions. While we support the overall intent of these initiatives to increase security of supply and lower costs to consumers, we believe that refinements are needed to ensure the proposals are practical, cost-effective, and deliver the intended benefits.
45. This submission is not confidential and can be publicly disclosed.
46. If you have any questions or queries on aspects of this submission which you would like to discuss, please contact us on 03 363 9898.

Yours sincerely,

Connor Reich

Regulatory Lead – Electricity Authority

[30] Energy Trusts of New Zealand, page 2

Appendix A: initiative 2A

Submitting organisation	Orion New Zealand Limited (“Orion”)
Contact person	Connor Reich

Questions	Orion’s response
Problem definition	
Q1. Do you agree with the problem definition above? Why, why not?	Orion submits that while we acknowledge the intent to address barriers to distributed generation investment, we believe the problem definition overestimates the impact that small rebates will have on consumers’ investment decisions. The Task Force's own analysis shows minimal monthly rebates to consumers ($0.00-$0.72), which with solar + battery systems costing $22,000-$37,000, will not meaningfully influence investment decisions. Orion submits that the problem definition also fails to adequately address the complexities of network constraints and the challenges in implementing location-specific rebates that deliver genuine network benefits. Orion has approximately 5,800 distribution substations, and 52 zone substations. If location-specific pricing is implemented at the LV or MV level, the number of potential pricing categories would become untenable for both distributors and retailers to implement. This is exacerbated when considering the number of zone substations and distribution substations across Aotearoa. Additionally, the problem definition does not consider how these rebates may undermine the development of more sophisticated flexibility services markets that could deliver greater network benefits through coordinated aggregation rather than fragmented individual responses. Please refer to paragraphs 24-26 for a detailed discussion of network constraints, paragraphs 13-16 for a discussion on the Authority’s problem definition, and paragraphs 19-23 for a discussion on the flexibility services market.
Proposed solution: principles-based rebates	
Q2. Do you agree with these principles? Why, why not?	Orion submits that we support principles-based approaches over prescriptive requirements. However, the principles should more clearly emphasise that rebates should only be provided where **<u>genuine</u>** network benefits can be demonstrated. The current principles do not sufficiently address the practical challenges of identifying and quantifying network benefits or the potential for unintended consequences of providing rebates in areas where injection may not provide network benefits or could even create additional costs. Please refer to paragraphs 24-26 for a detailed discussion of network constraints, paragraphs 13-16 for a discussion on the Authority’s problem

Questions	Orion’s response
	definition, and paragraphs 19-23 for a discussion on the flexibility services market.
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?	Orion submits that we agree that the principles should only apply to mass-market consumers. Larger consumers and generators typically have more sophisticated arrangements and different network impacts that are better addressed through bespoke connection arrangements.
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)?	Orion submits that the principles should not apply to all mass-market DG, including inflexible generation. While the principle of rewarding all mass-market DG is reasonable in theory, the critical caveat is that rewarding inflexible generation may potentially lead to scenarios where rebates are provided where no genuine network benefit exists. The Task Force should provide clearer guidance on how network benefits should be assessed for different types of generation. The Task Force should explicitly exclude thermal generation from the principles.
Q5. Do you agree with the direction of the guidance that would likely accompany the principles? Why, why not?	Orion submits that the guidance contains several inconsistencies and contradictions that would make implementation challenging: • The guidance states higher rebates should be given for near-term constraints, but also states that stable, long-term signals are needed for investment decisions (principles c & e). • There is a contradiction between maintaining stable signals and reducing rebates once sufficient DG exists, or the network constraint has been resolved (principles e & f). • Using AMPs to identify network constraints conflicts with the reality that these are long-term forecasts, not dynamic identification tools, and these constraints may not eventuate (principles a & b). • The guidance recognises retailer limitations in passing through granular signals, yet emphasises location-specific rewarding of injection (principles c & g). • There are conflicting approaches: maintaining rebates for existing connections while eliminating them for new ones, or reducing them for everyone (principle f). The first option creates inequity, while the second undermines mass-market investment certainty (principle e). • The guidance acknowledges rebates might be offered even when they risk over-incentivising injection in ways that could harm the network, which contradicts the principle that rebates should only be provided when injection offers network benefits (principle h).
Q6. Are there any additional issues with the principles where guidance would be particularly helpful?	Orion submits that additional guidance would be helpful on: • How to define and measure "network benefits".

