1 October 2024

Electricity Authority
PO Box 10041
Wellington 6143

Submitted via email to policyconsult@ea.govt.nz

Consultation Paper – Code Review Programme #6

Introduction

1. Thank you for the opportunity to submit on the consultation paper 'Code Review Programme #6'.[1] This submission is not confidential and can be publicly disclosed.
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 227,000 homes and businesses and are New Zealand's third largest Electricity Distribution Business (EDB).

Orion summary points

3. We have reviewed the consultation paper, and our specific responses to the questions posed by the Authority as well as other feedback we consider appropriate to the consultation are set out in Appendix A.
4. Orion acknowledges the Authority's efforts to address shared load control, but we believe the complexity and potential impacts – particularly on network management and investment deferral – have not been fully captured. We urge the Authority to reconsider its framing of the problem, particularly the implication that competition is necessary between retailers and distributors. In its current form, the proposed Code amendment does not recognise the critical role that existing ripple load control plays in managing peak demand, deferring network investment, and keeping costs low for consumers. Orion's ripple control system, which reduces peak demand on our network by approximately 20%, provides significant benefits to consumers, estimated at over $19.5m on an annual basis.
5. As raised by the Electricity Networks Aotearoa (ENA) submission, we support the ongoing development of new customer propositions for managing devices' load and injection. The Future Networks Forum's (FNF) workstream is currently exploring the future capability, roles and functions required to enable distributed flexibility resources to minimise whole-system costs to consumers.

[1] https://www.ea.govt.nz/projects/all/code-review-programme/consultation/code-review-programme-6/

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6. We agree in principle with the comments raised in the ENA submission to this consultation. Furthermore, we agree that addressing the changes required to enable shared control must be done in a deeply considered, systematic way, by clearly defining roles and responsibilities for the shared management of all load and injection. Rather than addressing hot water control in isolation, we urge the Authority to consider the broader implications of shared control across all types of distributed energy resources, ensuring a robust and adaptable regulatory framework for the future that manages the transition well.

Concluding remarks

7. Thank you for the opportunity to provide feedback on this consultation.
8. 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

Appendix A

Submitter	**Orion New Zealand Limited ("Orion")**
Proposal Number	**CRP6-002**

Questions	Comments

Q1. Do you agree the issue(s) identified by the Authority need attention?
 	
Any comments?
	While we agree that the issues identified need attention, we believe that the Authority has not yet fully captured, or understood, the complexity and potential impacts of shared load control – particularly on network management and investment deferral. Specifically:
	
	1. Orion operates 43 ripple injection plants on our network, at 26 urban and 17 rural substations.
	2. Our ongoing, and long-term investment in ripple[2], ensures that our control systems can reduce peak demand on our network by approximately 20% through Peak and Fixed Time Control. This deferral of network investment equates to a significant benefit to Orion's consumers of over $19.5m each year.[3]
	3. The problem definition does not adequately address the role of ripple control in our role of providing electricity distribution services. It serves numerous additional critical functions, including[4]:
	    a. Managing peak load on our network and on Transpower's grid[5],
	    b. Lowering load limits following faults or failures, and facilitating planned maintenance,
	    c. Switching on hot water cylinders and night store heating loads during cheaper night periods,
	    d. Signalling higher priced congestion periods,

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[2] Orion has utilised ripple to control load on our network from the mid-to-late 1950s. Work was completed on installing ripple relays across our network by June 1959. https://issuu.com/orionnzltd/docs/orion-community-update-02-august-2024?ff.

[3] According to the Boston Consulting Group's "The Future is Electric" report, the average cost of supplying 1kW is $130/year. If Orion were unable to utilise ripple for load management, we would be required to build excess capacity on the network to meet peak demand.

