Submission

28/11/2024

To	The Electricity Authority
Consultation	Network connections project – stage one
Subject	DG approval for planned new build connections. DG approvals on secondary networks.

Context

Revolve Energy is a consultancy that works with DG system owners and those intending to invest in DG. In this role we work on projects where DG is being considered as part of a new connection, often for a building, where the new connection has not been approved by the EDB.

We also work in the area of community energy, and microgrids. This involves working with existing and planned secondary networks.

During this work we have encountered a number of issues that should be considered as Part of this amendment. In our view they require further changes to the Electricity Industry participation Code 2010 (Code) to remove barriers and confusion to the implementation of new load connections and DG connections.

We appreciate the opportunity to provide a submission, we are available to meet with the Authority and discuss this submission.

Prerequisite to load and DG network connections

While we acknowledge the Authority's efforts on data access, the lack of access to relevant network information remains a significant barrier to innovation, one that should have been addressed long ago. Currently, access to this information is slow and cumbersome.

While low-voltage (LV) voltage data and peak demand information could be gathered through transducers installed on networks, more detailed information would be better obtained from AMI meters at customer installations. This information could include data such as electricity conveyed through an ICP per phase, network phase balancing, phase voltages, congested periods, overloaded service lines, and more.

As we move further into decarbonisation, access to this information is becoming increasingly critical. Networks need this data to optimise the use of existing infrastructure while keeping downward pressure on customer pricing. Customers also need fast access

re/
vo/ve
energy

w: revolveenergy.co
p: +64 9 303 4922
e: info@revolveenergy.co

3 Glenside Crescent
Eden Terrace
Auckland 1010

to metering information to determine retail pricing options, costs for new or modified connections, or to offer flexibility services. Without this information, the alternative can only be increased investment in assets, which would raise customer costs.

Transparency of network capacity information is also crucial for efficient network operation. It enables the connection of new or upgraded installations, assessment of network alternatives, integration renewable distributed generation and BESS, and setting of appropriate consumer pricing. Transparency on network capacity and congestion information enables the connection of distributed generation and flexibility services that can benefit consumers.

Although Metering Equipment Providers (MEPs) could hold this information, they often have exclusive contracts with retailers for AMI data, and are contractually prohibited from sharing it with distributors due to cost and privacy concerns. However, the cost of AMI is not paid by retailers, it is paid by leases fees by customers who bear all of the electricity industry costs.

Meters have evolved beyond being simply a trading tool, to an operational tool. Until AMI data access issues are addressed, there can be little progress in improving the overall electricity delivery system. In instances where MEPs are supplying information to distributors, and if a retailer switches MEPs, disruption could occur to a distributor's information chain. For this reason, switching of MEPs should be limited to instances where it is essential for the service a retailer will deliver, and any change in MEO must be coordinated with other contracts for the point of connection that the MEP has contracts for.

While distributors receive EIEP1 and EIEP3 files, their use is restricted to invoicing purposes only unless the retailer consents otherwise. Until AMI data access is resolved, making meaningful progress in improving access to and utilisation of networks will be challenging.

Changes to the Code are necessary to require:

a) Model network connection and operation standards.
b) Distributors to collect and publish relevant network information to allow assessment of opportunity, connections costs etc without undergoing full, and expensive, network studies.
c) MEPs to provide relevant information to all distributors.
d) Switching of MEPs is prevented unless all contracts the losing MEP has is honoured by the new MEP for the same price.
e) MEPs to provide an automated way for customers to share their meter data with their advisors. This should be in the form or an API to allow software platforms to provide analysis on behalf of the customer.

DG approval for planned new build connections.

The problem.

New electricity network connections for buildings are now often not just for the supply of electricity, but also for the connection of generation and storage for self-use and export.

Where a PV array, and/or BESS are to be included in the construction of a new building, there are significant interfaces between the building, and the DG system that must be coordinated between the DG designer, and the various building design disciplines.

All EDBs that we have encountered on projects treat a new connection as a different process to a DG application, although the background considerations are similar. In all of these cases the EDB will not accept DG applications where no ICP has been issued. However a distributor will not issue an ICP identifier until a connection is going to proceed. This means that no application can be made to connect the DG before the building has been tendered for construction and construction is well advanced.

