GC0156 – SUMMARY OF WORKGROUP RESPONSES

VERSION 1

Respondent	Consultation Question	Consultation Response	ESO Response	Impact on Grid Code Drafting
EDF – Andy Vaudin	Do you believe that a cost benefit analysis should be undertaken by the Workgroup and if yes what factors should be considered?	The workgroup should undertake an analysis of the proposal to confirm that it is following a cost-effective route. Included in this would be that the proposer has not made clear (e.g., through presentation of analysis), the quantity of plant that would be expected to receive commercial Top up Restoration Service Provider contracts, and also the quantity of non-funded plant that would be required for restoration.	Cost Benefit Analysis has been done by Ofgem ahead of making ESRS a Licence Obligation.	
	Do you believe that parties obligated by GC0156 should have a cost recovery mechanism in place?	Retrospective obligations (where material) should have cost recovery. It is noted that a current CUSC Proposal could address this issue. It is not reasonable for parties to pay material costs.	CMP398 is looking to address this	
	Do you think that the proposals are sufficient and cost effective to ensure that NGESO can meet its ESRS licence obligations?	It is assumed that the Proposer has carried out analysis, which confirms that the proposals are sufficient and cost effective to ensure that NGESO can meet its ESRS licence obligations. This analysis should be provided to the workgroup in order to address this question.	Ofgem carried out the CBA, further analysis carried out by ESO are confidential due to national security reasons	
	The ESRS restoration target is expressed in terms of transmission demand rather than total demand (see Glossary and Definitions). Do you understand the implications of this, and are you happy with those implications?	BEIS confirmed to the workgroup that the restoration target is based on advice and analysis provided by NGESO. This advice and analysis have not been provided to the workgroup. This would be required for the workgroup to take a view on the implications of the restoration target.	BEIS attended the GC0156 work group on 18th August 2022 to confirm that restoring transmission demand is the obligation on the ESO. Analysis carried out by ESO that was provided to BEIS is confidential for national security reasons.	
	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	The proposer has not made clear, e.g., through presentation of analysis, the quantity of plant that would be expected to receive commercial Top up Restoration Service Provider contracts, and also the quantity of non-funded plant that would be required for restoration. This would be	There are several elements required to achieve ESRS, the Restoration Service Provider is one of the elements, and the more providers we can procure, the higher the chance of meeting ESRS.	

		important to decide the scope of plant included in the mandatory changes.	CMP398 is addressing this	
		• Retrospective obligations (where material) should have cost recovery. It is noted that a current CUSC Proposal could address this issue. It is not reasonable for parties to pay material costs.	The legal text has been updated accordingly	
		• Plant where it is known to be prohibitively expensive or definitively not feasible to comply with the mandatory requirements should have hard coded exemptions in the legal text. It is not efficient to expect these generators to follow a derogation process	Special Condition 2.2.5 of the license clarifies that ESRS compliance is expected under circumstances that are reasonably controllable.	
		• The mandatory obligation to have personnel availability to restart needs to be based on reasonable endeavours (e.g., if trees are down and roads are closed, a generator may not be able to restart).	This issue needs to be discussed in the workgroup. It was flagged as an issue in responses to the legal text. It must be ensured that the plant can operate correctly during a restoration period. This issue is addressed in revised drafting to CC/ECC.7.11.2	
		• The CC 6.3.5.2 obligation to adjust governor settings is unclear and open ended. Generators would be unable to confirm compliance as it stands	This issue has been addressed as part of the legal review session and the draft legal text has been updated in CC/ECC.6.3.7	
		• The proposer has not provided an analysis of the feasibility of achieving compliance with retrospective mandatory obligations by 2026 (and providing assurance of this compliance). This could be a further risk to meeting the restoration obligation.	The detailed analysis is confidential due to national security reasons.	

	Do you agree that the draft legal text is appropriate and sufficient to implement GC0156?	• The proposal should be clear that safety grounds are allowable grounds to reject restoration re-synchronisation instructions. BC 2.9.2.1 allows the rejection of emergency instructions on safety grounds, but this should also be explicitly stated in the OC9 legal text. In particular it should be recorded that nuclear plant would require a large GB wide synchronised power isnad to be in place, prior to restarting	We are happy to add this to ensure consistency with BC2.9.2.1	
	Do you have any views on how the requirements should be implemented into the Grid Code bearing in mind the requirements of the ESRS are not enforceable until 31 December 2026?	The implementation date in the Grid Code could be 31/12/26, with the ESO undertaking a programme to facilitate any required plant modifications and ensure compliance. Cf - the ALoMCP, where prior to the implementation date, a change and compliance assurance process was progressed.	We need to review the legal text to make it clear when the obligations apply. There are two parts to this requirement: the first covers when a specific obligation applies (e.g., assurance or critical tools and facilities and the second covers operational requirements. We discussed this issue at the legal review sessions and the revised legal text will be updated to address this issue.	
Elexon – Kathryn Coffin	As a stakeholder, are there any implications of the proposed future requirements which are not clear?	The scope of the required BSC changes are currently unclear and a BSC Modification Proposal has not yet been raised to progress them. See our further comments below. **Changes to BSC terminology, to reflect the Grid Code terminology change from 'Black Start' to 'System Restoration'.** This includes both updating BSC references to Grid Code defined terms and changing the BSC's own defined terms that include the words 'Black Start' (e.g., 'black start compensation 'and 'black start instruction'). We note that GC0156 continues to define System Restoration as the recovery procedures following either a Total or Partial Shutdown, whose own definitions remain unchanged in the Grid Code. We therefore	BSC Mod is being raised imminently.	

		believe that GC0156 does not alter the actual BSC processes for determining when and how to suspend and resume normal BSC market operations. **Updating BSC cross-references to relevant parts of the Grid Code that have been renumbered by the GC0156 legal text.** For example, the BSC refers to NGESO's determination under Grid Code OC9.4.7.9 of when the Total System could return to normal operation. This triggers the BSC process for determining the end of the BSC's own contingency provisions. While the GC0156 legal text hasn't changed the actual activities in this OC9 step, it has renumbered it. The BSC cross-reference will therefore need updating to avoid confusion. **Changes to the BSC's rules for who can claim compensation for Black Start instructions and, potentially, for what types of instruction.** Currently only a BSC Party who is the Lead Party for a BM Unit that's given a Black Start instruction by NGESO under the Grid Code can claim BSC compensation. The BSC defines the eligible instructions by cross-referencing specific types of NGESO instruction inBC2 and OC9 of the Grid Code. We understand that the intention of GC0156 is to expand the BSC's compensation arrangements, so that on-BSC Parties providing contracted Restoration Services to NGESO (defined as Anchor and Top-Up Restoration Services in the GC0156 legal text) should be able to claim BSC compensation for instructions given to them during System Restoration. This will require changes to the BSc's claims rules and procedures, as well as likely changes to BSC/ Elexon systems.		

		We note that GC0156 replaces the existing Grid Code concepts of Black Start Station and Black Start Service Provider with the new concepts of Anchor and Top-Up Restoration Services and Anchor and Top-Up Restoration Service Providers. Where these Restoration Service Providers are distribution-connected, we are currently unclear from the GC0156 legal text whether any instructions they receive from Distribution Network Operators to enact these services will be considered to be NGESO instructions for Grid Code purposes under BC2/OC9. If they are not, then neither BSC Parties nor non-Parties providing these distribution-connected Restoration Services will be able to claim BSC compensation unless changes are made to the BSC		
	Do you support the proposed implementation approach?	We believe the current 10WD implementation approach creates risks in the operation of the end-to-end Black Start process, as it's very unlikely that the BSC changes can be raised, progressed and implemented by mid-2023 (which we understand is NGESO's target implementation point for GC0156). We initially estimate that the timescales to progress the necessary BSC Modification Proposal are likely to be around 9months for Workgroup/Panel assessment and Ofgem approval, followed by around 6months for implementation of the approved changes to BSC documents and systems. The exact timescales will depend on the final scope of the required BSC changes, as developed and assessed by a Workgroup once a BSC Modification Proposal has been raised.	ESO acknowledges that the new requirements for ESRS will be implemented over an extended period of time and not within 10WD. The ESRS standard allows the industry to make necessary changes to network, plants and the regulatory framework up until Dec 2026, when the Licence Obligation takes effect. The Grid Code legal text will be updated to ensure what obligations are required and when they apply.	

		Further comments on implementation approach We believe that, if the current GC0156 implementation approach doesn't allow the Grid Code and BSC changes to come into effect at the same point, this creates risks to parties in the end-to-end Black Start (System Restoration) process. If a Black Start (System Restoration) event occurs in between implementing the Grid Code and BSC changes, then the risks are that: There will be confusion caused by the two Codes using different terminology and by some existing BSC cross-references no longer pointing to the correct part of the Grid Code. There will be confusion and lack of clarity on what types of instruction are eligible for BSC compensation. In the worst-case scenario, a disjoint between the Grid Code and BSC rules could mean that some Black Start (Restoration)Service Providers are unable to recoup the costs they incur during the event. -We understand that the Electricity System Restoration Standard doesn't come into force until 31 December 2026. We believe that affected parties will also need time to make the necessary operational and contractual changes that are needed to comply with the new GC0156 requirements. Usually in this scenario we would expect GC0156 to have a fixed implementation date, by which parties must be ready to comply with the new rules (e.g., This could be31 December 2026, or some other earlier fixed date). Other impacted Industry Codes could then align implementation of their changes on that same date, so that all aspects of the new end-to-end process come into effect at the same time.	We acknowledge this and are working with Elexon to progress the BSC Mod.	