[4] Further details about the use of ripple relays on Orion's network can be found here: https://www.oriongroup.co.nz/assets/Be-prepared/NW702602.pdf

[5] The practical impact of ripple control in managing network load is significant. For instance, in May 2024, after Transpower issued a Customer Advice Notice (CAN) about a Low Residual Situation, using ripple, Orion was able to reduce our load by 52MW – nearly 10% of our total network load at that time.

	e. Switching dual rate (e.g. day/night) meter registers, f. Switching some forms of street lighting on and off, and g. Switching load in response to retailer's requests (from time to time). 4. The problem definition and proposed Code amendment does not adequately address the challenges of shared control or adequately address multiple aspects of load control. While these elements may, and should, be covered under load management protocols, the proposed Code amendment should cover the following areas: a. The priority order in Schedule 8 should be expanded to include Network Emergencies or System Emergency Events and Load Shedding, as defined in section 33.2 of the DDA. This expansion would recognise the historic and ongoing importance of ripple control for these purposes and align with requirements and definitions found in Schedule 4 of the DDA. Our ripple control system has been instrumental in managing not only peak loads, but also in responding to various emergency scenarios, ensuring grid and network stability and reliability. In our conversations with retailers establishing hot water control trials, they have been very clear about their intent to prioritise network needs, and the use of ripple for load control. Therefore, it is reasonable for the Authority to consider formally recognising these use-cases in the priority order in Schedule 8. b. Clause 5.6 should be broadened to ensure that all load, including that load controlled by Traders, or other third parties (e.g. aggregators), is made controllable by distributors during emergencies as defined in Part 1 and Schedule 4 of the DDA. As the energy landscape evolves with the integration of new technologies, it's critical that distributors maintain the ability to control these loads during emergency situations. This broader scope would future proof the system and ensure that distributors can effectively manage grid and network stability and reliability. c. Trader load management practices should also ensure that network emergencies are avoided whenever possible, and the Authority should clarify that Traders must support Distributors by avoiding network emergency events. Restoring load after a control event requires extensive co-ordination, and may take time to safely achieve. While a load management protocol can be developed that establishes when Traders operate their manageable load, there is a risk that Traders may inadvertently breach a network's operating limits – both physical (thermal) and power quality, if they operate in tandem or during similar periods.

	d. Appropriately assigning service level agreement responsibilities to prevent customer complaints. Shared control introduces complexity in determining which party is responsible for maintaining service levels. Clear delineation of responsibilities will ensure that customers receive consistent service and know who to contact in case of issues, ultimately leading to better customer satisfaction and more efficient problem resolution. e. Ensuring that traders do not breach network operational limits and that they mitigate restoration 'snap back' or secondary peaks. This is particularly important as uncoordinated control by multiple parties could lead to unexpected load spikes that strain the network. From Orion's, and other distributor's experience, these load spikes have been larger than the load that is initially shifted as controlling load takes away natural diversity.[6] By including this in the Code amendment, we can establish clear guidelines for traders to follow, ensuring that their actions do not compromise network stability or lead to inefficient use of network resources. This would help maintain the reliability and efficiency of the network, which is crucial for both consumers and network operators. This is particularly important given retailers have an incentive to control hot water in response to spot prices, which are very volatile. Networks do not yet have sophisticated enough pricing to signal network congestion at a local level to ensure that shifting of load into these times does not impact the network.[7] f. The ENA FNF are working with EDBs to understand the use of HWC load control by retailers and aggregators, which may assist in the development of aligned load management protocols. Until this work has progressed further, we caution against moving forward with these changes. It's also unclear what happens if a load management protocol cannot be agreed upon - what actions should the Trader or Distributor take in this case, and how would such disputes be resolved? These issues need to be addressed before proceeding with the proposed changes.

[6] https://www.powerco.co.nz/news/media/residential-hot-water-control-trials

[7] This relates to the Market Development Advisory Group's (MDAG) Recommendation 5 (Develop design and trial tools to enable security constrained economic dispatch on the distribution network). https://www.ea.govt.nz/documents/4335/Appendix_A2_-_Final_recommendations_report.pdf, pages 83-84.

