
# Improving information on high-voltage network capacity

16 June 2026

## 1 Submission and contact details

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| Consultation | Improving information on high-voltage network capacity |
| Submitted to | Electricity Authority |
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## 2 Introduction

This submission is provided in response to the Electricity Authority's 2026 consultation on high voltage (HV) network visibility requirements.

We acknowledge the Authority's objective of improving transparency to support efficient market participation and informed decision-making by access seekers. We support the underlying intent of reducing information asymmetries where doing so demonstrably promotes competition and efficiency.

However we have the following concerns:

The proposed requirement to provide capacity information at each point along a circuit where design capacity changes are overly prescriptive and unnecessarily granular. The proposal does not adequately demonstrate that such detailed information is required by a broad set of access seekers, nor that it will materially improve outcomes.

- The costs of implementation, including system transformation, data management, and ongoing compliance, are likely to outweigh the incremental benefits.
- The timeline is unnecessarily tight.

A better approach is available that would achieve the Authority's objectives at materially lower cost.

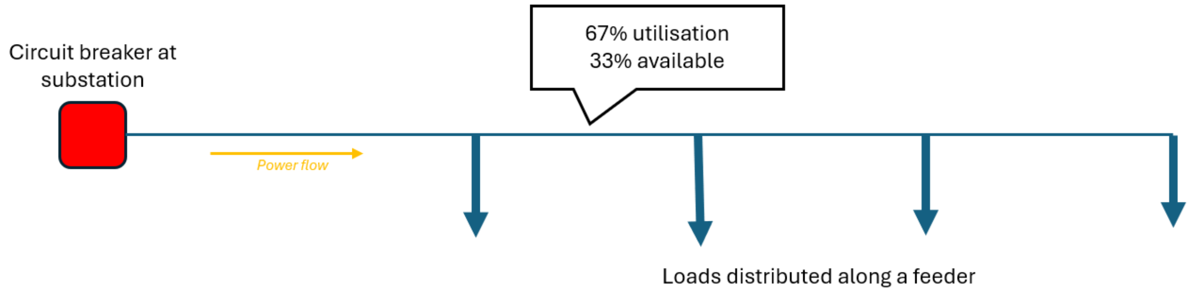
We recommend that the Authority:

- Refine the scope of required data granularity
- Provide flexibility in system implementation timelines
- Adopt metrics better aligned with customer interruption frequency (CAIDI/CAIFI)
- Explicitly assess cost benefit trade-offs in line with good regulatory practice

# 3 Meshed network intricacies

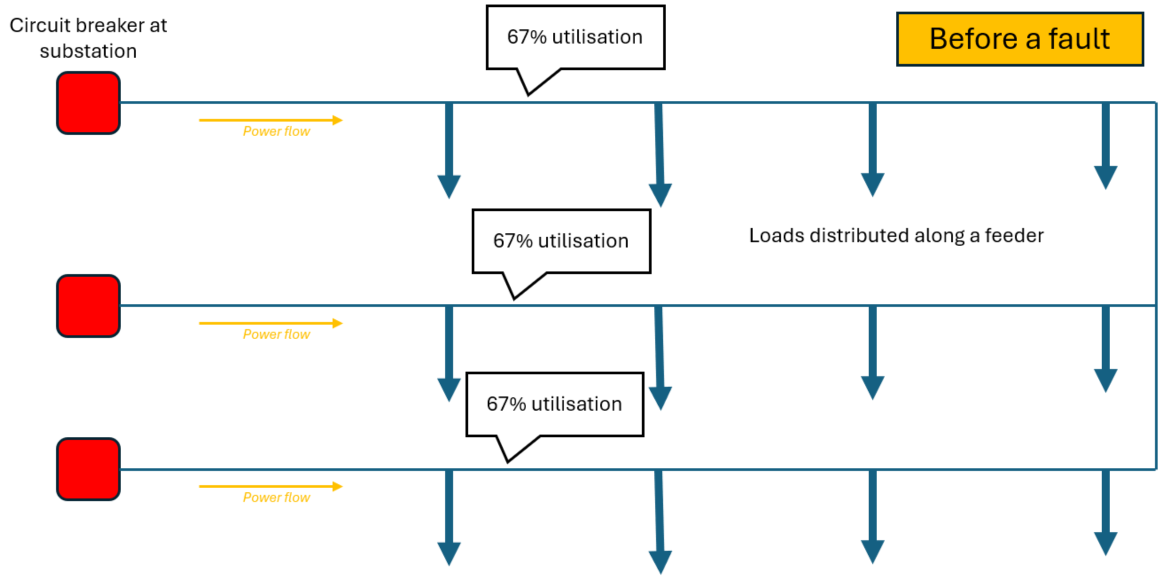
Wellington Electricity's network is uniquely complex in New Zealand with significant meshing in the HV level as well as considerable LV meshing which affects modeling of the upstream HV. While simpler networks may be able to easily model their radial constraints in a simple GIS format, we* cannot do this accurately without building a complex integration between our spatial system and power modelling system.

