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LV Monitoring Disclosure

31 August 2024

1 Introduction

This disclosure has been prepared in accordance with Clause 2.6.1B and Clause 17.2.2 of the Commerce Commission's Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024. It collates extracts from WELL's 2024 Asset Management Plan that provide a narrative description of WELL's progress towards monitoring and forecasting load and injection constraints on its low voltage (LV) network.

2 The Changing Technology Environment

There continues to be much interest around distributed energy resources (DER) and how these will impact transmission and distribution networks, metering, central generation, and retailers. This new technology could also impact customers, with new markets developing for customers if they choose for their assets to be used for demand management.

The growth of new technologies in the energy storage and market trading environments has a significant effect on the development of smarter electrical networks, and the ability of WELL to influence energy consumption. Greater visibility of energy transfer in the form of real-time network monitoring and improved digitised data is required to enable WELL to adequately manage this space. WELL continues to monitor evolving technology trends and the uptake of new technology that is likely to impact the electricity sector. This includes (but is not limited to) monitoring the uptake of commercial and residential solar panels (Photovoltaics or PVs) and energy storage systems, the increasing penetration of EVs in New Zealand's vehicle fleet, and the applicability and use of technology for network monitoring, design, and operation. Technology will have an increasingly significant impact on customer behaviour as EVs, PVs, and battery storage become more affordable.

Industry changes required to enable the introduction of this new technology include:

- **New technology standards:** Introduce new standards for new technology, allowing better and lower cost integration;
- **Mandatory registration:** Require customers who want to install new technology to register their devices to a demand management platform. This will ensure that the installation of the new technology complies with the standards of the network for two-way power flows;
- **Congestion standards:** Introduce standards on how congestion is defined and require network congestion to be disclosed;
- **Low voltage monitoring:** Improve the monitoring of the network particularly LV with DERs where current monitoring is inadequate and where changes are most likely to be felt;
- **Support with efficient prices:** Introduce efficient price signals that reflect the benefits new technology can provide, while ensuring that this does not result in cross-subsidisation from customers who are unable to install their own DER;

- **Consumption and power quality data:** Consumption and power quality data are needed to support the operation of the low voltage network with an increasing prevalence of DER. The industry needs to decide what data is needed, and how to collect, store, protect, and utilise the information; and

- **Appropriate funding:** Ensure the regulatory framework provides the allowances required to develop and implement these changes, and to purchase data and demand response services.

Regulatory support is required to ensure these changes can be implemented.

As well as working with industry and regulators to ensure these changes are implemented in the short term, WELL continues to learn from others and to trial new technologies to further learn and prepare for the changes ahead. WELL believes testing new technology through trials is a prudent and flexible approach to managing the uncertainty associated with new and emerging technology, while avoiding the risk of overbuild in the short term. It is WELL's view that new technology will enable the monitoring and management of the LV network, and working closely with other industry participants will deliver the best long-term solution for New Zealand.

WELL will continue to utilise its position as part of the CK Infrastructure Holdings Limited group to leverage experience with new technology from its global sister companies. This provides WELL with unique access to intellectual property and resources from across the globe. In addition, WELL collaborates with local EDBs, technology providers, and other industry participants, to draw on the New Zealand-specific experience with DER integration.

(Reference: 2024 Asset Management Plan, Section 3.7.2)

3 Innovation Practices

WELL's desired outcome from its innovation workstreams is to reduce the impact of DER on the network peak demand, delaying capital investment and therefore reducing the rate of electricity price increases for its customers.

Success for these innovation practices is defined by them:

- Being proven to meet the network use case;

- Being proven to be commercially attractive for participants, and

- Having a lower lifecycle cost than traditional network expenditure.

If this can be proven by the trials, then subsequent commercial adoption depends on the availability of allowances to allow WELL to fund the practice.

WELL collaborates with other companies in industry forums, for example through its leadership of EV Connect (see Section 10.3.1.1) and its participation in the FlexForum (see Section 10.3.1.2). WELL is directly engaging with other EDBs and companies through commercial trials that are underway. WELL believes that collaboration with other companies across the electricity supply chain is essential for realising the desired benefits, by producing efficiencies and stacking value for customers.

A significant component of innovation activities is developing tools for the acquisition and analysis of information required to identify and predict network constraints, particularly metering data to indicate the performance of the low voltage network. The accurate targeting of innovation practices at constraints will be critical for meeting their success criteria. Information will be sourced in a coherent and efficient manner when a workstream is established to explore the relevant use case.