	The Authority should also clarify whether 'load management' in this context also includes injection, as this could have significant implications for future energy scenarios. SA Power Networks, the distributed network service provider (DNSP) for South Australia have developed a 'Flexible Exports' option, which allows the DNSP to manage their consumer's exports to the local network.[8] This allows the DNSP to smartly respond to local community power needs, or if the local power substation becomes congested. It adds the additional benefits of ensuring that the network is prevented from becoming congested, and allows consumers to export at higher rates than the original 1.5kW export cap. The definition of 'Trader' has not changed with this Code amendment. The Authority may have overlooked that there would be no requirements on third-parties or other types of roles (if not a Retailer – e.g., an aggregator). These parties will still not be obligated to meet DDA requirements. This oversight could lead to inconsistencies in the application of load management protocols and potentially allow such entities to have incentives for behaviour not envisaged by the regulatory framework. This may potentially lead to an uneven competitive playing field between retailers and non-retailers, or at worst, create an unacceptable risk to the network, consumer, and public safety. Such entities must operate their load under Good Electricity Industry Practice, and be required to notify, communicate, and coordinate their activity with other participants. We urge the Authority to consider expanding the definition of 'Trader' or creating additional participant categories to ensure all relevant parties are subject to appropriate obligations under the Code for load management.
Q2. Do you agree with the objectives of the proposed amendment? **Any comments?**	While we support the objective of the proposed amendment (i.e. to increase competition in the electricity industry and reduce electricity market operational costs), we have several concerns: 1. We do not agree that the proposed amendment promotes the reliable supply of electricity as set out in section 32(1)(b). Simply put, the balance between promoting market participation and maintaining essential network management functions is not adequately addressed. As outlined in our responses to Q1, Q4 and Q5, the Code amendment should explicitly recognise the critical role of ripple load control in managing peak demand, deferring network investment, and keeping costs low for consumers.

[8] https://www.sapowernetworks.com.au/your-power/smarter-energy/flexible-exports/

	2. The Authority appears to have the view that there must be a competitive market for demand management (given the statement "*all service providers are able to compete on a level playing field*" in the problem definition section of the Consultation Document).[9] This framing feeds into the Authority's assessment of how the proposed amendment promotes the statutory objective in section 32(1)(a), and the promotion of "competition in the electricity industry". We urge the Authority to consider a more nuanced approach that recognises the unique role of distributors in providing system-wide benefits through load control, while still encouraging innovation in demand management services. While we understand the Authority's perspective on competition for emerging demand management services (e.g., for EVs), we believe this view does not fully account for the current value provided by ripple load control. The service we are currently providing via ripple load control is valuable to the whole system, especially due to existing deferred capital investment at both the distribution and transmission levels. Consequently, the transition to dual control needs particular attention so as not to undermine the gains from ripple control that are already in place. This is particularly important until other forms of demand management reach sufficient scale to provide comparable system-wide benefits. We question whether the Authority's framing leads to a proposal that is truly in the best interests of consumers, particularly given the lack of a quantitative cost-benefit analysis examining the historic and on-going network investment deferral achieved by EDBs through ripple load control. This analysis should compare these benefits to the potential savings that retailers may offer to customers through shared control. 3. The proposed amendment does not adequately address the challenges of systems integration and 'signalling' between parties to coordinate between distributor and retailer control, including maintaining visibility of controlled load. Potentially significant investment by distributors, and retailers, may be required to support the transition to a shared control environment. This could include upgrades to existing systems, development of new communication protocols, and implementation of advanced monitoring and forecasting tools. On this basis, the proposed amendment does not promote the statutory objective in section 32(1)(c) of the efficient operation of the electricity industry.

[9] https://www.ea.govt.nz/projects/all/code-review-programme/consultation/code-review-programme-6/, Page 12.