		We recognise that there may be complexities of which we're unaware, e.g., around contractual and testing arrangements, that might require some GC0156 requirements to come into force earlier than others. In this scenario, we would usually still expect an overall fixed date for implementing the legal text. However, this date could be earlier, with the legal text including transitional arrangements to apply during the period in which the new rules are phased in. Examples of BSC changes where the legal text has included transitional provisions include the introduction of BETTA2 and the changes to support TERRE3. The Market-wide Half Hourly Settlement (MHHS) Programme is also likely to include transitional provisions within its legal text to implement MHHS in the BSC and other Codes. Elexon's Legal team would be happy to run through past example of BSC transitional text with NGESO's lawyers, if that would be helpful. At the GC0156 industry webinar on 7 December 2022, NGESO advised that it's considering operating two parallel versions of the Grid Code between 2023 and 2026 –one with the current rules, and the other with the new GC0156 rules. NGESO indicated that this could also require other impacted Code bodies to operate two live versions of their Codes, including the BSC. We can confirm that it's not possible to have two live versions of the BSC in force simultaneously. Our Legal team would be happy to discuss this further, in case there's been confusion over past BSC approaches (e.g., for BETTA).	We are now looking at an option so there is only version of the code so it is clear what the obligations are and when they apply.	
	Do you agree that the draft legal text is appropriate and sufficient to implement GC0156?	Because of the interaction between the Grid Code and BSC provisions, it's difficult to answer this without understanding fully what changes are required to the BSC. For example, see our question above about the instructions given to	ESO acknowledges that the new requirements for ESRS will be implemented over an extended period of time and not withing 10WD. We also acknowledge that there will be issues if a Black	

		distribution-connected Restoration Service Providers. The GC0156 legal text also replaces (overwrites) the existing Black Start process in the Grid Code. Given the proposed 10WD implementation date for GC0156, it's unclear what happens if a BlackStart (System Restoration) event occurs before parties are ready to start providing the new types of Restoration Services. Not all of the GC0156 deletions to existing provisions in OC9 are showing as redlined strike-out text, which makes it more difficult to see/understand all the changes.	Start event where to occur during the transition. We are therefore working with our tender team to ensure that should a Black Start where to arise post implementation but before 31 January 2026, the Grid Code provisions and associated contracts will still work.	
Engie – Simon Lord	Do you support the proposed implementation approach?	The impact on various classes of generation has not been established we suggest a "survey" of all existing transmission connected generation should be performed via a simple questionnaire to establish the practicality of this proposal this should drive the implementation approach	The relevant Regulatory Frameworks are being updated with clear responsibilities/impact on the various classes of generation.	
	Do you have any other comments?	Given the importance of the issue we think the workgroup should consider if the various changes should be consolidated into a separate sub code of the Grid Code in a similar way to the Connections Conditions. This would be a new "ESR Conditions"; some of the conditions would apply to all parties whilst the majority of the conditions would apply only to active participants in System Restoration. Consideration needs to be given as to the funding of the retrospective obligation. Funding should be set at an appropriate level and should relate to average	We believe that there will be a lot of complexity with this approach as some of the ESRS requirements are also required for BAU operation of the network. We have also taken the opportunity to review the draft legal text with the Workgroup on several occasions including post workgroup consultation. There has been no appetite for this change so we propose to leave the text as is. CMP398 is addressing this	

		class funding rather than on an individual cost-plus basis. The obligation for 72 hrs is a “shall” obligation as such it is absolute. Retrofitting this could be a major task for some existing generators: thus, we suggest a “reasonable endeavours” for existing generators and a “shall” for new generation. It is expected that some types of generation the cost to achieve the 72 hours will be prohibitive as such it is expected that these types will likely seek derogations from the requirement and Ofgem should establish a fast-track route for this.	The legal text for this requirement has been updated in CC/ECC.7.11.2~~.~~ Agree – This is now a feature of the revised drafting.	
	Do you believe that a cost benefit analysis should be undertaken by the Workgroup and if yes what factors should be considered?	Whilst in principle a cost benefit analysis should be undertaken for any code change of this magnitude, it is self-evident that the cost (loss of economic activity) of an event that leads to a widespread loss of power will far exceed the cost associated with improving the resilience of the UK generation fleet. The key issue is establishing the level of cost imposed on the generation fleet and how these costs are recovered from consumers. At present the burden of costs imposed by the Grid Code on generation is effectively passed through to customers via traded markets. Costs associated with Grid Code compliant generation are significantly higher (per MW installed) than those imposed via distribution codes, but market players access the same market. The cost benefit analysis should thus be limited to establishing the cost imposed on Grid Code compliant generation (per MW) and a payment mechanism should be designed to ensure that any class of generation that suffers disproportionate costs (taking account of costs imposed on distribution code compliant generation) should be held whole (effectively a System Restoration capacity payment).	Cost Benefit Analysis has been done by Ofgem ahead of making ESRS a Licence Obligation. Cost recovery mechanisms were discussed in the “Markets and Funding Mechanisms” Subgroup GC0156. CMP398 has since been established to develop this further.	

		If all classes of generation (distribution and grid code) suffer a similar level of cost increase, then this can be picked up via the existing energy market mechanisms. Indicative compliance costs has not been established we suggest a "survey" of all existing transmission connected generation should be performed via a simple questionnaire to establish the practicality and cost of this proposal. The distribution code ROCOF relay payment mechanism is an example of such a mechanism being put in place. Although this had some design problems as it was part funded by transmission connected generation via BSUoS. So, there was a cost increase on the class of compliant, Tx-connected generation. That is, there was effectively a cross subsidy from BSUoS paying generation to small non-compliant generation; this was economically inefficient.	Indicative costs can only be requested when we know the full extent of the changes being required via the Regulatory Framework	
	Do you believe that parties obligated by GC0156 should have a cost recovery mechanism in place?	See above. A cost recovery mechanism is appropriate only if a class or classes of generation suffer excess costs relative to the whole generation fleet (that is above a de minimis level [1 MW]) Funding should be set at an appropriate level and should relate to average class funding rather than on an individual cost-plus basis	CMP398 is addressing this	
	Do you think that the proposals are sufficient and cost effective to ensure that NGESO can meet its ESRS licence obligations?	The Grid Code change effectively just passes the NGESO obligation on to generation subject to the Grid Code. Without a payment/derogation or less onerous obligation NGESO is unlikely to meet its licence obligation. There is more work to be done to ensure a wider acceptance of the 72-hour issue and ensure it is universal across all generation above a de minimis level.	We do not believe that generators alone must support the ESO in meeting the ESRS obligations. Network Operators and Transmission Owners also have a critical role in achieving ESRS. The legal drafting also include provision for a derogation process	

			CMP398 is addressing the payment.	
	Do you believe there are further changes to the network i.e., NETS and/or Distribution Network required to implement ESRS obligations?	Licence change to generation licences to require generators to comply with ESRS direction from ESO.	New requirements will be reflected in the Grid Code	
	The Annex (pages 29 – 32) in the Future Networks subgroup report covers 2 scenarios where site supplies are lost up to 72 hours. Which of these 2 scenarios is the most realistic? (The full details of these scenarios can be found on pages 29 – 34 of the Future Networks subgroup report in Annex 4	☐Scenario 1 ☒Scenario 2 There are three classes of generation effected by this proposal. **Type A** Generation that is Anchor or “anchor”-capable is likely to be relatively unaffected by the event and will have planned for such an event. Little or no modifications will be required **Type B** There is a class of site where local backup supplies will have been provided to allow for limited emergency supplies (lighting safety system barring gear etc) for a short period of time (perhaps up to 24 hrs). For this type of limited modification will required principally additional fuel stores combined with addition on battery re-charge faciality typical small on-site generators. **Type C** The vast majority of newer asynchronous sites will have limited backup supplies and will likely be dispersed (wind/solar/ recips). Whilst the control point may have backup supplies it is “unlikely” that the communications and power will be in place to allow the remote sites to be self-sustaining. Physically visiting remote sites could be challenging given the likely issues for road transport. For this type major reworking of systems will be required which in many cases will	The requirement for 72Hrs resilience was factored into the CBA carried out by Ofgem. The proposal is for CUSC parties to have the requirement and legal text have been worded to cover exceptional scenarios.	

		not be practical. As such this class will likely seek a derogation from the requirement based on the "harm" caused by the retrospective obligation which will undermine the intent of the change. The financial and practical impact on various classes of generation has not been established we suggest a "survey" of all existing transmission connected generation should be performed via a simple questionnaire to establish the practicality of this proposal		
	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	All parties should be impacted in the same way. Distribution and grid code generation should face the same cost. If only one group is impacted, then they should be held whole by funding from the network companies.	Both DCode and Grid Code are being updated for ESRS. A Workgroup Consultation has been held for both Codes.	
	The GC0156 proposed solution 72 hrs resilience is expected to be applied retrospectively to existing CUSC parties. Do you agree with this retrospective application and if not, what is your rationale / view about this?	Retrospective imposition of obligations without compensation is in general a bad idea. In this context it is only acceptable if distribution and grid code compliant generation are impacted to the same financial extent (above a de minimis level of [1MW]).	CMP398 is addressing this	
	Do you believe it is appropriate to have a mains independence minimum resilience period of 24 hours as required by the NCER or 72 hours as a general GB standard for existing black start purposes as proposed with the GC0156 solution for Grid Code parties, BM parties, VLPs and restoration service providers? Do you agree with a retrospective application of this and if not, what is your suggestion / views about this?	72 hours as a minimum for all BM parties. It just needs to be clear that this applies to systems on the "physical site" and does not relate to wider systems or Energy Management. In the context of distributed control plant its unclear what this actually means (solar arrays, wind turbines, reciprocating engines). If the national systems (internet, Openreach etc) are down it won't be possible to restart the generation until those systems return even if they are capable of restarting once communication is possible. Retrospective imposition of obligations without compensation is in general a bad idea. In this context it is only acceptable if distribution and grid code compliant generation are impacted to the same financial extent (above a de minimis level of [1MW]).	We expect the control points to be resilient also. Wider systems are not going to be exempt from 72 hr resilience requirement. The ESO will give instructions to parties at their Control Points or Control Centres so it is important that once they receive an instruction they can act on those instructions. CMP398 is addressing payment	