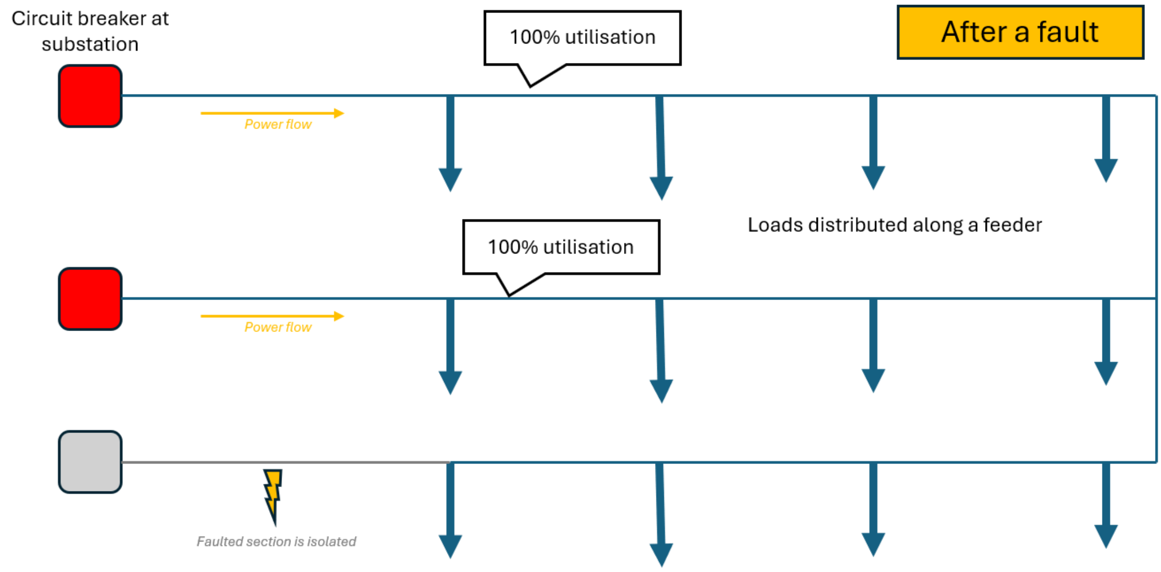
For example, on a radial feeder that is typical of a rural network, the available capacity can be easily reported and calculated based on the utilisation of network assets – as shown by the figure below:




However, in Wellington Electricity's CBD network, the typical feeder configuration has multiple sources meshed, providing a continuous supply. This network architecture provides a higher level of security (Commerce Commission Quality Targets) – meaning that customers will not experience an interruption if a fault occurs on a part of the feeder. However, this requires that the entire feeder has spare capacity to accommodate for the total load after loss of a single system component.

This is demonstrated in the figure below, which shows a scenario where a distribution feeder, whilst operating within its limits before a fault, can exceed the limits after a fault:




Wellington Electricity must preserve sufficient capacity to maintain the level of security to which our quality standards are measured.

Calculation of this security limit is complex, requiring several iterations of load flow simulations in PowerFactory to determine the worst-case fault locations. Reporting on the available capacity on a feeder may then contradict with Wellington Electricity's security assessments.