Q3. Do you agree the benefits of the proposed amendment outweigh its costs? **Any comments?**	Without a comprehensive, quantitative, cost-benefit analysis that includes the potential impact on network investment deferral and long-term consumer costs, it's difficult to determine if the benefits outweigh the costs. We urge the Authority to conduct such an analysis before proceeding. Specifically, the Authority should: 1. Quantify the benefit received by consumers of the historic and on-going deferral of network investment, at both the distribution and transmission levels, that is the result of ripple load control. As outlined in our response to Q1, Orion provides a significant benefit to our consumers of over $19.5m yearly in deferred investment. This significant benefit must be weighed against any proposed changes. 2. Consider the costs of implementing new systems for coordination between distributors and retailers, and distributors and the system operator. This includes upgrading existing control systems, developing new communication protocols and interfaces, implementing advanced monitoring and forecasting tools to maintain network stability, and training personnel to operate in a shared control environment.
Q4. Do you agree the proposed amendment is preferable to any 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.**	Yes, we agree that the proposed amendment is preferable to any other option. However, we encourage the Authority to consider the potential benefits of a Distribution System Operations (DSO) model in future regulations. Incorporating DSO functions could further enhance the efficiency and reliability of the electricity industry, in line with the Authority's statutory objectives. As outlined in our response to the Authority's consultation on 'the future operation of New Zealand's power system', the DSO model has shown promise in addressing the challenges of an increasingly distributed and flexible power system.[10] Orion, along with other upper South Island distributors operate as a proto-DSO through our management of the Upper South Island (USI) load management system. This collaborative system integrates information from Orion and other USI distributors' SCADA systems, enabling us to monitor the total USI system load and dispatch control signals to various distributors' ripple control systems. This coordinated approach allows us to manage the USI total load to meet specific targets. This cooperative venture not only supports efficient power system operation, but also delivers substantial benefits to both Transpower and to each of the participating distributors through the deferral of network investment and thus benefits to customers. This showcases the potential advantages of a more formalised DSO model.

[10] https://www.oriongroup.co.nz/assets/Our-story/Submissions/EA/Orion-submission-future-operations-NZs-power-system-Apr-2024.pdf

	However, as noted in this submission, it is critical that the Authority consider developing a regulatory regime that clearly defines DSO roles and functions, to enable real-time network operations to remain within distributors, to ensure clear accountability for network reliability. As mentioned previously, the FNF workstream is currently exploring the future capability, roles and functions required to enable DSO models, and aims to develop a 'least regrets' capability development roadmap for distributors. It is also critical that the Authority appropriately considers the on-going work of the FNF and develops a regulatory framework that ensures 'flexibility traders', who are not captured by the definition in the Code for Traders, provide appropriate visibility of flexible resources and coordination requirements, particularly in an emergency.[11]
Q5. Do you have any comments on the drafting of the proposed amendment?	If this amendment is to be included, we propose the following changes, in red text, to Clause 5 and Schedule 8: **5 LOAD MANAGEMENT** 5.1 **Distributor may control load**: Subject to clause 5.3, the Distributor may control part or all of ~~the~~ a Customer's load (as the case may be) in accordance with this clause 5, Schedule 1, Schedule 4, and Schedule 8 if: (a) the Distributor provides a Price Category or Price Option that allows for a non- continuous level of service in respect of part or all of ~~the~~ a Customer's load (a "Controlled Load Option"), and charges the Trader on the basis of the Controlled Load Option in respect of the Customer; or (b) the Distributor provides any other service in respect of part or all of ~~the~~ a Customer's load advised by the Distributor to the Trader from time to time (an "Other Load Control Option") with respect to ~~the~~ a Customer (who elects to take up the Other Load Control Option). (c) for the avoidance of doubt, where the Distributor provides a Controlled Load Option under subclause (a), or an Other Load Control Option under subclause (b), and charges the Trader on that basis, the Distributor shall be considered the incumbent with respect to all load at that ICP for the purpose of this Agreement. (d) Any requested changes by a Trader to a Customer's Price Category or Price Option must be made in accordance with clause 8.4 of this Agreement.

[11] Ibid, page 7.