This creates significant risks and challenges for the customer including:

- Input from the EDB is required during the design of the building so that the grid protection scheme and any EDB interface (e.g. SCADA) can be designed and costed.
- The design of the DG must be finalised during the design process of the building so that the DG system build can be included in the scope of the building contractor, and completed as part of the building construction.
- Currently the DG build is tendered, but with uncertainty that it can be connected as the designed scale, and with the specified grid protection regime.
- The current regulations are mute on this issue, and current EDB processes do not recognise the reality of designing and constructing a new building where there is DG.
- This creates material risk for the building owner and DG investor as the system scale, and requirements cannot be confirmed during the design phase, ahead of the building construction.

The solution.

In our view regulation for the DG connection process should be updated to address the challenges highlighted above. The following would help to address the issues identified above.

- A process for a new connection to a network, that could be one of load only, load + distributed generation, or distributed generation only where an ICP identifier is not required in order to make an application

- A process for the change of an existing connection that could be a change to load or distributed generation capacity where an ICP identifier is required in order to make an application

- Both processes should consider the hosting of DG for self-use applications where there is either partial or no distributed generation export.
- A process for DG approvals for new buildings should be explicitly defined in the regulations to allow DG investors to formally engage with an EDB to:
    - Determine the scale of the DG that can be connected.
    - Understand any technical requirements the EDB may have on the DG system including the projection scheme and any interfaces to the EDB (e.g. SCADA).
    - Understand the requirements for any network studies that need to be completed.
    - Obtain approval for the connection of the DG behind the meter of the new proposed grid connection.

Provision of information for assessing behind-the-meter non-wires alternatives

The problem.

We have encountered situations where onsite storage or flexibility is being considered to reduce the grid connection capacity. To allow a customer to consider if they should invest in storage or flexibility, the costs of the two scenarios need to be understood. These scenarios are:

1. Where the site is supplied from the grid only.
2. Where the site is supplied from a lower capacity grid connection with on-site storage and/or flexibility to reduce peak demand.

When engaging with EDBs in these situations we were not able to obtain a price comparison for the two scenarios. The EDB process appeared to be designed around receiving a request for a single option of grid connection and providing a price for this.

The current barriers create a competition issue, as the value of onsite storage/flexibility can not be objectively assessed against the base case of supply from the grid only. This favours the incumbent solution (grid supply on), and is an impediment to the use of onsite (behind the meter) storage and flexibility in new building projects.

Another related issue that we have encountered is that EDBs do not appear to be equipped to provide information on the available connection capacity that exists within a certain part of the network, as they often do not have access to relevant metering information. Without this information, a customer's design team cannot assess at what connection capacity a significant grid connection investment is required. If this information was available the customer's design team could advise on strategies to avoid triggering network upgrades, therefore reducing costs.

The solution.

In our view, the following would assist in ensuring that the use of behind-the-meter storage and flexibility to reduce network connection costs and ongoing related opex can be objectively assessed.

1. Update regulations to require EDBs to
    a. Provide the available capacity and supporting information to connect to a network.
    b. Provide incremental price information for at least two connection capacity scenarios.

Lack of information on grid voltages

The problem.

It has become clear* that parts of many LV networks are operating at or outside the limits of the regulated grid voltages (230 +/-6%).

Many EDBs are now requiring that active anti-islanding functions in inverter systems be enabled. These settings require inverters to supply/absorb Vars (volt-Var), or reduce real power (volt-watt) to manage grid voltage.

EDBs generally do not appear to monitor LV voltages and are unable to provide historic voltages for a section of a network, despite MEPs having that information.

Without access to this information, DG investors cannot determine if they can expect their generation to be curtailed as a result of the grid operating outside or near to the regulated voltage limits.

The solution.

In our view regulations should be updated, requiring EDBs to provide information on the historic operating voltages of their networks. This would allow DG investors (or their advisors) to assess if the operating voltages of networks could reduce the viability of their investment.

This requirement may also encourage EDBs to monitor the voltage of their LV networks and maintain them within regulated limits.

*as the result of the voltage information from DG systems.

DG approvals on secondary networks.

The problem.

The code is unclear about what obligations apply to secondary networks. In addition to local networks directly connected to the grid, there are privately owned networks that are indirectly connected to the grid through another network. These are known as secondary networks and can be categorised into the following configurations:

1. Customer network
2. Network extension
3. Embedded network

The Electricity Industry Act 2010 (the Act) was amended on 1 July 2017 with the addition of Subpart 2A, Section 131A. Prior to this amendment, the term "distributor" used in the Act and the Code applied only to local networks. However, following the amendment, we believe that the term "distributor," when used in the Code, now applies to both local networks and secondary networks. Despite this change, no clarification was made in the Code regarding the removal of obligations for secondary network owners. Section 131A states that the *"...Act, the regulations, and the Electricity Industry Participation Code 2010 (Code) apply, with all necessary modifications, to a secondary network provider as if that provider were a distributor..."*.

