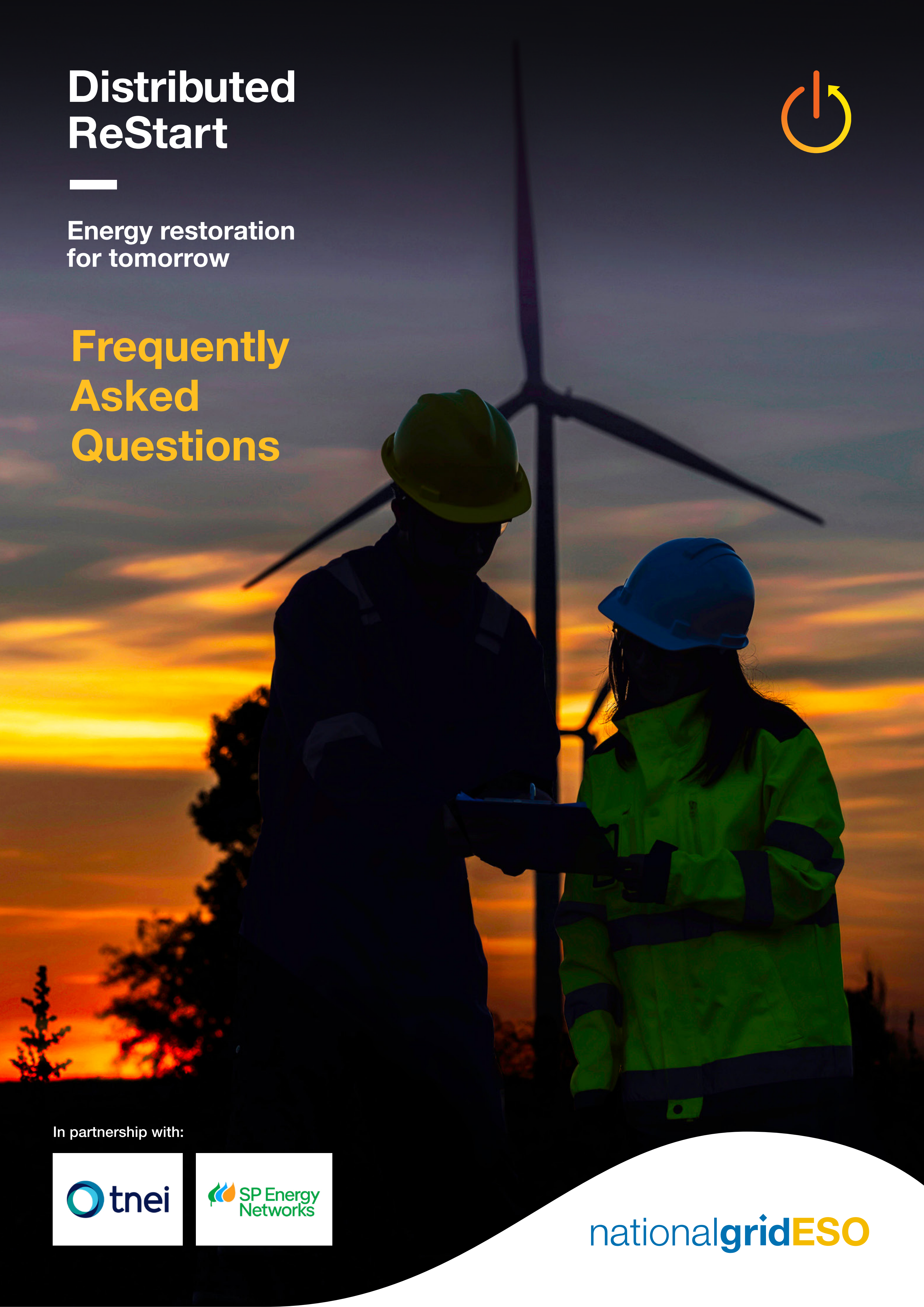
Distributed ReStart

Energy restoration for tomorrow

Frequently Asked Questions



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Stakeholder Engagement Summary

Distributed ReStart aims to incorporate the views of wider industry at every opportunity, bringing in the diverse expertise found across the electricity market to solve this world first challenge of black start using distributed energy resources (DER).

Across all our stakeholder events we have captured the questions posed and used these to inform our future outputs. However, we are aware that these questions may be valuable to wider industry or prompt further questions which drive innovative approaches.

All key questions to date have been responded to and are included in this document to provoke thought and further discussion. If you have any queries or comments stemming from these, don't hesitate to contact us at ReStart@nationalgrideso.com.

Power Engineering and Trials Q&A

Question	Answer
For a controller that is installed as part of a trial, does the scope of the controller go right up to the transmission voltages or does the controller just look at stuff happening in the Chapelcross network?	We don't have any new controller being tested in the live trial at Chapelcross. The live trials have all been based on existing generator controllers, like the AVR and governor, and manual switching of the network and instructions to other resources. The DRZ Controller prototype is being tested in hardware-in-the-loop simulation using a model of the Chapelcross network. The scope of control for this design is the distribution network only. The idea is that the transmission network would still be handled by a control engineer, as now, while the DRZC could look after the resources at distribution level.
Did you detect significant levels of negative sequence V or I when energising Glenchamber and/or North Rhins wind farms? That was the main cause of failure of an earlier (1980s) attempt to fire up Longannet feed pumps from a GT at Dunfermline. The fundamental problem is the lack of adequate/any transposition of single circuit OHLs.	We did not detect anything excessive or problematic with phase imbalance or negative sequence. The current on the long circuit lengths was quite low. The main lengths of overhead line used in the test are double circuit lines and the other side remained energised; this will have had some effect. Also, of the two main lengths of circuit, BG route from Glenlee to Newton Stewart has phasing BYR, while BT route from Newton Stewart to Glenluce has phasing RYB. So we will have benefitted from some transposition effects on the energisation route as a whole.
Even if the assets are connected at 11 kV are these embedded or are they connected to the 132 kV at PoC?	Our designs have focused on DER in the 10–100 MW range and connected at 33 kV but we have also considered the implications of DER connections at higher and lower voltages. It is important to be flexible and not rule out resources that might play a useful role in a distribution restoration zone (DRZ).
What is a block load?	The step-change increase in load when supplies are restored to customers, which the generators in the DRZ need to be able to handle while keeping frequency within limits.
An anchor generator is not necessarily embedded? It could be sitting at a GSP of 132 kV?	Yes, if it can be part of a viable DRZ. The assessment of viability will be done by the ESO in collaboration with the local DNO and TO, taking account of the DER in a given area and the expressions of interest in participation in a DRZ.
If the anchor generator is BESS, will there be a stability problem for wind farms to join in the early stage of restart?	It is no worse for wind than for other sources, but the design relies on the ability to control/limit the power output from participating DER.

What is the most challenging problem for cases with BESS as an anchor generator rather than synchronous machines?	For all converter-based sources, challenges include transformer energisation, network protection, and ensuring sufficient system strength to allow other converter-based resources to connect. Please see our Power Engineering and Trials reports for further details on these issues.
The guidance of block loading of 10–20% of gen capacity is very useful context.	It varies depending on generator type and the specific capabilities of each plant and its control system.
Do you see fast balancing moving down to smaller block loads << 1MW? I am thinking of EV chargers, commercial/domestic HVAC and heating loads etc. to IIoT?	There will be a trade off between the cost of the comms and control infrastructure and the size of individual resources. In early DRZs it seems more likely that a fewer number of larger resources will be controlled to provide the fast balancing capability. There may be an opportunity for aggregation or indirect control of smaller loads, e.g. at domestic level, but that may introduce additional delays in the comms and so may be more suitable for slow balancing.
Do you see GFrm BESS/IBR re-energising the grid at < 1pu frequency to reduce transformer inrush?	We have focused on energisation with voltage magnitude below nominal, and this has been demonstrated in our live trials to be very effective.
What is the impact to the 'anchor' generator in a DER world? e.g. Does the technical risk change when connected to multiple (lesser voltage) generators?	A DER 'anchor' generator will move from a 'steady state' role (where it would typically provide a fixed MW output continuously), to a more 'dynamic' role where it may now have to respond by varying its MW/MVAr output to match the connected network (where the frequency and voltage will be inherently less stable than before). Offline analysis will be undertaken to ensure the additional operational requirements are within the capability of the machine, and network restoration/control options chosen to minimise any additional stress.
Does Cruachan have a big role to play?	We expect future black start plans to include a range of diverse resources including large, transmission-connected generators, HVDC interconnectors to other countries, and DER-based solutions like those being developed in this project.
Are you considering a similar approach for transmission connected assets which can provide a partial black start service? e.g. transmission connected wind.	See the latest black start strategy and procurement strategy for further information.
Have protection solutions such as adaptive overcurrent/earth fault been considered? It would detect change in network topology and toggle protection settings as required.	We are considering all protection alternatives that might be available. These might be adaptive in their own right, or they may change to different settings under instruction, possibly from a DRZ Controller.