Questions	Orion's response
	• The appropriate level of rebates for a network benefit. • How best to integrate rebates with other flexibility mechanisms, and how to ensure that rebates do not cut across the development of a flexibility services market. • The treatment of rebates in regions with multiple constraints affecting different network levels. • How to handle the potential for constraints to shift over time due to network reconfiguration. • How to address consumer equity concerns when rebates are available in some areas but not others.
Q7. Do you agree the principles should be incorporated within the Code, rather than being voluntary principles outside the Code? Why, why not?	Orion submits that the principles could be effectively applied and monitored outside of the Code. Incorporating them into the Code creates a rigid framework that may be difficult to adapt as the flexibility market evolves. A more flexible approach would allow for innovation and adaptation as distributors gain experience with injection pricing and as the market matures. Refer to paragraphs 8 and30 for an overview of Orion's two-way power tariff trial.
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.	Orion submits that the proposed timeline presents significant challenges, if we are required to implement the proposed Code amendment as currently drafted: • Implementing location-specific rebates requires substantial system changes and analytical capabilities that many distributors do not currently possess. • The timeline does not allow sufficient time for distributors to model network benefits, consult on pricing methodology changes, and implement new systems. Additionally, as the Task Force has set an effective date for the Code change of 1 April 2026, then it can only impact pricing methodologies set on or after 1 April 2026. Pricing methodologies must be disclosed before the start of each disclosure year (before 1 April 2026, or 20 business days earlier if there is a change to the methodology). A more realistic timeline would extend implementation to April 2027, with phased introduction allowing for appropriate system development and consultation. Furthermore, as demonstrated in our Lincoln Flex Trial, even with substantial incentives, consumer participation takes considerable time to scale - a challenge that cannot be resolved by expediting this initiative's implementation timeline. Initiative 2A's timing does not align with the reality of constraint management, where near-term constraints (1-3

Questions	Orion’s response
	years) require immediate solutions that cannot wait for gradual consumer uptake. Please refer to paragraphs 24-26 for a detailed discussion of network constraints, paragraphs 13-16 for a discussion on the Authority’s problem definition, and paragraphs 19-23 for a discussion on the flexibility services market
Q9. Do you agree the proposal strikes the right balance between encouraging price-based flexibility and contracted flexibility? Why, why not?	Orion submits that the proposal does not strike the right balance. The rebates risk undermining the development of more sophisticated flexibility markets by: • Creating expectations of payment for all exports during peak times, regardless of whether they provide genuine network benefits. • Potentially crowding out more efficient aggregator models that could deliver greater benefits at lower cost. • Introducing pricing signals that may conflict with other flexibility mechanisms. Our experience with flexibility trials, particularly Lincoln Flex and Resi-Flex, demonstrates that a more coordinated approach involving aggregators is necessary to achieve the scale required for meaningful network benefits. Refer to paragraphs 19-23 for information on flexibility services market development.
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?	Orion submits that based on our experience with flexibility trials, we are sceptical of the claimed long-term benefits. The rebate levels are too small to drive significant mass-market consumer investment, and the anticipated network benefits may not materialise at the scale required to offset costs, leading to higher costs for all consumers.
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?	Orion submits that a principles-based approach is preferable to prescribed rebates. Network constraints and benefits vary significantly across different networks and even within networks. Prescribed rebates would inevitably over-incentivise some exports while under-incentivising others, leading to inefficient outcomes and potentially increasing costs for all consumers.
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?	Orion submits that we agree with the Authority’s analysis, and that consumption-linked injection tariffs should not be preferred.
Q13. If this approach was progressed, do you think:	Orion submits that we agree with the Authority’s analysis, and that consumption-linked injection tariffs should not be implemented.

