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Dear Steve,

Re: Call for evidence: Visibility of distributed generation connected to the GB distribution networks

Please find detailed below Scottish Hydro Electric Power Distribution plc (SHEPD) and Southern Electric Power Distribution plc's (SEPD) response to the above call for evidence and the specific questions raised by Ofgem.

In addressing this call for evidence, which is focused on the 9th August 2019 events and the series of findings and recommendations to improve the resilience of the GB electricity system, we have focused on our role as a DNO/DSO in relation to the prevention of, live management, and recovery from low frequency loss of supply events. We recognise that the management of such events is much wider than individual DNOs and must include the ESO, TOs and other parties across the whole electricity system, however our response does not comment on their specific requirements.

1. **DCUSA modification DCP350 will provide data on a number of characteristics for DG greater than 1MW. Are there additional characteristics for DG, such as real-time MW/MVAr output, load factors and protection settings, which would aid in the prevention of, live management, and recovery from loss of supply events?**

DCP 350

We note DCP350 was raised for a specific purpose i.e. to publish and maintain a register of connected distributed energy resources with a capacity greater than 1MW in the context of improvements to the Capacity Market. Essentially, DCP350 draws on data sets already held by DNOs to provide greater clarity and transparency to third parties. We understand that this change was not developed to address the specific issues referenced by Ofgem in the letter of 4th August 2020 i.e. to assist in the provision of real time data to DNOs associated with distributed generation connected to their networks to facilitate real time management and recovery from loss of supply. We consider the nature and target audience of both requirements are different and do not believe the issues referenced in this call for evidence would be best addressed through DCP350.

Network Users and Flexibility Providers

We also note there are a wide range of network users, and DNOs increasingly draw on flexibility services from a wide range of parties including, but not limited to, distributed generation. Service providers may also include batteries and demand side response. We anticipate that any new requirements to help manage the network should be considered in parallel, across all relevant parties

- collectively referred to as Distributed Energy Resources (DER). This will ensure there are consistent arrangements, and no unintended consequences or market distortions.

Relevant Timescales for Planning and Operation of the Network
It is helpful to note, we use data to plan and operate our networks across three timescales:

- System planning – longer term investment analysis (1 to 10 years ahead) to ensure networks have sufficient capacity and capability to meet obligations and maintain security of supply.
- Operational planning – shorter term analysis (up to a month ahead) to ensure the network is configured and optimised to accommodate the mix of network users and available capacity under live management situations.
- Live management – live and post event analysis to avoid and where necessary recover from loss of supply events and maintain security of supply.

It is important that any future requirements carefully consider data requirements across all three timescales.

Real Time Data Requirements
In response to the specific points raised in the Ofgem letter and call for evidence, the following table sets out improvements to data that we believe could assist in the prevention of, live management, and recovery from low frequency loss of supply events. As set out above, we have split this out across the different planning and operational timescales:

	System and Operation Planning timescales	**Live management timescales**
Power flow Should a low frequency demand event occur, parts of our network will necessarily and automatically be disconnected to ensure overall GB stability. Information is needed to plan the network in advance of and after such an event to aid efficient restoration.	Analysis must consider the full envelope of potential operation and draw on agreed Maximum Import or Maximum Export Capacities (MIC/MEC) alongside historic telemetry (SCADA) data. Existing provisions allow us to request future anticipated profiles from generators for the next 7 years so we can assess the impact of any longer-term changes (i.e. plant closure or repowering etc.). However, experience has shown that this is often only meaningful for the largest sites and we do not usually consider it practical or proportionate to extend such requests to smaller sites. Operational analysis considers network operation for specific situations by drawing on MIC/MEC and SCADA data and nearer term	Should a low frequency demand event occur then, in coordination with the ESO, our operational actions are to restore demand and generation in a phased manner to ensure the overall system remains balanced and individual circuits are operated within safe limits. This is enabled through an assessment of the underlying demand and generation that will be restored when sections of the network are re-energised. This draws on telemetry (SCADA) data of how the network was operating before the event; disaggregation of the underlying demand from generation; and an assessment of how generation and demand will behave once re-energised. We believe the following data sets could further improve our analysis:

	projections of network use. This could be further enhanced through greater short-term visibility (i.e. up to a month ahead) of: 1) Future planned operation and obligations e.g. any ancillary service contracts, where it is proportionate and meaningful for the DER to be asked to provide this.	2) Extending live telemetry of power flow to cover more DER (i.e. SCADA data). Our present standard requires new DER connections above 200kW to capture these details. This standard could be further extended to smaller sites. 3) Enhanced information on the post fault behaviours of DER e.g. forecast output, fuel level or running hours currently available, any specific additional load to be picked-up on restoration (or which could be deferred to aid restoration) e.g. Electric Vehicles or Demand-Side Response.
Compliance with standards The Distribution Code, Grid Code and related Engineering Recommendations (EREC) etc define the performance characteristics that individual connections must meet to ensure whole system stability.	Evidence from the 9th August event has highlighted concern that the situation at individual sites may change over time and compliance with these standards may be impacted. For example, we understand on 9th August many DG control systems ceased to operate when frequency dropped below 49Hz. To help address this consideration could be given to extending requirements under Code to require DERs to provide: 4) Regular/routine confirmation from the site that it is operating within standards and/or a declaration of any deviation to assist our ongoing System and Operational Planning analysis.	
'Downstream' network operators GB arrangements allow a variety of different parties to be	The actions of individual DERs connected to these networks and their impact on net demand and generation across the whole system is not	

involved in the distribution of energy. These include: Independent Distribution Network Operators, Building Network Operators and Private Network Operators.	visible to the host DNO. As such we believe further consideration should be given to: 5) Increased visibility of the underlying demand from generation and DERs connected to these networks, provided by the relevant downstream network operator.	
<u>'Upstream' connected network operators</u> These include ESO, TOs or other DNOs who are connected to a DNOs network and whose actions may have wider consequences for the stability or operation of our network. They may also include potentially wider market participants (e.g. aggregators).	Further consideration should be given to providing: 6) Increased visibility of the underlying demand from generation and DER behaviours on connected networks. This would be helpful, especially where these are influenced by the actions of 'upstream' network operators.	
<u>Summary of potential additional requirements</u>	• Regular/routine confirmation that a connection remains within requirements or parameters set out at Connection or through any subsequent modification • Enhanced short term visibility of future operation or ancillary service contracts	• Further live telemetry from DER • Information on the post fault behaviours of DER • Visibility of downstream DERs within IDNO, BNO and private distribution networks • Visibility of DERs and impact of 'upstream' network operators

2. What value will these additional characteristics provide to improving the planning, security and real time operation of the GB transmission and distribution systems?

We believe such information would potentially help ensure we have a more accurate, up to date and more granular view of connections to the network, and any variations once connected. It would also provide additional detail regarding how DERs operate and use the connection. This could potentially help facilitate more efficient planning and operation of the network and improve reliability of supply, helping us transition to net zero.

Please see table in question 1 detailing the role and purpose of specific information.

3. What value will the above characteristics provide to improving DSO function delivery by the DNOs or other stakeholders? DSO functions may include network management, flexibility procurement, and service conflict avoidance.

In general terms, the more we can understand what connected parties are doing in real time, the further we can efficiently manage capacity and operation of the network, whether this is for demand or generation. For example, increased visibility of a generator's future expected operating patterns may allow us to maximise use of existing assets and further improve efficiency in terms of operation of the network. For instance, information would allow us to coordinate release of unused capacity, avoid unnecessary investment, better plan and mange network outages, permit other generators to export during network outages and identify where there is a need for network services to support efficient development and operation of the network.