Can you have a backup supply to the tap changers or are there too many of them? **And do you need bigger substation batteries for multiple switching before energisation?**	The problem of backup supplies at lower voltages exists with the current approach to black start. It is possible that voltages may have to go outside normal limits for a short period during the restoration process, before tap changers operate, as long as equipment is not damaged. Backup supplies are constantly being improved. The need for backups will be assessed on a case by case basis. In some cases a DRZ may do little more than enhance resilience of the local network. Local DER might be used to re-energise the network, including substation auxiliary supplies, but without reconnecting customers. Then when sufficient supplies become available from the transmission network or neighbouring areas, the network is operable and can support more rapid restoration of supplies.
What about blocking the OLTC during restoration?	It may be appropriate to block transformer on load tap changers (OLTC) or override their usual settings but it will depend on the specific circumstances. For primary substation transformers we want the OLTC to operate to bring the voltage within limits.
Nice presentation of options, what are your assumptions on the permitted volt drop on, e.g. BSP transformer energisation. Comply with P28 or not?	We assumed P28 compliance in most of the studies but the existing approach to black start, as recognised in the Codes, allows for voltage and frequency to go outside the normal limits if necessary in the early stages of restoration. We do expect that fairly detailed power system studies will have to be done when establishing a new DRZ to confirm expected behaviour.
I think 10% block load capability is probably optimistic for most hydro generators if the lower frequency limit is 47.5 Hz. 4–5% is more realistic unless the generator has a digital governor and a high head. **The interesting bit will be matching gen to demand with relatively large block demand restoration. Having run a black start test using at GT in 1974. Reaction to mismatch needs to be very fast or the recovering island will stall.**	Block load capability of DER has been identified as a critical limitation and we are exploring different ways of getting around this. This may involve adapting switching patterns to impose smaller step changes, improvements to the DER like a new governor, or compensating for the limitations of one resource by coordinating its response with others using the DRZ Controller. Batteries are seen as a particular area of opportunity given they can act as demand or generation with fast response, but are we always seeking to define our requirements in a technology-neutral way.
Block load pickup: surely a second block would compound the residual frequency drop from the first, and so on? Wouldn't this mean that subsequent blocks are smaller than the first? Or should the first be scaled down to permit constant-sized blocks, for simplicity?	The anchor generator operates in isochronous mode, so every time a block load is picked up, the frequency is brought back to 50 Hz, although this takes time. Picking up the same size of load shouldn't lead to a lower frequency. Where this is a problem we can either reduce the size of the block loads or we can use other DER to increase the capability.
I take it with variable renewables involved you need a faster recovery of the integrated network?	The sooner we can restore the system and build the strength that comes from having multiple, diverse and flexible resources, the sooner we can accommodate more variable sources.
What power factor do you assume for the load pickup?	In the studies presented here the power factor was assumed to be the same as normal. We recognise that power factor may be different due to motor starting and other effects after restoration of supply but this has not yet been examined in detail.

What makes one assume cold loads as constant power type? (As opposed to constant current or constant impedance.)	The cold load characteristic will depend on the type of demand supplied by the substation. A constant power characteristic was assumed as a conservative scenario. It is an important area that deserves further attention, not just in the context of cold load pick up during black start but also for our understanding of distribution system behaviour in general.
We have to address the issue of transmission network imbalance (e.g. negative phase sequence) on very lightly loaded circuits.	Imbalance is a concern. Reference was made earlier to traction supplies. This is an example of one type of load that could not be connected early on. The issue of imbalance on transmission circuits due to phase configuration on overhead lines is not being explored in any detail in this project, but we do appreciate that any DRZ used like a virtual power plant to energise the transmission system must be similarly capable of absorbing negative phase sequence currents.
Chapelcross is a very small GSP in comparison with some. How would you expect the viability to change for e.g. a 240 MVA GSP? Or a very large one, e.g. 1400 MW of demand and 700 MW of embedded generation?	The principles remain the same but there will clearly be differences in the details. We have tried to derive conclusions or rules of thumb that are widely applicable but this only goes so far; some level of power system analysis will be required for each DRZ to account for its unique circumstances. Our second study case, Galloway, is larger than Chapelcross, with a lot of embedded DERs.
33 kV black start can energise 132 kV if it's big enough. Then, if there are further assets on the 132 kV system that can be added at this point (e.g. wind, if it's blowing), then it may help with the 400 kV system; but plans should not rely on this.	Yes, these are options that we are considering, where DER can contribute to an overall improvement in service by being used in combination with other resources.
As intermittent generation sources of black start power can all fail simultaneously (e.g. a windless night), they cannot be core to black start which needs 24/7 availability.	We would expect to have 24/7 availability for some resources but for a total GB shutdown the overall restoration process is likely to last for days. Intermittent sources are likely to have some role to play.
EVs with 75–100kWh batteries, 3.5 miles/kWh average daily journey 20 miles. Lots of SoC range to work with?	The scope for vehicle to grid services was considered in a preliminary piece of work in early 2019 – the reports are available on our website. The technology is developing rapidly but is not yet available at scale. We are trying to specify requirements and solutions in such a way that they are flexible to the changing context and technology offerings.
There are grid scale energy storage technologies that are locatable, synchronous and that can charge and discharge concurrently so can support black start greatly. Batteries are not the only option and it would be good to know what potentials there are to trial these technologies as part of a stage two re-start.	We are trying to make all solutions technology-neutral as far as possible and we are excited at the potential of new energy storage technologies, of all types. But within the project timescales, we focused on working with assets already connected to the network, or due to connect soon. However, these are mere demonstrations and do not indicate preference for any future procurement of services.
Can battery storage be used as an anchor generator or support for voltage and frequency control?	To be used as an anchor a battery (or other converter-connected resource) will need a grid forming capability. For example, you may have seen reference to virtual synchronous machine (VSM) in recent National Grid ESO research projects. If joining a power island already established by an anchor generator, batteries and other forms of energy storage, with appropriate control systems, could certainly be used to help with frequency and voltage control.

Have you also considered minimum fault level for correct operation of converter-connected generation, especially for FRT?	This is recognised as a challenge and is discussed in some detail in our reports. It may be necessary for phase-locked loop gains or other control parameters to be adjusted to allow for stable operation during the early stages of restoration when the system is especially weak.
Will the anchor gen be able to handle the Magnetic Inrush (possibly up to 2 x rating) as they are brought back on line?	We have been examining this in power system studies and exploring this issue more generally with DER owners/operators, manufacturers and others. It is an example of something that will require detailed assessment in each case. In some cases mitigation measures may be required.
Looks like you'd need ~5 re-started DRZs interconnected before you can attempt a 400 kV energisation?	To achieve the capability required to re-energise the 400 kV network will almost certainly require multiple DER resources to be combined; that is a key element of the project. A 33 kV power island is not capable of providing enough fault infeed to enable 400 kV protection to operate (minimum required is 250 MVA) due to the network impedances. An anchor DER at 33 kV may enable the restarting of larger resources at 132 kV, which then provide the combined strength to energise at higher voltages.
250 MVA is very high. Is that transient or synchronous? What combined MVA rating of synchronous machines do you think would be required to supply that?	The 250 MVA requirement is after a time period of 1s (transient/steady state). This is the slowest back up protection operating time anticipated at 275 kV and 400 kV. After 1s we have assumed that a synchronous generator connected to the 33 kV network might deliver 3 times its rating in terms of fault level at its terminals. If the 33 kV island provided 100 MVA of fault infeed (~35 MVA DER connected directly to the grid 33 kV busbars) then approximately 250 MVA of additional fault infeed would be required at 132 kV (~85 MVA 132 kV generator) to provide a total of 250 MVA at 400 kV. If the 33 kV island produced its maximum feasible fault infeed (~300 MVA), an additional ~100 MVA fault infeed (35 MVA DER) would be required at 132 kV to give the minimum 250 MVA fault infeed required at 400 kV.
Have you looked at pre-emptive measures? Monitoring harmonics?	All parties involved in electricity system operation will always take whatever measures they can to prevent a total shutdown. Black start is an essential backup plan but we don't want to ever use it.
Decentralising black start has opposing effects on resilience. It benefits in as much as there will be somewhere that recovers. It is a disadvantage in as much as there will also be places where re-start is much harder.	We hope to provide the industry (and society in general) with new options, utilising DER if appropriate, so that the needs of all parts of the country can be met. We expect Distributed ReStart to be part of a mixture of solutions.
Also to energise substation auxiliaries at the earliest stage? Compressors and battery chargers.	The enhancement of substation resilience, and maintaining operability during an extended power outage, may be one of the benefits of a distribution restoration zone, even if the number of "real customers" that can be restored in an area is limited by DRZ capability.
Can digital protection relays settings be changed remotely?	It will depend on the specific model and the telecoms infrastructure, but it is feasible in principle. Modern relays have the facility for several settings groups to be applied and can be changed remotely via SCADA.

Should we consider changing distance protection (at least at 33 kV) to unit protection?	Distance protection at 33 kV is not very common and typically requires 10% nominal current to 'pickup' (the same as unit protection). Unit protection has the advantage that grading may be easier, although it may require additional comms. Where possible we will look to utilise existing protections.
Given the increasing number of DERs with limited fault level, should we not be considering changing distribution protection (at least at 33 kV) to unit protection, rather than graded.	Protection in converter-dominated systems is also a challenge at transmission level as the margin between load and fault current will be eroded or non-existent. This is one example where the issues faced in the project are aligned with those being tackled more generally across the industry. Our challenge is to ensure that the changes made for other reasons are supportive of what is proposed for black start.
What timeframes are you analysing fault current on? Transient?	The fault levels given in the presentation were based on a break time of 1s (thus transient/steady state). We have assumed a generator output of 3x at this point (reactance 0.333pu).This is the slowest it is expected that backup protection at transmission levels would operate and thus is a worst case (you need that fault level available after it has decayed for 1s).
Usually the DNO breakers like Grid 1 on the SLD are not equipped with functions like check sync. Its absence will present an issue when eventually closing the breaker when main system is up and running again. Would all the breakers at potential interfacing points need check sync functions installed?	Yes, if a breaker is a possible point of resynchronisation then a check sync, or similar, function will be required. We have considered some different ways of achieving this, such as a "virtual check sync", but in early roll-out it is likely that conventional equipment will be used. This is an example of how various changes will be necessary to make a network area "black start ready". This will likely be a bigger issue at distribution voltage levels where voltage transformers are not so readily available and thus may have to be installed.
Could you not use some voltage restrained overcurrent protection to cope with the low fault current?	Yes, if there is not sufficient discrimination available between load and fault current then voltage dependent devices can be installed (an alternative group of settings is activated when the voltage falls below a set threshold – i.e. during a fault). This would require additional protections to be installed, a VT signal may not be readily available at the right location, and detailed studies would be required to ensure correct operation for all fault types. However, it is certainly an option to be considered if traditional current/time grading is not feasible.
Do we have info on the positioning of auto sync or remote manual sync gear at the 132 kV level? Obviously the DGs have sync gear. But with an inverter-powered island we obviously need sync gear back to the recovering system.	For the Chapelcross case study example given, synchronising is available across several of the 132 kV circuit breakers. It is envisaged that identifying suitable synchronising points at transmission voltages should not be too problematic given that there are typically many more VTs used for the likes of distance protection. At 33 kV, VTs tend to be installed on the LV side of grid transformers and at the DER. There is typically no 33 kV busbar VT at the grid substation to facilitate synchronising across a transformer 33 kV incoming circuit breaker.
Interconnecting active islands at distribution level may require extra synchronising gear?	Agreed, the biggest issue will likely be the lack of a voltage transformer at a suitable location. The switchgear may need changing to provide this.
Point-on-wave switching a (expensive) solution necessary for key transformers?	Point on wave is one possible means of limiting transformer inrush currents.