5.2 **Trader may control load**: Subject to clause 5.3, if the Trader offers to a Customer, and the Customer elects to take up, a price option for a non-continuous level of service by allowing the Trader to control part of or all of ~~the~~ that Customer's load, the Trader may control part or all of ~~the~~ that Customer's load (as the case may be) in accordance with this clause 5, Schedule 4, and Schedule 8. For the avoidance of doubt, the load controlled by the Trader or any part of it may also be controlled by the Distributor.

5.3 **Control of load by Entrant if some load controlled by Incumbent**: If either party (the "Entrant") seeks to control all or part of a Customer's load at a Customer's ICP, but the other party (the "Incumbent") has obtained the right to control all or part of the load at the same ICP in accordance with clause 5.1 or 5.2 (as the case may be), the Entrant:

(a) may only control the part of the Customer's load that the Customer has agreed the Entrant may control under an agreement with the Entrant; and

(b) if any part of that load (including all of that load) is already subject to the Incumbent's right to control, must control that part of the load in accordance with the protocol agreed under clause 5.6.

5.4 **No interference with or damage to Incumbent's Load Control System**: Both parties must ensure that neither they nor their Load Control System interferes with the proper functioning of, or causes damage to, the other party's Load Control System.

5.5 **Remedy if interference or damage**: If either party or any part of that party's Load Control System interferes with, or causes damage to, any part of the other party's Load Control System, the first party must, on receiving notice from the other party or on becoming aware of the situation, promptly and at its own cost remove the source of the interference and make good any damage.

5.6 **Trader to make controllable load available to Distributor for management of system security**: If the Trader has obtained the right to control all or part of ~~the~~ a Customer's load in accordance with clause 5.2, the Trader must:

(a) within 5 Working Days of having first obtained such a right, notify the Distributor that the Trader has obtained the right;

(b) unless the Distributor agrees otherwise, and within 60 Working Days of providing the notice under paragraph (a), develop and agree jointly with the Distributor (such agreement not to be unreasonably withheld by either party), a protocol to be used by the parties to this Agreement that:

	(i) is consistent with the Distributor's System Emergency Event management policy set out in Schedule 4, and the Code; (ii) is for the purpose of coordinating the Trader's controllable load with other emergency response activities undertaken by the Distributor during a System Emergency Event, such purpose having priority during a System Emergency Event over other purposes for which the load might be controlled; (iii) assists the Distributor to comply with requests and instructions issued by the System Operator when managing System Security in accordance with the Code during a System Emergency Event; (iv) assists the Distributor to manage Network system security during a System Emergency Event; (v) if applicable, allows both parties to share control of the same load, including in accordance with the priority order in Schedule 8; and (vi) contains the same or similar terms as protocols agreed between the Distributor and other Traders; (c) during a System Emergency Event, operate its controllable load in accordance with the protocol developed in accordance with paragraph (b); and (d) at all times, operate its controllable load as a reasonable and prudent operator in accordance with Good Electricity Industry Practice. **SCHEDULE 8 – LOAD MANAGEMENT** **Use of controllable load** S8.1 A party may use a Load Control System for 1 or more of the following purposes, which are ranked in order of priority, provided that it has obtained the right to control the load in accordance with clause 5.1 or 5.2: (a) Grid Emergency: As defined in Part 1 of the Electricity Industry Participation Code 2010; (b) System Emergency Event: As defined in clause 33.2, and set out in Schedule 4; (c) Load shedding: As defined in clause 33.2, and set out in Schedule 4; (d) Market participation: Any other right to control load.