Questions	Orion’s response
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?**	
Regulatory statement	
Q14. Do you agree with the objective of the proposed amendment? If not, why not?	Orion submits that while we agree with the objective to "incentivise investment in and operation of DG when and where it provides network benefits by avoiding or deferring network costs," we are not convinced the proposed amendment will achieve this objective in a meaningful way. Refer to paragraphs 17-18 for information on the value proposition and paragraphs 24-29 for implementation challenges.
Q15. Do you agree the benefits of the proposed amendment outweigh the costs?	Orion submits that the benefits do not outweigh the costs. The implementation costs for distributors will be significant, including system changes, analytical capabilities, and operational processes. Based on our experience with flexibility trials, the network benefits are likely to be modest at best, and may not materialise at all in many cases. Refer to paragraphs 19-23 and 32-33 for information on our experience with flexibility trials and paragraphs 24-29 for implementation challenges.
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 Authority’s statutory objectives in section 15 of the Electricity Industry Act 2010.	Orion submits that of the options presented, a principles-based approach is preferable to prescribed rebates or consumption-linked tariffs. However, we believe that allowing flexibility services markets to develop naturally, supported by appropriate regulatory frameworks, would be a more effective approach to delivering network benefits from distributed generation.
Q17. Do you have any comments on the drafting of the proposed amendment?	Orion submits that although the proposed Code amendment states that rebates should be paid "*when injection provides network benefits*,”, it also states that “*network benefits* [is where injection of electricity] *avoids, reduces, or defers the costs of required investment in the network*.” As discussed in paragraphs 12-14, current penetration of mass-market DG would not “*avoid, reduce, or defer the costs of required investment in the network*”, and would thus not qualify for the proposed rebate.

Appendix B: initiative 2BC

Submitting organisation	Orion New Zealand Limited ("Orion")
Contact person	Connor Reich

Questions	Orion's response
Q1. Do you agree the issues identified by the Authority are worthy of attention? If not, why not?	Orion submits that improving pricing options for consumers is worthy of attention. However, we are concerned that the proposed approaches may not deliver the intended benefits and could create unintended consequences, particularly the requirement for distributors to use half-hourly data for billing purposes. Refer to paragraphs –35-40 for our concerns with Proposal Part 4 and the mandate that distributors bill using EIEP3 half-hourly data.
Q2. Which option do you consider best addresses the issues and promotes the Authority's main objective? Are there other options we have not considered?	Orion submits that we believe that allowing distributors flexibility in how they implement time-varying pricing, rather than mandating specific approaches like half-hourly data use, would better promote the Authority's objectives.
Q3. Should we require retailers to offer a price plan with time-varying prices for both consumption and injection? Why or why not?	Orion submits that it is reasonable that where time-varying distribution pricing is available, these options should be passed on to consumers. This allows consumers who can shift their consumption or generation to benefit, while those who cannot or do not want to adjust their patterns can remain on non-time-varying plans. However, the Task Force should remain mindful that most (Australian) consumers want simplicity – they want simple, and reliable electricity service at a good price.[31] Orion sees parallels of this in the New Zealand consumer base, as according to Consumer, "*45% of New Zealanders have been with their current electricity provider for more than 5 years*."[32] This is also supported by the findings from our Resi-Flex project, where a key priority area is "*simple solutions for the end consumer… even if industry signals are complex or data rich*."[33]
Q4. Do you have any feedback on the design requirements?	No comment.
Q5. Is there a risk that injection rebates will not be passed through to the	Orion submits that our Resi-Flex project findings highlight significant challenges in ensuring price signals reach end consumers effectively. Our research into the flexibility value chain revealed that the path from

[31] https://energyconsumersaustralia.com.au/publications/consumer-energy-report-card-consumer-knowledge-electricity-pricing-responsiveness-price-signals
[32] https://www.consumer.org.nz/articles/record-savings-available-to-people-who-switch-power-providers
[33] https://www.oriongroup.co.nz/assets/Your-energy-future/Resi-Flex-Public-Report-Release-2023.pdf, page 25.

