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Targeted Information Disclosure Review (TIDR) 2024 – Vector's cross-submission to Draft Decision

1. This is Vector's ('our,' 'we,' 'us') cross-submission on the Commerce Commission's (Commission) draft decision on the TIDR 2024. No parts of this submission are confidential, and it can be published on the Commission's website.

A. Regulatory burden

<u>Retrospective regulation is poor practice</u>

2. The majority of EDBs who submitted have urged the Commission to delay the quantitative measures to regulatory year (RY) 2025. Alpine Energy, Aurora, Electra, FirstGas Group (FirstLight), Horizon Energy (Horizon), Network Waitiki, Northpower, The Lines Company (TLC), and Vector have each requested that the Commission push back the implementation of quantitative changes to no earlier than RY25, to avoid retrospectively having to report on items that were not known at the beginning of the regulatory year.

3. The Commission simply cannot expect EDBs to be able to change processes and systems midway through the year to accommodate changes, then retrospectively go back through historic data for RY24 and re-categorise accordingly.

4. Vector agrees with Horizon:

> *"The statements made by the Commerce Commission regarding the amount of effort required to comply with the obligations, leaves Horizon Networks concerned that the Commerce Commission does not understand how our disclosure systems and processes*

work or what is required to set up our systems and processes to meet new obligations, to a level that can meet audit and director certification requirements."

Lack of prior engagement

5. The Commission has not engaged with auditors prior to their TIDR draft decision. As outlined by Unison:

- *"Audit requirements raise questions of practicality and utility of an accountant reviewing the information. Definitions and guidance would be required to ensure simplicity for EDBs and auditors.*

- *We would be interested to understand whether the Commission has engaged with auditors about the amendments. Do auditors consider they are easily auditable and able to be fit into the existing audit schedule. For example, it is difficult to imagine that the potential time and effort to perform the amended vegetation management disclosures would be considered an efficient use of auditing time, comparative to other audit tasks.*

- *It should also be kept in mind that there is a significant resourcing cost for EDBs going back and forth with auditors on impractical requirements, in addition to the increased cost of audit."*

6. It is disappointing that the Commission has shown no evidence of engagement with auditing firms to ensure the costs of their audited proposals are outweighed by the consumer and stakeholder benefits. If the Commission wanted this information, they also could have spoken directly to EDBs to understand the costs involved. Without this, we can only presume that no cost benefit analysis was conducted prior to the draft decision.

Remove superfluous requirements

7. Alpine Energy suggests that:

"As the TIDR work programme progresses, we urge the Commission to continue to identify opportunities to refine existing ID requirements in a way that meaningfully reduces the unnecessary regulatory burden where there is low value for interested parties and EDBs. This would align with the government's expectation that regulatory agencies "pay particular attention to requirements that appear unnecessary, duplicative, ineffective or excessively costly"."

8. Vector has repeatedly called on the Commission to review and remove superfluous requirements and we believe that Alpine Energy is right to point out the government's expectation of regulatory agencies.

Workshops or more direct engagement must be held prior to consultation

9. We agree with Horizon that:

> *"Prior to issuing decisions, the Commerce Commission workshop potential solutions and timing with EDBs and affected stakeholders to ensure potential solutions and timeframes are achievable, practical and will provide meaningful information for stakeholders."*

10. It is better regulatory practice to collaborate and workshop on reporting changes with stakeholders, EDBs and regulators all present. In Great Britain, Ofgem hosts and attends working groups ahead of any consultation on their Regulatory Instructions and Guidance (RIGs) changes[1].

11. Even though in our opinion this should have been done before the draft decision was issued, Vector suggests that the Commission holds another workshop similar to the one held in March 2023 to tease out the outstanding issues raised in this consultation. EDBs will struggle with implementation, audit and definitions – the Commission must hear them out ahead of their final decision.

12. If workshops are too cumbersome, then the Commission could easily reach out to a subset of EDBs to understand their issues with the proposals. Unfortunately, we have seen nor heard any evidence of this.

<u>Information disclosure is not always the best solution</u>

13. Vector notes Drive Electric's concerns around having access to the right level of information:

> *"Decarbonisation is obviously top of our list of concerns, but we are of the view that some of the information that we seek to allow us to deliver a network of public chargers could be (or should be) included in the asset management plans (AMPs) of the EDBs. We do consult the AMPs to try and identify whether our preferred charging sites are 'doable' in an EDB network sense, but current AMPs are short on being fit-for-purpose in this regard.*

14. On this point we recommend that Drive Electric consults directly with EDBs on specific matters because AMPs are only produced annually, then become static points of information and data.