	S8.2 If both parties have obtained the right to control all or parts of the ~~consumer's~~ Customer's load in accordance with clause 5.1 or 5.2, and both parties want to control load for a purpose specified in clause S8.1 at the same time, the party entitled to control load will be the party with the higher priority rank as specified in clause S8.1. Notwithstanding any other provision in this Agreement, the Distributor retains the right to control all load in accordance with S8.1(a), (b) and (c), and may direct the Trader to control load in accordance with S8.1(a), (b) and (c), with the Trader required to comply with such directions promptly and in accordance with the agreed protocol under clause 5.6.
Q6. Do you have any further comments on the proposal?	Based on a strict interpretation of clause 5.1(a), it appears that by offering a Price Option or Price Category that allows for a non-continuous level of service in respect of the Customer's load, (a "Controlled Load Option"), and charges the Trader on that basis, that Orion is the incumbent on **all** load at that ICP. This interpretation is important, as it positions distributors, or future DSOs, to respond effectively to Grid Emergency or System Emergency Events. This interpretation seems appropriate, given that Orion lacks a direct relationship with the end consumer, and bills the retailer rather than the end consumer. Orion requests that the Authority review and confirm this interpretation, as it is essential that how distributor acquires and maintains access rights under 5.1(a), by billing the retailer its control tariff for that ICP, endures. It is critical that the Authority considers scenarios where a Trader may seek to remove the incumbency status from a Distributor. Orion is concerned that Traders, who currently include the customer agreement in terms and conditions, may remove this from their terms and conditions and thereby a Distributor's right to control a customer's load. For the avoidance of doubt, the Authority should seek to ensure that Traders must not request changes to a Customer's Price Category for the purposes of gaining incumbency status. The Authority must evaluate the potential unintended consequences for distributor's AUFLS response capability and broader Grid Emergency response if retailers begin to offer load previously controlled by a distributor into the instantaneous reserves market. There may be unforeseen complications, where a Trader may enter into an ancillary services arrangement with the System Operator to provide resources into the instantaneous reserves market, which must be excludable from the controllable load estimate that the connected asset owner (distributor) estimates will be available for use by the system operator. This highlights the need for a comprehensive approach to shared control that both acknowledges the current state, while providing an all-of-sector response to ensure system security.

	The Authority should also consider Option E, and the potential impacts that may arise of shared control given the 2023 Code amendment.[12] We strongly recommend that the Authority liaise with the Commerce Commission regarding the upcoming DPP4 reset to better understand the complexities and potential unintended consequences that may arise if retailers begin controlling load extensively on our network during peak periods. As the Authority is aware, distributors must forecast revenue that is claimed back on a yearly basis. While there is a 2-year wash-up mechanism in place, the revenue smoothing limit may restrict our ability to fully wash-up any reductions in revenue. This could lead to significant financial implications for distributors if there is a material shift in load control patterns due to retailer interventions. The Authority must consider how these regulatory frameworks interact and ensure that any changes to load control arrangements do not inadvertently undermine the financial stability of distribution businesses or their ability to invest in and maintain critical infrastructure. The Authority should consider and evaluate necessary system changes to the Registry to support the effective implementation of shared control. Registry information is currently static and is insufficient for us to operate shared control effectively in the future. As a result, we do not have sufficient visibility of DER managed via third parties in real time and the potential impact this has on our network. This could impact our ability to optimise the network and provide an affordable and reliable service to customers. The Authority should assess the feasibility of requiring that the Entrant's control parameter information be updated in the registry by Entrants and shared with Incumbents. The Authority must develop a dynamic system capable of near-real-time updates, review and update tags and fields to capture comprehensive load control information and consider how to support future dynamic load management needs. These enhancements can ensure that all parties have access to accurate, up-to-date information about load control across the network, facilitating effective coordination between Traders and Distributors as load management becomes increasingly complex.

[12] https://www.ea.govt.nz/documents/2942/Decision_paper_-_Clarify_the_availability_and_use_of_discretionary_demand_control.pdf

	There are no transition timelines for the new clauses to be put in place. To put in place the proposed Code amendment, we would be required to update all DDAs with retailers on our network – which is a significant undertaking. Orion requests that this proposed DDA amendment be aligned with the other DDA updates that the Authority is progressing.[13]