Likewise, greater visibility may allow us to build confidence in the security of supply contribution that DERs can provide when assessing the need for future reinforcement. It may also reveal otherwise hidden changes in underlying demand and improve our longer-term strategies to accommodate these through increased capacity and/or through flexibility services procurement.

However, we should highlight that increased visibility on its own would not have prevented the issue that arose on 9th August 2019 (i.e. abnormal fault coincidence and DER control system design) but may have assisted post-event restoration. It is important to recognise the increasing reliance that GB supply arrangements have on smaller DER and the responsibilities that this entails. Steps may be needed to support and encourage smaller operators to regularly check and confirm their installations continue to meet the required standards.

4. At what temporal resolution (instantaneous, seconds, minutes etc.) would real time data on DG be valuable to improve the resilience of the GB electricity system in the prevention of, live management, and recovery from loss of supply events?

Aside from planning horizons as set out in the table above, for operational purposes, the ideal resolution is near-instantaneous where all changes are automatically reported and fully visible to the DNO/DSO as they happen. However, the communications and data network infrastructure necessary to achieve this is likely to be extremely expensive and is likely to be a barrier to parties looking to connect. The cost/benefit case for such an approach is uncertain at this stage but is likely to be unnecessary for all but the largest installations.

A more pragmatic solution is likely to involve the use of communications which would routinely poll DER sites. We could either routinely poll for status updates or report by exception when there is a material change. Different dead-bands could be considered for the size of change depending on the type of generation and accuracy required. Consideration could be given to the need for a wider dead-band for more volatile generation such as wind to avoid excessive data flows but this would need to be balanced with network impact.

With solicited communications, the polling frequency will dictate the temporal resolution of the analogue values. The achievable polling frequency is also likely to be highly dependent on communications infrastructure and the cost/benefit case.

We consider that the resolution should be related to the capacity of the generation and suggest that different frequencies are appropriate to Type A though to Type D generation[1]. Resolution of 5-10 minutes should be adequate for Type A generators trending to a resolution of 5 seconds or less for Type D generators. However, this is subject to more detailed technical and cost/benefit analysis.

5. What investment would be required for monitoring, collecting, storing and disseminating real time operational data associated with DG? Which party should be responsible for these investments? How does this vary, based on the size of visible DG at 1MW or 50kW?

We have updated requirements for communications for embedded generation in line with G99 to now require a real-time communications link to be established for all generators greater than 200kW. Between 200kW and 1MW, we accept a dial-up connection, which will only report a change of status. Above 1MW we require a permanent connection which is routinely polled for status updates. The cost of providing these communications links is generally borne by the DER customer as part of the costs of connection.

However, this leaves a large volume of connected DER where we have no visibility. Retrospective installation of such communications for all other DERs would be highly dependent on location and available communication infrastructure. Where a signal is available, we could seek to deploy cellular communications for a dial-up connection. We estimate a retrofit capital cost of around £8k per site. If a satellite solution is required, the capital cost would increase. For a permanent connection, a range of solutions could be deployed depending on proximity to and robustness of telecoms infrastructure. A retrofit capital cost may average around £20k per site. We note there are further costs for data transmission, which are highly dependent on the resolutions required and the type of communications link.

Given the potential scale of costs, including costs associated with analysing the data, and the fact that customers have connected based on arrangements at the time, we believe it would not be appropriate to require existing customers to fund these costs should changes be taken forward. We suggest changes should be funded through the regulatory framework, with allowances being provided to DNOs. This also recognises that many of the benefits of increased DER visibility flow through to all customers through improved system reliability and security and are GB wide.

At this point, we are not able to comment on the scale and funding required to develop appropriate DNO systems to store and disseminate this data, or costs related to new processes, procedures or additional staff to support new activities. This will require further consideration and a better understanding of proposed approach. While we hope our initial views are helpful, we believe more detailed cost benefit analysis and impact assessment is required to inform future developments.