Some DNO have connectivity at 66 kV and 100 kV. How will this be handled?	As with all innovation projects, each network operator will have to take the project learning and adapt it for their own circumstances. But we are engaging with all the DNOs as we go through the project. We believe the principles are applicable to these other voltage levels.
Are interconnectors being considered as anchor generators, if not, why not?	We are looking at the use of converter-based DER as anchor generators. The use of large HVDC interconnectors for black start is already being considered by National Grid ESO.
What is the best strategy when energising a DRZ?	The best strategy for energising a DRZ is to first restore supply to the additional participating DERs so that their auxiliary supplies are restored, and they are ready to provide support as and when required by the anchor generator. The next step, before connecting any non-participating customers, is to energise the larger grid/super grid transformers and any higher voltage circuits, so that any voltage dips and/or switching over-voltages will not cause quality of supply problems for non-participating customers.
How was the energisation of SGT transformers achieved, soft or direct?	Energisation of large transformers can cause problems because there can be a high inrush current that can cause a voltage dip or high distortion that affects other plant. In a restoration process it is important that transformer energisation can be achieved without an adverse affect on already energised plant, especially the anchor generator. The level of inrush current depends on the remnant flux within the transformer, the applied voltage, and the exact point on the sine wave at which a circuit breaker closes to re-energise the transformer. We have tested different approaches in our live trials including normal, direct energisation at nominal voltage, energisation at reduced voltage, e.g. 70 or 80% of nominal, and the use of point on wave switching relays. The trials demonstrated how reduced voltage and point on wave relays can mitigate inrush risks significantly. In the upcoming Redhouse trial we plan to apply a similar range of methods. Soft energisation is normally taken to mean a gradual ramping up of the applied voltage from zero to nominal. This has been demonstrated elsewhere and requires special control of the generator or voltage source being used for energisation. We did not test this in our live trials but our academic colleagues performed studies of soft energisation processes using grid forming converters. Further details are available in our Power Engineering and Trials workstream reports.
Are the grid forming BESS compliant with the requirements for grid forming inverters as per GB Grid Code?	The GB Grid Code has recently been modified to include new sections on grid forming behaviour, including specific performance requirements. The BESS converter being used in the Redhouse trial is using a grid forming mode from the equipment vendor that is expected to satisfy the requirements of the live trial. That is not necessarily the same as it being fully compliant with all the grid forming requirements now in Grid Code.

Could you expand on the BESS limits for phase angle, frequency slip and voltage when resynchronising to an intact grid?	We're not able to share the specific technical limits of the BESS or other items of the user's plant in the Redhouse live trial. The trial will be delivered in phases with phase three to include resynchronisation of the BESS power island to the intact network. The DRZ Controller includes functionality to control the BESS (or load bank or other resources) to adjust the voltage magnitude and phase at the circuit breaker that will be closed for synchronisation. The DRZC design includes for the use of phasor measurement units (PMUs) on both sides of the breaker to help ensure the frequency and voltage is aligned before the breaker is closed. However, as is current practice, the closure of the breaker will be controlled by a synchronising check relay that ensures the difference between the two sides is small when the breaker closes. This minimises the disturbance seen by the BESS and other equipment in the power island.
How have you determined the demand requirements? Embedded completely distorts true demand requirements.	We recognise the challenges associated with variability in the demand on a relatively small power island. Our approach is to consider the net effect of demand and generation. If there is variable intermittent generation on the power island then that might be a greater source of variability than just the underlying demand. This will be different in each case and our recommended approach is that each case needs to be assessed. It is possible that in some cases the DNO will conclude that the level of variability in the area is too much and it is therefore too risky. In this case a distribution restoration approach may not be appropriate. The variability might be mitigated by keeping some customers turned off or selecting the feeders that are energised. Or variability can be handled by procuring resources with enough flexibility to deal with that variability. Fast responding resources such as batteries could be useful for this. In our live trials we have tested fast and slow balancing functions to deal with variability, block load capability and step change responses with different generator types and made recommendations on how to approach this issue.
Can we assume energy storage will have sufficient energy stored to support restoration? Stored energy may be called on/exhausted prior to system failure.	Similar to how pumped hydro is used today, if energy storage resources are contracted to provide restoration services then retaining sufficient energy reserves to deliver the service when needed will be part of that contract. If a battery or similar resource is used as an anchor generator then the plan for the distribution restoration zone is likely to involve re-energisation of another energy source as a top-up service provider to restore the level of stored energy. Many of the principles explored within this project are also applicable at transmission level as new resources are incorporated into the overall strategy for restoration.
What is the view on the issues faced if we were to look at re-energisation of a more capacitive network (e.g. via longer cables rather than OHLs)?	A more capacitive network will mean a bigger requirement to absorb the MVAr produced by that network, and that will be something that needs to be assessed and considered in the design of a DRZ and the procurement of services from DER to provide what is needed in the specific area.

The trials have used what could be seen as relatively small generators, which is fine to prove the concept. But what size of generators do you expect to be used in a real DRZ? And what do you expect to be the aggregate power of the anchor and other generators in a DRZ? Then as a follow on, how many of these sizes of generators do you think there are?	We have been thinking that a typical DRZ might be in the 50 to 100 MW range, using an anchor generator in the 10 to 50 MW range and then supplementing it with other DERs to meet the peak demand that you might get in a typical grid supply point area. It's not hundreds of megawatts as you might get with a large coal unit or something like that. However, a DRZ could be bigger if the local resources are available, the concept can be scaled up. Within the SPEN network area there's probably half a dozen or so locations with something that looks like an anchor generator, or could be made an anchor generator, with some other resources around it that you might be able to harness. But hardly a day goes by now when we don't get an application for a new battery in the 20 to 30 MW range, many of which could have grid forming capability, so that is a real opportunity where you could have a DRZ built around grid forming batteries, possibly in a large number of locations.

Organisation, Systems and Telecommunications Q&A

Question	Answer
The model for telecoms arrangements seems to come from traditional black start arrangements, i.e. large power stations have their own control centres. **For DER the generator may not be co-located at the same control site. Is it the intention that the communications link from the DNO will run to the generator or just to the generator control site where another piece of power resilient hardware will need to be added? And who is responsible for this? Furthermore, what if the control site is out of country or on another side of the country?**	The proposed design is that the DNO provide communications to the generator point of connection on the power network. Then it will be the responsibility of the DER to provide communications to wherever they want that to be. If it is at another location, and potentially out of the country, then they may find it harder to meet the functional specifications in terms of latency.
What is the bandwidth and reliability requirement on the DNO communication network for the DRZ Controller to meet its performance requirements	We have produced a set of telecommunications functional requirement in our report but this may vary with implementation by different restoration zone controller vendors. The published functional specification is as follows: **End-to-end Service Availability:** The end-to-end availability for a single-routed service (an unswitched service). 1. This shall be minimum of 99.94% over a rolling 12-month period. 2. There shall be no more than one break in service of greater than 10 seconds duration in any one year for any single service. 3. The difference between the total number of severely errored seconds and the total number amount if unavailable time expressed as a percentage of total time shall not be greater than 0.002%. ENA 48-6-7. **Fast balancing communication link:** For IEC 61850-9-2LE up to 5.760 Mbps per analogue measurement may be expected. **Slow balancing communication link:** This is expected to be low due to the relatively slow polling rate of the protocols used (expected to be 1–2 seconds). Using DNP 3.0 protocol, the bandwidth requirement is approximately 20 kbit/s.
Is it the intention to say that the DNO is responsible, for example, to the metering breaker to provide comms and then the third-party generator will put their infrastructure to that point?	Yes, the proposal is that the DNO provide to the point of interface and then if the DER need to extend it within their sites, or to elsewhere, they are responsible for that.

