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Submission to Targeted Information Disclosure Review 2024

14 September 2023

Submission and contact details

Consultation	Targeted Information Disclosure Review 2023 Draft Decision
Submitted to	Commerce Commission
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Release of information

This report contains no confidential information and can be publicly disclosed.

1 Introduction

Wellington Electricity (**WELL**) welcomes the opportunity to respond to the Commerce Commission's (**the Commission**) Targeted Information Disclosure Review (**TIDR**) 2024 – Electricity Distribution Businesses Draft decision - Reasons paper published 17 August 2023. Information Disclosures (**ID**) are an important regulatory tool, providing stakeholders with the ability to assess the performance of Electricity Distribution Business (**EDB**). We support regularly reviewing the information provided to ensure they continue to reflect distribution services customer want. Our initial submission on TIDR 2024[1] supported many of the Commission's proposed changes to improve information on decarbonization, asset management, and quality of service. As part of our submission, we developed principles to assess whether the proposed changes meet the purpose of the IDs and whether the changes would provide material benefits. We have used the same principle to assess the proposed Tranche 2 changes**.** There are some changes in their proposed form we do not support or the cost to

[1] Wellington-Electricity-Submission-on-EDB-targeted-ID-review-process-and-issues-paper-20-April-2022

implement is greater than the benefit provided. We have provided alternative solutions that provide a better fit to the principles. The principles are:

1. **Do the new measures reflect what customers want**? Either measuring a quality factor consumers' have said they find important or an asset management practice that is needed to provide consumers' confidence that the network is being managed in line with industry practice.
2. **Is the benefit provided by the information greater than the cost**? The cost of providing new information should be carefully considered and compared to the benefits it provides. Some new information may be very expensive to produce or purchase from other parties and may not have an offsetting corresponding benefit.
3. **Do we understand the cost of providing additional information and will regulatory allowances be first adjusted to provide the additional funding needed**? Some new measures may come at a cost that networks are not currently funded to provide. Many of the suggested changes are proposed to be implemented before the next price path is set. While some new information may already be collected by networks, others are not. Any changes should be supported by a corresponding increase to the regulatory allowance (if any are required). Practically this may mean a gradual application of the new measure to time with the price/quality reset process.
4. **Do the measures support one of the four limbs of Section 52A(1) of Part 4 of the Act**? – New IDs must support interested parties in assessing whether at least one of the four limbs of the Act (incentive to innovate and invest, incentive to improve efficiency and quality, share benefits of efficiency gains with consumers and to limit the ability to extract excess profits) is being met in order to deliver outcomes which are consistent with those of competitive markets.
5. **Does the information collected align with price/quality regulation**? – It is important that the ID's support and align with price/quality regulation to ensure that:
    a. The quality and performance information collected aligns with the level of quality that customers have agreed to fund and that networks are funded to deliver.
    b. The quality and performance information collected is consistent with how network performance is rewarded and penalised.

1.1 The wider provision of information

The ID's are an important data set to support electrification and decarbonisation, providing consumers with the ability to track and assess an EDB's progress on building new capacity and incorporating flexibility. EDBs also need access to new data. EDBs need visibility of the low voltage networks they manage and they need to know where EVs are being connected and where customers are converting from gas to electricity. Improving and evolving the information provided via the IDs is an important change, but wider regulatory changes are also needed to provide EDBs with smart meter data and the location of new customer devices. We ask that the Commission supports the wider regulatory changes needed to provide all stakeholders with the data they need to implement their part in New Zealand's decarbonisation.

1.2 This submission builds on the ENAs submission.

The Electricity Network Association (**ENA**) has also provided a submission in response to the TIDR. WELL participated in the development of the submission and supports most views of the ENA's submission and its assessment of the issues and the prioritisation of those issues. This submission builds on the ENA's views and provides further context around the prioritisation and possible solutions. We have highlighted where our views differ to the ENA's submission.