Questions	Orion's response
consumers targeted? If so, how could we safeguard against this risk?	distributor to consumer involves multiple stakeholders with varying commercial objectives. As identified in our trial, "*commercial mechanisms additional to distribution pricing should enable open market that can attract a liquid pool of resources*", and distributor value needs to be "*sufficient for flexibility suppliers to package alongside their wider offerings*." Simply mandating that retailers pass-through distributor rebates without addressing the complex commercial ecosystem may not achieve the desired outcomes. Refer to paragraphs 32-33 for a discussion on our Resi-Flex trial learnings, particularly around the complex stakeholder ecosystem and value stacking requirements.
Q6. Which retailers should be captured by the proposal and why?	No comment.
Q7. What are your views on the proposed timeframe for implementation of 1 January 2026? Would 1 April 2026 be preferable, and if so why?	No comment.
Q8. What are your views on Part 2 of our proposal that would require retailers to promote the time-varying price plans?	No comment.
Q9. What should the Authority consider when establishing the approach to and format of the reporting regime?	No comment.
Q10. Should the Authority include a sunset provision in the Code, or a review provision? Why?	No comment.
Q11. What are your overall views on Part 3 of the proposal?	No comment.
Q12. What are your views on Part 4 of our proposal to amend the Code to require that consumers are assigned to time-varying distribution charges, that retailers provide half-hourly data to distributors for settlement?	Orion submits that while we support retailers providing half-hourly data to distributors, we strongly oppose mandating the use of half-hourly data for billing purposes. Our current approach using EIEP1 files with defined time-of-use bands achieves the same outcome without the significant costs and complexity of utilising EIEP3 files. The proposed requirement would: • Significantly increase data processing and storage costs. • Create challenges in meeting billing timelines. • Add unnecessary complexity with minimal consumer benefit.

Questions	Orion's response
	Refer to paragraphs 35-40 for further details about our concerns with mandating the usage of EIEP3 half-hourly data for billing.
Q13. Do you agree with the objective of the proposed amendment? If not, why not?	Orion submits that we agree with the Task Force's objective of improving pricing options but disagree with the proposed implementation approach, particularly regarding mandating half-hourly data for billing. The objective could be achieved through less prescriptive approaches that allow distributors flexibility in how they implement time-varying pricing.
Q14. Do you agree the benefits of the proposed amendment outweigh its costs?	Orion submits that for Part 4 regarding half-hourly data for billing, the benefits do not outweigh the costs. The proposal lacks a quantitative cost-benefit analysis that accounts for data storage and processing requirements. Our analysis indicates that processing and storing half-hourly data for 220,000 ICPs would require handling approximately 3.96 billion lines of data annually, with significant associated costs.
Q15. 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 Authority's statutory objectives in section 15 of the Electricity Industry Act 2010.	Orion submits that there are simpler, less costly approaches to achieving the same objectives, such as our current approach using EIEP1 files with defined time-of-use bands. The proposed amendment is unnecessarily prescriptive and does not allow for innovation and efficiency in how distributors implement time-varying pricing.
Q16. Do you have any comments on the drafting of the proposed amendment?	Orion submits that the use of override clauses like "*despite anything else in this Code or in a distributor agreement*" represents poor regulatory practice and creates confusion in the interpretation and application of the Code. This approach: • Contradicts the Government's expectations for good regulatory practice. • Creates significant uncertainty about which specific Code provisions and distributor agreement clauses are being overridden. • Makes compliance unnecessarily complex as distributors and retailers must maintain parallel understandings of the regulatory framework. • Fails to properly assess the regulatory change required and integrate those changes coherently into the existing Code. • Prioritises expedient implementation over enduring, quality industry regulations. Refer to paragraph 40 for further details about our concerns with the Task Force's regulatory approach.