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DER Technical Forum

07 October 2024
1400 - 1600

Welcome, Housekeeping and Introductions

Agenda

14:00	Welcome, Introductions and Acceptance of Agenda
14:05	Actions from previous meeting
14:05	Revised IT guidance
14:20	New Issues • Harksys Issue • Fault Current Interrupters • Minor conflict between G100 and G99 7.6.1
14:50	Minor Technical Changes to G99 – progress
15:05	SAF Update
15:25	Existing Issues update
15:30	GC0117
15:35	EU Update
15:40	AOB
	Next Meeting

Actions from previous meeting

None that are not on the Agenda

Revised IT guidance

New Issues

New Issues

Harksys – issues surrounding the interpretation of G100

Bingham Hart – use of fault current interrupters

Minor conflict between G100 and section 7.6.1 of G99

Harksys

Clarifications around G100 Requirements for Complex Sites

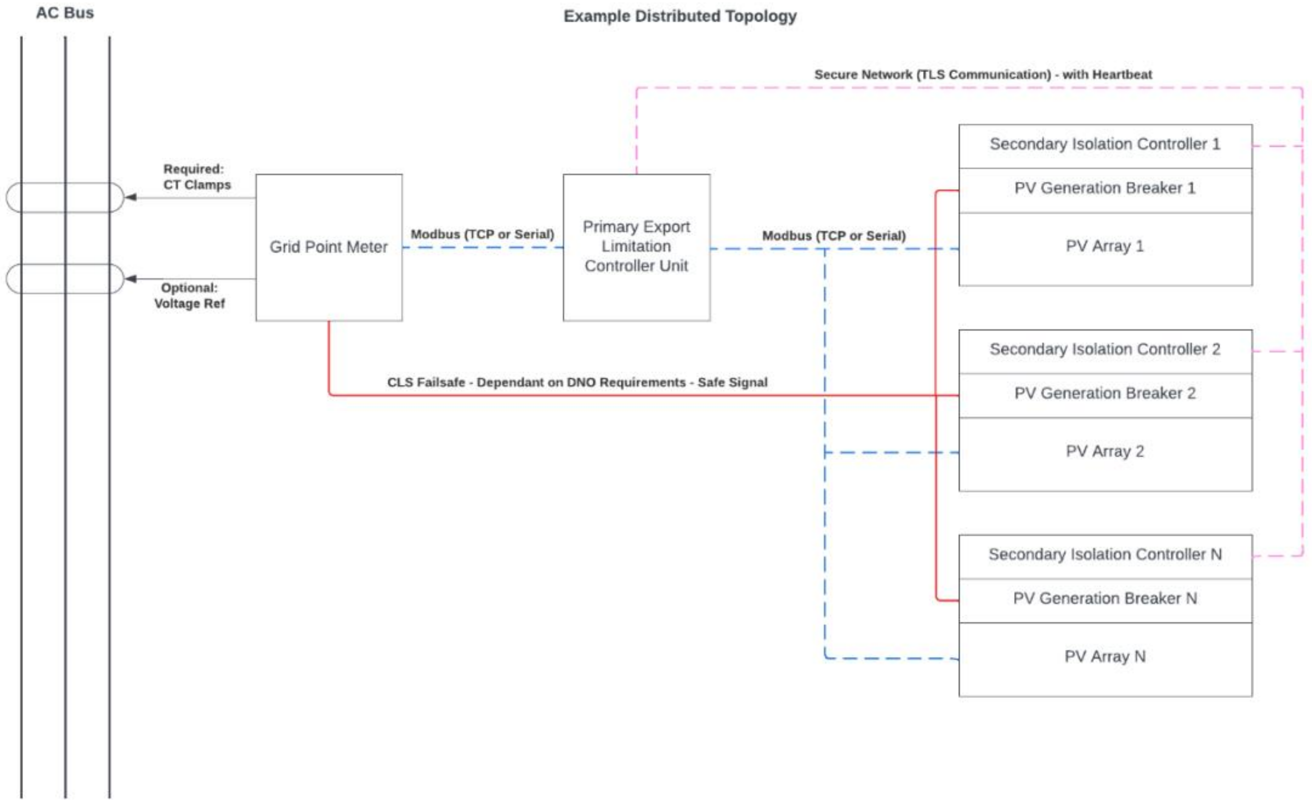
Damon Roberts

400kWp carport and 768kWp on roof_Evolv
Waterloo, Canada

Background

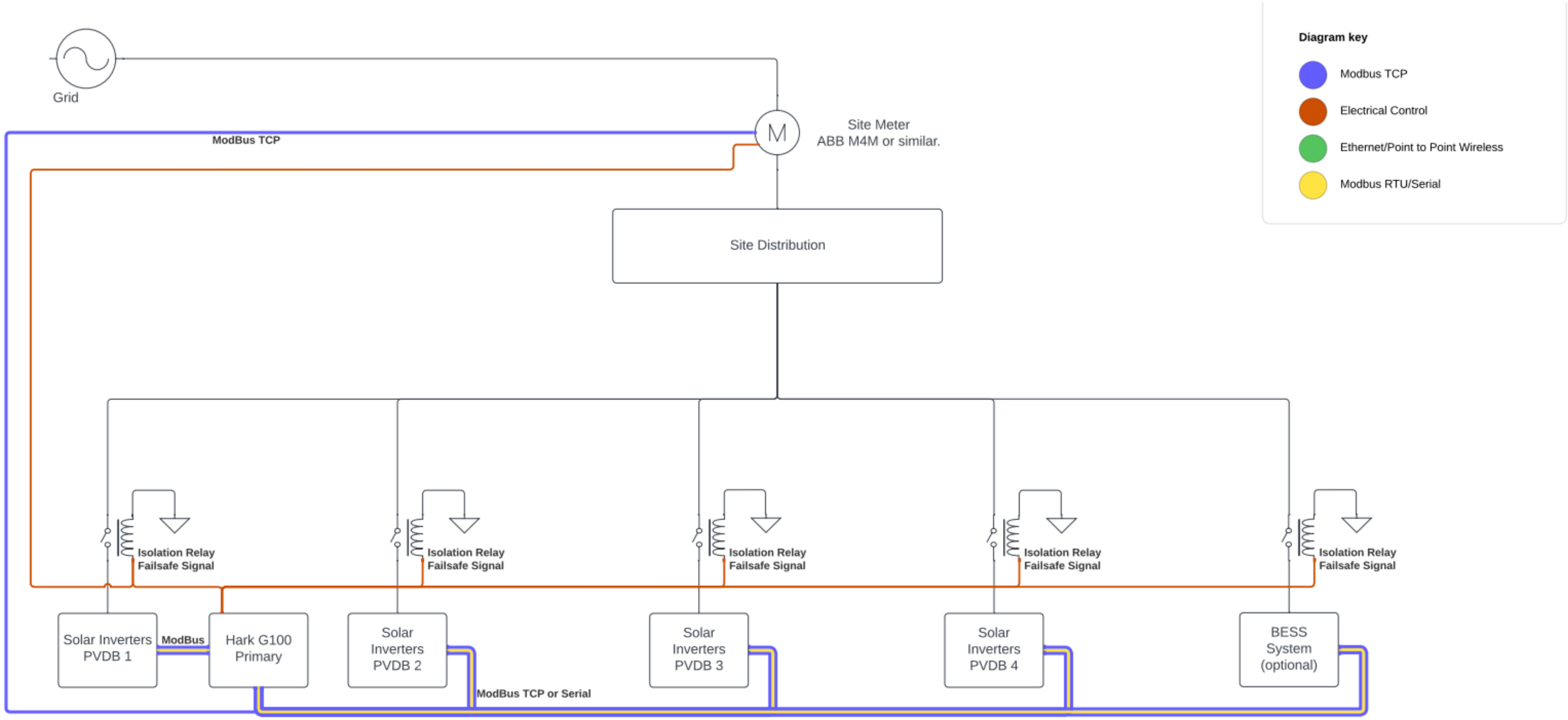
Hark/SolarEdge Solution to G100-2

- Distributed G100 Hardware and Software



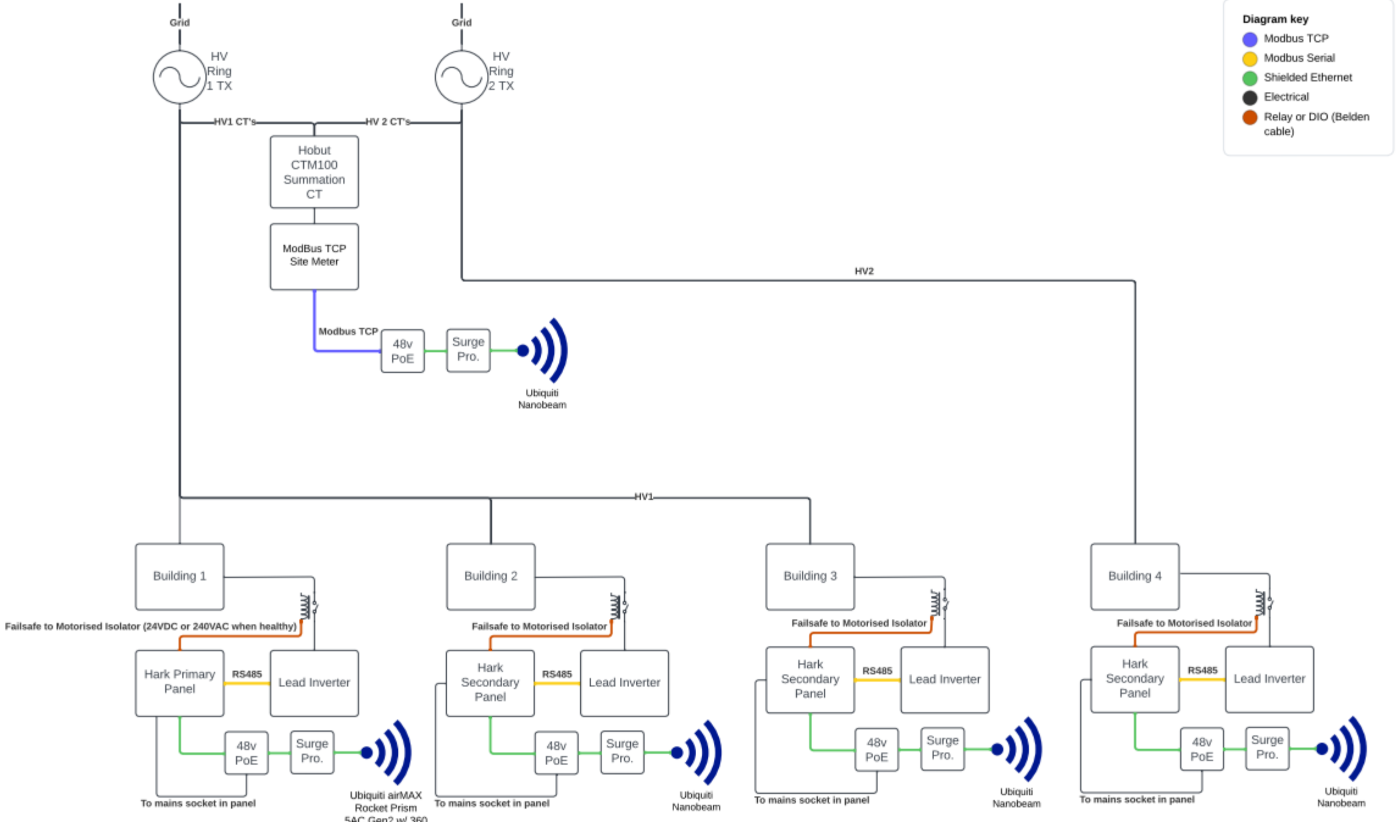
Worked Examples

Simple Site



Worked Examples

Complex Wireless Site



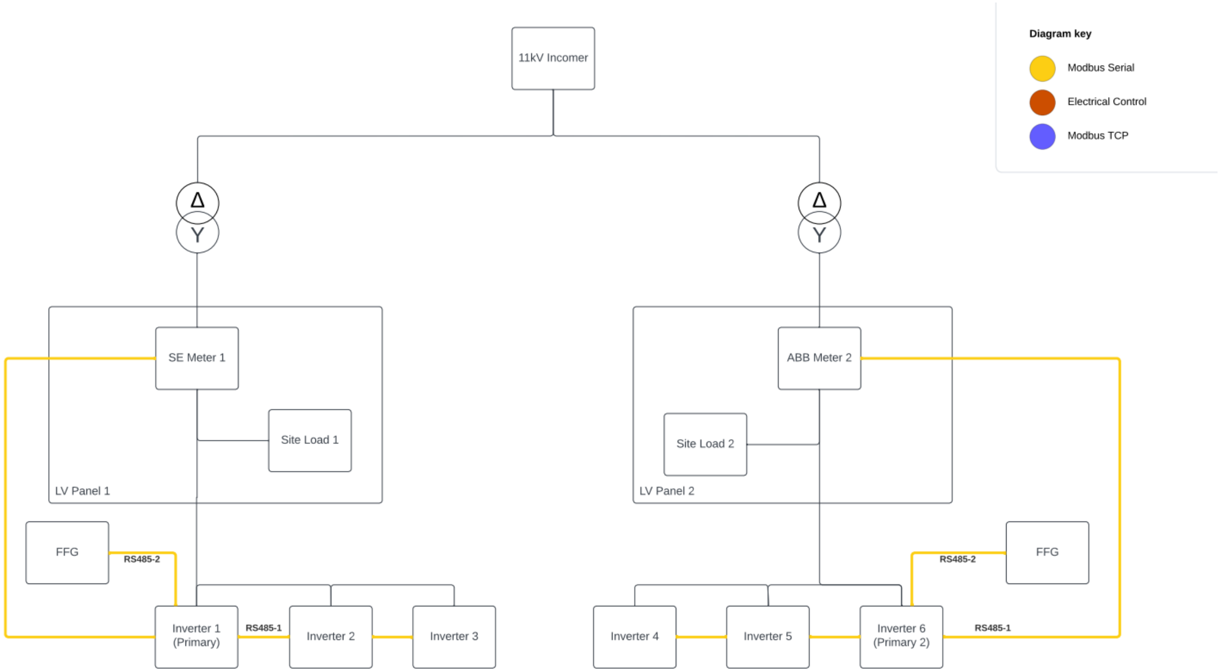
Challenges

Unclear Wording, and Inconsistent Application of RPP Requirement

- The specific wording of the latest G100 revision is 'For all High Voltage connected installations overload and/or reverse power protection (as described in section 4.5.3) shall be installed to disconnect the installation (or relevant Devices by agreement) in the event that the CLS fails to appropriately manage export or import.' which can be interpreted in one of three ways:
  - The generation being directly connected to HV. 11kV inverters are rare for anything other than full on power station scale generation,
  - The customer's site, ie their entire (electrical) installation being connected to HV,
  - The solar being able to feed into an HV ring on the site, as opposed to being export limited onto an LV bus. This is the case for sites where you use the G100 systems integrated into energy meters or inverters, and limit the site at LV.
- Earlier versions of G100 specified this differently, mentioning the requirement for RPP being on 'HV metered sites', which is a clear requirement.