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[1] The RIGs are the annual reporting templates and guidance that network companies in Great Britain submit on an annual basis to Ofgem. Each regulatory year reporting requirement changes are proposed by all parties (Ofgem, DNOs, energy sector stakeholders etc.) and logged for transparency. The changes are then discussed at the relevant working group (i.e. if they relate to reliability, they are discussed at the QoS working group). Template changes, definitions and worked examples are derived at working group level. Ofgem then proposes the changes to the RIGs based on the engagement from working groups, in consultation form (i.e. the consultation document comes after months of direct engagement with the sector, so the changes proposed are expected and understood).

15. Meanwhile, we agree with Drive Electric's that the regulators should work together to ensure the right regulatory settings are in place across the board, in particular when it comes to new connections practices and pricing. Drive Electric state that:

> *"We consider that the resolution of the issues that are giving rise to an emerging market failure will require a well-coordinated regulatory approach by the Commission and the Authority."*

16. Vector believes that the demarcation of roles between the Electricity Authority and the Commerce Commission needs to be clarified when it comes to pricing. We explain further below under amendment D6, but it appears that the Commission is proposing changes that the Authority desires without understanding the wider context nor the implications they have on EDBs.

B. Decarbonisation

Amendment D3—Network Constraints

Require EDBs to report more meaningful network constraint (and supporting) information in Schedule 12b(i) – do not support unless changed

17. The Commission must look again at its proposed requirement to include details around 20-year forecasts. Alpine Energy, Horizon, Network Waitiki, Northpower and Vector have urged the Commission to remove the 20-year changes from Schedule 12b.

18. Schedule 12b is part of the AMP disclosure where all other forecasting requirements are 10 years; the requirements should therefore align.

Require EDBs to disclose geospatial data about their networks in a generic geospatial file format – do not support

19. It is apparent that this proposal needs further work for a number of reasons. A static annual map will not provide stakeholders meaningful information. Aurora explains that:

> *"The provision of annual data will make this national map a static one, updated five months after year-end. Aurora Energy questions how useful a static network constraints map is to interested persons and whether there is a better approach that the Commission might take around mapping network constraints. On this basis, we request the Commission to consider what it intends to do with the geospatial data and reconsider the value that introducing this requirement will add."*

20. Vector appreciates that Meridian is “very supportive of the Commission’s proposals to require the disclosure of capacity and constraint information for each zone substation through easily accessible geospatial file formats.” But we agree with PowerCo:

“This data may however not offer substantial benefits to stakeholders. We’ll presumably attribute capacity & constraint information to each substation supply area. Yet, these areas cover extensive territories, and the capacity and constraint details pertain solely to the respective substations. While we are required to name all Feeders, the data wouldn’t reveal the routing of these feeders or provide capacity and constraint metrics at individual points along the feeders.”

21. There are also security concerns with providing coordinates of zone substations as explained by Wellington Electricity (WELL):

“There is also a security concern around publicizing the exact coordinates of zone substations and critical network assets. This gives bad actors the ability to identify and target critical assets. It is important that physical asset security has the same critical lens as cyber security applies to Information Technology infrastructure.”

22. Whilst these issues exist with the current proposal, Vector nonetheless sees value in the provision of geospatial network constraints for our stakeholders and customers. To achieve the best outcomes we propose the following steps.

    a. A full day workshop to understand the needs of stakeholders, and determine a roadmap for EDBs to provide the right level of geospatial constraint data on a consistent basis. Electra has suggested that:

    “The Commission may find the ENA an appropriate conduit for further discussions with EDBs, ERANZ, MEUG, and other stakeholders on the practicalities of the national map.”

    b. The roadmap is explicit on funding requirements for DPP4 to ensure EDBs are correctly compensated to provide sophisticated network constraint maps.

<u>Amendment D5— Work and investment on flexibility resources (non-traditional solutions)</u>

23. Most EDBs attest that the definition of ‘non-traditional solutions’ needs further work. Aurora, Electra, FirstLight, Network Waitiki, Orion, PowerCo, Vector and WELL have all raised issues with amendment D5 because of the ambiguity around the definition.

24. Aurora Energy recommends:

“[…] that the Commission workshop the proposed changes to Schedules 6b, 12b, and the terminology change and definition of ‘non-traditional solutions’ with stakeholders before making its final decision. The workshops would assist the Commission in fully scoping the

amendments and land new reporting requirements that are useful, meaningful, and appropriate."