Northern Powergrid – Alan Creighton	Do you believe that a cost benefit analysis should be undertaken by the Workgroup and if yes what factors should be considered?	We understand that a CBA was carried out by government to establish the ESRS obligations, but it is unclear to us whether the GC0156 proposals are the minimum required to achieve ESRS or whether the proposed new obligations are more than those required to achieve the ESRS requirements. Given that the cost of remedial work that would be required, by generators in particular, will be ultimately borne by consumers, we believe that any new obligations and the associated expenditure over and above that reasonably required to achieve the ESRS should be subject to a CBA.	Based on our work and the information shared with Ofgem/BEIS, we believe that the requirements specified to achieve ESRS are at an appropriate level.	
	Do you think that the proposals are sufficient and cost effective to ensure that NGESO can meet its ESRS licence obligations?	We do not believe that NGESO has provided sufficient information for us to be able to answer this question. The fact that NGESO has raised this modification implies that their view is that the present arrangements are insufficient to meet the ESRS, however the gap between the ESRS requirements and the restoration that could reasonably be expected to be delivered via the existing capability is unclear. Hence, it is difficult to assess whether the proposals in this modification are sufficient or excessive. The workgroup has not discussed the costs that may be incurred by generators, nor the wider societal benefits, so it is unclear whether the proposals are cost effective.	Some of the information requested here is sensitive due to national security reasons however, we can confirm that the present arrangements are insufficient to meet ESRS hence the reasons for the code changes.	
	The ESRS restoration target is expressed in terms of transmission demand rather than total demand (see Glossary and Definitions). Do you understand the implications of this, and are you happy with those implications?	We understand the nuances associated with the use of the term Transmission Demand, but we are not convinced that this is the correct term or concept that should be applied as there is a risk that it will raise customer expectations about supply restoration that are greater than those required or that will be delivered by the ESRS. We understand the thinking that the ESRS provides a target demand that should be restored within specified timescales, but we believe from a customer perspective, basing the requirement on	The use of Transmission Demand is based on directive from BEIS. The Grid Code, in particular OC9 and OC1.7 and the use of existing definitions in the Grid Code has been amended to reflect this requirement.	

		the gross demand that should be restored at each Grid Supply Point substation and therefore the proportion of customers that should be restored at each Grid Supply Point substation would be better understood by stakeholders.		
	The GC0156 proposed solution 72 hrs resilience is expected to be applied retrospectively to existing CUSC parties. Do you agree with this retrospective application and if not, what is your rationale / view about this?	We are comfortable with the proposed 72 hours resilience from a Network Operators perspective. As mentioned previously, it is not clear to us that the proposed resilience requirement needs to be applied retrospectively to all the existing CUSC parties, as opposed to a targeted group of CUSC parties. We are of the view that the proposed resilience requirement should only be imposed on those CUSC parties where the proposed resilience is reasonably required to ensure NGESO can meet its ESRS obligations	The 72-hour resilience requirement is imposed on all CUSC parties in order to meet ESRS. We acknowledge this might be technically impossible for some generators, and the Grid Code (CC/ECC.7.11.2) has been updated to reflect this issue.	
	Do you have any views on how the requirements should be implemented into the Grid Code bearing in mind the requirements of the ESRS are not enforceable until 31 December 2026?	The new requirements need to be included in the Grid Code as soon as practicable to give certainty to affected stakeholders, however, as stated earlier in our response to question 2, there needs to be clarity of the date when each of the new requirements will come into force. We do recognise that some requirements e.g., those relating to Distribution Restoration Zones will only become relevant as they are developed. Others, such as the requirement to provide 72 hours resilience, will need to have a clearly defined implementation date, presumably 31 December 2026.	This is being progressed. As part of the updated legal drafting it is proposed to have a set of text which clearly identifies what the obligations are, when they apply and also ensure that were a Black Start event to occur following implementation (but before 31 January 2026) the Grid Code text works. We are also working with our colleagues in the tender team on this issue.	
SSEN Transmission – Michelle MacDonald	Do you support the proposed implementation approach?	We agree with the approach but there are some key points missing. The skeleton network is crucial to restoration and the quality of assets/upgrades that need to be built hasn't been looked at. Under the whole system approach, the remainder of restoration will still need to be considered, in addition to ESRS	Upgrades that are required for the formation of the Power Islands will be identified during the LJRP/DRZP stages, since these are related to the Anchor/Top Up plants.	

	Do you have any other comments?	SHET believes this proposal leads to a fundamental performance change for Transmission Owners and other users. This is expected and it will cost. We also believe there will be changes required to R45. SHET feel the consultation itself and the number of questions asked of industry has been quite convoluted.	The GC0156 Mod is rather complex and we tried to simplify the questions as much as practically possible. It is also important to note that consequential changes to the STC as a result of GC0156 will be presented to the STC Panel in February which itself is a separate Governance Process.	
	Do you think that the proposals are sufficient and cost effective to ensure that NGESO can meet its ESRS licence obligations?	We believe that most of the proposals are supportive enough to work towards ESRS however are not sufficient to achieve it fully. Further changes outside of this piece of work will be required to ensure that the licence obligations are met. GC0156 does not fully answer how to speed up restoration. Obligations under the STC and Grid Code are currently clearly defined, and the changes proposed under ESRS are not yet clearly defined in order to assess the impact these changes will have on our TO obligations. For current obligations, the scale change, complexity, and number of interfaces with new parties proposed under ESRS has a significant impact. SHET's view on the consultation is there has been a lack of clarity on what this means for Transmission Owners, and the impact these changes will have in terms of cost effectiveness, we would need to review the outcome of any CBA, cost comparison etc. (question 5). A review of the current re-opener approach may need to be carried out.	The ESO will implement a Restoration Decision Support Tool which will significantly speed up restoration process. We agree that this is outside the scope of GC0156. The STC Mod is being progressed and will be presented at the February STC Panel where we expect a Workgroup to be established.~~.~~	
	Do you agree that all the costs associated with TO/DNO implementation of ESRS should be recovered through their respective price controls? If not, what funding mechanism do you favour?	SHET believes that to provide the requirements requested under GC0156, we would require additional funding than is already allocated under RIIO-T2. We require this additional funding and commitment from the ESO to allow for us to accelerate our scale up on our path to delivery. We would only be able to do this if we had the	Ofgem has confirmed that TO/DNO funding should be discussed directly with them.	

		commitment from Ofgem prior. While we appreciate there is the opportunity for reopeners, these are currently only every 12 months, and this could lead to delays in us meeting the timescales currently laid out. We would propose a 6 monthly reopener specifically relating to ESRS to allow us to scale up to meet the requirements. Following the implementation of ESRS, we would propose to move to ongoing funding from traditional mechanisms such as through price controls.		
	The ESRS restoration target is expressed in terms of transmission demand rather than total demand (see Glossary and Definitions). Do you understand the implications of this, and are you happy with those implications?	SHET believes that across the industry there is still ambiguity around the definition and clarity of 'Transmission Demand'. We believe there should be as much clarity as possible as to what this definition is, prior to the event occurring as this would likely cause delays to the restoration during an ESRS event.	The use of Transmission Demand is based on directive from BEIS. BEIS also provided an update of this interpretation at the meeting held on 18th August 2022. The issue has also been discussed at the legal review sessions and updates have been made to OC9, OC9 and the Grid Code Glossary and Definitions.	
	Do you think that there is a common understanding between stakeholders of the demand to be restored in GB required by ESRS?	We think that there is an understanding of the high-level demand to be restored, e.g., 60% in 24 hours and 100% in 5 days. The section "Clarification of Definition of Restoration Demand" highlights that there is still some fine tuning to be done before a common understanding will be in place. The definition "transmission demand" is derived figure based on forecast values. The aim to restore any percentage of this creates a measure but does not achieve an industry ambition to restore all customer demand. It has been a point of confusion during development of GC0156 and workshops and is most likely to remain so in the ESR event.	BEIS confirmed at the GC0156 WG meeting on 18th August that the intent of the ESRS standard is to ensure that all the demand on the network is restored as soon as possible. Further clarity on the definition of demand has been provided within the legal text in OC9, OC1.7 and Glossary and Definitions~~.~~	