Common 'Non-compliant' Installations

- Manufacturer specific G100 systems installed on LV, with an HV metered connection.
  - This often means multiple banks of solar cannot export horizontally across a site. OEM solutions rarely support multiple meters, or HV connected meters.
- Customers do not understand the issue, or why they need to spend 5 figures rectifying a 'working' system to enable them to use more of their own generation. This hits small/medium size sites more than others, especially if HV works are required to add in the required CTs/VTs.



Clarifications

Hardware

- What is the intended definition of: 'For all High Voltage connected installations?
- How much of the G100 system, and the RPP system can be shared, assuming all components/both systems are configured as to be failsafe?
  - Metering?
  - Communications Lines?
  - Controllers/PLCs?
  - Isolation Mechanisms?
- Often, a connection to the DNO meter, or utilization of its VT's and CT's would significantly reduce installation cost and complexity, but this is rarely, if ever allowed. In some cases, access to the gridpoint on site has not been allowed.
- G100-2 introduced allowances for wireless G100 systems. Can the RPP system also be wireless?

Clarifications

Control

- How is RPP intended to be graded alongside the G100 system? 60s of excess export is allowed prior to isolation of assets by G100, however the below has been used to suggest the RPP should be fast acting, meaning the G100 system will need to be set equal to the export limit, and in some instances not give enough time for the G100 control to react and ramp down.
  - ‘For all HV installations, and installations at LV where a non Fail Safe CLS is installed, the Customer shall install overload, or reverse power, protection at the Connection Point. Overload protection shall be set no higher than the state 2 limits, import or export or both as appropriate. The protection shall be instantaneous (ie fast acting with no definite-time delay.)’.

Clarifications

Interaction with G100 Systems

- ANM is being required by a greater number of sites, however this currently seems DNO area specific.
- Clearly these constraints, when applied will override the G100 export limits. How much of the infrastructure can be shared in these instances? IE could the ANM system just be used to dynamically change the programmed in export limit for the G100 system?
  - If some infrastructure cannot be shared, do all elements involved in responding to ANM signals also need to be failsafe? Assuming an RPP requirement, there are potentially 3 failsafe systems that need to be designed, and graded together, which becomes even harder to explain to the clients!

Bingham Hart – Fault Current Limiting Devices

A discussion to cover the following points:

- Update on NIA funded EDGE-FCLi project between NGED (WPD) and GridON
- Progress on moving to BaU since publication of final report in June 2022
- Is there anything delaying adoption
- Position of other DNOs on this and other fault current limiting technology
- ENA engagement in adoption or approval of this technology?

G99 7.6.1 – suggested (future) modification

The current wording is:

7.6 Type A Power Generating Module capacity for single and split LV phase supplies

7.6.1 The maximum aggregate capacity of Power Generating Modules that can be connected to a single phase supply is 17 kW. The maximum aggregate capacity of Power Generating Modules that can be connected to a split single phase supply is 34 kW.

This wording is derived verbatim from the 2008 publication of G59. It is not really in line with the approach taken in recent years where G100 is used to control the export to the system.

The limits of State 2 in G100 would appear to be entirely appropriate in all these cases.

7.6.1 could be rewritten thus:

7.6.1 The maximum aggregate capacity of Power Generating Modules that can be connected to a single phase supply without the use of a EREC G100 export limitation system is 17 kW. Similarly t~~T~~he maximum aggregate capacity of Power Generating Modules that can be connected to a split single phase supply without the use of a EREC G100 export limitation system is 34 kW.

Minor Technical Revisions to G98, G99 and D Code

Minor Technical Revisions and Housekeeping

The last comprehensive (as opposed to single issue) revisions to G98 and G99 were in 2021, and published in amendments 6 and 8 respectively in September 2021.

Since then a number of issues have been identified by DNOs and by stakeholders, primarily via the DER Technical Forum.

In many cases the issues arising from the DER Technical Forum have been discussed here and the proposal for modification agreed, subject to public consultation of course.

The consultation for this modification ran from 09 June until 09 August.

The following slides summarise the responses to the consultation, and the DNOs' proposed inclusion in the modification.

Consultation Responses

There were four responses to the consultation, from:

- NGESO
- Northern Powergrid
- Scottish Power Electricity Networks
- UK Power Networks.

All respondents supported the changes being made.

All respondents made a number of suggestions to improve the proposed modification.

The material suggestions which the DNOs agree should be included are listed on the next slide.

There are a number of editorial and minor wording etc improvements suggested by respondents, which are listed in Appendix 1 of the draft Report to the Authority

Each respondent will receive a detailed explanation of the actions taken against each of their comments.

Proposed additional amendments following consultation

EREC G99

- Following the appointment of the NESO as the ISOP, the references to NETSO have been updated to ISOP throughout.
- The existing text for pumped storage should be amended to exclude pumped storage from the new requirements on falling frequency – this mirrors the Grid Code. It is inappropriate to expect pumped hydro technology to comply with the requirements, and the Grid Code reflects the assimilated law on this.
- Additional paragraph concerning the requirements for and positioning of safety labels on customers’ equipment associated with generation sharing technologies.
- Some modifications to the proposed text on the compliance process for embedded generators with bilateral contracts with the NESO to emphasize the need for tripartite co-ordination of Grid Code and G99 compliance activities.