Proposal Number	**CRP6-006**
Questions	**Comments**
Q1. Do you agree the issue(s) identified by the Authority need attention? **Any comments?**	We do not agree that the issue identified by the Authority needs attention. Whilst we acknowledge the obligation in clause 16A.16(1) of the Code on participants to pay the costs of some audits, we do not see the necessity for the Code to regulate payment by a specified date on an invoice for an audit. The terms of trade between the parties should always be determined between the parties, and subject to individual contractual provisions.
Q2. Do you agree with the objectives of the proposed amendment? **Any comments?**	In our view, this amendment is not necessarily going to contribute to the efficient operation of the electricity industry. We do not think it is correct to say that "*Without the proposed amendment, auditors are forced to use the court system to recover any debts due. This is costly, and some auditors may choose not to take action, forgoing payment.*" There are a range of other cheaper options such use of a debt collection agency to recover a debt due or small claims court rather than using the district court system or resorting to a compliance process under the Code.
Q3. Do you agree the benefits of the proposed amendment outweigh its costs?	No, we do not agree. The auditors already have the comfort that they will be paid because this is the effect of clause 16A.16(1) of the Code.

[13] https://www.ea.govt.nz/projects/all/default-distributor-agreements/consultation/default-distributor-agreement-and-consumption-data-templates/ and https://www.ea.govt.nz/projects/all/default-distributor-agreements/consultation/proposed-changes-to-the-default-distributor-agreement/.

Any comments?	
Q4. Do you agree the proposed amendment is preferable to any 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.**	See above.
Q5. Do you have any comments on the drafting of the proposed amendment?	If such an amendment is to be included, we would prefer it to be in similar terms to clause 16A.16(5). An auditor could prescribe an unreasonable due date on an invoice, and the participant that is the subject of the audit may not be able to comply and therefore breach the Code. There at least needs to be a reasonable payment period specified and not just a reference to the due date on the invoice. Different business will have different payment terms which can be agreed between the parties as a matter of contract.
Q6. Do you have any further comments on the proposal?	No.

Proposal Number	**CRP6-012**
Questions	**Comments**
Q1. Do you agree the issue(s) identified by the Authority need attention? **Any comments?**	Orion supports the proposed Code amendment.

Proposal Number	CRP6-014
Questions	**Comments**
Q1. Do you agree the issue(s) identified by the Authority need attention? **Any comments?**	Yes, we agree that the issue identified by the Authority needs attention. However, we would like to propose that rather than the standard 24-month appointment (with the provision for carry-over audit work), appointments are for a period of longer than 24 months. This would be in keeping with other sectors where audit partner appointments can be for up to 5 to 7 years. For example, see the audit requirements of the New Zealand Stock Exchange for public listed companies[14], and the audit requirements of the XRB for public interest entities[15].
Q2. Do you agree with the objectives of the proposed amendment? **Any comments?**	We note that the objective of the proposal is to reduce electricity market operational costs by ensuring auditors and participants are clear how the timeframe for auditor rotation operates and dealing with situations where an audit runs over the end of the 24-month period, and do not incur unnecessary audit costs. We agree with this objective, but in keeping with our submission above, unnecessary audit costs could be reduced further by allowing for longer audit appointments, say up to 5 years rather than 24 months. This would reduce frequent procurement costs for participants required to engage auditors.
Q3. Do you agree the benefits of the proposed amendment outweigh its costs? **Any comments?**	No comment.

[14] https://assets.ctfassets.net/m5mydry9e35f/6hiV0rk8OfR6Z5fN5xpGse/ba6236bc5b78ba5f4d31cec08e04b531/NZX_Listing_Rules_1.8.2_-_24_July_2024.pdf, page 46.
[15] https://www.xrb.govt.nz/standards/assurance-standards/professional-and-ethical-standards/auditor-rotation/faqs/

Q4. Do you agree the proposed amendment is preferable to any 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.**	See the discussion above.
Q5. Do you have any comments on the drafting of the proposed amendment?	Yes. If the Authority is going to proceed with its original proposal, then our submission is that proposed subclause 4(a) could be clarified as follows: (e) the 24-month period begins on the day the **auditor** first undertakes any work for an **audit** in respect of the **participant** ("the first day") and ends at ~~5~~11:59pm on the last day of the month that is 24 calendar months ~~later~~ after the first day:
Q6. Do you have any further comments on the proposal?	No comment.