Counties Energy

14 September 2023

Commerce Commission New Zealand
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Wellington 6140
By E- Mail: regulation.branch@comcom.govt.nz

Re: Submission on Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses

Counties Energy Limited's submission is in regard to the Commerce Commission's (the Commission):

- *Targeted Information Disclosure Review (2024) – Electricity Distribution Businesses. Draft decision - Reasons paper (*the paper);
- *[Draft] Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024* (the determination), and;
- *Accompanying 'Draft Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination' Schedules x 3* (the schedules).

Amendment D3 – Network constraints

Counties Energy is supportive of the reporting in the ID that enables stakeholders to better comprehend whether EDBs understand their network constraints, have a plan for addressing them and how the constraints are communicated with potential new connecting parties and flexibility service providers.

- Regarding the proposed changes to schedule 12b(i): We are supportive of the proposed changes.
- Regarding the proposed changes to schedule 9e(iii): We are supportive of the proposed changes.
- Regarding the proposed change to disclose network data in a geospatial file: We are supportive of the proposed changes.
- Regarding the proposed change to include policies and practices for constraints: We are supportive of the proposed changes.

Amendment D5 – Work and investment on flexibility resources (non-traditional solutions)

Counties Energy is supportive of the reporting in the ID that enables stakeholders to better understand how well each EDB is performing regarding considering the use, and uptake, of flexibility resources. We note however that non-traditional solutions are in the early development phases and anticipate that forecast

OPEX values may be unreasonable to expect by the 2025 AMP update, but expect this to mature in subsequent AMP cycles.

Amendment D6 – Standardised pricing components including transmission costs

Counties Energy believes that the disaggregation of the “distribution” and “transmission” components of the billed quantities and line charge revenue fields will provide misleading results. This is because the new transmission pricing methodology (TPM) benefit-based charges can not be allocated with any meaningful accuracy to customer groups.

The calculation of the benefit-based charges by Transpower is complex because it involves market modelling using historic hydro inflows to simulate GXP prices with and without a long list of transmission assets. Add to this the list of transmission assets will grow over-time making the analysis increasingly complex. Consequently, it is not possible, or of value, for EDBs to then accurately split their line prices between the distribution and transmission components. Given this, what is the insight that the Commission is seeking from EDBs providing a split of its billed quantities and line revenue into distribution and transmission?

Amendment AM6 – Vegetation management reporting

Counties Energy is supportive of reporting in the ID that enables wider stakeholders to better understand the risks that vegetation presents to the network. In particular, the impact that out-of-zone trees on reliability, which are not presently in the scope of tree regulations[1], have on the network.

Regarding the proposed changes to schedule 6: Counties Energy is supportive of the changes and already has internal systems mostly aligned to the proposed categories. We do however believe better clarification is required as to what is to be included in the *‘service interruptions and emergencies - vegetation-related’* category. For example, if a tree were to fall into lines, damaging them and causing a feeder outage there would be a variety of costs associated with:

a) Initially responding to the feeder outage and restoring customers wherever possible (first responders, feeder patrols etc.);
b) Site work associated with clearing the fallen tree;
c) Site work associated with repairing the damaged lines and distribution equipment; and
d) Potentially generation costs for impacted customers in some cases;

In this example, where the cause is vegetation, it is not clear if all the above listed costs be included under the new vegetation category or just those directly associated with vegetation (i.e. item b in the above list). We believe the ID is most effective when clear definitions are available that are not open to interpretation. This ensures consistency is applied to all EDB reporting that then best enables comparisons across different years and between different EDBs.

Regarding the proposed changes to schedule 10: We are supportive and already have our internal systems mostly aligned to the proposed categories. Our only concern here is the inclusion of ‘inclement weather’ as a cause. Our concerns with this are:

[1] *Electricity (Hazards from Trees) Regulations 2003.*

- This term does not appear to be clearly defined anywhere. We suggest if this is to be included, this should be defined in absolute terms. For example in terms of sustained wind speeds over a certain timeframe. If this term is not defined, there is likely to be a high level of subjectivity, and therefore variance between disclosed schedules over different years and between different EDBs.
- Other parts of the ID/schedules use the term 'adverse weather' and this could be used instead of introducing a new term and category 'inclement weather'.

Regarding the proposed changes to schedule 9c: We do not believe the proposed changes to this schedule will achieve the objective of stakeholders better understanding risks. This appears to be largely defined on the numbers of hazard trees identified, cut or trim notices (CTN) and hazard warning notices issued. Consequently, it is not clear whether this is intended to mean the total number of notices issued during the disclosure year, or something else, and we suggest a clearer definition is needed.