There were no significant issues raised by respondents to the proposed changes to either the Distribution Code or EREC G98.

The Distribution Code has also been updated to refer to the ISOP.

Next Steps

Subject to DCRP endorsement, the Report to the Authority, and the revised Distribution Code, ERECs G98 and G99, should be submitted for approval.

The proposed implementation date is 01 January 2025, although of course this may need to be later if Ofgem need more time to review the Report.

The compliance date for the new storage requirements would be 01 January 2026, unless the 01 January 2025 date slips, in which case it would be on year later than the revised implementation date.

SAF Update

SAF

DNOs are still working on this, with a view to collecting more information from developers earlier in the life of a project – as a response to Issue 126 as raised by UB Grid Consultancy.

In parallel the Strategic Connexions Group of the ENA has identified similar issues, and also wishes to include checks at an early stage of a project to ensure that it appears to be appropriate viable.

The opportunity is also being taken to update some of the wording and questions to reflect the outcome of the Strategic Code Review.

The key proposed changes to the SAF

For new sites, information supporting the viability of the project in terms of access to the relevant land etc, will be expected to be submitted, including heads of terms of the agreement with the landowner etc (waived of course if the applicant owns the land).

An initial project plan through to commissioning/completion.

Parts 3 & 4 need to be completed on first submission for all Type B, Type C and Type D power generating modules, whereas Type A only need to complete Part 3 as part of the original submission.

All data for all types must be complete before synchronising.

Previous Issues

Outstanding Issues – see appendix 1:

Registered Capacity – 112

BESS connexions – issues 113, 114

Delays associated with DNOs being able to submit Mod Apps to NGESO because of inadequate SAF data – 126 – As above, the DNOs are updating the SAF.

Initial P28 assessments for generation tripping and/or load rejection etc. – 127 – should be picked up in the guidance on P28 being developed by the ENA.

IONs for Type B and Type C – 129 – now included in the proposed G99 update.

Various issues from BPA - 130

GC0117

GC0117 – alignment of Large, Medium and Small across GB

This was submitted to Ofgem on 14 May 2024

The three main options are:

- The baseline (ie existing arrangements unchanged)
- The original proposal (ie Large starts at 10MW in all of GB)
- WAGCM1 – extending the E&W arrangements (including Medium PSs) to GB

A majority of the Workgroup voted for the baseline.

The Grid Code Review Panel members' votes on the proposals were split, with no consensus.

Although Ofgem initially suggested they would rule by mid August, they have now announced that they will run a six week consultation in October, and expect to make a decision to be published 06 December 2024.

EU Developments

Update

The following slides were included in our previous meeting. Whilst there is a lot of work going on in the EU to advance these issues, including a possible minor revision to the proposed RfG and NC DC text, there is nothing concrete to report on.

Therefore the following slides still give a good overview of the issues.

EU Network Codes – ACER proposal

The key issues (at least for DNOs) are:

- Electromobility
- Certification
- Aggregation of generating units
- Storage
- Grid Forming
- Simulations and Models

The following slides give a little detail on the issues above – but only from a DNO perspective.

The EU Commission will process ACER's recommendations into EU law later this year or early in 2025– at least that is the current timetable. There will still be amendments to the draft text by the Commission, and there will be a 4 week public consultation as part of the process.

Electromobility

ACER is proposing three classes of V2G:

<2.4kW – probably connected via a domestic plug/socket.

2.4kW – 50kW – probably the bulk of EVs, and many will be DC connected. Requirements similar to Type A

50kW – 1MW - requirements similar to Type B

All EVs (and heat pumps) will have to have equipment certificates provided by the manufacturer – minimizing admin etc for both owners and DNOs.

International standards bodies are working on updating relevant standards to implement the requirements, but work will still be needed to create the compliance schemes incorporating mandatory certification.

It may be appropriate for GB to consider harmonizing the GB requirements with the standard UE requirements, to minimize any cost differentials between the EU and GB markets.

Certification –mandatory for EVs and heat pumps

Background (as MK understands it!)

The concept was introduced in the NC RfG, DC etc in 2016

The RfG drafting seems to be an EU description of the existing situation in Germany, Spain and possibly some other countries (although without the mandatory site certification that Germany requires)

An equipment certificate must be awarded by an authorised certifier.

The authorised certifier in turn must be accredited by a national authority in accordance with Regulation (EC) No 765/2008. (requirements for accreditation and market surveillance relating to the marketing of products and repealing Regulation (EEC) No 339/93)