We are mindful that particularly in our Scottish Hydro Electric Power Distribution area, the cost of increased visibility may be disproportionately high where there is a high degree of generation for a relatively low number of customers and communications infrastructure in many more remote areas may not be as well developed.

The impact also needs to be considered in relation to wider policy objectives such as Net Zero and wider consequences or impacts for networks overall.

[1] As defined in EREC G99. Type A is <1MW, Type B is 1MW to <10MW, Type C, 10MW to <50MW and Type D is 50MW and above. Anything connected at 110kV or above is classed as Type C or D.

To ensure efficient implementation, we would also expect obligations and code modifications to be developed and consulted on in the usual manner to give transparency and legitimacy to arrangements. This would also ensure active participation and input to the development of an efficient solution from all parties.

In this response we have focused on the data needs of a DNO/DSO, but we also recognise (subject to Question 6) that increased visibility is also helpful to other parties. We are keen to help facilitate this and are actively involved in initiatives to make our data readily available, for example via the Flexr energy data sharing platform being developed by Electralink and all GB DNOs.

6. **What are the credible technical, regulatory (industry codes, licences and governance) and legal barriers and costs associated with increasing the data collected, stored and shared regarding DG operations, and in obligating parties to do so?**

It is crucial that proper consideration is given to current legislation which binds us in relation to data sharing in the electricity industry. This was drafted over 20 years ago and does not reflect the current direction of travel with regard to data sharing and transparency. This legislation promotes confidentiality of customer data above all else and does not permit the levels of data sharing now envisaged for a modern digitalised energy system, as set out in the recent Energy Data Taskforce report. Examples of barriers to data sharing include section 105 of the Utilities Act which makes it a criminal offence to share information obtained from customers except in limited and specified circumstances, and the Distribution Code DIN6 which also requires customer data to be kept confidential.

While workarounds can sometimes be achieved to allow some data sharing in specific cases, for example by adding new parts to the DCUSA, these workarounds tend to be slow to achieve as they are required to be progressed through the code change process, and they are very situation specific and inefficient. For instance, DCP350 is designed to allow a specific register of data to be created and shared with third parties but does not allow sharing of data more widely in respect of distributed generators. It would not be simple or appropriate to retrospectively add data sharing requirements into DCP350.

Given the recent change in industry approach to data sharing we believe it is crucial that a more efficient and holistic approach is adopted across the industry, not just in relation to this specific requirement, but more widely. We believe the time has come to introduce legislative change through BEIS, to match wider industry ambitions, for example by amending or deleting section 105 of the Utilities Act.

At present data sharing also tends to be at levels of 1 MW and above. This means issues are primarily around commercial confidentiality. Where details of smaller generators form part of data to be shared, there are greater risks that personal data may also be collected e.g. the details of solar panels located at a named individual's residential property etc. Breaches of data protection legislation carry potential for very severe penalties. The introduction of clear legislation and/or code provisions setting out a legal requirement for DNOs to collect and share such data would permit limited but appropriate sharing of data for the specific purposes of improved network development and operation. We note this appears to have been recognised in relation to recent discussions regarding PSR data sharing. As a result of advice given by the Information Commissioner, Ofgem and Ofwat are now proposing changes to relevant licences creating an obligation to share data and creating a clear legal basis for network activities in this area.

There is potentially some cost and time for BEIS, Ofgem and DNOs in updating the legal and regulatory framework to drive such an approach but it is not envisaged that this should be significant.

Finally, in considering any changes, it may also be necessary to consider the responsibilities of individual parties, including the role of a DNO relative to a DSO, particularly given current discussions as part of RIIO-ED2. It is important that arrangements relating to data collection, storage, sharing and management are proportionate but also promotes practical management and best use of data to drive efficiencies across all areas.

We hope our comments are helpful. If you have any questions or would like to discuss this further, please do not hesitate to contact me.

Yours Sincerely,

Beverley Grubb
Head of Electricity Distribution Network Regulation