2 Executive Summary

We continue to support the intent of the review and most of the proposed changes. The measures to capture network constraints and the use of non-traditional solutions will be important to support networks and customers' transition from using fossil fuels to renewable electricity. While flexibility services haven't been developed to the scale needed to be used as a viable wire alternative yet, the new disclosures will allow EDBs to incrementally build their disclosures as the services mature. This will allow customers to track and monitor an EDB's progress to incorporate non-traditional solutions into their asset management planning.

We note that the ability of a network to incorporate non-traditional solutions into its asset management planning is also dependent on the availability of regulatory allowances to develop the tools and processes to use flexibility and the allowances to purchase those services. Networks will not have any new regulatory allowances until April 2025 at the earliest so it is likely to be a long time before price/quality regulated EDBs will be in a position to use the new disclosures. It will also be a long time before customers benefit from any cost savings that flexibility could provide. Some of the measures suggested in this paper will add significant cost while providing marginal benefits to the consumer. For example, we disagree with providing geospatial data to support a national congestion map because the public provision of the data will be expensive and the benefit to those providing non-traditional solutions will be limited and potentially misleading. Congestion is only one consideration of whether non-traditional solutions would be a viable alternative and we think a better approach is for networks to focus their resources on disclosing where they want to purchase flexibility services once they have assessed all of the factors.

Another example is the identification of outages caused by in and out-of-zone vegetation. Practically it is very difficult to identify when vegetation has blown in from out-of-zone vegetation. Developing auditable data will be expensive and is likely to always be inaccurate. The proposed reporting will add significant cost to provide data that can't be relied on. We think a better use of the resources is to focus on identifying and mitigating at-risk trees outside of the zone. This assumes the review of the Tree Regulations provides EDBs with the ability to force tree owners to cut or trim at-risk vegetation they are responsible for.

We would like to commend the Commission on the process in general. The combination of a staggered implementation and the use of workshops ensured that stakeholders had good opportunities to provide meaningful input. The timelines were also appropriate which meant that the process was not rushed and the draft decision was based on well-understood and expected solutions. Well done the Commission.

3 Decarbonisation

3.1 D3 – Schedule 12b(i)

WELL supports the additional constraint requirements proposed in Schedule 12b(i).

We do not support publishing constraint solutions in schedule 12b(i) (i.e 'constraint solution type', 'constraint solution progress' and 'remaining solution lifespan'). We think the AMP is a more appropriate form of disclosure for an EDB's forecast constraint solutions. We think these new categories should be added to the AMP schedules. We also think that the 'Year of forecast constraint' metric should also be changed to a range of years.

While we support providing the additional constraint information, we also note that high-voltage network constraints may not have a strong correlation to where flexibility services are needed. The previous regulatory framework has encouraged the efficient provision of electricity in a low-growth environment. On the Wellington network, we have catered for new growth within the existing network capacity. However, this now means we have little high voltage capacity headroom to meet the step change in decarbonisation-related growth. The high voltage network is also ageing and will need replacing soon, even if there has been no new growth. It's unlikely that flexibility services will be developed to the scale needed in time to provide a non-traditional alternative to building sub-transmission capacity. We think flexibility will provide future alternatives to building low voltage capacity (and potentially medium voltage) which isn't yet captured in the capacity measures.

WELL also supports the separation of zone substation transformer capacity into EDB owner capacity and non-EDB owned capacity as this is easy to implement with the data readily available.

3.2 D3 – Other

WELL does not support the general requirement to disclose geospatial data. When assessed against our principles we believe the cost of providing the data is greater than the benefits provided, and that the data will be of limited value to consumers.

Network constraints are just one of the aspects that an EDB will consider when deciding whether to use a non-traditional solution. We don't believe that a national constraint map will provide customers with a meaningful information source which they could base non-traditional investment decisions on. The general provision of geospatial data will mean providing data for areas where a network may not be considering non-traditional solutions. EDBs would incur unnecessary costs.

We believe that the proposed constraint data provided in Schedule 12b(i) and the associated information about the proposed solutions to those constraints (which we think should be disclosed in the AMP, rather than schedule 12b(i)), will provide a general overview about whether networks are considering non-traditional solutions.