Opportunities

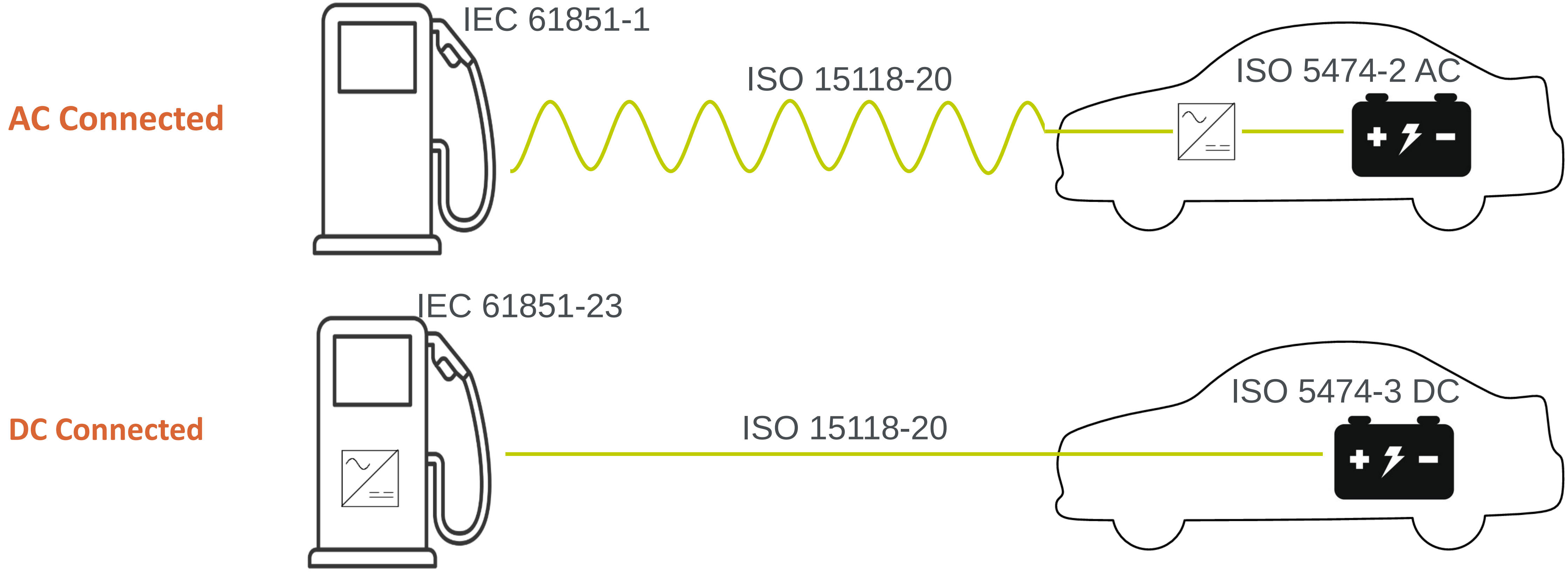
A (complete) certificate for a PGM (or heat pump) would mean that there is no RfG compliance assessment needed on site.

This would allow the connexion of small scale generation to DSOs' networks with minimum DSO interaction.

This is particularly valuable for mass market developments such as domestic PV, and increasingly electric vehicles, domestic storage and heat pumps

ACER's proposal to the EC includes the legal text making certification mandatory for EVs and heat pumps.

V2G EV standards



ISO 5474 - 2	Functional and safety requirements for AC power transfer
ISO 5474 - 3	Functional and safety requirements for DC power transfer
ISO 15118-20	Communication interface between EV and EVSE
IEC 61851-1	Main standard for EVSE certification
IEC 61851-23	Standard for DC EVSE charging stations

Aggregation of generating units

It has always been the case that non-synchronous generating units on a site should be aggregated into a single power generating module.

ACER is proposing that this arrangement be stopped, and that aggregation would only be of like technologies – ie so this would stop the aggregation of, for example, PV and storage into a single PPM.

ENTSO-e is very against this, and the DNOs are supportive of ENTSO-e's position because of:

- The risk of owners gaming the technology boundaries to avoid being a higher Type (eg two Type B PPMs rather than a single Type C PPM)
- Perceived unfairness of existing post-RfG customers.

Currently this remains unresolved and is likely to remain so until the Commission decides.

Grid Forming

Imposition of grid forming likely to lead to a greater incidence of unintended islands.

The risk is accepted by ENTSO-e & ACER.

The current drafting proposed by ACER is to allow mandatory GF capability for larger PGMs which are connected to a substation (or on a dedicated feeder) where 110kV or higher exists.

A few larger Type B PGMs (in some countries with a high B/C boundary) would be caught by the above, but smaller Type Bs and Type As would have to have GF capability starting from when a nationally agreed road map has allowed time etc for DNOs to have adapted their systems.

RoCoF as anti-islanding protection is excluded from the new 4Hzs^{-1} ride through requirements – although other frequency protection used for anti-islanding might need to be reviewed.

Simulations and models

To the extent that ACER's draft legal text follows the text in the ISSM EG report, there is probably little to comment on as part of the current consultation.

The RfG does not appear to specify how the TSO will receive models from DNO connected generation, if the TSO requests it – maybe this is something for local TSO/DSO agreement?

In the longer term it might be that DNOs either individually or collectively will need to develop expertise in EMT modelling.

Storage

The ACER text fully implements the Expert Group on Storage's recommendations.

Storage is just treated as part of the PGM, but with additional requirements for responding to emergency underfrequency conditions.

The proposed LFSM-U response is subtly different from that in the GB Grid Code – however as this is a current specific software setting, it makes sense to follow the GB Grid Code characteristic.