25. Vector agrees with the proposal of a workshop and would like to ensure that the workshop covers:

    a. How the reporting of non-traditional solutions interacts with the proposed Input Methodologies change to the innovation project allowance to become the 'innovation and non-traditional solutions allowance'.

    b. Clarifies how 'third party' is defined in relation to a non-traditional solution. Aurora explains:

    "We note that the Commission has not defined 'third-party' in the context of non-traditional solutions.' A third party could be a related third party (i.e., the EDB shares common ownership with that party) or an unrelated third party (i.e., the entity is vertically and horizontally separate from the EDB). A comparison of opex could be skewed if it is unclear whether the expenditure reported is exclusively related to a third party (as would be the case with opex reported in s5b) or includes expenditure to all third parties (i.e., related and unrelated third parties)."

    c. Develops a meaningful definition and name; in our submission to the draft decision we suggested 'non-wired alternative' is a better option. The term is internationally recognised and already adopted in New Zealand and across other EDBs' AMPs.

    d. Provokes a discussion around how the Commission expects EDBs to forecast expenditure relating to the 'Non-traditional solutions provided by a third-party service supplier' in Schedule 11b; including a review of alternative options to forecasting such as uncertainty mechanisms (use-it-or-lose-it allowance or pass-through). As explained by WELL, relying on forecasts could lead to inaccuracy:

    "We also note that forecasting what opex expenditure a network will require for purchasing non-traditional solutions will be difficult and any forecast provided in 11b is unlikely to be accurate."

<u>Amendment D6 – Standardised pricing components including transmission costs</u>

Amendments to ID requirements for EDBs to disclose their prices within standardised disclosure options, including transmission cost – does not support

26. Like Alpine Energy and WELL, we are concerned the Commission is straying into the regulation of distribution pricing, creating a conflict and overlap with the EA's distribution pricing oversight regime.

27. Vector is aligned with WELL; we do not support the standardisation of pricing categories in Schedule 8. WELL explains:

> *"We would also not support making the standard price categories mandatory. For our future pricing structures, this would mean recutting the volumes and revenues into new categories that are unrelated to the actual pricing structures. An EDB's Pricing Methodology, Pricing Roadmap and the Electricity Authority's Distribution Scorecards provide a better source of information for assessing an EDB's pricing performance."*

28. Horizon Networks believes:

> *"[…] this additional level of disaggregation adds unnecessary complexity and may in some cases result in EDBs disclosing individual consumers consumption and distribution charges."*

29. We agree with Horizon on this point and also with their suggestion that:

> *"The Commerce Commission and Electricity Authority clarify how the proposed updates to reporting in Schedule 8(i) and (ii) align with the work on distribution pricing reform. This will help ensure EDBs develop pricing that can meet both the Commerce Commission and Electricity Authority's needs."*

30. The population of Schedule 8 will suddenly become onerous and as we do not set our prices in the way prescribed by the Commission's proposal.

31. The definitions need refining. If each EDB interprets the categories differently, the Schedule loses its comparability objective. We are also concerned that additional explanations may be required from each EDB to explain how components from its pricing methodology are mapped to the new standardised categories.

32. Vector also has concerns about the separation of reporting quantities for distribution and transmission. In our April 2023 price setting, we changed our transmission pricing to GXP level. This means that there will be no transmission billed quantities to report at a price component level because we now charge the retailer directly for the previous year's quantities billed for each of Vector's GXPs.

33. We are not alone with this concern. Horizon states that:

> *"Requiring the quantities to be reported separately for distribution and transmission component of the quantity is resulting in the draft Commerce Commission template reporting an inaccurate total billed quantity."*

34. And Network Waitiki points out that:

"The schedule should not add Distribution billed quantity and Transmission billed quantity for the same price component as it will overstate the quantities billed."

35. Finally Major Energy Users' Group (MEUG) has requested:

"In the Commission's next consultation on further improvements to the ID regime, we would strongly encourage the Commission to look at further improvements around pricing information disclosed and information on the level of engagement between EDBs and their customers."

36. As prescribed by the Electricity Authority, when it comes to pricing, Vector's customers are the retailers who pay our line charges. However we assume that MEUG is referring to end consumers. In our experience engaging with end consumers on the subject of pricing is not well received by retailers. There are exceptions to this; Vector has dedicated account managers who liaise directly with consumers on a non-standard agreement.

37. On this very point Vector has called for greater clarity as the Electricity Authority and the Commission seem to have different expectations to the required levels of consumer engagement (especially when it comes to pricing). Many of the Commission's required disclosures assume billing at a consumer level however this is not the case as we largely bill retailers and not end consumers. With this in mind will the Commission be reviewing its pricing disclosure requirements given that many are no longer relevant or fit for purpose?