Scottish islands offer ideal geographic definition for a DRZ with the highest wind resource in Europe. When will the DRZ map be defined to enable these islands to plan new DERs to negate associated grid losses and provide more resilience?	Some locations will have greater DRZ potential than others due to local DER, or greater potential benefits in terms of reducing restoration time (compared with a conventional top-down approach). The Scottish islands are within the “Northern” region for which there is to be an ESR tender later this year (at time of writing in 2022).
Providing telecoms capability to DER will enable the DER to participate in many other current and future DSO/ESO services, black-start is just one. Therefore, the wider GB system may benefit by considering the telecoms requirements from a range of DSO/ESO services and procuring a single telecoms service rather than individual telecoms contracts/services for separate DSO/ESO services. How will you approach this?	The idea of procuring a single telecoms service rather than individual telecoms contracts/services for separate DSO/ESO services would seem to be the most cost-effective solution overall. We are considering all options for ownership of telecoms infrastructure. For example, the DERs may need to own the telecoms infrastructure and hence design such with their business/ future plans incorporated into the requirements. The telecoms infrastructure could also be owned by the DNOs with inputs from DERs; in which case, the DNOs and DERs may agree financials/ costs dependent on the balance of funding streams/use of the infrastructure for additional services. Generally, if the telecoms infrastructure is designed for ‘operational use’, it is likely to meet the service criteria. We are currently looking to define functional specifications that will cater for Distributed ReStart requirements, whilst being mindful of other activities in the market. However, the specifications may not cater for all bandwidth requirements. We do not want to place excessive bandwidth requirements on all participants, and we will not know what future services DERs may want to provide. The key will be building a network with appropriate redundancy to meet future needs, whilst balancing costs to participants and consumers. We will ensure that we discuss these issues further with DNOs/DERs.
I think you are missing the roll of DNOs switching around their network/protection settings.	This is recognised in the review of organisational impacts and in the design of a possible DRZ Controller. We appreciate the impact of switching on restoration times, but also the practicalities of performing significant remote switching actions and changing protection settings given what is currently installed. We expect that any network area that is to host DRZ will need various updates to its existing systems to support the implementation, to make it “black start ready.
Not clear if changes to protection/control settings are done once and for all, or as part of restart procedure.	It is intended that the protection and control settings will be adjusted at the start of the black start process, and may have to be adjusted again, before being returned to normal at the end. This may be one of the functions of a DRZ Controller.
Clearly OT needs to be standardised (agnostic) with each DSO, aggregator, ESO providing different elements of an OT fabric. Private 3GPP wireless provides the right capabilities yet we are often inhibited through regulation to foster this into the right GSPs and touchpoints. Often modern edge compute can be facilitated supporting voice/data autonomy.	We are working with all DNOs, Ofcom and trade associations (including REA) to consider all reasonable operational telecom options and, as far as possible, develop a technology agnostic set of requirements.
Are you considering the effects of major solar flares/coronal ejections (one is overdue) or electromagnetic pulses (a weapon of war and possibly of terrorism?) These could knock out many communications, and also other systems.	We are currently looking at the threats, including those stated, and whether a spread of technologies could/should be required.

It appears a lot has to go right on the day, even for just one GSP to be restored. Will you be doing a failure modes and effects analysis (FMEA) study to look at how resilient the whole process will be taking into account probability of any part failing and its impact?	We've not decided yet on whether to conduct a full FMEA but we will be explore the overall process in more detail, and testing it, in the desktop exercises planned for 2021.
So, do we run the islands up to 132 kV only with distribution interconnection (not normally closed up) as appropriate? But recharge transmission by main generation then synchronise at SGT LV and resplit distribution to radial operation? But to re-energise transmission with mainly offshore wind?	Yes, these are options that we are considering, where DER can contribute to an overall improvement in service by being used in combination with other resources.
Distribution restart zones probably have a natural boundary by virtue of their radial connection to GSPs, but not at transmission level. So how do you allow for emergency control powers that have to overlap the zonal boundaries shown in yesterday's slide?	We think the ESO already has the power it needs for all control on the transmission system. So far we have not encountered the need for a DRZ that might split across DNO licence areas – this may be too complicated from a control authority perspective. The need for asset protection and the legal authority for network operation points to the control entity being the ESO or DNO, rather than a third party – but things may change as we enter a "DSO world". We are considering what would need to be done for the ESO to be directly operating distribution assets.
DSO or ESO lead depends on the area of the disconnection. If just Distribution then DSO lead informing ESO. Otherwise ESO?	We believe the most viable approach is for the ESO to maintain strategic leadership of the restoration process. DNOs will be instructed to commence restoration processes in their areas then inform the ESO on progress, but it does impose new responsibilities on the DNOs in terms of system operation. Organisational changes will be required as well as appropriate supporting systems.
How would the DRZ Controller cope with the unknown? i.e. DERs not responding as expected or loads being smaller/larger than expected? It's hard to see how you can take people out of the loop.	We do expect the DRZ Controller to have to act quickly to respond to disturbances or the unknown. But the various DER will still have their own AVRs, governors providing fast dynamic response. And while trying to exploit the opportunities of automation we recognise that there will still have to be people in the loop. We are trying to explore this more fully, including in the desktop exercises we plan to run in 2021.
Manpower: through the discussions with the DNO's what views do you have with regards to extra man power? With the new Distributed ReStart zones, with the number of engineers we currently have, it will be a trade off because you dont want to over staff people and have them do nothing. We would want the controller and intelligence doing a lot of the work for us, with fewer manpower.	The process is expected to utilise staff on standby as there will be some delay with time for flexible staff to be made available.
How many hours of power resilience will there be?	There is an assumption that 72 hours of power resilience is necessary and sufficient for all substations, telecoms and protection in a DRZ. Distributed ReStart considers operational telecoms only. Any telecoms not between active black start participants is considered out of scope, e.g. DNO to consumers, ESO to BEIS.

Are DER start-up procedures automatic?	DER start-up procedures are not entirely automatic under control of the DRZC. For anchor generators we assume that start-up will not be an automated procedure. However, we do expect an automatic response to setpoint signals after start-up. For other DERs (both manned and unmanned sites), start-up procedures need not be automated, i.e. they may require human intervention. However, it is assumed that once a DER has started, it will accept control signals and respond automatically if required.
More anchor generators	For each DNO area, it is expected that there will be more possible DRZs (more anchor generators) than will need to be contracted. There will therefore be scope for competition between possible anchor generators (and DRZs) across a DNO area (or across a black start region).
DNO responsibility	The DNO will be responsible for local operational actions within the DRZ on its own network, no matter whether the overall process is ESO-led or DNO-led. This is recognised in the Central Model for organisational processes.
System restoration after shutdown	While recognising the potential value of 'trip to island' functionality or other defensive measures, which often feature in 'microgrid' designs, the project is focused on the challenge of system restoration after shutdown. We have identified specific challenges that would make a direct transition from normal to island mode especially difficult at 33 kV and above, e.g. the need for different earthing and protection. Therefore, this functionality is not included in our generic design for a DRZ Controller. However, we recognise that this functionality may be developed in future. A transition to island function could be used to support planned outages, network constraint management or reactive power optimisation and is a further use case for any potential Distribution Zone Controller type hardware.
When can the transition to island function be used?	A transition to island function could be used to support planned outages, network constraint management or reactive power optimisation and is a further use case for any potential Distributed Zone Controller type hardware.
How is it envisaged to prove the telecoms providers and services compliance with black start level resilience – particularly if using already existing providers?	In restoration using our existing plans we have a dedicated power resilient network called the 'Optel Network' that facilitates communications between the ESO and transmission connected providers. We are aware that public communications are not currently power resilient to the extent that is is necessary to facilitate a distribution level restoration plan. This is why our functional telecommunications specification sets out all of those requirements for power resilience as well as performance measures like bandwidth and latency. This will facilitate the restoration zone control system by specifying what elements of the telecommunications network must be made power resilient and ensuring that we have a a suitable design in terms of the testing regime to ensure that telecommunications remain power resilient. Work is ongoing to ensure that we properly test communications capabilities of providers. The assurance framework is is a key part of restoration overall.

What considerations have there been for DERs re-connecting in an uncontrolled manner to the network following a shutdown?	We understand this as being about the risk that DERs re-connect automatically when their power supply is restored then inject power or otherwise disrupt the delicate balance of generation and demand on an early-stage power island. The primary risk may be with small-scale DER like rooftop PV but there could also be risks with larger DER connected at higher voltages. The key aspect is that they are outside the direct control of the DNO or system operator, or any control system that may be installed. Our research of international practice in restoration identified that in some cases an early-stage power island will be deliberately operated outside of normal frequency limits, e.g. at 53 Hz instead of 50 Hz, as the protection on small-scale DER (the local equivalent of the G59 or G99 protection in GB) will prevent them from automatically re-connecting. The system operator will bring the frequency within normal limits once the power island is large and flexible enough to handle the additional variability introduced by these uncontrolled DER. In our designs we have not explicitly catered for this approach, but equally our proposed approach does not preclude it, so it remains an option that could be used if a review of the circumstances in a given DRZ deemed it necessary. Our approach has been to treat the possible variability due to uncontrolled DERs in a similar way to the variability due to demand or intermittent power sources. Whether it is block load pick up, wind gusts, electric vehicle charging, rooftop PV or other sources of variability, in establishing a feasible DRZ it will be necessary to understand and analyse the expected variability in uncontrolled power demand and generation, then devise a DRZ plan to deal with it accordingly. The risks can be managed through a variety of means that might include: • introducing new communications and control to larger DER so they can be limited or instructed during a restoration process • opening the circuit breakers on individual customers, or areas of network, that are considered too high risk in the early stages of restoration; they will be restored as quickly as possible as part of the wider restoration process • improved data collection and modelling of behaviour (including after extended outage) so that the variability is better understood and the DRZ plan can include sufficient flexible resources to respond as needed • restoration of power at times of lower risk, then disconnection if necessary at times of higher risk. For example, if a restoration process lasted several days then an area with very high penetration of uncontrolled PV may be disconnected during daylight hours • as noted above, operation of the power island outside of normal limits (most likely frequency, but perhaps voltage) so that DER protection prevents it from re-connecting. There are various options available, some more disruptive than others, but it should be recognised that a system restoration is an exceptional circumstance when normal market and operating rules are suspended. Selective disconnection of individual resources or areas of network may be necessary to achieve the fastest and most robust restoration process overall. They key point is that the risk must be assessed and understood. This will be done in the process of DRZ viability assessment and design by the DNO and ESO.