We also think more detailed information about non-traditional solutions should be published continuously over a year rather than annually as part of their AMP disclosure. The decision whether to use non-traditional solutions is not static and will change between AMP disclosures and as flexibility services mature and demand requirements change. An annual disclosure is not suitable for data that is changing continually. We would then support providing geospatial data in support of the request for flexibility services. We think this more detailed information is best provided via a network website rather than AMP disclosure. An expanded data information set could be provided to support a flexibility provider to develop innovative solutions to an EDB's request for flexibility. This could include equipment operating limits and detailed, and potentially real-time, consumption and quality data providing the characteristics of the constraint.

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.

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.

3.3 D3 – AMP Attachment A

WELL supports adding descriptive policies and practices for the treatment and status of forecast constraints to inform potential consumers of where and when potential ‘non-traditional’ solutions might be requested.

We note that networks are still developing methods to assess whether flexibility could be a viable wire alternative and the processes to incorporate those services into their asset management practices. The development of this capability is complex and will take time. For example, our sister company in Australia has taken five years and has invested $4m p.a. to develop this capability. The accuracy of the information provided in the new information disclosure will evolve with time and networks may have little to disclose initially.

We also need funding to develop this capability and access to smart meter data and the location of connecting EVs to provide us visibility of the LV network so we can identify constraints.

3.4 D5 – AMP Attachment A

WELL supports the insertion of a “non-traditional solutions” definition and subsequent descriptive requirement of investigations into the ID’s. This will encourage the development of these services and provide transparent information for stakeholders competing for these solutions.

However, we believe that the definition non-traditional needs to be improved to capture non-wire solutions that have been offered for years but still offer an alternative to building physical capacity.

3.5 D5 – Schedules 5b(i) and (iii), 5d(i), 5f, 6b(i), 7(iii) and 11b

WELL supports the addition of non-traditional solutions in OPEX figures for Schedules 5, 6, 7 with the expectation that there may be nothing to report on until services have been established. It can also be expected that the amounts will increase as the services evolve and the use of non-traditional solutions becomes more common.

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. Forecasting opex expenditure for non-traditional solutions is difficult because:

- An EDB will not know how much a flexibility provider will sell services for (noting that EDBs will be competing with other flexibility buyers) and whether services can be purchased at a price that is less than the cost of building new capacity.
- What sort of demand response a flexibility service will provide, and for how long a capex investment can be delayed for (before demand increases exceed the additional capacity headroom flexibility can provide). This will depend on how fast the market matures and whether all of the components required to provide flexibility at the scale needed are in place.
- What assets will be constrained in the future and what assets will a non-traditional solution be a viable alternative. Network constraints will be a result of peak demand increases which are influenced by many external factors like EV uptake, Government emissions-related incentives or penalties, Government policy changes (like whether to continue with gas), technology changes impacting appliance prices etc.
- A network's visibility of the LV network and how efficiently the LV management tools allow a network to incorporate flexibility into their demand management (noting networks still need to develop the capability to see and forecast LV constraints and the tools to use flexibility and they need the allowance to fund that development).

These areas are discussed in WELL's IM submission in more detail. [2]

3.6 Schedules 8(i) and 8(ii)

WELL does not support standardized pricing components in schedule 8(ii)[3]. EDBs have a range of different customer pricing categories and many of those do not align with the proposed categories. For example, our future pricing structures will have four main categories, residential and small, medium and large commercial pricing categories. We will use a connected capacity charge ($ per KW of connected capacity) to eliminate the need for multiple commercial pricing categories which are usually created to apply increasingly larger fixed daily prices. A connected capacity charge will avoid step changes in prices as customers transition between categories. We consulted with retailers on the new price structure and they support reducing the number of price categories and using a connected capacity charge to simplify prices and remove price step changes.

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[2]

[3] We initially supported this change but we have changed our view once we considered the wide range of different customer pricing groups used by EDBs.