(Reference: 2024 Asset Management Plan, Section 10.2)

4 Managing Peak Demand Before Flexibility Services Are Available

Before flexibility services have been developed as a meaningful demand management response, EDBs must develop processes and tools to accommodate large DER onto their networks. As part of WELL's response to the May 2022 ERP, it has started to model and test the impact of the large-scale connection of DER to its distribution network. WELL's studies have indicated that 50% penetration of EV chargers larger than 2.5 kW would exceed what the Wellington network has been designed to accommodate.

The simultaneous operation of large DER risks causing LV networks to exceed their safe operating limits. The operating limits include both thermal and voltage limits, with both needing to be managed to provide a secure supply. Currently, EDBs have no visibility of where many of these devices are connecting and have no way of ensuring that they will operate within the network's operating constraints.

EDBs will need an early form of a flexibility service to manage the rapid connection of large DER. Important early steps are needed so that networks can manage, aggregate and coordinate the connection of large DER so their combined operation remains within the network's operating limits. These are also early steps in the development of a full flexibility service – they provide a simplified flexibility service providing network security while the industry develops flexibility services that deliver the full value stack. The early steps, preceding the development of the full flexibility services are:

1. Customer education and strong peak period price signals to encourage customers to use electricity during off-peak periods, especially large new appliances like EV chargers.

2. An application process for the connection of large DER (over 2.5 kVA) to provide EDBs with visibility of where DER want to connect so that they can test whether the network has the capacity to securely connect that device. There is currently an application process for solar devices, but not for other DER like EV chargers. The process will need to be automated to streamline the connection process.

3. Strong incentives or standards to ensure DER devices are capable of being remotely managed and can participate in flexibility services.

4. All large DER are to be registered and participating in flexibility services so that their use can be managed away from peak demand periods on the network.

These four steps will help EDBs to accommodate DER, providing a stable platform to facilitate the development of more complex flexibility services and a market for trading flexibility. This approach has worked well for managing solar DER in South Australia. Solar devices that are registered to a central platform and are participating in flexibility services are not restricted in how much electricity they can export back onto the network. This provides the network operators with the ability to dial back export rates on the rare occasions when network security is at risk. Those not registered and participating in flexibility are heavily restricted in how much they can export. The restrictions reflect the impact that their unmanaged operation has on the network.

The implementation of these changes will either need very fast policy updates or it may be that networks will need to apply them through their own network connections standards. It could be that initial implementation is via network connection standards with the permanent solution reflected in a later Electricity Code change.

The development of flexibility services is complex and will need time and funding to develop. EDBs will not have the allowances to develop flexibility services or to purchase those services until the next regulatory period in 2025. Furthermore, EDBs will need to develop an Advanced Distribution Management System and Distribution System and Operator SO capabilities to incorporate flexibility services into their demand response. Experience from WELL's sister companies in Australia shows this to be a multiple-year process. An early form of a flexibility service and a change in customer behaviour is needed before then to manage the connection of large DER and to shift electricity use to off-peak periods.

(Reference: 2024 Asset Management Plan, Section 4.2.2.1)

5 Development of Flexibility Services and a Flexibility Services Framework

Flexibility services are forecast to be valuable across the electricity supply chain. Sapere has estimated the value of flexibility services to be $6.9b from a range of different uses, from deferring distribution and transmission network reinforcement to retailers arbitraging the spot market for purchasing electricity.[1] However, these are only forecasts and have yet to be released. The industry is in the early stages of its development and the implementation is complex and requires the coordinated development of new capabilities across the supply chain.

WELL's EV Connect Roadmap[2] and the FlexForum's Flexibility Plan 1.0[3] provide the key actions and steps needed to develop flexibility services in the form needed to manage the secure connection of DER and to support the ERP. The actions also include the steps needed

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[1] D. Reeve, T. Stevenson & C. Comendant (2021) Cost-benefit analysis of distributed energy resources in New Zealand: A report for the Electricity Authority, Wellington, New Zealand
[2] https://www.welectricity.co.nz/about-us/major-projects/ev-connect/
[3] https://flexforum.nz/flexibility-plan/

to provide flexibility at the scale needed to provide an alternative to building traditional approach to congestion of building more capacity. Of those actions, there are eight critical steps:

1. **Coordinated implementation**: WELL's EV Connect programme identified industry leadership as a key driver for the development of flexibility services. The actions needed span the flexibility supply chain and require a coordinated approach.