		We agree with the general concerns that there would be a proportion of Distribution demand that is not covered by ESRS. In the Scottish network area, there could be a considerable proportion of demand left off supply due to the non-return of embedded generation following an ESRS event. SHET believes there needs to be a line added to confirm that Scottish TO's will be required to talk to BM participants on the ESO's behalf. The TO would not be able to instruct any parties if there has not been an exchange of information.	That is the current agreement for implementing restoration in Scotland. It is also codified in the Grid Code but also in STC 06-1	
	Do you see any barriers for Network Operators and Users to deliver the changes proposed to implement the ESRS by December 2026?	We don't see any barriers at present as duties & responsibilities should not be changing. However, there will need to be re-openers or upfront funding to allow for more staff to be brought in due to the size of the changes required. On top of this there will be the need to procure the appropriate equipment and upgrade the network to the standards required by ESRS.	Ofgem has confirmed that TO/DNO funding should be discussed directly with them.	
	Do you believe there are further changes to the network i.e., NETS and/or Distribution Network required to implement ESRS obligations?	The Distributed Energy recovery system will lead to several embedded islands. Codes state that TO's in Scotland will instruct and manage power islands with DNO operating frequency and voltage control. These small power islands will have an impact of the effectiveness/speed of the restoration so there will need to be a review of how we connect them to Transmission Connection Assets. There will need to be another interface between TO's & DNO's as we will need to coordinate and instruct any DER. Regarding the work required by TO's under Annex 13, we will require appropriate time to review network capabilities and topology to	Agree This would be through agreement of the Restoration Plans which parties would have visibility of.	

		facilitate the standard and new mechanisms of the restoration.		
	The Annex (pages 29 – 32) in the Future Networks subgroup report covers 2 scenarios where site supplies are lost up to 72 hours. Which of these 2 scenarios is the most realistic? (The full details of these scenarios can be found on pages 29 – 34 of the Future Networks subgroup report in Annex 4)	We think both scenarios are based upon the current as is world, and not based on GC0156 being put in place. Our view is that any scenario should be looking at where the resilience is included	Acknowledged	
	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	Transmission Owners are not mentioned in the 'analysis of parties' in the consultation and we believe there should be a section analysing the effect on TO's as these changes do have an impact. As a TO we meet the requirements highlighted, and where we don't, we are already resolving this through the RIIO-T2 price control. However, in some aspects there is still a requirement to scale up and we do not believe this has been captured.	The STC Mod is being progressed.	
	Do you agree that the draft legal text is appropriate and sufficient to implement GC0156? If not, please provide your suggestions?	The drafting is overly complex given the scale of the changes, but it appears to set out a framework for the changes that are to be implemented. Much of the actual change (and the impacts of the change) will arise from subsidiary documents which make it impossible to confirm that the current text is appropriate and sufficient in its own right. Where possible, it would be advantageous to specify any definitive requirements which will apply within the Code itself to promote certainty and clarity. Similarly, it would be helpful for the "Electricity System Restoration Standard" to be defined in the glossary on its own rather than through reference to the Company's Licence conditions.	Acknowledged	
	Do you believe there should be further assurance activities in addition to those described in the proposed legal text within	The mechanisms set out in OCR 5.7.4 and 5.7.5 look broadly fine from a drafting point of view.	The obligation in OC5.7.4 and OC5.7.5 refers to CC/ECC.7.10 and CC/ECC.7.11 which refers to up to 72 hours. There is not	

	OC5? If yes, please state the activity and explain why?	We note that the consultation document refers to a minimum period of 72 hours for certain requirements (e.g., in terms of the period in which communication systems must remain operational, an ability to restart etc.) but this is expressed as a lessor obligation of “a period up to 72 hours” in OCR5.7.4.2(v). Presumably, this timescale should be increased to “a minimum period of 72 hours” so that assurance activities are measured against the underlying requirements?	intended to be any relaxation here – ie the minimum requirement is 72 hours although there is a derogation option available where this requirement cannot be achieved.	
	Do you think the right requirements have been identified for Network Operators in terms of Network design and operational capability as summarised in the consultation document and annex and as detailed in the proposed legal text in CC/ECC.6.4.6.3b and OC9?	No as there is still work to be done on the amendments to the STC and STCPs. We believe the ESO has intentions to do more work in this area	The STC Mod is being presented to the February STC Panel where it is expected a Workgroup will be formed..	
Kinlochleven Power Ltd – Steven Pollock	Do you have any other comments?	What (if any) exemption or derogation process will be in place? Has consideration been given to system restoration capabilities that would realistically be available from generators that have no ability to supply ESRS. Attempts were made to use Kinlochleven Hydro to black start the local DNO system, but all attempts proved futile.	Derogation process will be applicable where relevant. Grid Code CC/ECC.7.11.2 has been updated to address this issue.	
	Do you believe that a cost benefit analysis should be undertaken by the Workgroup and if yes what factors should be considered?	Value for money of mandating ESRS capability for existing plant and for new plant.	Agree, having ESRS requirements on new plants alone won’t achieve ESRS.	
	Do you see any barriers for Network Operators and Users to deliver the changes proposed to implement the ESRS by December 2026?	Requiring modifications to existing User plant and confirmation of compliance is likely to be costly, time consuming and in many cases of no practical use to the network operators. Not all existing User plant may be suitable or cost effective for delivering ESRS services even if modifications were to be made.	Legal text has been drafted to reflect this and allows for a derogation process through CC/ECC.7.11.2	

	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	It is not appropriate or cost-effective for all existing Users to be required to comply when not all Users are intended to be contracted to offer System Restoration Services. Any requirement to be able to operate in island mode is exceptionally onerous for grid-connected hydro plant in general, and for Kinlochleven Hydro in particular. These requirements should not be applied to existing plant, which was not designed to, is not able to, and does not intend to, offer System Restoration Services.	Legal text has been drafted to reflect this see above (CC/ECC.7.11.2)	
	The GC0156 proposed solution 72 hrs resilience is expected to be applied retrospectively to existing CUSC parties. Do you agree with this retrospective application and if not, what is your rationale / view about this?	These requirements should not be applied to existing plant, which was not designed to, is not able to, and does not intend to, offer System Restoration Services. If any of the requirements are mandatory, then the necessary plant modifications should be fully funded	Legal text has been drafted to reflect this - see above CC/ECC.7.11.2	
	As a stakeholder, are there any implications of the proposed future requirements which are not clear?	Exactly how hydro plant would be able to achieve and demonstrate compliance is not clear.	We believe Hydro plants can demonstrate compliance with ESRS requirements. If there are any particular requirements you are concerned about, please kindly indicate accordingly.	
SIMEC Lochaber Hydra Power 2 Ltd – Steven Pollock	Do you have any other comments?	What (if any) exemption or derogation process will be in place? Has consideration been given to system restoration capabilities that would realistically be available from complex User connections and those with site demand? Lochaber Hydro is an embedded generator with vulnerable smelter demand at the same connection point.	Derogation process will be applicable where relevant see CC/ECC.7.11.2~~.~~	
	The Annex (pages 29 – 32) in the Future Networks subgroup report covers 2 scenarios where site supplies are lost up to 72 hours. Which of these 2 scenarios is the most realistic? (The full details of these scenarios can be found on pages 29 – 34 of	☒Scenario 2 Lochaber Hydro has smelter demand at the same connection point. Loss of DNO site supply for 72 hours would be more of a concern for the demand plant than for the hydro generation.	Acknowledged	

	the Future Networks subgroup report in Annex 4)			
	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	It is not appropriate or cost-effective for all existing Users to be required to comply when not all Users are intended to be contracted to offer System Restoration Services. Any requirement to be able to operate in island mode is exceptionally onerous for grid-connected hydro plant in general, and for Lochaber Hydro in particular. These requirements should not be applied to existing plant, which was not designed to, is not able to, and does not intend to, offer System Restoration Services.	In the case where compliance with ESRS requirements is prohibitive for an existing plant, a derogation can be requested – see CC/ECC.7.11.2~~.~~	
	The GC0156 proposed solution 72 hrs resilience is expected to be applied retrospectively to existing CUSC parties. Do you agree with this retrospective application and if not, what is your rationale / view about this?	These requirements should not be applied to existing plant, which was not designed to, is not able to, and does not intend to, offer System Restoration Services. If any of the requirements are mandatory, then the necessary plant modifications should be fully funded.	Derogation process will be applicable where relevant. – see CC/ECC.7.11.2 CMP398 is addressing the funding	
	Do you believe it is appropriate to have a mains independence minimum resilience period of 24 hours as required by the NCER or 72 hours as a general GB standard for existing black start purposes as proposed with the GC0156 solution for Grid Code parties, BM parties, VLPs and restoration service providers?	24 hours We do not agree with a retrospective application of an increased resilience duration	Acknowledged	
Nicola Barberis Negra – Orsted	Do you have any other comments?	As an overarching comment, Ørsted do not believe that the process used is suitable to implement all changes within this Mod, given that several elements – in our view – stray outside the Terms of Reference. With regard to the specific requirements, we've detailed in Q2 and in the rest of our response it is our view that a separate Mod or working group should be formed with relevant parties involved to ensure the correct impact of such changes are evaluated. Further detail on our position can be found in our	Acknowledged	