How will cross control boundary operation work?	In our proposed organisational design, the interfaces between ESO, TOs and DNOs are kept as similar as possible to existing practice for restoration, with different responsibilities only as necessary for a distribution restoration. The ESO remains the lead within the overall command and control structure. A DNO with a distribution restoration zone will undertake a new role, communicating with the TO and ESO as required as well as with DERs. If the restoration process involves the connection of two DNO areas, so is crossing a control boundary, then we propose that the ESO takes overall responsibility for that coordination.

Procurement and Compliance Q&A

Question	Answer
The slides presented show that the plan is to go for expressions of interest in the Northern region at the start of October this year. There's a lot of work for all parties to do between now and then. The list of activities is quite extensive and it looks as though to meet those deadlines we may have to start work half way through the school holidays this summer? Could this create a challenge to resource both within the project and within DNOs engaging with them?	The BAU tenders are separate from the Distributed ReStart project with a different team and their own rules and processes. The tenders have been informed by the project outcomes and there is some overlap in the people involved but we should note that Distributed ReStart itself is just a NIC project. The firm details of the BAU process will come through that process. The high level timelines are driven by when existing contracts for restoration services come to an end and the time we think might be needed to prepare replacements for them. But there is no certainty that distribution restoration will be an option or need considered in the Northern region. It will depend on what comes back in the expressions of interest. However, given the possible need to start working on DRZ designs and preparations from later this year, we wanted to engage with DNOs to share the Distributed ReStart project findings and help everyone prepare for might come.
By Northern Region do we mean Northern Powergrid's patch or do we mean Northern England including ENWL's?	The Northern Region includes North-East and North-West England and Wales and Scotland, so includes both NPg, ENWL, SPM, SPD and the SSEN Scotland license areas.
How much is spent roughly per annum at the moment on restoration and how do you see that increasing as we move forward? I'm conscious as we get more and more thermal plants shutting down and coming offline, it's going to get more expensive, but have you got any sort of feel for the numbers?	Black start costs in recent years have been around 50 to £100 million. Within the project we have done a CBA, the outputs of which were included in previous reports, and which is being updated for our Closedown Report. Although distribution restoration may start off as an additional cost we expect the expansion of restoration capability to deliver value over time. Costs will vary across DRZs depending on the resources available and DRZ design. The need will vary across the country depending on how soon large generators are 'retired'. We expect distribution restoration to only ever be part of the overall restoration strategy, which will still involve large generators and probably HVDC interconnectors.
Do we have the final findings report for the Procurement and Compliance workstream? This will throw light on the necessary policy and regulation changes.	Yes, the final report and detailed appendices can all be found on our website: https://www.nationalgrideso.com/future-energy/projects/distributed-restart/key-documents. The regulation changes are part of the code text drafts which are being consulted and refined as part of GC0156 code modification process. Check out Appendix 3 for the proposed changes.
Will go live be 2025 at the earliest?	Yes, potentially, so long as we get a feasible shortlist of bidders in the upcoming South East Tender that will form a feasible DRZ to supplement the traditional 'full service' bids. Or in the Northern Tender that will follow later this year.

How can this coordinate with traditional restoration? Will this DR lower the costs of traditional methods?	Yes, the processes have been developed considering running a distribution restoration approach in parallel with a transmission-based restoration process. Joint planning stages have been kept common, whilst distributing the local descision making to DNOs via the restoration zone controller makes better use of overall control engineer resources. We are formulating our assessment criteria in the SE Tender to enable merit stacks across full service, AG and TuS bids. Regarding future cost, only time will tell as we need a live environment to understand the differences between different technology types bidding in for the different categories in this tender.
Existing BS procurement lists several criteria to be met. Will it be possible to set different criteria for different technologies as part of an integrated solution? (For example, diesel generators can provide a lot of MW but are not great at leading MVAr.)	The currently published information relates to procurement under the current strategy. It may be that amended requirements are developed for DER or for an integrated solution under this project, however, we can't speculate at this stage what those may look like. We expect that any technical requirements will be functional and technology neutral, and we will consider whether some 'components' of a service can be procured separately. The new tenders have new requirements, informed at least in part by our project. This question and answer from several years ago are no longer relevant.
Given the (hopefully) infrequent execution of a restart plan, why the emphasis on economically efficient procurement?	We hope to never have to use any black start resources for real, but we nevertheless have to make sure they are there if needed and this involves paying for them to be available at all times, whether they are used or not.
You're focusing on the decoupling of black start capabilities – but what if a new distributed resource can deliver the entire service? They would be greatly disadvantaged by salami-sliced services even though what that plant delivers is superior.	It will depend on the options available in a given circumstance and how service providers price their offerings. We expect there will have to be multiple DER involved to achieve what is needed in each DRZ, and equally do not want to exclude those who can offer part but not all of the components in an economic manner. The existing proposal includes a single "anchor generator" service, which will require a single resource with multiple capabilities. This will then be supplemented by other DER that may provide one or more services.
Will contracts be let before plants are built, so that the capability can be built in? And for contract durations sufficient to provide the return on assets to do so?	We're still considering the benefits of different approaches. Placing of contracts for black start is likely to depend on testing and demonstration of capability. This is easier with well-established technologies. The overall trend in the electricity system is towards shorter term contracts, including in black start. However, we recognise that this approach is new and it needs to be proven and become familiar before the most flexible types of market mechanism can be adopted. so early contracts are likely to be for longer durations to get the concept established. Note that the project itself is not placing any contracts for services; this will happen after or outside the project.
All this focus on existing resources: what about contracting with future resources if more cost-effective and/or better capabilities? This would require sufficient time between contract let and start of delivery to allow permitting and construction.	This is not ruled out. The ESO Stability Pathfinder is currently taking this approach, considering resources already connected and not yet constructed. The goal is always to satisfy the need at the best value for the end consumer, by whatever means. The existing approach to black start, as with other services, seeks to give an indication of future requirements and clear statement of intent. Note that the project itself is not placing any contracts for services; this will happen after or outside the project.

I don't understand how this project can impact the black start Tenders in a material way e.g. the northern Britain black start tenders are due mid October 2020. Am I missing anything?	The project itself is not looking to contract. Contracting will be handed over to whichever party will be responsible for procurement after the project completes in 2022. There will be a transitionary period between project handover and commencement of procurement processes.
If there are transmission-connected synchronous resources available, these should always be used as they provide much better scale and speed of re-start. Therefore tenders for these should be a first stage, only considering distributed re-start where (a) transmission is unavailable and/or (b) distribution-connected re-start enhances the transmission-connected capability.	Specific procurement models are under investigation currently but it is possible that it may be more economic to have a distribution level plan which can feed a transmission level resources supply. Distributed ReStart is about ensuring we have additional technical options for procurement in addition to conventional providers and may be procured separately or in parallel dependant upon the ongoing commercial design. The future black start strategy will include both traditional 'top-down' approach and Distributed ReStart 'bottom-up' approach to meet the restoration timescales set in the Black Start Standard.
Doesn't it make sense to have separate restart code provisions for top-down and bottom-up?	We are exploring what code changes may be necessary to facilitate what is proposed. This may mean there are different provisions for different types of approaches. But we do aim to specify changes to existing codes, not define wholly new codes.
Is there a single date implementation?	The roll-out of black start from DER and the transition to business as usual adoption will be at a different pace in different places. There will not be a single date when it is implemented everywhere. Implementation will depend on the need, costs and appetite in each area. The project aims to demonstrate viability and have Distributed ReStart become part of the road map for black start service development. The first BAU step towards implementation will be in April 2022 when DER options will be invited to express interest in a tender for black start services in South-East England and Scotland.
Will black start strategy involve a mix of service providers and solution?	The overall black start strategy will continue to involve a mix of service providers and solutions appropriate to the requirements and opportunities in each area, including conventional large power stations and HVDC interconnectors. Distributed ReStart will become part of the overall strategy alongside these other options.
Is there scope for cost reduction over time?	The electricity industry is changing at a rapid pace. With a transition to smarter networks, the capability of the network is likely to increase over time, and the incremental costs of 'converting' the network to being black start capable should decrease. Thus, while initial costs for implementing the Distributed ReStart concept may be high, there is significant scope for costs to reduce over time.
Can emergency instructions be used to participate in the overall DRZ restoration process?	For DER considered 'large' and therefore a CUSC signatory, emergency instructions can be used to have them participate in the overall DRZ restoration process. The anchor generator will still have to be contracted, like existing black start service procurement. Other DER contributing to DRZ formation and management will have to be contracted with and paid for providing restoration services, rather than rely on emergency instructions or other non-commercial method of progressing the restoration process.
Will there be an opportunity to participate?	The opportunity to participate is to be open to all who can satisfy the technical requirements and contribute to an effective restoration capability. The level of service and combination of resources required will depend on the specific needs in each location.

Are there large capacities of emergency standby?	It is noted that there are large capacities of emergency standby generation in certain areas, e.g. central London, and that these may, in future, have a role to play in coordinated system restoration. At this time, however, these generators are considered out of scope because they are not designed, or contracted, to operate in parallel with the DNO networks and therefore present particular additional challenges that are outside the project scope.
Distributed ReStart will retain differing treatment of transmission owners under OC9 arrangements.	Under Distributed ReStart any differences in the treatment of and arrangements with different transmission owners such as those arising during Local Joint Restoration Plans may be reflected or applied as they are to ‘traditional’ black start services and arrangements. This is not to mandate that they will be treated differently but to accept that historically they are and that this may continue.
What are the national zone areas?	As per the original tender and subsequent initial Power Engineering and Trials reports we have based calculations and assumptions in respect of restoration figures on total GB demand and not any national zone areas as per the new Electricity Restoration Standards however it is expected these will be referenced in subsequent overall restoration plans (rather than Distributed Restart project).
How likely are interconnectors to be useful? Most black start events (Solar event etc) would knock out Europe as well.	Interconnectors are useful. We currently have several interconnectors to Europe that are technically capable of providing restoration services. It is important that we have a diverse mix of restoration service providers and interconnectors are expected to form part of that mix. The project aim was to make it possible for DER to also be part of that mix. The ESO is charged with coordinating the overall strategy of restoration and how it feeds into restoring the national and regional systems following power outages. This feeds into the regional tender approach for procuring services.
Have National Grid ESO explored the idea of bespoke simulations per restoration zones as the current tenders are asking for technical requirements with no substantiation?	As the tender process progresses through the different stages more simulation studies will be done at each stage. The proposed design has technical studies being completed at multiple points. This is part of our final findings for the procurement process. These studies will be done in conjunction with DNOs.
Is there a system in place for coordinated risk assessment/coordination on the grid as a whole between the ESO and DNOs?	National Grid ESO will continue to monitor overall restoration needs and capability. For the future and as part of the ESRS implementation, a real-time restoration tool will be developed to monitor compliance with the standard. It is expected that there will be an increased number of providers with various technologies providing the restoration service, due to more competitive procurement events and results from the Distributed ReStart project. Therefore, it is important to evolve our process of conducting assurance activities. This will form part of the discussion in the Assurance Activities Workgroup for ESRS implementation (GC0156).