C. Asset management

Amendment AM6—Vegetation management reporting

Require EDBs to disclose additional information on vegetation management operating expenditure, and vegetation-related interruptions – do not support

38. The Commission must consider the operational reality of our field service providers (FSP) whose primary focus when attending outages is to restore power safely and swiftly for our customers. We are concerned that further disaggregation of reporting of expenditure (Schedule 6b) and interruptions (Schedule 10) will be an unwarranted distraction.

39. Horizon has articulated this very issue:

"Horizon Networks is concerned that field staff will not be able to provide quality data while remaining focussed on ensuring consumers' power is promptly restored. While it may be simple to identify if an outage is vegetation-related, it can be difficult and subjective to determine if an outage was caused by an in-zone tree, an out-of-zone tree or if it meets the definition of 'inclement weather.' This will result in delays to restoration, inconsistent classification of interruptions and a lack of traceable evidence that the correct criteria has been assigned. The lack of consistent, traceable information will impact the auditability of

this information and the work required by field staff to document the exact cause while still focusing on consumer needs."

40. Vector agrees with Horizon and suggests that the Commission speaks to FSPs about their proposed changes.

41. Additionally, there are real concerns around definitions, guidance and therefore the auditability of the proposed changes.

42. Alpine Energy explains that:

    "[…] we are concerned with the auditability of these disclosures, particularly the differentiation between in-zone and out-of-zone OPEX and interruptions. Should this proposal proceed, we recommend the Commission provide explicit guidance on acceptable evidence of in-zone and out-of-zone vegetation that is workable for field operations."

43. Network Waitiki has raised issues with the definition of 'inclement weather':

    "This definition is not clear. Can any type of bad weather during which an interruption is caused by vegetation contact be classified as "inclement weather?"

44. And Northpower are right to point out the overlapping categorisation of interruptions cause by vegetation management:

    "[…] an event caused by an "out-of-zone" tree, by "windborne debris," and "related to inclement weather" could legitimately be reported in all three categories."

45. There is consensus across EDBs that the Commission should wait for the outcomes of MBIE's Tree Regulations work programme ahead of proposing new ID requirements in relation to vegetation management.

46. Alpine Energy recommends that:

    "[…} the Commission work closely with MBIE to align regulatory outcomes. As we stated in our submission to MBIE in May 2023, we were concerned that the review of the Trees Regs misrepresents the balance of interest between 'tree owners' and 'works owners' (EDBs), providing disproportionate protection to tree owners at the potential cost to electricity safety and reliability."

47. Electra proposes that:

    "[…] the Commission wait for MBIE to complete its review of the Tree Regulations before making its final decision."

48. Unison explains that:

"Engagement with MBIE about those workstreams may be helpful before imposing new reporting requirements that would have limited effect on the choices available to EDBs regarding vegetation management."

49. This is also a view shared by Orion:

"Industry is also waiting on the outcome or progress on the Tree Regulations. This review could change the way in which we approach customers about vegetation management and it may be better to postpone this reporting requirement to TIDR 2025 when the results of this review may be clearer."

50. Vector suggests that the Commission rolls back on the AM6 proposal and, once MBIE has completed its consultation and has clear recommendations for the sector, re-ignites a specific TIDR for vegetation management.

Require EDBs to report 'Number of overhead circuit sites at high risk from vegetation damage' – do not support

51. Like Aurora we do not support replacing the metric with 'overhead circuit sites at high risk from vegetation damage.' As explained by Aurora:

"The proposed new metric is vague and, therefore, unlikely to result in consistent or useful reporting of EDB vegetation management practices."

52. We agree with the above assessment and recommends that the Commission adopts the metric which currently applies to Aurora under clause 1.6.4 of the Determination:

"For the purpose of vegetation management, the percentage of the network that Aurora has— (a) Inspected; and (b) Felled, trimmed, removed, or sprayed."

53. This measure is far more practical for EDBs to report, and easier for stakeholders to digest.

D. Interruptions

Amendment Q14 – Expand ID requirements to include raw interruption data and information on worst-performing feeders

Require publication of raw interruption data, consistent with that provided by non-exempt EDBs in advance of PQ resets, including location, cause and SAIDI and SAIFI values as well as other data – do not support

54. Vector continues not to support this proposal for the reasons explained in our initial submission to the draft decision. However if the Commission decides to go ahead with its

proposal, we recommend that the requirement be removed from the Schedule 1-10 workbook and instead sits in a standalone Excel workbook to be published on EDBs' websites.