For Wellington Electricity the proposed requirements would necessitate:

- Significant data transformation between GIS and modelling platforms
- Establishment of new data governance, validation, and maintenance processes
- Potential system reconfiguration or duplication

## 4 Data granularity requirements

As the current wording of the proposal is drawn up, there will be five data sources that need to be amalgamated.

1. SCADA. This provides real-time data from specific locations in the network, and stores historical data at a resolution of 5-minute averages.

2. GIS. This is the geographical representation of the network, recording what assets are installed, where they are installed, and their connectivity. There is no data link or common identifier between objects in GIS and their real-time representation in SCADA.

3. PowerFactory. This is our load flow analysis tool. It contains a single line diagram representation of the network, including asset capacities. There is no data link between the topological representation of objects in PowerFactory and either the geographical representation in GIS or the real-time representation in SCADA.

4. Load Forecast. This applies scenarios to the prior year's demand at an HV feeder level, to forecast demand into the future. The output of the load forecast is run through PowerFactory to identify constraints as part of the annual planning process.

5. Reliability records. The data is sourced from SCADA, recorded with outages aggregated to the HV feeder level. It goes through significant quality assurance work, auditing, and certification before it is published for our annual disclosures.

The requirement to provide data at all points along a circuit where capacity changes would effectively require replication of the five data sources as described above. Most notably the engineering model would have to be linked to an externally published geospatial dataset. This raises several concerns because connection and planning decisions are typically made at discrete nodes or segments, rather than 'along a line'. Matching data between an engineering model used for planning/capacity information, with GIS mapping software continuous along-circuit variation would require 20,000 GIS objects to be assigned a designed capacity, forecast remaining capacities, and reliability information. We currently provide ~250 data points as part of the AMP disclosure requirements and is only provided annually.

The marginal benefit of additional granularity is likely to be small and diminishing, particularly relative to the cost (see our comment below re proportionality).

## 5 Suggested improvement to performance Metrics: SAIDI/SAIFI vs CAIDI/CAIFI

We recommend that if the Authority sees value in visibility of specific locational performance metrics, they should consider replacing reliability metrics (SAIDI/SAIFI) to customer interruption measures, specifically CAIDI and CAIFI (Customer Average Interruption Duration and Customer Average Interruption Duration). CAIDI is an indicator of the average length of outage for the customers affected, and CAIFI is an indicator for the number of outages experienced by affected customers. These are potentially more meaningful to customers than SAIDI/SAIFI, however these can only be provided at a feeder level and not at locations along the feeder.

CAIDI and CAIFI are better measures because SAIDI and SAIFI are network reliability indicators rather than measures of locational reliability. Two locations with the same contribution SAIDI/SAIFI may have wildly different customer experiences depending on the number of customers on the feeder and the number of customers supplied by the network.

## 6 Proportionality

The consultation appears to assume a generalised need for highly granular HV network data. In our experience only a limited number of sophisticated access seekers (eg. large-scale generators, advanced DER developers) require detailed capacity modelling outputs. As we understand, the majority of stakeholders can make effective decisions using aggregated or node-based information. The proposal risks standardising a high-cost solution to meet the needs of a narrow subset of users, which appears to be disproportionate, and does not clearly have a positive cost/benefit. In general, this level of data is not required to run a network efficiently.

| Customer Numbers by Customer Group | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Domestic | Large Commercial | Medium Commercial | Small Commercial | Large Industrial | Small Industrial | Un-metered | Individual Contracts | Total |
| Mar-26 - Actual | 160,108 | 534 | 491 | 14,589 | 40 | 527 | 834 | 191 | 177,314 |
| Feb-26 - Actual | 160,062 | 533 | 488 | 14,587 | 40 | 528 | 842 | 191 | 177,271 |
| **Customer Movement (Month)** | 46 | 1 | 3 | 2 | 0 | (1) | (8) | 0 | 43 |
| Mar-25 - Actual | 159,086 | 525 | 482 | 14,746 | 40 | 519 | 851 | 191 | 176,440 |
| **Customer Movement (Year)** | 1,022 | 9 | 9 | (157) | 0 | 8 | (17) | 0 | 874 |
| *Mar-26 - Budget* | 159,344 | 513 | 471 | 15,037 | 40 | 512 | 848 | 191 | 176,957 |
| **Customer Variance** | 764 | 21 | 20 | (448) | 0 | 15 | (14) | 0 | 357 |