AOB and next meeting

Appendix – historic Forum issues

Outstanding Issues – 1

No	Issue	Assumed Status
112	A common issue that keeps coming up is Registered Capacity vs design install and grid agreements. I have a specific case where the G99 and connection agreement is for 9MW, the developer undersized the inverters slightly. So it can only produce 8.5MW (in round numbers) whilst operating in the 0.95 lag/lead range. This is what is shown when we do the G99 study, and we noted this shortfall. So the question arises, of what happens to the site now and what can it do. Specifically, 1) Is it's new official RC 9MW or 8.5MW ie do they retain their original agreed capacity, or is this list back to the DNO? This is a common sticking point, taking the above example it cannot meet the 9MW required, but they may upgrade an inverter later to give them more MVAr headroom and it could then operate at 9MW. 2) If the DNO doesn't want/need them to operate across the 0.95 lag/lead range can they then operate at 9MW active power and say unity or 0.98pf. In this case they are producing their official R, but their system design does not meet the required G99 standard for a 9MW site.	This is an issue that does re-appear from time to time. We have attempted to deal with it in the past in issues 40, 80 and 83. We went through it with slides at the 7 June 2022 DER TF. DNOs have summarized how they specify maximum capacities and power factors in their connexion agreements. We propose that we incorporate the material from the 7 June 2022 meeting into the next version of the DG guides

Outstanding Issues – 2

No	Issue	Assumed Status
113	P28 has the usual classifications of frequent events, infrequent events (4 per month) and very infrequent events (1 per 3 month)…. what should we be assessing a storage system performing a dynamic containment service as? The UK grid is reasonably stable, at the moment, but with more conventional plant dropping out, the power swings are going to get a bit more sever, and the DC type services will be getting worked more often. Classing it as a very infrequent event probably isn't realistic, but what about infrequent events? I could see that it is possible that you could get to around the 4 events per month, although probably not at the full power swing.	This is a good point, and one that probably would benefit from a consistent consideration by DNOs. It might be sensible to base the frequency on the observed incidence of frequency excursions, over the last 18 months say, that trigger a specific level of response from such services. The response level might be set locally, and the P28 "frequency of event" set by the historic track of frequency excursions triggering that level of response. This can be calculated from the information NGESO publish monthly. This should be picked up as part of ongoing work to develop a common approach to BESSs between the DNOs. However, note that in the BESS discussions on 18/11 it was pointed out that the 3% limit essentially applies at any time once the transients have died away, so for BESS power swings the 3% probably applies in all cases, irrespective of frequency of event. The DNOs work on reviewing customers' issues with P28 should pick thi

Outstanding Issues – 3

No	Issue	Assumed Status
114	We have concerns relating the voltage step change for Battery Energy Storage Systems (BESS) when the systems are designated for fast frequency response. A number of network operators define step change to be full declared export to full declared import for real power P and for reactive power Q. The FFR contracts do not have a contracted obligation to reverse the direction of reactive power flow and no obligation to match the fast MW response with a MVAr response. When importing, there is no obligation to operate at a particular power factor only to operate within a +/-0.95 range. If a full MW ramp has occurred, it is reasonable to assume the system is under stress. To reverse Q at this point would be the worst of all strategies at it would exacerbate the stress of the system by introducing an unnecessary voltage step. It is likely that EFR or FFR BESS is located at a point with a high X/R ratio (close to a BSP or GSP). Therefore a unit change in Q would have at least 10x the impact on at the voltage step that of a unit change in P. This Q reversal condition appears to be based on a false assumption about the default behaviour of inverters under FFR. We believe it is a matter for the customer to demonstrate through simulation the voltage step change under power reversal. It is a matter for the customer to produce a reactive power strategy that meets the constraints of the D Code and the connection offer. Confirmation of the simulation can be done via commissioning tests with frequency injection for smaller steps. The imposition of this requirement distorts the market by essentially limiting the capacity of a BESS scheme to around half the capacity of other technologies thus creating hidden barrier to the penetration of the technology. The customer should demonstrate how they meet the voltage step change challenge through modelling and if necessary to verify through commissioning demonstration, not for the network operator to impose a control philosophy.	To be picked up in the BESS sessions

Outstanding Issues – 4

No	Issue	Current Status
126	Customers are still seeing very long delays for DNOs to submit a Modification Application to National Grid for the appropriate GSP. A developer accepted a scheme Sept 2020 and only had the Mod App response back August 2022 (even with pushing for a Mod App to be done with escalation). This is not an isolated experience. One part of the delay occurred as the DNO informed us they are allowing customers to only fill in sections 1 -3 before receiving a distribution offer, but required customers to fill in section 4 before they were able to submit the Mod App. Whilst the customer UBGC represented had filled in Part 4 when the scheme was applied for, others which accepted before had not and a Mod App was further delayed, to allow customers who accepted ahead to fill in the form. This would have been 14+ months after they had initially accepted their offers. If Part 4 is a requirement for a Mod App but the DNO feels comfortable making a distribution offer without part 4, can it be agreed that part 4 it is filled in within a set period, I.e. 2-3 months of acceptance to prevent further delays in Modification Applications in the future or that the Mod App is submitted based only on the information within parts 1-3.	The timing of the provision of data is prescribed in DPC1 of the Distribution Code – needs review to see how this suggestion might be accommodated. Need to set up some discussions with appropriate DNO experts as soon as possible. Following a meeting between Philip and DNO experts from NGED and Electricity North West it is suggested that Part 4 of the SAF becomes mandatory.