		response to the specific questions in the workgroup consultation.		
	Do you believe that a cost benefit analysis should be undertaken by the Workgroup and if yes what factors should be considered?	Our understanding of the current proposal is that some requirements will be imposed retrospectively to Generators (e.g., CC.6.3.5.2, CC.6.3.5.4, CC.7.10, CC.7.11 (and equivalent clauses in ECC)): some of the proposed changes have not been factored in when these plants were designed many years ago and some are operating with equipment that may be difficult to upgrade to account for the new requirements. For example, this would be true for offshore wind farms, where wind turbine technology has rapidly evolved over the past 15 years. We believe that a CBA should be performed on a case by-case basis, but also acknowledge that some plants may not be able to accommodate any of the proposed changes: plants should not be penalised for this reason. An effective-from date should be applicable here, should some of the proposed changes be approved and, in any case, pending the outcome of the CBA assessment	Acknowledged. Derogation process will be applicable where relevant – see CC/ECC.7.11.2~~.~~	
	Do you believe that parties obligated by GC0156 should have a cost recovery mechanism in place?	This should be assessed following the CBA exercise for each project: we expect some of the proposed changes to have large economic impacts for the projects in question and a mechanism to recover such costs should be considered.	CMP398 is addressing this	
	Do you see any barriers for Network Operators and Users to deliver the changes proposed to implement the ESRS by December 2026?	WE believe some of the requirements that are proposed to be applicable retrospectively to every GB Generators (e.g., CC.6.3.5.2, CC.6.3.5.4, CC.7.10, cc.7.11 (and equivalent clauses in ECC)) could not be implemented for every User and further consideration should be given to the proposed changes. Some plants have been in operation for many years and their equipment may not be suitable for the proposed changes	Derogation process will be applicable where relevant – see CC/ECC.7.11.2~~.~~	

		without considerable investment (potentially in the region of £m), which would require years for their completion. This could lead to a delay and could take longer than 4 years.		
	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	We believe that further work needs to be done before the mandatory requirements for all GB Generators are implemented, especially when it comes to their retrospective applicability. We do not consider the proposed changes to be entirely within the ToR of the Working Group, as it is not clear – in our view – that this Mod should have focused on amending existing requirements for Generators in operation. Therefore, we believe that a separate Mod or working group should be setup with relevant parties involved to ensure the correct impact of such changes are evaluated. We are also unsure that the ToR are currently met by the proposed changes: the first item in the ToR Scope of work, clearly states that "Cost and implementation" should have been considered. However, in the WG report it is stated that the "Communication and Infrastructure" subgroup "had insufficient time to make an assessment of the costs that might be incurred by stakeholders". We see a shortage on the work to support the proposal and suggest that further work is done on this before retrospective requirements are implemented in the Grid Code	We believe the remit of GC0156 is to identify requirements to meet ESRS whether from existing plants, new plants, TOs, DNOs or ESO. Cost Benefit Analysis has been carried out by Ofgem.	
	The GC0156 proposed solution 72 hrs resilience is expected to be applied retrospectively to existing CUSC parties. Do you agree with this retrospective application and if not, what is your rationale / view about this?	We don't believe this could be a blanket requirement applicable to any Generator of any size and age. For instance, with respect to offshore wind turbines, there is a large difference in the range of capabilities depending on how long such machines have been in operation for: newer wind farms may be more suitable due to the use of SST/TIM or similar preventing dry-out solutions for converters; but older turbines may not have such capability. This should be assessed	We believe it is important to have a level playing field and the derogation process will apply where relevant – see CC/ECC.7.11.2	

		on a project-by project basis, against existing technology and accounting for cost implications		
	Do you believe that cyber security requirements in accordance with the NIS standard are sufficient and as referenced in the proposed Grid Code drafting (available in Annex 6)?	Critical Tools and Facilities are essentially all systems needed for provision of a System Restoration. This means that in addition to the capacity statements of UK NIS (larger than 100MW), the proposed change is additionally requiring (in the Grid Code) that UK NIS must be upheld regardless for almost all systems, as CC6.3.5 implies that all System Restoration must be supported. While we understand the need for Cyber Security the convolution of Grid Code and Cyber Security is concerning, as UK NIS already has enforcement actions and penalties. A power plant must be secured if mis/maloperation has an adverse impact to the electrical grid, hence the capacity threshold of UK NIS – this is not affected by the addition of System Restoration to the Grid Code. We wonder why this is needed as part of the Grid Code when it is adequately covered in the UK NIS regulation? Moreover, we understand that cyber security, which was not mentioned in the TOR, has been discussed under the Communication and Infrastructure sub-group: we believe that this inclusion is outside the scope of such sub-group and hence beyond the ToR. More clarity on this would have ensured that relevant experts in cyber security could have participated to the Working Group activity.	We do need cyber security as provided for in CC/ECC.7.10.6. If it is covered in the UK NIS this should not cause an issue but we do need to make sure adequate protection of generation for cyber security purposes. We accept there may be issues for historic sites but for future sites we would expect this to be a requirement of the design process.	
NGET – Lewis Morgan	Do you support the proposed implementation approach?	We do not believe that the approach provides sufficient time to comply with the consequential industry and code changes required from the GC0156 modification.	The STC Mod is being progressed and will be presented to the STC Panel in February 2023 where we expect a workgroup to be formed.	

		It would be advantageous for other code changes, inclusive of the STCP modifications to run in parallel with this change. We believe this would enable us to better establish work scopes and funding requirements at the earliest opportunity.		
	The ESRS restoration target is expressed in terms of transmission demand rather than total demand (see Glossary and Definitions). Do you understand the implications of this, and are you happy with those implications?	The consultation refers regularly to Transmission Demand and Total Demand, neither of which are defined terms as per the Grid Code Glossary and Definitions. The Grid Code makes two definitions in relation to demand, these are as follows. • "National Demand" • "National Electricity Transmission Demand" -The consultation documentation does not provide clarity in its separation of these two definitions as it refers interchangeably to NETS Demand and National Demand.	OC9 and OC1.7 have been updated to address these issues. We now refer to National Demand in the Grid Code which is a defined term.	
	Do you think that there is a common understanding between stakeholders of the demand to be restored in GB required by ESRS?	The draft legal text of OC1 offers a clear and unambiguous definition of Electricity System Demand under ESRS. It is noted that NGESO currently publish daily forecast of Peak National Demand. The proposed changes to OC1 as part of this proposal will stipulate NGESO to provide continual provision of regional ESRS Demand figures which will ensure a common understanding. Further clarification is required to denote the regional categorisation, particularly where significant LV interconnections occurs at the boundaries of these regions.	We recognise this because as you pointed out, the entire network is interconnected, however, we will have- demand defined within regions. As part of the legal review sessions we have also take the opportunity to update OC1	

	Do you see any barriers for Network Operators and Users to deliver the changes proposed to implement the ESRS by December 2026?	We envisage considerable STCP modifications will be required to facilitate the changes; these have not yet been proposed. Some changes may be administrative and capable of implementation relatively quickly. Some areas of change may require extensive alterations to processes, systems and actual network configuration with a much longer implementation period and requirement for regulatory funding approval. For any modifications to the NETS, system access requirements must also be considered. Whilst we support testing and assurance activities, the required testing as outlined in OC5 must be balanced against the burden of workload, given the high number of participants.	Acknowledged – We will also be presenting the STC Mod to the STC Panel in February where we expect a workgroup to be established.	
	Do you agree that the draft legal text is appropriate and sufficient to implement GC0156? If not, please provide your suggestions?	The draft legal text has clear alignment with the ESRS license obligations but does not make clear the effective implementation date of 2026.	Thank you, further considerations are being given to this in the latest drafting.	
	Do you believe there should be further assurance activities in addition to those described in the proposed legal text within OC5? If yes, please state the activity and explain why?	Modifications to OC5 refers to computer simulations where network outages cannot be facilitated. We believe that sharing results of dynamic simulations for all LJRPs / DZRPs, prior to DLC or remote synchronisation testing would be a useful assurance activity.	We expect the relevant TO/DNO to be part of the simulation studies during the LJRP/DRZP development stage	
	Do you think the right requirements have been identified for Network Operators in terms of Network design and operational capability as summarised in the consultation document and annex and as detailed in the proposed legal text in CC/ECC.6.4.6.3b and OC9?	We have not provided a response based on the reasons outlined below. • We could not reference CC/ECC 6.4.6.3b in any of the annexes / draft legal text provided. • The updates to OC9 in respect to network design and operational capability requirements relate primarily to DRZPs. The impact and requirements of these are best assessed by the network operators. • The existing capabilities for transmission licensees remain largely unchanged in OC9. We	Apologies, the reference to CC/ECC 6.4.6.3b has been updated. Network Operators have also been involved in the drafting process.	

		expect the design / capability of transmission owners to be outlined in modifications to STCP06 at which point we can make further analysis.	As part of the STC Mod there will be a consequential change to STCP 06 – 1.	
	Are you aware that Anchor Plants may be expected to carry out a deadline line charge test and remote synchronisation test as described in OC5.7.2.2(h) / OC5.7.2.3(d)? If so, do you have a view on this test?	These tests will interrupt system access and increase outage requirements across network operators. An increased volume of testing will also require offline assessments and operational resources to facilitate. There should be compensation mechanisms in place for network operators and restoration providers to recover these costs. In the event of an LJRP it is NGESO who define the requirement to conduct testing requirements of Anchor / Top Up providers, for DRZPs this is directed by the network operator (See 5.7.2.2 H , 5.7.2.3 H). Given that ESO lead on procuring restoration services, should ESO maintain overall accountability for the compliance of restoration providers.	Assurance Tests are an integral part of the Restoration Service Provider's commercial contract. This will be for the Network Operators to asses under their price control. We believe ESRS assurance should be a joint effort	
	Do you have any views on how the requirements should be implemented into the Grid Code bearing in mind the requirements of the ESRS are not enforceable until 31 December 2026?	Due to the fragmented nature of the changes to the legal text we believe that the modification should reach approval stage but should not be implemented until closer to the ESRS date of December 2026.	Whilst we agree in principle, we are developing the legal text so it is clear what the obligations are and when they should apply. We are also working with the Tender team on this issue.	
ENWL – Tolulope Esan	Do you have any other comments?	This modification proposes some radical changes to the design and operation of distribution systems with embedded generation. There is as yet no operating experience for these proposals. It is highly likely that unforeseen issues will arise, and there should be the expectation that further detailed work and code modification will be required. The new definition of "GB Restoration Service Provider" should not be in the Grid Code since it is not used. It is used in the defence and	Agreed. The learning so far is from Distributed ReStart project. We are aware of this issue and it has been discussed with the	