WELL has 90% of the 177,000 network connections at 15kVA capacity with an after diversity maximum demand (ADMD) of around 4kVA each. There are likely to be only 500 of the remaining connections above 1MVA which accounts for 0.2% of current customers who would be concerned with network capacity at the time of connection. There is not a material number of customers that would benefit.

There is limited evidence that publishing and maintaining capacity maps would deliver enduring national benefits, particularly given the small number of customers needing this information. Connection enquiries are most effective when managed through direct enquiry. The current process already provides indicative charges and supports customer decisions on capacity and price – quality trade-offs, reducing the value of a generalised map.

Recent large connection requests have required tailored modelling with multiple iterations, reflecting that a static map would not provide the level of detail customers seek (e.g. costs, timeframes, tariffs, and security of supply). While we recognise the Electricity Authority's net-zero emissions objective, large-scale developments often require bespoke solutions that a capacity information would not sufficiently provide. For example, the Mill Creek wind farm required a dedicated 33 kV twin-circuit connection. In this case, a capacity map would have had limited practical use.

If progressed, capacity mapping may be more relevant at higher voltages (e.g. 33 kV), where generation typically connects to the transmission grid, as lower-voltage networks are unlikely to support large-scale generation efficiently.

We note that the Authority's assessments of costs and benefits are qualitative only. While we appreciate that it is difficult to establish robust quantitative benefits, there appears to be a significant and speculative assumption of substantial and widespread benefits from this type of initiative (from paragraph 5.67 onwards of the Authority's paper). While that's possible, much narrower benefits are also very plausible. Given there is a material cost involved in complying with the Authority's proposed requirements, we suggest taking a more proportionate approach with reduced data granularity and flexible implementation pathways. This would still head in the right direction – promote the Authority's objectives – while being lower cost for consumers and allowing more option value as the Authority is able to observe actual use of the capacity data.

## 7 Interaction with recent Code changes

This amendment replaces a previous amendment to the Code, Part 6.3(2)(da)-(df), due to come into effect on 1 December 2026, with that amendment now only applying until 1 September 2027. We are currently spending money developing the new capability and tools to implement the changes required by that amendment, which is now proposed to be superseded after it will have been in effect for just nine months.

This amendment also conflicts with what is required under IDRs. The Commission requires one map under the IDRs, and the Authority wants a different one. The Commission has asked for reliability and capacity to be reported in one manner in the AMP, and the Authority wants them reported in a different manner. This will be confusing to customers.

It would be helpful, and more efficient (and therefore lower cost for consumers), if there was a single requirement that gives the regulators the information that they need in a consolidated manner, instead of similar information presented in a different way.

We would welcome further engagement with the Authority on refining these proposals.

## 8 Appendix B Submission form

| Submitter | Wellington Electricity |
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| **Questions** | **Comments** |
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| Q1. Do you agree with our assessment of the current state of the information and capabilities needed to inform network hosting capacity? If not, please explain why. | WE* agree that the EA's focus on efficient connection of DG and load, are aligned with visibility information rather than the Commerce Commission's information disclosures but the regulators should not work in isolation.<br><br>WE* believe that the Authority has made the incorrect assumption of the understanding of network topology under 3.14 of the consultation. The explanation is simplified and assumes the data collected under IDRs can be transformed for the EA's visibility requirements. This is incorrect. The basic data disclosed is not a reflection of the internal systems, processes and data maturity of a network. A basic spatial model of the network is required for these disclosures, while having a fully-fledged connectivity model intricately tied to a power modelling system is not. |