Under the proposed new ID's we would create customised price categories to reflect our customer categories and we would not use the standard price categories. We see little value in providing standard price categories when an EDB can still customize the price categories to match their own categories. We support retaining the current approach which allows EDBs to use their own categories.

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.

WELL supports disaggregating "distribution" and "transmission" components of the billed quantities and line charge fields. This provides clarity for customers on what the breakdown of charges is and the controllable portion of their bill that they can influence.

WELL also supports the removal of "unit charging basis" and "rate" fields, as this allows greater flexibility for EDB's to customize their pricing structures to suit their customers.

To decarbonize the network, customers need to be more engaged in their energy usage. Pricing is an important tool for signalling the high cost of using electricity during the network peak and for optimising network investment.

4 Asset Management

4.1 Schedule 6b(i) – rows 8, 9, 10

4.2 WELL supports reporting EDB's OPEX for 'service interruptions and emergencies' allocated into 'vegetation-related' and 'other'. This is a straightforward breakdown that gives the customer a clear indication on how vegetation accounts for interruptions and the cost associated. Schedule 6b(ii) – rows 14-15

WELL supports disaggregating vegetation management costs by in-zone or out-of-zone in schedule 6(ii). This is information that is already collected and would provide valuable insights into a network's vegetation management programme.

4.3 Schedule 9c

WELL supports the definition of 'overhead circuits at high risk of vegetation damage' as this identifies a portion of vegetation out of an EDB's control that poses a risk to service. However, reporting as a snapshot in time would not capture a network's risk exposure over the whole year and may reflect a time that is not representative of the effort undertaken by an EDB to resolve.

It would be more useful to provide a total number of ‘overhead circuits at high risk of vegetation damage’ identified throughout the disclosure year and the percentage of those circuits that have been actioned or resolved. This would provide a consistent view and comparability of EDB’s proactive mitigation of high-risk vegetation.

We also think that an additional level of disaggregation of vegetation management costs, separating the cost of repeated hazard tree and cut and trim notice visits, could be useful. This would highlight the unnecessary costs caused by customers not responding to notices to mitigate identified, at-risk, vegetation.

WELL supports proportionally breaking down circuits that require vegetation management by a range of categories because this allows EDB’s to customise their reporting and gives consumers useful context about the quantity of vegetation management a specific network requires. WELL is already stratifying its categorisation of vegetation and it corresponding treatment network risk.

4.4 Schedule 10

We do not support providing interruption data caused by vegetation from ‘in the zone’ and ‘from outside of the zone’. While we support the intent, we think the costs may outweigh the benefits for networks with a high proportion of their network surrounded by vegetation. We can provide the information by relying of the effective trimming of ‘in-zone’ vegetation which eliminates ‘in-zone’ vegetation from contacting electrical equipment (we would then make all vegetation outages caused by ‘out-of-zone vegetation’). We implement regular audits of the effectiveness of the programme which could be used to support the audit of the IDs. However, we recognise this is a resource-intensive process that may not be affordable for some networks.

5 Quality of Service

5.1 Schedule 10a (New)

WELL supports the intention of Q14 to provide raw interruption data. The data is already audited annually and is also re-audited and provided every five years as part of the Default Price Path reset. Providing it annually would avoid having to re-audit the data every five years.

However, WELL would like the Commission to acknowledge that there will be additional costs associated with providing the data at such a forensic level. WELL's outage structure is not set up in this manner to report on its current state. While we collect the data already, there is significant additional reporting to breakout the data for outages that affect multiple feeders into individual entries in the outage schedule.

We also note that the term feeder is not defined. For example, WELL refers to feeders as a 11kV circuit. It will be important to ensure that the definition is applied consistently.

WELL agrees that interruption data provides insight when assessing or understanding an EDB's performance over time and in comparison to other EDB's. We also note the more detailed information will require a level of expertise to analyse and understand. Network designs are not homogenous and comparing interruption data at the proposed more granular level may result in mistaken concerns raised if the reader does not have the expertise to interpret the information.

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.

WELL supports removing the existing requirement for disclosure of normalized SAIFI and SAIDI and also support the additional cause category 'other'.