		restoration plans – but it is (a) not needed and (b) not appropriate. If it has to be defined, then it should be defined only in the documents it is used in as: "A party who is a CUSC signatory or a party who is not a CUSC signatory but who has a contract with The Company to provide a Restoration Service"	Workgroup. It will be removed from the Grid Code drafting.	
	Do you see any barriers for Network Operators and Users to deliver the changes proposed to implement the ESRS by December 2026?	Key parts of the process are still only just emerging from trials stages. For example, the draft functional specification for a DRZC has only just been published, and the market, and DNO processes, for procuring has not yet been tested, let alone the engineering challenges of installing and commissioning, along with all the other network (and customers' plant) changes that are necessary. It will be important to keep an appropriate project management approach in place to ensure that NGESO's target for ESRS implementation by December 2026 can be met.	Acknowledged	
	Do you believe there are further changes to the network i.e., NETS and/or Distribution Network required to implement ESRS obligations?	There is still much uncertainty as to what will be required, especially for DRZCs – the creation of DRZCs is bound to require network changes in DNOs' systems. The extent of these will only be known when each DRZ is planned in detail.	Agreed. The learning so far is from Distributed ReStart project.	
	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	There probably remains confusion over the ESRS role of aggregators and other CUSC parties without physical assets. In light of the REV project undertaken by Sygensys for NGESO, there seems a lot more to do on the ESRS aspects of widely distributed resources.	The issue of aggregators will need to be picked up through Grid Code Mod GC0148 which has been sent back to the Grid Code Review Panel. The Grid Code Legal text (OC5) have been updated to address concerns around things like cold load pickups.	
	The GC0156 proposed solution 72 hrs resilience is expected to be applied retrospectively to existing CUSC parties. Do	We do not believe the case has been made to apply the GC0156 resilience requirements to CUSC parties without physical assets.	For GC0156 we would expect this to apply as an instruction from the ESO would be issued to	

	you agree with this retrospective application and if not, what is your rationale / view about this?		that party who would carry out the instruction. This would require them to have control of their assets. For aggregators we expect the issue to be picked up through GC0148.	
	Due to comments received from some Workgroup members on Appendix 9 (technical requirements associated with restoration services) of the ECC draft legal text, the ESO has proposed that a separate subgroup should be established under the umbrella of GC0156 to develop a set of technical requirements associated with restoration services for inclusion in the Relevant Electrical Standards which would include appropriate experts from across the industry. Do you believe this is an appropriate way forward if not why?	Yes – whilst we note that these requirements can be dealt with through the contracting process, we agree that they would be better being in a governed document. A RES would seem to fulfil that role. If such work is started, it would be very helpful for DNOs' understanding and preparedness if suitable DNO representatives could be included.	Acknowledged	
	Do you believe it is appropriate to have a mains independence minimum resilience period of 24 hours as required by the NCER or 72 hours as a general GB standard for existing black start purposes as proposed with the GC0156 solution for Grid Code parties, BM parties, VLPs and restoration service providers? Do you agree with a retrospective application of this and if not, what is your suggestion / views about this?	For the present it is inappropriate to include parties without physical plant. We would expect much development in this space in the coming years	See above response.	
	Do you have any views on how the requirements should be implemented into the Grid Code bearing in mind the requirements of the ESRS are not enforceable until 31 December 2026?	Most of the requirements only become requirements on the award of contracts – so they do not need specific introduction timelines. The 72-hour resilience issues are retrospective – so there needs to be a grace period for non-compliant installations to become compliant.	We do not aim to award contracts to all generators on the network. RSPs will have commercial contracts with associated implementation dates.	
Scottish Power Renewables – Priyanka	Do you believe that a cost benefit analysis should be undertaken by the Workgroup	SPR believe a cost benefit analysis will be necessary to assess the impact of standardised requirements across regions vs ESRS tender and	Cost Benefit Analysis has been carried out by Ofgem.	

Mohapatra/Ross Strachan	and if yes what factors should be considered?	market requirements being derived through regional studies and study of capabilities of types of generators based in different LJRPs and DRZPs. We firmly believe that this study will highlight that NGESO's current one size fits all approach will have huge cost burdens on GB customers and will not guarantee system restoration in the case of a national power outage. CBA should also include cost to generators in designing or retrofitting plant for restoration services. The regional requirements for system restoration vary significantly and lack of system studies and/or understanding of the types of generators connected will lead to procurement of services which are not fit for purpose.	We do not intend to procure services that are not fit for purpose. Our procurement process assesses the network needs.	
	Do you believe that parties obligated by GC0156 should have a cost recovery mechanism in place?	Yes, beyond the original Grid Code, CUSC and distribution code obligations, any additional obligations placed through GC0156 should have a cost recovery mechanism in place. There also need to be additional market incentives to encourage more generators to participate in ESRS service.	Acknowledged	
	Do you think that the proposals are sufficient and cost effective to ensure that NGESO can meet its ESRS licence obligations?	SPR believe that although the proposals made under GC0156 cover significant grounds at the outset of implementation of GC0156, we do not believe that they are adequate for full implementation of the ESRS by 2026. As discussed above, we firmly believe there will be grid code changes required to distinguish between regional requirements and various capabilities of connected generation.	Acknowledged	
	The ESRS restoration target is expressed in terms of transmission demand rather than total demand (see Glossary and Definitions). Do you understand the implications of this, and are you happy with those implications?	SPR would like to share the concerns of various stakeholders in the working group that transmission demand no longer represents the true demand of the system, as there is significant embedded generation and demand in the network. Also, the current definition may leave vulnerable consumers in various parts of the network with lower demand in outage for several	BEIS confirmed at the GC0156 WG meeting in August 2022 that the intent of the ESRS standard is to ensure that all the demand on the network is restored as soon as possible.	

		days although all transmission demand will be met in principle. We urge NG ESO to reconsider this definition and as per our previous comments introduce the concept of regional and in case of larger regions localised demand which will be more appropriate and will result in more homogenous restoration, as compared to just meeting a percentage figure across the NETS.	 We are unable to change the directive from BEIS	
	Do you see any barriers for Network Operators and Users to deliver the changes proposed to implement the ESRS by December 2026?	We believe that a greater degree of co-ordination is required between generators, ESO, Tos, DNOs and OFTOs. Especially with the changing landscape of system restoration and type of restoration providers detailed regional studies and plans need to be developed to minimise risks and ensure Tos, DNOs and OFTOs understand the differences in response between various connected assets during restoration and prepare for adequate contingencies and resilience. This includes but not limited to resilient and secure communication infrastructure to individual restoration providers, suitability of transmission and distribution network equipment to withstand transient conditions, trained personnel to understand differences in restoration response from a converter-based generation vs synchronous generation. We believe significant work, studies and training is required in close collaboration with generators to achieve a realistic restoration sequence in each LJRP and DRZP. We stress that detailed studies and practical experience is crucial as the restoration landscape will be significantly different to that in the past.	Acknowledged LJRPs and DRZPs are jointly developed with the RSP and relevant TO/DNO. Detailed studies will be carried out where relevant and include all parties who are signatories to those plans~~.~~	
	The Annex (pages 29 – 32) in the Future Networks subgroup report covers 2 scenarios where site supplies are lost up to 72 hours. Which of these 2 scenarios is the	☒Scenario 1 ☒Scenario 2 SPR believe this question is not framed correctly. Scenarios 1 and 2 are both realistic and refer to	Acknowledged	

	most realistic? (The full details of these scenarios can be found on pages 29 – 34 of the Future Networks subgroup report in Annex 4)	two different situations. One dealing with a simple trip of the windfarm, whereas Scenario 2 is a more detailed description of a national power outage situation and the logistical and practical challenges that will be encountered. We believe the points and questions raised in Scenario 2 should be taken into careful consideration by NGESO to ensure contingencies, assurance processes and plans are in place to address most eventualities as highlighted in Scenario 2.		
	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	Fundamentally we agree with the need to maintain 72 hours resilience at sites. However, we strongly disagree with the position that it needs to apply to all transmission connected or large embedded sites, especially in terms of retrospectivity. As per our response to Q11, we believe NGESO should perform regional studies to determine which plants need to come back up to meet regional demand and only those plants should have 72hr resilience. Otherwise, the cost to consumers in terms of implementation of 72hr resilience by all CUSC parties will be unjustifiable, given there is no studies or cost assessment to justify this requirement. While specifically referring to the requirement, “the generating site or storage site or interconnector site needs to either have or be capable of mobilising all required personnel and resources to site within the required timescales whilst all external electricity supplies are dead. This capability to start must be maintained for a period of at least 72 hours from the failure of the external electricity supplies.” Given the large volume of connected generators on the network, we believe it is practically impossible to mobilise staff to sites given the significant logistical challenges that will ensure following a national power outage, as highlighted in detail in Scenario 2 of Q13	We have updated the legal text for this requirement as appropriate and referred to a derogation process in CC/ECC.7.11.2 The requirement applies to all types of sites and parties. A derogation process does exist as per CC/ECC.7.11.2	