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| Q2. Do you agree the issues identified by the Authority are worthy of attention? If not, please explain why. | Yes, standardization is beneficial in the industry, and should be developed for EDBs to follow when choosing to publish network constraints. Issues arise when a subset of EDBs have already developed the capability, and the rest must accelerate digitization at substantial cost. |
| Q3. Do you agree with our assessment that now is the time to regulate for network visibility? If not, when do you consider would be the right time? | Yes, we agree that now is a good time to start standardising network visibility for the networks that have embarked in network visibility projects but WE* believe it would be inefficient in the short term to regulate complete visibility nationally under the current granular proposal. As described above, there are assumptions that the data already exists and is not being used, whereas developing this capability will most likely cause deferral of other investments. A better approach would be to reduce the scope of the published data, then analyse the utilization of the data, before mandating further development. |
| Q4. Do you agree with our assessment of the outcomes that network visibility supports? If not, why not? | WE* agree that network visibility supports objectives (a) – (d). With the exception of (e). As mentioned in the paper, some distributors know they have no constraints on their network and this proposal will force them to spend money that could otherwise be spent elsewhere. |
| Q5. Do you consider the proposed amendments to Part 6 of the Code would promote the Authority's statutory objective? If not, why not? | Yes, if the requirements are scaled back and the timeline extended. |
| Q6. Are there any matters you believe are missing from the proposed Code amendment? Please specify. | N/A |
| Q7. Is the indicative timeframe for implementing the proposed Code amendment likely to be adequate? If not, please provide information supporting a | No, the indicative timeframe is too soon and should be delayed by 2-3 years. |

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| different timeframe, including identifying cost savings from a later implementation date. | The network geographic information disclosures required under clause 2.5.2A, was decided under the Targeted Information Disclosure Review (TIDR) in February 2024, and was first required to be disclosed on 31 August 2025. This gave EDBs 19 months to comply with the requirement. This disclosure is updated annually and, for WE*,only uses 33 data points. To compare, requirements in this consultation will use ~20,000 data points, is updated quarterly, and (assuming a decision is made before the end of 2026), would give ~10 months for implementation of a much more complicated set of requirements.<br>EDBs are already developing solutions to comply with the Network Connections Stage One visibility requirements from December 2026. Meeting these requirements will demand dedicated resources to develop and publish the information, and it would be an inefficient use of effort for a dataset that would only be utilised for only three quarters. Given that a subset of high-voltage visibility data will already be available from December 2026, we do not consider that the level of urgency currently attributed to the proposed Code amendment in this consultation is justified. |
| Q8. What are your views on the proposed approach where detailed information about the data sets captured within the definition of network capacity information would be contained in technical specifications? | We agree that a technical specification is crucial to ensure standardization across EDBs. |
| Q9. Do you consider that the proposal to develop network visibility specifications in consultation with interested parties would be effective? If not, why not? | We agree that specifications should be developed with interested parties to ensure the right information is being gathered and interpreted correctly. |

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| Q.10. Is the proposed timeframe for developing the specifications likely to be sufficient? | We do not agree that 6 months from decision announcement will be sufficient to develop the specifications. |
| Q11. Do you agree with the proposal to start with high-voltage network visibility? If not, please share your perspectives on where best to start. | We agree to starting with HV visibility. A lot of the LV network in Wellington is underground and it would be a significant challenge to capture information due to the network being installed prior to digital systems. |
| Q12. Do you agree with the assumptions the Authority has made? Why/Why not? | WE* disagree with 5.45(a) and 5.45 (b). Despite having SCADA systems, power modelling systems and geospatial systems, these must be tied together for an output to be accurately generated at any congestion point. There is separation between each of these systems, and some spatial systems have considerable limitations for data sharing, API interfaces and web hosting. |
| Q13. Have we correctly identified the benefits of network visibility? | We agree that the Authority has correctly identified the right categories of benefit. The amount of benefit is uncertain. |
| Q14. Do you have any information that might help quantify the value of these benefits? If so, please provide this information. | N/A |
| Q15. Have we correctly identified the costs of network visibility? | WE* disagree that the Authority has considered the varying scale of data maturity between EDBs.<br>Distributors make different choices about how to prioritise their limited expenditure allowances, allocating investment to areas they consider most critical for their networks. At the same time, there is a wide variation in the capability of IT systems across EDBs, meaning that the cost and complexity of implementing the new requirements will be minimal for some, |