DRZC Independent System Testing Report Webinar Q&A

Question	Answer
Is the GE solution the only option for a Distribution Restoration Zone Controller (DRZC)?	The project has produced a generic functional design that sets clear requirements for the control system. We also commissioned front end designs from four different organisations to incorporate the best elements of each, but also keep open the option for competitive procurement. These documents are available on the project website. We believe the GE solution is at present the only demonstrated solution to a black start zone with multiple resources co-ordinated within a zone. It will be for the DNOs to identify the DRZC solutions as part of their normal procurement processes and within their price control agreed by Ofgem.
Will the DRZC do anything in normal operating conditions? How can you be sure it will work when needed for restoration?	The scheme will continuously provide measurements and status from the DRZC system, and alerts and alarms can be provided to a supervisory system. In future, it is feasible to derive other grid services using the same zonal measurement and control infrastructure. This would not only increase the value derived from the zone, but also provide more regular confirmation that active control of units in the zone is working correctly. It is possible that the DRZC functionality would be implemented on a system that is used in normal conditions for other purposes.
Does the DRZC correspond to a specific product of GE?	The overall solution comprises new logic and interfaces created and configured for DRZC using standard GE products. Flexibility for automation to create the solution is built into the core products, including the ADMS network management software, WAMS visualisation, phasor-based logic control and synchrophasor measurement units. DRZC is therefore a system solution involving multiple products.
How does the DRZC deal with different converter technologies which may have different control characteristics?	A DRZC may have to deal with a range of different resources, some converter-connected, others using synchronous machines, but all with different control characteristics. The classification of a unit as proportional regulation (PR), primary balancing control (PBC) and secondary balancing control (SBC1/2) depends on the capability of the unit. This equates to whether the unit provides proportional control for frequency and voltage, and/or setpoint control capability. The configuration of the DRZC scheme will also incorporate the expected speed of response and settling time. The real-time control scheme is agnostic to whether a unit is grid forming or following, although the design of the zone as a whole will account for this.

One of the learnings is that testing is recommended for business-as-usual (BAU) DRZC development, do we mean live tests or more controlled tests?	It is recommended that a wide range of different testing methods be used as appropriate in the development and deployment of distribution restoration zones. We believe there is a role for lab-based testing, such as that done in the project using real-time simulator environments, but the project experience has also demonstrated the value of live trials on the real network. The maintenance of restoration capability has always involved a range of testing of providers and processes, and this is expected to continue.
Please can you clarify that a DRZC will be used for the Redhouse live trial? Assuming it will and if successful, would that remain as BAU on that part of the network?	The Redhouse live trial is intending to include testing of the prototype DRZC. There are no plans for the equipment to remain for use on that part of the network. The selection of restoration service providers by the ESO is done as part of a competitive tender that takes account of requirements at a national and regional level. The testing of a DRZC, or any of the other live trials done in Distributed ReStart, do not confer any competitive advantage to the parties involved or the network areas where tests were performed.
Do your latency calculations consider the impact of data being passed across different companies or are you assuming there will be direct communications?	There is fast-acting control within a zone, which would be contained within a single company, up to the point at which signals pass over to the controlled plants. Data communication from the zone to a central control room or across companies for regional co-operation is not time critical and therefore the requirements for latency between companies is not stringent and is similar to normal data sharing of SCADA and synchrophasor data.
During the total shut down, how can the DRZC provide fast balancing response?	All elements of the DRZC including the field sites, zone controllers, measurements, communications, and the central control is all fed from secured power supplies with requirements specified for the time that supply is sustained. The resilience of the system was studied in Distributed ReStart, leading to specifications being defined.

Energy Systems Integration Group Webinar Q&A – August 2023

Question	Answer
Can you explain the terminology "mock tender"?	It was an artificial procurement event where we went through the process of issuing a tender pack and invited participants to submit pretend bids. These were then assessed, reviewed and discussed. In this way we tested the commercial design and were able to engage meaningfully and usefully with industry stakeholders.
Can you provide a link to or the name of that black start legislation that drove some of these efforts?	The Electricity System Restoration Standard: https://www.nationalgrideso.com/industry-information/balancing-services/electricity-system-restoration-standard https://www.gov.uk/government/publications/introducing-a-new-electricity-system-restoration-standard/introducing-a-new-electricity-system-restoration-standard-policy-statement
Do the batteries have to hold a minimum state of charge at all times, i.e. what happens if the black out happens when the batteries are drained?	Yes, if a battery is to provide the "anchor" generator service, which is the first resource to start during the restoration process, then it would need to have sufficient stored energy. However, this could be quite a small amount if other resources nearby can be energised and used to provide the required energy for ongoing restoration. Batteries might also be contracted to provide a service that harnesses their flexibility to help with power balancing, where they may be required to rapidly change from charge to discharge. This type of service could be provided from a battery that has no stored charge because the energy required would come from other sources.
Did you consider using some battery energy storage systems (BESS) as a load during black start to match up with generator output?	Yes, this was done as part of the Redhouse trial. We see batteries as potentially very useful for fast power balancing in early-stage power islands.
Is there a recommended ratio of grid-forming (GFM) to grid-following units required for a successful black start restoration?	This will depend on the specific circumstances and technologies involved. We have not reached any firm conclusion on ratio, but our trials have demonstrated a range of stable operating conditions. This included running with grid-following solar producing power while the grid-forming battery consumed power.
Could you comment on island operation of distribution using BESS GFMI to provide voltage for inverter PLL?	This was studied earlier in the project then demonstrated in the Redhouse live trial.

Did you specify grid-forming inverter settings that could operate normally (grid tie) and when needed, be able to stand alone and start-up other resources?	In the Redhouse trial, the grid-forming battery was used to establish a power island and then this was resynchronised with the main system, with the battery continuing to operate with the same settings. We didn't test going in the opposite direction, from grid-tied to islanded. We decided early in the project that we would not consider auto-islanding as it added further complexity and is not necessarily beneficial to the overall system.
Are you in touch with AEMO? One of the fascinating problems we have in Australia is that the DNS are at many times virtually independent.	We've had some minor engagement with AEMO and are aware of the significant achievements and ongoing challenges in system operation in Australia. We're not actively talking to them on this topic at the moment, but National Grid ESO and AEMO are both part of the Global PST Consortium where a wide range of topics, including system restoration, are discussed.
Do your anchor generators also have to be able to establish frequency as well as voltage? If yes, how much does that restrict your pool of possible anchors?	Yes, the anchor needs some capability to balance power on the island network, but this could be minimal if the anchor can be used to re-energise other resources that then enhance the total capability for frequency control.
Compare to hydro and steam plants, what are some of the specific challenges you need to overcome when using BESS for network restoration?	The industry is still getting used to BESS operation, especially in grid-forming mode, so one challenge is simply a lack of familiarisation and confidence, which means thorough analysis is required. Fault current and the impact on network protection is one challenge, but we found that it could be addressed with appropriate changes to settings. Our live trials showed that the BESS performance in frequency and voltage control was better than what is typically seen from hydro and steam plants.
Could you describe again the restart transformer energising?	Details of this will be available in our Demonstration of Black Start from DERs (Live Trials Report) Part 3, which is due to be published in October 2023 and will be available on our website.
What was the total MWh capability of the battery used in the test?	8 MWh
Did you have to modify the protection settings, particularly for the inverter to cater for the high inrush current when energising the transformer?	Protection settings were modified across the network as per a detailed study completed prior to the trials, the inverter settings were modified based on the outcomes of that study and a couple of further amendments were made during the trials to produce greater resilience to unnecessary tripping.
PoW is to reduce inrush current of transformers. For that you need single phase or CBs with different closing times per phase. What did you use?	The PoW relay used in the trials is designed for use with three-phase circuit breakers with the same closing time on all phases, as typically found on distribution networks. It is not as effective as having single phase CBs but still offers a marked improvement.
Resynchronisation when there are a number of independent restart regions?	Use DRZC control of island assets to match V, f and phase angle of independent regions and then breakers with CheckSynch functionality at the synchronising boundaries. Do this one at a time to grow and grow the islands.
For the point on wave relay is there any difference in performance based on how long the transformer is de-energised for prior to re-energising?	None, as long as the transformer is de-energised for more than a few seconds. The remnant flux will then remain approximately constant indefinitely so the PoW can be used hours/days after de-energisation.