		Also, no changes should have been done to the Connection Conditions (CC) of the grid code as this implies retrospective requirements for all parties already involved in restoration.	We are not anticipating any retrospective changes to plants that are currently Restoration Service Providers. The legal drafting has also been updated to reflect the derogation process.	
	The GC0156 proposed solution 72 hrs resilience is expected to be applied retrospectively to existing CUSC parties. Do you agree with this retrospective application and if not, what is your rationale / view about this?	SPR believe that the 72hrs resilience retrospectivity as described in workgroup report section "All Generators required to provide Mandatory Services" will first require a cost recovery mechanism, and second may well prove challenging to implement at certain sites based on their remoteness and physical and communication network accessibility and potentially adding cost to install new plant. NGESO should perform a cost benefit analysis to determine if this is actually required at all sites or certain key sites within a LJRP or DRZP to maintain a stable island condition and meeting the required percentage of demand connection.	CMP398 is addressing the cost recovery mechanism. We have updated the legal text for this requirement as appropriate LJRPs and DRZPs only cover the respective Restoration Service Provider and not other generating sites.	
	Do you agree that the draft legal text is appropriate and sufficient to implement GC0156? If not please provide your suggestions?	SPR challenges that NGESO's draft legal text for GC0156 differs in some significant ways to the way current ESRS tenders are being executed. For example, the current ESRS tenders still refer to primary restoration service providers. However, there is no such term in the draft legal text. The obligations for a primary restoration service provider are hence not defined in the grid code. Similarly, it is not clear how the anchor generator in grid code which aims to achieve parity across all transmission and distribution network connected generators is reflected in the technical requirements of ESRS tenders.	We acknowledge that this is a transitional issue that impacts all existing Restoration Service Providers, as they all are referred to as BlackStart Providers in their contracts. The primary RSP is now referred to as Anchor or Top Up RSP. The naming convention does not affect the requirements. Sone further work is required with the tender team to align the Grid Code drafting with future tender documents.	

		We believe as stated before that in order to ensure implement GC0156 this discrepancy should be addresses with utmost urgency. In addition, clause *"ECC.6.3.5.7 Generators in respect of OTSDUW Plant and Apparatus with a Completion Date on or after XXXX shall ensure their Plant and Apparatus is designed to include a System Restoration capability which would include but shall not be limited to the requirements of ECC.7.10 and ECC.7.11*". is making the requirements mandatory and this could affect project in construction as these projects can be caught by the proposed modifications and affect CfD projects potentially affecting the end user.	We have now introduced an update to the legal text (CC/ECC.7.11.2) to refer to the derogation process.	
	Are there any barriers to new entrants to provide restoration services that are not covered in the GC0156 legal drafting?	SPR believe there are still significant barriers to new entrants to provide restoration services. The barriers though posed through the ESRS tenders, do also put the burden on GC0156 to create alignment, as a fair tender process cannot be performed unless the grid code obligations are clear to all tender participants. We would like to highlight that neither GC0156 nor the ESRS tenders differentiate between, the different technical capabilities of converter based and synchronous generation for provision of restoration services. The inertia, SCL and reactive power requirements for "full restoration service" in ESRS tenders are based on capabilities of a synchronous generator not that of a wind generator and do not take in consideration the real values required for restoration of specific zones. The workgroup has this issue in numerous occasions to NG ESO.	The tender team have confirmed significant interest in the tenders launched. We aim to have a level playing field, as such ~~,~~ we have amended our technical requirements to allow for diverse technologies to participate in providing restoration service, and the feedback has been very positive. The evidence we have were provided by generators as part of	

		If NG ESO believes that is not the case, we kindly request to see evidence in the form of studies, industry feedback etc, that shows the following: • that any wind generator regardless of its size can meet the inertia, SCL and reactive power requirements with its existing capabilities and installed plant, • and any wind generator of smaller size can meet the above-mentioned requirements. We have proof that wind generator without meeting those large inertia, SCL and reactive power requirements can still restore the grid. Therefore, SPR is of the opinion that the current requirements pose significant barriers for wind and other converter-based generators. In order to address this within the Grid Code, SPR proposes that there is a separate anchor generator definition for converter-based technologies within GC0156 to allow for converter-based technologies to better align technical requirements within various ESRS tenders.	their tender assessment. This information is confidential. We aim to have a level playing field for all generators.	
	Do you believe there should be further assurance activities in addition to those described in the proposed legal text within OC5? If yes, please state the activity and explain why?	SPR believe that NGESO should perform additional assurance activities to ensure that the regional requirements in a LJRP and DRZP have been identified and the capabilities of the connected anchor and top-up generators are utilised in an optimal way. It is imperative that NGESO acknowledges the regional differences in system requirements and the need to better understand multiple generator type capabilities especially those of converter-based generation. Hence, we propose 3 additional requirements to be included in the assurance activities	The ESO procures services based on regional requirements This done when the LJRPs and DRZPs are developed to ensure they can actually initiate the	

		1. Regional power system studies to define regional ESRS requirements 2. Power system simulation with both RMS and EMT models (ref GC0141) of LJRPs and DRZPs to ensure successful restoration can be performed with the contracted anchor and top-up service providers taking into account various fault conditions	restoration process and would involve all signatories to the Restoration Plans.	
	Do you think the right requirements have been identified for Network Operators in terms of Network design and operational capability as summarised in the consultation document and annex and as detailed in the proposed legal text in CC/ECC.6.4.6.3b and OC9?	SPR would like to add that as per this requirement CAPEX and OPEX costs for any new communication data link, monitoring and operational metering requirement on the company to enable ESRS service should be recoverable via a suitable cost recovery mechanism.	CMP398 is addressing this	
	Due to comments received from some Workgroup members on Appendix 9 (technical requirements associated with restoration services) of the ECC draft legal text, the ESO has proposed that a separate subgroup should be established under the umbrella of GC0156 to develop a set of technical requirements associated with restoration services for inclusion in the Relevant Electrical Standards which would include appropriate experts from across the industry. Do you believe this is an appropriate way forward if not why?	We fully support establishing GC0156 subgroup, to address these concerns and the need for regional studies to establish realistic technical requirements for restoration service providers.	Acknowledged	
	Are you aware that Anchor Plants may be expected to carry out a deadline line charge test and remote synchronisation test as described in OC5.7.2.2(h) / OC5.7.2.3(d)? If so, do you have a view on this test?	Although SPR considers those tests are adequate, NGESO need to consider how synchronization will be achieved with a loaded Restoration provider i.e., requirement for synchroscopes or similar equipment. Who will be responsible for owning this equipment? In addition, for renewable restoration supplier there need to be a clear guidance on how the tests are expected to be carried out.	The ESO will coordinate synchronisation via the breakers or PMU's. The assets are owned by the TOs. Acknowledged	
	The distributed restart legal text has been drafted on the basis that ESO will lead on	We believe DNOs and TOs should play an active part in the restoration process, especially in	TOs and DNOs play an active role in developing the LJRPs and	

	the procurement of restoration services. Do you think this should move to DNO led in future? If yes, please explain why	performing regional restoration studies and establishing regional restoration requirements. They should also provide input into the technical feasibility of restoration from various connected generators; however, we believe the overall process should be NG ESO led.	DRZPs, which sometimes includes studies to identify any further network requirements.	
	The distributed restart legal text has been drafted on the basis that: i) there will be a connection agreement with the DNO that binds an embedded restoration service provider to the Distribution Code and ii) a tripartite agreement that binds the embedded restoration service provider to the relevant parts of the Grid and Distribution Codes. Do you see any difficulties with this proposed contractual arrangement?	As discussed in our response Q14 and Q15. SPR believe that the 72hrs resilience retrospectivity as described in workgroup report section "All Generators required to provide Mandatory Services" will require a cost recovery mechanism and may well prove challenging to implement at certain sites based on their remoteness and physical and communication network accessibility. We strongly disagree the position that it needs to apply to all transmission connected or large embedded sites, especially in terms of retrospectivity. We believe NGESO should perform regional studies to determine which plants need to come back up to meet regional demand and only those plants should have 72hr resilience. Otherwise, the cost to consumers in terms of implementation of 72hr resilience by all CUSC parties will be unjustifiable, given there is no studies or cost assessment to justify this requirement.	CMP398 is addressing this. We have updated the legal text for this requirement as appropriate This is part of the internal review and selection process which has to remain confidential. However once parties have been selected then the studies will be run as part of the LJRP or DRZP process.	
	Do you believe it is appropriate to have a mains independence minimum resilience period of 24 hours as required by the NCER or 72 hours as a general GB standard for existing black start purposes as proposed with the GC0156 solution for Grid Code parties, BM parties, VLPs and restoration service providers?	SPR strongly disagree with the retrospective application of this requirement as this could represent the installation of additional plant at an additional cost which could affect cost to the consumers.	Acknowledged – Note also the updates to CC/ECC.7.11.2 to reflect the derogation process.	
	Do you have any views on how the requirements should be implemented into the Grid Code bearing in mind the	The requirements should be implemented within a grace period similarly done for the inclusion of RfG requirements back in 2016/2017 as this will allow existing projects under construction	Acknowledged – we also note the intention to update the code drafting to reflect the implementation process.	