2. **Understand consumer preferences for flexibility services:** For flexibility services to be developed to the scale needed to provide a viable wire alternative, customers must have a smart device that can be remotely managed and be willing to participate in flexibility services. The industry must develop services that customers are comfortable participating in.

3. **Implement an industry-wide hierarchy of needs**: Develop a hierarchy of needs framework in the Electricity Code to ensure network operators (EDBs and Transpower) have access to flexibility services in emergency situations when direct intervention is needed to 'keep the lights on'. These are rare events that would have a limited impact on competing flexibility services.

4. **Ensuring DER are smart and are participating in flexibility services:** This includes ensuring all large DER are visible and registered with a flexibility provider – so that EDBs can ensure they are connected securely, and their continued operation remains within the network security limits.

5. **EDBs to develop an LV management capability**: Forecasting where flexibility will be needed and incorporating flexibility services into their asset demand response. This will allow EDBs to identify network constraints and where flexibility services could be a viable wire alternative. LV Management systems combine spatial GIS data with ICP level consumption and power quality data to forecast demand and network capacity constraints. These systems are complex and will take time to develop.   LV management is a precursor to Distribution System Operator capability.

6. **Streamline access to ICP level data**: EDB LV management systems require ICP data – without the data EDBs have no visibility of LV constraints or where they could use flexibility services. The provision of ICP data includes ensuring all privacy responsibilities are met.

7. **Flexibility provider tools that coordinate DER and aggregate a demand response**: Flexibility providers need to develop the capability to aggregate and coordinate the management of multiple DER. The tools must have common communication protocols that allow services to be coordinated with buyers.

8. **EDBs are funded to develop and purchase flexibility services**: EDBs are not funded to purchase flexibility services. They do not have OPEX allowances to purchase services and the IRIS mechanism does not allow OPEX/CAPEX substitution if the deferred CAPEX benefits span multiple regulatory periods. Until EDBs have regulatory allowances to purchase services, their use of flexibility services will be limited to small-scale trials and tariff services. This is being discussed as part of the IM review.

5.1 Significant Development in EDB Capability

The ‘least regrets’ actions provided above are the key capabilities that the industry needs to develop to enable flexibility services. The EDBs’ actions represent a significant investment in new capability that will take time and additional allowances. Purchasing a full data set needed to support the development of LV visibility is likely to cost over $0.5m per year, and the ongoing software costs to collect, store, and analyse the data could double this. Forecasting network constraints and managing the application of flexibility services requires the development of an LV Advanced Distribution Management System (ADMS) which combines GIS spatial data with ICP level consumption and voltage data. In South Australia this capability cost approximately $37m (including $4m per year in operating costs) and took five years to implement for the 900,000 connections they service. While the deployment of similar technology in Wellington will cost less, the investment is still significant. It is also important to note that the funding for these new investments will not be available until the next price path reset in 2025.

The investment in the current hot water ripple control systems provides a useful comparison. This capability has required EDBs to invest millions in the ripple control system, relays, and communication network. Retailers and meter providers have also had to install ripple meters and their own communications. WELL agrees with the industry that flexibility services will be valuable, but it is necessary to highlight that the development of this capability will take time and investment to develop.

(Reference: 2024 Asset Management Plan, Section 4.2.2.3)

6 LV Management and the DSO

As highlighted above, WELL will not need the full DSO capability immediately and can develop each component over time as it is needed. The immediate focus is on developing LV visibility using a low voltage Advanced Distribution Management System (ADMS) which combines GIS spatial data with ICP level consumption and voltage data and transformer monitoring information. WELL’s current hypothesis is that less expensive ICP data can be used to build up a general picture of the LV network, and expensive but more accurate transformer monitoring equipment will be installed in congested parts of the network to provide additional intelligence.

6.1 ANSA LV Constraint Risk Modelling

WELL commissioned ANSA in 2023 to develop a low voltage constraint risk and capex forecasting tool. The tool analysed WELL’s residential LV network, combining GIS data, consumption data, decarbonisation load growth forecasts, and standard costs, to forecast LV constraints and the CAPEX required to resolve them over a 50-year horizon. The output of this tool has been incorporated into WELL’s System Growth CAPEX forecast presented in this AMP.