55. Aurora has explained why this makes sense:

> *"We question, however, the benefit of publicly disclosing raw data to interested persons and in the format proposed in s10a. Our raw interruption data is approximately 5,000 rows, making the Schedule 10a format unwieldy and useless to interested persons. If the Commission chooses to retain this requirement as it has proposed (i.e., to disclose the raw interruption data publicly), we recommended that the requirement be to publicly disclose raw interruption data in an Excel Workbook format only and that the Commission not proceed with its intended s10a format."*

56. As does PowerCo:

> *"Our sole concern regarding this proposal relates to the potential scale of the schedule, especially for larger EDBs like us. For example, in the disclosure year 2023, we experienced over 6000 interruptions. This suggests that the schedule may be extremely large, potentially affecting its user-friendliness. To address this concern, we recommend excluding it from the disclosed ID schedules and, instead, have EDBs fulfil this requirement by providing the data in Excel format on their respective websites."*

57. If the Commission does move forward with its proposal, we would like to see evidence of how it will be used and who it will be used by on an annual basis, in the final decision paper. We are concerned that the effort to produce this information in the format required outweighs its useability and effectiveness for stakeholders.

Require information on the worst-performing feeders in the distribution network – do not support unless changed

58. Alpine Energy, Aurora, Northpower, PowerCo, Orion and Vector all agree that this proposal will be made more effective if limited to only unplanned SAIDI and SAIFI.

59. We agree with PowerCo that:

> *"Excluding planned outages from this data […] will offer a clearer picture of the feeder's underlying performance."*

60. As we pointed out in our initial submission, the metric is flawed and can misrepresent feeders as "worst performing" when in fact it can be distorted by the length of the feeder, or as pointed out by FirstLight, the feeder has a large number of ICPs on it:

> *"The feeders that contribute to high SAIDI and SAIFI may not necessarily be the worst-performing feeders. For instance, a feeder with a very low number of ICPs would contribute*

to low SAIDI and SAIFI, even after experiencing many interruptions throughout the year. On the other hand, a feeder with a significant number of ICPs can contribute to high SAIDI and SAIFI, even if there are only a few interruptions on that feeder. The disclosure should not be referred to as the "worst-performing feeder list" but rather as "feeders contributing to high SAIDI and SAIFI." To identify the worst-performing feeder, one should calculate the ratio of the ICP number on that feeder to the total customer minutes of all interruptions on that feeder."

61. We agree with FirstLight that the name should change to "feeders contributing to high SAIDI/ SAIFI" but continue to support dividing by feeder length rather than ICPs.

62. Meanwhile WELL has called a change to the terminology also and suggests adding a materiality threshold to the metric:

"WELL supports the introduction of worst-performing feeder metrics, but recommends a different terminology to be used 'Worst-performing feeder' implies that the feeders are underperforming. By reporting the 90th percentile, there will always be 10% of an EDB's feeders represented in this metric no matter what level of performance the feeders are at."

"We think this measure needs further clarification and definition to ensure feeders captured have a material level of outages by adding an additional materiality threshold of 5% of network SAIDI/SAIFI. i.e. 90th percentile and at least 5% of network SAIDI/SAIFI. Currently applying just the 90% threshold on the Wellington network would capture feeders that have had a single outage which is not the intent of a worse-performing feeder metric."

63. Vector agrees with WELL, the Commission should add an additional materiality threshold of 5% of network SAIDI/SAIFI to this proposal.

E. Other

64. There were two additional suggestions to improve information disclosure requirements which Vector supports.

65. The first was made by Electra:

"We would also like to take this opportunity to recommend that the Commission revisit its decision at the Tranche 1 review to require EDBs to report expenditure on Cybersecurity (Commission only) in Schedules 6a, 6b and 7. We believe Cybersecurity (Commission only) should be disclosed in a standalone Schedule provided to the Commission only, similarly to Schedules 5f and 5g and not be a disclosed measure in the publicly disclosed Schedules 1-10."

"The pragmatic solution is to move the reporting of Cybersecurity (Commission only) in Schedules 6a, 6b, and 7 to a standalone Schedule, which would only be provided to the Commission and not disclosed on EDB websites."

66. Electra's proposal makes sense to ensure the confidentiality of Cyber Security costs is maintained.

67. Another suggestion was made by WELL:

> *"To publicly disclose requires the EDB to 'make copies of the information available for inspection by any person during ordinary office hours, at the principal office of the EDB making the public disclosure.' We believe that the 'publicly disclosure definition' needs to be adjusted so that any geospatial data is only required to be provided via the EBDs website or by email."*

68. WELL's suggestion is practical, and Vector supports it.

Kind regards

[redacted]

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