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| | but significant for others. These differences reflect historical investment decisions and differing operational priorities across networks. |
| Q16. Do you have any information that might help quantify the costs? If so, please provide this information. | As described above, there will be a large span of cost differential across EDBs.<br>Based on a partial solution proposal WE* had investigated 3 years ago, we would expect an increase in at least $150k per annum in licensing costs, with an additional $300k initial costs for the system implementation and training. |
| Q17. Have we correctly identified the regulatory overlaps? | The areas of overlap have been identified but the impact of overlap has not been fully realized. We consider that the Electricity Authority's focus on the efficient connection of distributed generation and load, places it in a strong position to develop and manage visibility information. However, this should be undertaken in close coordination with the Commerce Commission, recognising the Commission's established role in setting and administering information disclosure requirements. In our view, clearer delineation of responsibilities and greater collaboration between the two agencies would help ensure that disclosures are consistent with existing regulatory frameworks, rather than creating overlapping or misaligned requirements. |
| Q18. Do you agree with our assessment that there is a net benefit notwithstanding any regulatory overlap? If not, why not? | We agree that there is benefit to providing HV visibility through the EA's regulatory responsibilities. However, the timing is crucial to ensure that the data being published is worth the additional cost that will be borne by all customers on networks. The geospatial data required under the information disclosures has |

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| | only been available for 10 months. A longer implementation timeframe for other visibility requirements would give EDBs more confidence that the investment in data and systems, will benefit customers. |
| Q19. Do you have any information that might help quantify the costs and benefits associated with the regularly overlap? If so, please provide this information. | N/A |
| Q20. Do you agree that the Authority should consider reducing the regulatory overlap as the proposed specifications are developed? | Agree. |
| Q21. Do you agree with our assessment that there will be net benefit from the proposed amendments? If not, why not? | WE* disagree that there will be a net benefit from the proposed amendments, if the scope and trajectory are maintained for this proposal.<br>A reduction in scope and/or increase in the timeframe to implement will help reduce the need to rewrite visibility requirements (as has happened since the network connections stage one paper was decided).<br>Secondly, if the current Commerce Commission disclosure obligations do not meet the needs of customers, then the Commerce Commission should look to remove the requirements and remove the regulatory overlap, and then the Authority can consult on the information most useful to customers. |
| Q22. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010. | Discussed above. It would be more efficient, and lower cost to consumers, if the scope of the amendment was narrowed and the timeline relaxed. |
| Q23. Do you agree the Authority's proposed amendments comply with section 32 of the Electricity Industry Act? | |

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| Q24. Do you have any comments on the drafting of the proposed amendment? | The data is required to be disclosed on 15 December, 15 March, 15 June, and 15 September for “the immediately preceding 12 months”. “Immediately preceding” is not defined. Is it 12 months of data as at the end of the month immediately prior to the publication date? That would give just two weeks to collect the latest historical data, rerun load forecast, rerun the capacity analysis for all of the line segments on the network, and update the data behind the maps. That is an unreasonably short turnaround time given how manual the process may need to be.<br><br>What the Authority is expecting for “capacity” needs to be defined.<br><br>Forecast demand will differ between EDBs using different percentiles and methodologies. The forecast demand percentile (at WE*) is applied and then compared to network security limits, as these generally bind on our network before any capacity limits. Publishing the difference between the forecast and the capacity limit would give a different number, which is not what we assess customer connection requests against for network stability and reliability.<br><br>The amendment requires the provision of minimum and maximum available capacity, but it is unclear how these figures are intended to reflect the inherently variable nature of network capacity. Available capacity varies significantly depending on factors such as forecast assumptions, seasonal conditions, time of use, and the connection point. As a result, a single |

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| | minimum or maximum value risks being misleading without clear context. |
| Please indicate if you wish to be consulted during the development of the technical specifications supporting the proposed Code amendment. | Yes. |

[redacted]