This ANSA tool and its findings are discussed in Section 9.7 of the 2024 Asset Management Plan.

6.2 Future Grid Pilot

During 2022, WELL participated with seven other EDBs in Ara Ake's New Zealand Decarbonisation Challenge. This was focused on identifying potential solutions, both from New Zealand and internationally, for incorporating flexibility into EDB's asset management processes.

With the increase in electrification and increased deployment of DER within the network, greater visibility of the LV network is becoming more important for both planning timeframes and real-time operations. Increased LV visibility will help EDBs identify network constraints, enable proactive identification and resolution of power quality issues, and form the basis for any future market for flexibility services. All of these use cases will provide significant benefit to customers.

As a result of the Challenge, WELL chose to partner with Future Grid. Future Grid is a low voltage network visibility and management tool, which WELL identified as being a good fit to help resolve LV network information gaps, including constraint mapping and modelling the impact of flexibility services on network operations. A pilot of Future Grid ran during 2023. The findings of the trial were:

1. Third party ICP consumption data and WELL's spatial data were successfully incorporated into the tool.

2. Half hour consumption data was able to provide useful asset management insights, however having cost-effective access to voltage data is critical for the majority of use cases for the tool.

3. It is essential for regulation to provide for the ongoing funding of software, data procurement, and people to run and maintain it.

WELL's next steps will be to use the experience of the Future Grid pilot to develop a set of requirements for the procurement of a network-wide LV management tool.

6.3 Leveraging the Research and Development of WELL's Sister Companies

WELL's sister networks, United Energy (United) and South Australia Power Networks (SAPN) have been developing a DSO capability over the last five years. Their development programmes have highlighted the complexity and time it takes to develop the DSO functionality and the supporting tools needed. WELL is leveraging their knowledge and experience to design its own research and development programmes. This includes engaging with Future Grid, who has been working with both United and SAPN on their DSO development. Important lessons include:

1. Expect a large data correction and cleansing element. The Australian deployment of LV management software like Future Grid highlighted errors in the underlying GIS and ICP data.

2. Expect a multiple year development timeframe. Incorporating the DSO capability into network management functions is complex and will need to be staged.

6.4 Developing Access to Data

The trial of the Future Grid software focused on whether the software can be connected to the various data sources and whether those data sources provide the information at the level of quality needed. This required the development of data agreements and the handling of large third-party data sources:

1. The quality of ICP and GIS data has been tested as part of the Future Grid trial.
2. A Data Security Policy has been developed that meets the Electricity Code's Data Agreement requirements.
3. WELL is working with retailers to get agreements in place for the provision of consumption data.
4. Lobbying the Commerce Commission for the inclusion of new allowances for the purchase, storage, and analysis of ICP data.

6.5 Trialling Transformer Monitoring Equipment

WELL is currently considering the most effective and efficient combination of data to provide visibility of the LV network. The currently hypothesis is to support ICP level consumption and quality data with data from transformer monitors spread across the network and focused where the network is congested. The monitoring data would be used to validate the ICP information and to provide better visibility of network constraints.

WELL is trialling different monitoring technology. The trials results will be used to select standard monitoring equipment and to confirm the LV visibility hypothesis.

(Reference: 2024 Asset Management Plan, Section 10.3.2)

7 Changes to Electricity Act and the Electricity Code

Section 4.2.2 highlighted the important role flexibility services will play in ensuring networks can maintain a secure supply of electricity. Section 4.2.2 highlighted that there were two sets of changes needed:

1. Changes to support the rapid uptake of large DER (devices that are larger than LV networks were designed to host) before flexibility services have been developed to the scale needed.
2. Changes to support the development and operation of an enduring flexibility service.

Important changes to the Electricity Code are needed to support each of these steps.

7.1 Code changes to support the rapid uptake of EVs (before flexibility services are established)

Changes are needed to the electricity code to support the secure connection of large DER:

- A requirement for all large DER to apply to connect to a network. The assessment process would be automated so as not to slow the connection process and would identify where EDBs would need a more in-depth assessment to ensure the devices can operate within the existing network capacity or whether a flexibility service is needed to manage its operation.
- Strong incentives or standards to ensure DER devices are capable of being remotely managed and can participate in flexibility services.
- Very strong incentives or mandatory rules to ensure that large DER are participating in a flexibility service. EDBs need to be able to rely on flexibility services to ensure the simultaneous use of large DER does not impact network security.