Outstanding Issues – 5

No	Issue	Current Status
127	There is a requirement in ENA P28/2 (Although fairly sketchily defined) that we are supposed to consider what happens if a generator trips under full load conditions at different power factors ie 0.95 lag, unity and 0.95 lead. We have had a fairly large number of these sites come up that have a problem on them, and when we carry out the studies, we get a fail (ie the SVC is greater than +/-3%). When we hit this point there isn't really much we can do to help, as the SVC results are really just a function of the MW, MVAr flow and system strength – the only option is to constrain the generator MW output if it is at a problem PF – this causes headaches for developers Some general thoughts would be • A generator tripping on full load conditions would be relatively unusual – although with G99 LoM protection I guess it can and does happen, so I can see why its there. • Is it really realistic to consider it against minimum (outage) fault condition? • Should the developer really be doing this and finding problems - it is such a simple assessment the DNO should really do this, and check before issuing an offer. In reality just a simple loadflow of before and after.	DNOs broadly agree that the DNO should undertake these checks early in the application process. It is appropriate (and necessary in P28) to consider outages. To be investigated further as part of the refinement of BESS processes.

Outstanding Issues – 6

No	Issue	Current Status
129	Our issue is specifically regarding Type C PPMs. We have a number of Type C (solar) sites across different DNOs. Looking at G99 section 18.2 there is no EON or ION in the connection process for Type C PPMs, and to achieve FON we need to complete tests that require at least 65% (full voltage control) or 85% (reactive power and frequency response tests) of the maximum export capacity to be generated. For solar sites that energise over the winter months, it is unlikely that they would have such irradiation needed to achieve the required export to complete those tests until spring/summer the following year. For Type D PPMs there is the ION to cover this type of situation and allow export during this period until testing can be completed and FON achieved. Having discussed this with other developers there seems to be a consistent inconsistency. We have had varying processes for achieving FON from different DNOs as well as confusion and variance within the DNOs. I outline two examples: 1. DNO A issues a Nil Export Connection Agreement (export allowed for testing purposes only) and following all the tests that could be completed at the time, issued an ION and vary the Connection Agreement to allow full export. Following successful completion of the outstanding compliance tests the FON is then issued. This approach seems a pragmatic approach. 2. DNO B have stated that they require FON to be completed before they will counter sign the Connection Agreement and allow full export. This leads to a lot of confusion and questions over how we are going to be able to complete the testing which requires connection to the network and export without a Connection Agreement in place – they won't offer a Nil Export initially but only the final Connection Agreement with the full requested Export Capacity. Further, this will result in our site that is due to energise in December, not being able to export until March/April when we have the required irradiation to complete the remaining testing and achieve FON.	Suggested that a new clause is introduced into 17.3.6 and 18.3.6: "To aid completing the necessary tests, and to allow the interim export of energy for the Generator's commercial purposes, at the discretion of the DNO, the DNO and the Generator may agree an interim operating regime, including issuing and Interim Operational Notification, pending completion of all the necessary tests and data submission. In such cases the provisions of Section 18.4 shall be respected and Section 19.3 shall be used as a guide to the formality required."

Outstanding Issues – 7

No	Issue	Current Status
130	1. Do DNOs have any advice on how to challenge the current CUSC wording in relation to the criteria determining when a SoW is required? Are there any other forums where these issues could be discussed and progressed? 2. Diversity assessment of complex sites Does the company (DNO) have a formal policy on how to assess the diversity of demands and generation on complex sites when assessing new applications for that site? If so, is it published? Where? 3. Generation/Site curtailment Under what circumstances do you install equipment that can trip either a customer's generation? Or the customer's whole site? Under what circumstances could the latter apply? Is this approach published? Where? Where the company use the facilities installed in accordance with G99 11.1.3 or 12.1.3, or if the site is intetripped, what are the rules the determine which sites are affected and in which order? Are these published? What information does the company have to produce to the customer in relation to the likely volume and incidence of use of any of the above curtailment? 4. Combination of applications – under what circumstances does the company combine applications for quotations from different, or even from the same, customer? Can customers provide their own P28 and G5 studies and assessments? Are there published rules on this? If so, where? 5. Fault levels Fault level problems can lead to very long lead times for connexion. What is your company doing about this? Are there any technology solutions that can be deployed? On the DNO side, is your company considering Industrial Internet of Things (IIoT) technologies similar to export limiting and ANM requested from customers to monitor and control activities in your substations? What technologies could be adopted by customers to reduce fault current contribution from generation and storage assets? 6. Batteries Possibly an extension of 2a above, but does the company always treat generation and storage output as 100% additive when usually they will be substitutional? What mitigations exist to avoid treating the output as additive? Would an approach where customers would commit to storage trading strategies linked to site's demand, generation and potentially fault current levels enable faster transition to net zero? Such strategies could be subject to witness tests as export limiting and ANM solutions are. Storage would in essence be relying on the same type of technology as export limiting/ANM/intertripping to ensure reliability. 7. How can your company signal to developers etc where there are beneficial sites for siting or co-locating storage?	Issues raised with DNOs.

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