What other technologies exist other than point on wave relay to reduce transformer inrush current?	We could have utilised reduced volts or soft start (ramping up) in our tests but had no need given the success of the PoW. We did some testing of energisation with reduced volts in the Galloway live trials.
Can you provide a sample tender document for grid restoration services?	The materials from the project's mock tender event in 2021 are available on our website: https://www.nationalgrideso.com/future-energy/projects/distributed-restart/procurement-and-compliance The materials for the latest, real tender for restoration services are also available: https://www.nationalgrideso.com/industry-information/balancing-services/system-security-services/restoration-services#Document-library
In the resynchronisation of BESS with grid graph, why is there a voltage offset after synchronisation is complete?	Accuracy of data return issue/calibration error.
Can the PoW relay be used in normal grid operations?	In our case it lies 'dormant'/passive for normal grid operations and is utilised only when back energisation via DERs of the grid is required. But it could be used if thought useful.
Is there a point on wave relay for the transformer a commercially available product? Or was it developed specific to this application?	Yes, see: https://www.enspecpower.com/point-on-wave-switching/
What has been the response from distribution network operators? This seems like it would be a major increase in responsibility for them?	The DNOs already play a critical role in system restoration. The distribution restoration process does mean changes in responsibilities but the project designs were informed by extensive consultation with the DNOs, including their participation in our innovative online exercises. The industry regulator, Ofgem, has given assurance that DNOs will be funded for costs associated with these additional responsibilities.
Did you try using hydros/steam as anchor generators but with grid-following BESS to provide load balancing support?	Not specifically in our tests but we did do these elements in isolation and there is no reason to think that they would not operate as desired when combined given the individual test success.
The X/R ratio is influencing the inrush current. Have you considered that? It also means each transformer needs PoW relay and CBs (out of wave switching).	This formed part of the system studies done ahead of live trials. We don't believe it will be necessary to have PoW relays facing every transformer. As the power island grows the ability to energise transformers increases. The PoW relay used in the trials is designed for use with 3-pole breakers.
Do you find that the behind-the-meter resources, e.g. rooftop solar, behaviours complicates the restoration?	This issue was identified and has been discussed within the project and in our various stakeholder engagements. There will always be some level of variability in power that may arise due to changes in demand or generation. In designing any restoration process it will be necessary to be mindful of that, perform analysis as appropriate, and ensure there are sufficiently flexible resources to manage the variability. This may mean that some network areas need to be energised later in the process as a larger power island is needed to handle the variability.

I understand this will need synchronous condensers also in the distribution grid or inside the DNZ?	Not necessarily. It will depend on the specific requirements and resources in each area. The general philosophy of the project was that we were trying to find solutions with resources that are already there for other reasons as this is likely to be more cost effective. Although possible, it seems unlikely that a synchronous condenser would be installed at distribution level purely to support system restoration.
Which electricity market mechanism can support the black start functionality?	In Great Britain, the procurement of system restoration services is one of several balancing services procured by the Electricity System Operator (ESO). The materials for the latest, real tender for restoration services are available on the ESO website: https://www.nationalgrideso.com/industry-information/balancing-services/system-security-services/restoration-services#Document-library
Are the battery storage facilities cost competitive vs synchronous machines for black start services?	We believe they can be, as batteries are being installed anyway, but in Great Britain, restoration services are subject to competitive procurement so it depends on what offers are submitted.
Previous to Distributed ReStart, how was communication between DNOs and National Grid, i.e. direct communication or through transmission operators?	Industry structure in Great Britain is such that the approaches are different in Scotland compared with England and Wales, but the general approach is that there would be open communication between the parties involved in the restoration process. Section 7 of the following report describes the established communication process for the electricity industry during a restoration event: Organisational, systems and telecommunications viability report This can be found in the Documents Library on the Distributed ReStart website: Distributed ReStart Douments Library
What was the SCR of this simulated system? Low, medium, high?	We did a range of simulations earlier in the project covering different conditions but focusing on systems with low short circuit ratio. The live trials were done with real equipment so were not simulations; the SCR was generally low, sometimes very low.

Redhouse Live Trial Webinar Q&A October 2023

Question	Answer
From the island created by the battery energy storage system (BESS), how and when do you move from "grid forming" to "grid following" once the resynchronisation is accomplished?	You would expect that at the point of resynchronisation, the battery to transition from its grid-forming mode back into its grid-following mode. However, the trial was set up for the Distribution Restoration Zone Controller (DRZC) to cater for the resynchronisation, so when we made the resynchronisation, the battery was still in grid-forming mode, but we could still dictate what it did at that point. There weren't any issues, but by having it running in what was technically grid-forming mode when reconnected to the grid, we then changed the BESS back into grid-following mode for its normal training operation. In a genuine black start, DNOs would likely need functionality to make that switch from grid forming to grid following at the point of resynchronisation, or at the point of energisation. But we didn't experience any issues while having the BESS system in grid-forming mode at the point of resynchronisation, because it's just trying to drive the voltage frequency back towards 50 Hz and 33 kV, which is essentially where the grid is sitting at anyway, so the battery output was negligible at this point.
Has there been any analysis to date to better understand the amount of "cold load pickup" within or during an electricity system restoration event?	Our understanding is that it's the DNO's job to do the analysis in their respective areas to determine the disparity between regular demand and cold load pickup demand. As we transition to a more electrified network, particularly in the heating sector, then the cold pickup element is going to increase. Emergency system operators need to make sure that, when they're looking to re-energise demands, the cold load pickup analysis has been done, so they know they have sufficient generation to cope with the additional demand.
What is the cost of adding the required functionality to a commercial BESS?	We're not able to currently give this value.
Are you planning to test synchronisation of grid-forming BESS with a single synchronous machine in the future? Do you expect any problems?	We did do a miniaturised version of that during the trial. To support the network and to provide top up overnight to charge the battery, there was a relatively substantial diesel generator supplied by Aggreko, which was 3.5 MVA. We did several of the trials with these generators synchronised and a some without. When just synchronising the diesel generators to the BESS, there weren't any issues. However, when there's absolutely no load on the system, the performance was slightly more volatile, so the suggestion is to have a little resistive dampening to add some load just to balance the network.

How would the block load pickup capability be modified if the grid-following mode BESS is operated along with gird-following sources (e.g. solar farm)?	This is something we managed to test. We did the block load pickup capability tests when Middle Balbeggie Solar was generating, and when it wasn't, to see if there was any difference in performance and we found that there wasn't. It comes down to the BESS taking control in this situation. If there's a fast loss of generation or increase in demand, then the BESS is the buffer for the test network. It can cope with that on a sub-second basis, while other technologies are perhaps catching up. Ultimately, the block load pickup capability of the asset didn't change when we had the solar farm energised.
What proportion of the battery storage (and/or renewables) fleet would need to use grid-forming capable inverters to achieve this for the UK?	This is something that each of the DNOs and system operators need to work out, which means every plan will be different. Every region is going to have its own nuances with the generation that's available to it. The point of the trial was to prove that batteries are effective at being restoration service providers, which they are. And they have the added advantage of being able to be generation and demand, which is very useful in a black start scenario.
Did you encounter any particularities for the grid-forming algorithm, because the battery is connected to a 33 kV network instead of a transmission network?	There wasn't any difference in the grid-forming algorithm when we were connected with, or without, transmission assets. The network was set up so we always had to go through distribution assets to get to the transmission network. We were more concerned about whether the BESS could energise those assets efficiently, which, in every case, it could. We don't believe the grid forming algorithm changed. We did change the settings of the inverters to provide a more stable network and we made amendments to the frequency droop settings. We tried at 4% frequency droop, at 1% frequency droop and we tried several different configurations, which are detailed in the report, *Demonstration of Back start fro DERs (Live Trails Report) Part 3*. Furthermore, we tried changing the filter times to iron out any oscillations that might have been present and eventually landed on a particular configuration, but it wasn't the only configuration that was successful. We were just streamlining the effects and trying to make it as efficient as possible; all these configurations are detailed in the live trials part 3 report.
How will the operational readiness of a Distribution Restoration Zone Controller (DRZC) be assured given that it will be called on only rarely? Does it have to be kept "tuned" to its local network?	We did several hardware-in-the-loop tests with the manufacturer GE using a real time digital simulator with the DRZ Controller functioning as hoped. There were exhaustive tests done by GE and our future networks team to ensure this was the case. We then did additional tests to make sure the comms links were all up and running and that the monitoring devices we had across the network were providing feedback as expected. You can't really test it for real unless it happens for real, which is not something we want to occur. The methods the team implemented, namely the hardware-in-the-loop tests to simulate as much as possible, really set the foundation for the DRZ Controller implementation being successful during the trials.

What would be the maximum size of transformer to be energised by the battery with and without point-on-wave (PoW) switching?	We were successful when energising the 90 MVA grid transformer both with and without PoW, but we did experience a couple of trips when trying to energise the 90 MVA grid transformer without the aid of PoW switching – this was because we hit the point of the wave at a bad angle, and that's a completely random effect. We encountered no issues when energising the 10 or 24 MVA transformers but faced a few issues when attempting to energise the 90 MVA transformer. Consequently, from the best source, which was 11.6 MBA, it evidently falls within the range of 24 to 90 MVA, leaning towards the 90 MVA. The effectiveness of the point on the wave, as demonstrated in one of the earlier instances, is evident. While we wouldn't want to assign an absolute figure, we anticipate the transformer size would be substantial, considering the remarkable efficacy of the point on wave in mitigating the inrush current effect.
What if point-of-wave relay would not operate well? Would the BESS cope with inrush current?	It varies. In the case of the trials, it wasn't the BESS that was tripping out, it was more our protection systems tripping. Sustained periods of instability or voltage deviation would cause our protection systems to trip. If the point and wave isn't active, it makes the energisation of the transformer random and if you hit the wave at a good point, you're going to have a successful energisation. If you hit it at a bad point, then you run the risk of having substantial inrush current and therefore issues for your system, which is why we made the recommendation of having point and wave ability available at every anchor generator.
What happens if the solar (top-up plant) is unable to export, e.g. when there is no sun?	In the context of the trial, the impact on us wouldn't have been too detrimental since we had sufficient capacity to manage the solar farm not operating. This was also due to our complete control over the amount of demand that came online. If you were constructing a power island relying solely on a renewable resource with BESS as the anchor, we would suggest that it's not feasible. The BESS has a finite capacity, and eventually, if there is genuine demand, the battery will run dry. It makes more sense to complement the BESS system with a synchronous machine or another source with a highly reliable fuel resource. This way, the BESS can serve as a buffer and a balancing mechanism on the island, while the synchronous machine handles most of the demand.
Do you think that several small BESS would perform as well as one large BESS (provided that the sum of the total nominal power is the same in both situations)?	We would suggest that is likely the case. Most commercial BESS systems are modular, typically consisting of batteries of a certain size multiplied by the number of assets needed to reach a specific capacity. We had a similar setup during the trial. Therefore, we don't see any reason why a series of smaller batteries wouldn't have the same effect as one larger one, as that is what was observed.