If the schedule is intended to be total notices issued during the disclosure year, it could be that on the 1st of April we issue a CTN for a tree that takes a few weeks to resolve (trim), yet on 31 August the following year, some 16 months later when the ID schedules are published, we report on that long-resolved CTN in the context of being an 'Overhead circuit site at high risk from vegetation damage'. That CTN may even relate to a covered/insulated overhead LV service cable reported by a customer that poses very little risk to the wider network because the present tree regulations do not enable the issuing of CTNs to be distinguished by network importance or risk. An alternative interpretation may be the number of outstanding and unresolved notices as of the disclosure year-end. However, we do not believe this would give a clear measure either as the number of outstanding notices is going to be largely driven by the volume of recent vegetation inspections, and their location in terms of vegetation density in those particular areas.

We believe more consideration is required to determine effective metrics for inclusion in schedule 9c that meet the objectives, whilst also not being overly burdensome to report on, or open to interpretation or ambiguity. We are aware that other EDBs have had reporting metrics determined as part of CPP processes that may be usable. Alternatively, metrics based on notices issued could be workable, but clear definitions around applicable time periods are needed. Additional considerations could be notices completed versus those issued but noting that in cases such as 'second cuts' or 'hazard trees', those notices are typically outside of the control of the EDB to address, so the reporting would likely need to distinguish these.

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

Regarding the proposed schedule 10a: Counties Energy is presently an exempt EDB (from PQ regulation) so has not previously disclosed raw interruption data. We are however not against the principle of sharing this with stakeholders, especially the Commission, if it adds value. We do however believe that the proposed schedule 10a is not an effective way of doing this. For FY23 our planned and unplanned events numbered over 1,000. This would mean an extra 20-plus pages in the schedules we disclose to include all of these events and for other larger exempt EDBs the schedules would be even larger. We suggest that if raw data is useful to the Commission, we could provide this in a similar format and method that the non-exempt EDBs do.

For the public disclosure, we also do not believe the proposed Schedule 10a would be effective because with only the proposed fields available it will not be possible to draw any conclusions as to the network performance and service quality available in a particular area (a disaggregated view or understanding of the local causes of customer experience we understand being the intent). The vast majority of events only impact a handful of customers yet are linked to a distribution feeder that can have (for Counties Energy) up to 3,000 connected ICPs. Without knowing the location of the event on the feeder or having a link in the data to the particular transformers/ICPs impacted, forming an understanding of this disaggregated view or localised customer experience is not possible. We have some suggestions on how this could be done, related to our response to the proposed schedule 10(vi) below.

Regarding the proposed schedule 10(vi): Counties Energy is not against the principle of disclosing this information, and it would be quite simple to do so. However, for similar reasons described above we do not believe this will effectively meet the objectives.

- A distribution feeder can be across a large area. For example, Counties Energy's rural feeders are the longest and most exposed covering remote and rugged areas of the network that are consequently more susceptible to events. It is not uncommon for these feeders to be more than 100km long and serve an area of several hundred square kilometres.
- Network reliability is often not consistent along the length of a given distribution feeder. We have examples of feeders that are supplied from substations located in urban areas supplying urban customers, which then continue for many tens of kilometres through rural and rugged terrain. These feeders typically have mid-feeder protection or automation devices (such as auto-reclosers) based on the longer, more exposed, rural/rugged sections of network that are more susceptible to events. Although customers in these areas may experience higher network SAIFI/SAIDI, this experience is not the same for the urban customers at the start of the feeder.
- SAIFI/SAIDI are functions of the number of events, the number of impacted ICPs, and the duration of the event, all normalised across the network base. If an urban feeder is compared to a rural feeder, where the number of connected customers, outage durations and asset performance (fault rates per km) are all similar and the only notable difference is feeder length, then it would not be unexpected that a rural feeder four times the length of the urban feeder would have corresponding network SAIFI/SAIDI also four times higher. But this is with fault rates (asset performance) and response times constant. Long rural feeders supplying a reasonably large number of rural customers are almost always going to show up as worst performing in overall network SAIFI/SAIDI terms, and we question if this meets the objectives.
- Following on from the last point, we also caution on the interpreted meaning that the term 'worst performing feeder' may imply. We understand that SAIFI/SAIDI is a measure of customer experience made up of many factors but not necessarily a pure measure alone of asset performance or response times. A high network SAIFI/SAIDI contribution from a particular area doesn't necessarily mean an asset performance or network management issue because it could be just a product of the local geography and/or network topology.

Counties Energy's view is that only considering reliability down to a feeder level is not granular enough to create an informed view of the quality of supply customers could experience in a given area. To meet the objectives a more granular view is required. This could be in the form of a geospatial heatmap, customer average [CAIDI] either by a unit area (e.g. 10 km^2) or area served by a distribution transformer. Alternatively a statistical performance distribution view could be produced, by say distribution transformer, through plotting a distribution of customer experiences (annual group CAIFI/CAIDI) across the network relative to network average SAIFI/SAIDI values. Metrics could be produced that report on the number of network customers within performance bands relative to the average. This is an approach Counties Energy is already exploring in our internal reliability management reporting, accompanied by the consideration of service level standards across different geographical areas (e.g. urban/rural/remote).

Counties Energy would be happy to discuss any aspect of this submission.

Yours sincerely

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