7.2 Code changes to support flexibility services

Further changes are needed to the Electricity Code to support the development and operation of a full flexibility service:

- Providing EDBs with streamlined access to smart meter data (both consumption data and power quality data) and information on the location and operating characteristics of large DER. This data is needed as an input into the ADMS systems that are needed to manage congestion on the LV network. The collection and supply of metering data is a natural monopoly, and therefore requires careful regulation to ensure that the cost of its provision to EDBs (which will ultimately be paid for by the customers, who have already paid for its initial collection) is reasonable.
- Implement an industry-wide hierarchy of needs. Network operators (EDBs and Transpower) have been able to maintain a secure electricity system by having priority access to hot water ripple control in emergency situations – emergency situations being when direct intervention is needed to 'keep the lights on'. Currently the Electricity Code provides this capability for hot water ripple control via the DDA. These are rare events that would have a limited impact on competing flexibility services. This capability needs expanding to devices managed by flexibility provides not currently captured in the code. This capability will ensure a stable and secure electricity system that flexibility services can be built on.
- Consideration of the regulatory settings needed to support a DSO. As flexibility services are used more extensively and services are provided up and down the electricity system, their use will need to be co-ordinated so as to maintain the whole of system security. Central to this will be establishing a clear hierarchy of needs or services that the electricity system can use to prioritise and co-ordinate multiple purchasers/users of flexibility.

Note, WELL does not believe that whole-of-system coordination using a central controller of the end-to-end network will allow networks to maintain accountability for their quality performance. Networks have regulatory quality targets applied under Part 4 of the Commerce Act 1986 (SAIDI and SAIFI targets) and power quality obligations under the Electricity (Safety) Regulations and the Code (including ensuring that voltage at the point of supply remains within 6% of its nominal value). EDBs must retain the ability to manage network security to meet the regulatory obligations that they are accountable for.

(Reference: 2024 Asset Management Plan, Section 10.3.1)

8 Summary of Future Network Investment Plan

WELL has currently a strong focus on research and development to test new technology, to understand its ability to reliably meet network needs, and to establish commercial frameworks for its employment. This work is operational expenditure that is not funded by the DPP3 allowances.

As flexibility services are operationalised, there will be ongoing operational expenditure for the metering data and transformer monitoring necessary to support their employment, and licensing software to analyse the data.

There may also be an ongoing cost to purchase flexibility services. This will depend on whether services are purchased from an IRIS substitution of CAPEX savings or whether networks are provided with a direct OPEX allowance. At this early stage in the development of these services, it is assumed that they will be funded by substituting CAPEX savings. This also reflects the difficulty in forecasting an OPEX allowance that will depend on the specific details of each CAPEX deferral (i.e. this will depend on the aggregated value of the CAPEX being deferred and the length of the deferral). Conversely, funding flexibility by CAPEX substitution will mean that the savings will always be relative to the CAPEX being deferred. For CAPEX/OPEX substitution to work, the IRIS needs to be adjusted so that inter-regulatory period benefits can be recognised. The current IRIS does not provide offsetting CAPEX savings if the OPEX is incurred in one regulatory period and the CAPEX saving is in the next because future allowances will already include the impact of deferring the CAPEX and there will be no IRIS benefit to offset the initial IRIS penalty.

WELL's delivery strategy also assumes the development of a project management office, and data analytics and procurement functions. Additional resources have been added for these functions. WELL will also need to increase the capacity of its existing non-network overhead functions to support the doubling of the size of its network investment programme.

(Reference: 2024 Asset Management Plan, Section 10.4)

Schedule 18 Certification For Year-End Disclosures

Clause 2.9.2

We, Richard Pearson and Charles Tsai, being directors of Wellington Electricity Lines Limited's certify that, having made all reasonable enquiry, to the best of our knowledge-

a. the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

b. the historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, and 14 has been properly extracted from the Wellington Electricity Lines Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

c. In respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that-

    i. the costs and values of assets or goods or services acquired from a related party comply, in all material respects, with clauses 2.3.6(1) and 2.3.6(3) of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5)(a)-2.2.11(5)(b) of the Electricity Distribution Services Input Methodologies Determination 2012; and

    ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

Richard Pearson
Chairman

Charles Tsai
Director

30 August 2024