By using Aggreko load, consumption was probably fully controlled. Do you expect the natural variation of load would have any substantial effect on restoration?	It really depends on the time of day when black start occurs or the level of cold load pickup experienced when building a distribution restoration zone (DRZ). Operators need to be cognizant of these factors and incorporate sufficient generation to manage the daily variation in demand. This ultimately comes down to the maximum demand expected during that period.
Did you encounter any harmonic problems due to low SCR or transformer switching?	Not to our knowledge. We did experience a couple of oscillations when the BESS was running in grid-following mode, resulting in a few trips. Harmonics were likely contributors, but in terms of enduring detrimental harmonic effects, we didn't see any during the trials.
As flexibility services expand, might they be integrated with the island controls? Perhaps an area to explore with flex providers and aggregators. A next stage?	We believe flexibility would be disabled in an actual black start scenario due to its added complexity. Control rooms would dispatch directly controllable generation/demand until the distribution restoration zone (DRZ) reached a 'fully' stable stage. Flexibility would be provided by BESS systems rather than aggregators in this instance. Once the DRZ was re-synchronised with the grid, aggregated flex could then be re-enabled.

General Q&A

Question	Answer
Can you explain how ESRS, steering group, GC0148, GC0156 and the Distributed ReStart work are all related?	Distributed ReStart is a NIC innovation project focused on how to make feasible the provision of restoration services from DER. The other activities are more business-as-usual activities, related but separate from the project.
How engaging with the ESO strategic review of requirements and opportunities in each zone is the project. Is that something that is being done as part of the Distributed ReStart project? And I guess the obvious question from that is from that review, do you have any view around the requirements and opportunities within the Northern Powergrid zones?	No, it is not being done as part of Distributed ReStart. The strategic review of requirements and opportunities will be done separately by the ESO in collaboration with DNOs and TOs. The upcoming tenders for restoration services are separate from the project, albeit the approach has been informed by the findings and outcomes from Distributed ReStart. Within the project we have performed a preliminary review of opportunities across all of GB based on publicly available information.
Do you see Distributed ReStart as being an element of rebuilding the transmission system?	In some cases, yes, we would hope that a Distribution Restoration Zone would have capability to support and accelerate transmission system restoration and possibly the restarting of large power stations or other resources. This will depend on the resources available and their position in the network.
The scope of the Chapelcross DRZ was focused on part of the SPEN distribution network only? It looks like it finished at the LV transformer breakers at the GSP.	The plan for the Chapelcross live trial is to energise up from 33 to 132 kV then along a 132 kV circuit to Gretna and then energise one of the supergrid transformers up to 400 kV.
What are your thoughts on the use of intermittent power sources like wind for black start? How do we account for the reliability of such plant?	The intermittency issue is a big one, but not just for black start. Looking at the Future Energy Scenarios, there won't be enough conventional generation to meet the darkness peak demand so we're going to be relying on some percentage of the intermittent sources being available. It's a question that we need to answer generally as an industry and get used to that kind of concept. It's important to build that thinking into restoration as well. Within the project we have studied and tested how we can limit the output of a wind farm to provide a steady supply of power within a DRZ. This is based on there being plenty of wind but the power output is controlled to a fixed level. The tests have shown it can be done effectively.

Has the project looked at the Northern Powergrid area to review the opportunities for DRZs?	Only at the most cursory of level. We did a review of resources across the whole country based on what was in the LTDS publications, but we did not delve into any particular locations in NPg or any other DNO areas. We just focused on SPEN areas for the project case studies and live trials.
If the DRZ is going to be an automated process then what initiates the trigger to say that the transmission network has been lost? And where does that interface come from for that process to start recovery?	The design is not fully automated. It's more of an automated assistance type of design, so you would still have your control engineer starting it and interacting with it at certain points. So it's a supervised automation rather than it being fully automated. The initial trigger to start a restoration process we expect to be manual, instigated by a DNO Control Engineer following consultation with the ESO Control Centre, or a delegated authority if appropriate.
We are deploying solar and would like to future proof its design to be able to offer ESR. Will there be some sort of guide to help developers with this?	Our Final Findings and Proposals report is intended to provide an "entry point" into the project learning. You may also want to review the information published in the most recent business-as-usual tenders for ESR to understand the latest requirements.
To what extent are grid-forming convertors part of your thinking?	We have done a fair amount of work on grid forming converters, including work in collaboration with Strathclyde University. This has been reported on in previous Power Engineering and Trials workstream reports and our Redhouse live trial is set to demonstrate the use of a grid forming battery for restoration.
What do you see as the greatest remaining challenges or risks?	It is clear that distribution restoration is complex, involving more parties, new systems, and new ways of working for all involved. We believe the project has demonstrated the feasibility of the concept and proposed solutions to the main challenges, but there will be further challenges to overcome as the concept is implemented for real. This includes technical issues that may be arise due to the specific network topology and equipment in a given area, or ensuring appropriate training for all personnel that would be involved in a restoration process. All of this imposes costs and it remains to be seen whether distribution restoration can offer a consistently cost effective alternative to large power stations or HVDC interconnectors in providing restoration services.
Do other countries do this?	This project represents a world first for restoration (as far as we know). Other countries do, or are exploring how to, use smaller, more local generators for restoration. But we think the scope of what we are considering, with the idea of potentially having DRZs across the whole country to supplement large power stations or other large sources, is unique. We are aware of interest in this project from the USA and elsewhere.
It is important to establish how future network restoration for these Islands will be delivered in order to inform an EU project called AMAZE, Archipelago of Mull Actions for Zero Emissions.	We were not aware of the AMAZE project; please do let us know how we can find out more about it. You may also be interested in SSEN's Resilience as a Service (RaaS) project: https://ssen-innovation.co.uk/raas/
How has this impacted on investment in top down generation?	The ESO will continue to seek the most cost effective means of providing the required restoration services, which is expected to involve a mixture of resources. The Distributed ReStart project has sought to make it feasible for smaller, distribution-connected resources to become part of that mix, but it is expected that large, transmission-connected generation will also continue to be part of the overall restoration strategy.

Do the comms and roles need to be considered within the wider requirement for more active DSO participation in normal operation? With the enhanced ESO-DSO-customer systems (with market and suppliers also in the frame of course). Resources become more extensively engaged and more ‘active’.	We see this project as being closely aligned with these wider network changes as the DSO model is rolled out. We’re working closely with Open Networks, which is a project setup to define these interfaces more generally and enable efficient ESO/DSO cooperation. Our work on the design of a DRZ Controller is based on the idea that the functionality may end up being implemented on whatever system(s) have been installed for other reasons, e.g. a new DER Management System (DERMS).
Again, we need the enhanced ESO-DSO interface sorted out for normal operation with distributed resources becoming more ‘active’.	
Again emhasises the need for intensive ESO-DSO automatic systems. Especially with ‘monster’ cumulative EV charging connections at 7.4 kW each.	
Limiting wind (and solar) to their average loads is not “safe planning”; there is no guarantee that wind will generate anything, let alone 45% of nameplate capacity. Therefore there need to be plans for restoration when renewable generation is low and zero. Are you doing this?	Yes, at least within the project’s remit. The assumptions used to explore and demonstrate particular effects in power system analysis are not the same as those that would underpin planning for provision of restoration services. Note, however, that this innovation project is merely seeking to demonstrate new approaches and propose solutions. Decisions on what level of service is actually required to satisfy the GB requirements sit outside the project.
SSEN has experience operating islanded DNO networks at the moment on the islands, albeit with backup synchronous diesel stations rather than predominantly automated third-party generation. This does include in some limited forms tripping to island running. System earthing is also an important area to consider, who is responsible for it and where should it be located?	We have been sharing learning with SSEN through engagement on their Resilience as a Service (RaaS) project. The issue of the location and ownership of the sytem earth (at 33 kV) has yet to be finalised. An argument for DNO ownership and location is that they may want to ensure the integrity of the earth as it will be required to protect the DNO network. However, it may be more efficient to design/install as part of an anchor DER’s installation.
Is it time for the UK to consider a high MVA AC link to Europe?	If DER play any role in black start in future it is likely to be as one of a mixture of solutions that we expect will include large power stations, as now, and interconnectors from other countries, which seem more likely to be HVDC.
The CBA seems to be only focused in MW, would it not make sense to also evaluate other capabilities like reactive power between others?	We’ve used megawatts in the CBA but this is one of the many things that we’ve simplified. We’re not using the CBA to make individual decisions about whether to agree a contract or on how to restore the system, it’s more about understanding what’s required on a strategic level and has benefits to the consumer. As this translates into BAU we would need to evaluate it in more detail but at this time it is a mix of current and projected costs based on assumptions.
Cost comparison was done against current costs for providing black start, was it done against alternative options, e.g. dedicated hardware such as OCGT?	The CBA attempted to compare future costs for restoration services based on different resources being used, including what impact there might be from making it feasible to use DERs as part of the mix. The future cost estimates included the potential need for conventional black start resources like OCGT.

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