Following the definition chain in the Act and the Code are:

Definitions in Section 5 of the Act are

> **distribution** means the conveyance of electricity on lines other than lines that are part of the national grid
>
> **distributor** means a business engaged in distribution
>
> **lines** means works used or intended to be used to convey electricity

Part 1 of the Code also has relevant definitions as follows

> **distributor** has the meaning given to it by section 5 of the **Act**
>
> **distribution network** means the **electricity lines**, and **associated equipment**, owned or operated by a **distributor**
>
> **lines** has the meaning given to it by section 5 of the **Act**
>
> **network** means, except in Part 6A, the **grid**, a **local network** or an **embedded network**

When read together, these definitions suggest that whenever the Code uses the term "distributor," the obligations apply to all local networks and all types of secondary networks, this may not be the Authority's intention.

This creates confusion, not only in the current Parts 6, 6A, 10, and 11 of the Code, where the defined term *"distributor"* is used to place an obligation, but also in this consultation and the Authority's *"Distribution Connection Pricing Reform"* consultation. The Code and these consultations could be interpreted as applying to all three types of secondary networks, which may not align with the Authority's intention. We suggest that the Authority clarify the Code to address this ambiguity.

The current regulations do not provide any clarity of who is the approving party for DG connection on to a secondary network, as Clause 6.2 of Part 6 sets out the purpose of the Part to be a connection between a generator and a network, and not a network interconnection. There are potentially two approving parties for connection of DG onto a secondary network.

1. The secondary network owner and/or operator.
2. The EDB to which the secondary network is connected to.

We have observed an inconsistency in approach to the approval of DG connected to a secondary network on projects. Two examples were:

4. Connection of MW scale DG to a large embedded network was recently approved by the embedded network operator, after the completion of a network study and review of the protection scheme. The EDB to which the embedded network was connected to was approached. They advised that it was the role of the embedded network owner to assess and approve the connection of the DG.
5. The connection of ~100 x 4kW DG systems to a new embedded network was being considered. The designer of the embedded network reviewed the concept and advised that there would be no issue. The EDB that the embedded network was connected to advised that the embedded network owner (after the embedded network was connected, see the prior issue about new connections) would need to apply to connect a 400kWp large scale system to the EDBs network. If the large scale system was required to have centralised curtailment and projection, then the 4 x 100kWp systems may not be viable. Small DG systems are generally not designed to be controlled in a coordinated manner.

These examples highlight some specific issues:

1. The lack of clarity in the Code. Clause 6.2A of Part 6 states that Part 6 does not apply to embedded networks that convey less than 5GWh/year, but makes no mention of network extensions or customer networks.
2. The inconsistent approach of EDBs due to lack of understanding and regulatory direction.
3. Particular in the case of example #2, that the ownership of the network to which a customer is connecting DG to can result in potentially different connection application and technical requirements. A customer who could connect a 4kWp system with ease directly to the EDBs network, could experience significant barriers when connecting to the secondary network.

Some examples where the issues are likely to be surfaced include:

1. Connection of DG to secondary networks
2. Community BESS on a secondary networks.
3. The impact on the parent networks where multiple <10kWp PV systems on a secondary network that serves many residential properties.
4. Large DG systems on a secondary network that services industrial customers
5. Offer and dispatch arrangements for aggregated intermittent and aggregated BESS of 10MW or greater on secondary networks.

Connections that are larger than needed for supply to accommodate export.

We have seen a few cases, and expect to see many more where a connection capacity for a building or secondary network is driven by the export capacity of the DG, rather than the import capacity required to serve the load. In this case the ongoing connection capacity and demand charges are set based on the current pricing methodology. This could result in the customer paying higher lines charges in order to export, than if they had no DG.

If the DG was on its own generation-only connection, the lines charges would be significantly less. This creates a disincentive to co-locate large scale generation with loads. Generation that is co-located with load, where the generation exceeds the load requirements would not be able to compete with generation that is connected to a dedicated ICP.

We proposed that lines charges (e.g. capacity and demand) are levied on import capacity only on all connections unless an upgrade is required to the network to accommodate the export capacity. Where peak export exceeds import, chargers for the capacity required that is in excess to the import capacity are consistent with incremental costs for dedicated generation charges, set out in Schedule 6.4.

This approach would ensure that DG investors where the DG is connected along with load are not disadvantaged compared to generation-only DG connections.