	requirements of the ESRS are not enforceable until 31 December 2026?	(particularly offshore wind and onshore) to decide if they can participate in tender to provide restoration services. SPR would like to highlight that once the stage of design freeze is reached in any project any subsequent changes will be costly to the developer and hence the consumer.		
	Do you agree with Ofgem's proposed approach to the DNO ESR re-opener?	SPR believe it is necessary to have this reopener to allow DNOs to plan and implement additional infrastructure to meet the ESRS requirements.	Acknowledged	
Drax – Alastair Frew	Do you have any other comments?	This proposal currently lacks sufficient detail. There is no assessment or data provided by the proposer as to the gap between current capability and the required future capability. Also, there is no assessment of what contribution the mandatory additional measures on generators and others is expected to provide towards meeting the standard. This lack of transparent information limits assessment as to the cost effectiveness of the measures or discussion of alternative options that may achieve the same impact for less consumer cost	Information has been provided to the GC0156 WG that shows the current capability of 32hrs to restore 60% demand based on the existing network and the inclusion of the 72hrs requirement. The target is the ESRS standard.	
	Do you believe that a cost benefit analysis should be undertaken by the Workgroup and if yes what factors should be considered?	A CBA should be conducted to ensure the additional resilience requirements for generators and other parties connected to the transmission and distribution networks are the most appropriate and cost-effective arrangement for consumers to deliver the necessary additional capability. We note that the intention is that any costs will be recovered through BSUoS charges to consumers CMP398 in accordance with the policy direction from BEIS. With reference to GC0156 BEIS and the ESO undertook an RFI to establish the rough order of magnitude of costs. We note that the range of additional costs presented by the ESO from the RFI they conducted with BEIS was in the range of	Cost Benefit Analysis has been carried out by Ofgem. Acknowledged	

		£500/MW to £22000 / MW. Examining onshore wind, the range was up to an estimated £2200/ MW. Although this information does not constitute a CBA it is useful in giving a general indication of the cost impact based on the limited information provided in the RFI. We do not believe the RFI made any distinction between capital and ongoing costs. In our opinion a clear CBA should be undertaken that examines the benefit and costs to consumers of the proposed changes and other options available to the ESO to fulfil its licence obligations		
	Do you believe that parties obligated by GC0156 should have a cost recovery mechanism in place?	We think it is right that any additional costs on generators proposed as a consequence of the ESO's licence obligation to meet the ESRS should be socialised. However, this needs to be done in a cost-effective manner to ensure that consumers are receiving value for money. For instance, it may be cheaper for the ESO to purchase additional specific capability through the tender process (including from BTM and DSR V2G aggregators etc) than to retrofit with new capability the entire portfolio of distributed generation.	Acknowledged	
	Do you think that the proposals are sufficient and cost effective to ensure that NGESO can meet its ESRS licence obligations?	No. As highlighted throughout this response there has been no evidence presented as to the sufficiency of the measures or the cost effectiveness in comparison with other measures the ESO may be able to take.	Cost Benefit Analysis has been carried out by Ofgem.	
	Do you agree that all the costs associated with TO/DNO implementation of ESRS should be recovered through their respective price controls? If not, what funding mechanism do you favour?	We agree with the principle that all parties should be able to recover efficiently incurred costs. The price control process appears an appropriate mechanism for TO and DNO's as this is subject to industry and Ofgem scrutiny. The cost recovery proposals for other parties under CMP398 could be extended to encompass TO / DNO if this was judged to be the optimum method of recovery.	Acknowledged	
	he ESRS restoration target is expressed in terms of transmission demand rather than	There is not complete clarity amongst industry. We believe there may be a level of collective	Legal text has been drafted to clarify our interpretation	

	total demand (see Glossary and Definitions). Do you understand the implications of this, and are you happy with those implications?	understanding within the workgroup but do not believe the nuances of this are fully captured. The key element is clarity as to the ESO's obligations to achieve the standards set by BEIS. The publication of the order and related relevant correspondence between BEIS and the ESO may assist with wider understanding. The nuances of the standard and the ESO licence obligations need to be articulated by the ESO and BEIS more clearly to wider industry and consumers. Our understanding is that the standard is an outcome measure based on the prevailing forecast peak transmission demand that would have occurred but for the loss of electricity. The 60% and 100% measures are relative to that forecast peak transmission demand and not based on numbers of customers restored either on the transmission or distribution systems. Theoretically if one customer could consume 60 % of the forecast peak transmission demand, then restoration of that individual customer would satisfy the target. The process for calculating the proportion of restoration from each region has not been discussed in depth or the geographic boundaries of regions articulated within the workgroup report. The ESO should make available the direction letter and relevant correspondence that have shaped their obligation for workgroups and the code administrator consultation. The ESO could also hold webinars and use its communication outreach to ensure wider industry and customers understand that the standard is not based on restoration of individual connections but based on a changeable forecast of potential demand.	The technology and locational diversity workstream which included members from across the industry had visibility of the regions defined. The direction letter has been circulated to the GC0156 WG. The licence condition is also on Ofgem's website Special Conditions - ESO (ofgem.gov.uk) ESO held a webinar on 07 Dec 2022 to further explain the changes to the Grid Code as a result of ESRS to industry parties	

		We think there is undoubtedly more work by the ESO needed to clearly articulate the ESRS measures and to provide more analysis as to the range of scenarios the ESRS will and will not cover. It also needs to be clear what exemptions the ESO may rely on to relieve it of its obligations and what this would mean for achieving the restoration standards.	who are not members of the GC0156 WG. We are running our own internal studies coupled with Restoration Providers selected through the Tender process which will then be visible to the parties involved.	
	Do you see any barriers for Network Operators and Users to deliver the changes proposed to implement the ESRS by December 2026?	Most of the changes related to planning and execution of a restoration strategy between DNO TO and the ESO should be deliverable within the timescales as these are mainly procedural. For the proposed changes to connected assets there is a barrier in information. As there is no analysis that describes the gap in capability it is not yet possible to determine if the measures proposed in GC0156 will satisfy that capability gap, or how much capability each of the measures will deliver. The second barrier is funding of the proposed mandatory retrospective changes. This is being addressed and contingent upon a funding mechanism being approved through CMP398. Project delivery of mandatory changes may become constrained if there is uncertainty over funding arrangements, or if the technical requirements are altered at short notice.	Analysis carried out by ESO are confidential due to national security reasons. Agree Acknowledged	
	Do you believe there are further changes to the network i.e. NETS and/or Distribution Network required to implement ESRS obligations?	Possibly as it is not clear what foundation the plans have been made. There is a lack of information on the existing and the required capability and the assumptions used by the ESO. As an example, It is not clear that energising transformers, transmission and distribution	Further studies/assessments are carried out when the LJRP/DRZPs are developed.	

		circuits will not trip anchor generators. The Distributed Restart tests show that without mitigations like reduced voltages or point on wave switching the islands can collapse as the island grows by the addition of new sections. It is difficult to see how to assess these issues without actually doing tests on the network, but there are issues as to how far this can be taken without affecting customers. There is also an assumption that real customers can actually be used as load in the early stages of an LJRP we are not aware that this has actually ever been tested.		
	The Annex (pages 29 – 32) in the Future Networks subgroup report covers 2 scenarios where site supplies are lost up to 72 hours. Which of these 2 scenarios is the most realistic? (The full details of these scenarios can be found on pages 29 – 34 of the Future Networks subgroup report in Annex 4)	☒Scenario 1 ☒Scenario 2 The question is incorrect to imply that there is a choice between scenario one and two. Both scenarios are realistic and are illustrative of the implications of the control and return decisions that generators will have to assess before action to return to production. Both scenarios were written to illustrate different operating conditions and there is not a choice between them.	Acknowledged	
	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	In terms of retrospectively applying these requirements to existing parties who do not have these capacities this could be very difficult and expensive, with currently no way of refunding the costs to parties. It is not just funding technical solutions that need to be considered here. Staffing levels and locations have been adjusted and evolved to match current market conditions. There are now numerous parties that operate unstaffed sites, and organisations who sub-contract various activities to ensure efficient operation. To ensure that all sites have absolutely everyone needed to restart a de-energised site would be costly for consumers and given resource constraints (including technical) probably impossible nowadays.	We have updated the legal text for this requirement as appropriate CMP398 is addressing funding.	

	The GC0156 proposed solution 72 hrs resilience is expected to be applied retrospectively to existing CUSC parties. Do you agree with this retrospective application and if not, what is your rationale / view about this?	No. In the absence of any assessment of either the additional capability that '72hr resilience' will provide or the difference of the obligation applying to just new build or retrospectively then it is not possible to make a rational evidence-based decision on this.	Justification for the 72hrs resilience requirement has been provided to the GC0156 WG.	
	Do you believe that cyber security requirements in accordance with the NIS standard are sufficient and as referenced in the proposed Grid Code drafting (available in Annex 6)?	Whilst these appear to be adequate, there has to be more consideration of how all parties can implement these requirements and the timescales required to do so. If implemented without these considerations it is likely that consumer costs will be greater than need be.	Acknowledged	
	Do you agree that the draft legal text is appropriate and sufficient to implement GC0156? If not please provide your suggestions?	There are still areas which are not clear and there needs to be a fuller detailed description of the process. Also there needs to be more instructions aimed at parties who are just Users.	Detailed process for RSPs is developed in the LJRP/DRZPs.	
	Are there any barriers to new entrants to provide restoration services that are not covered in the GC0156 legal drafting?	Yes. One of the problems to a new entrant is there is no easy way to test their current capability to see what they can do. They are asked to commit to a tender process and the investment with the possibility at the end they are not successful and receive no recompense.	We assume that Plant owners will know the capability of their plants.	
	Do you believe there should be further assurance activities in addition to those described in the proposed legal text within OC5? If yes, please state the activity and explain why?	There are other areas of OC5 testing which also need discussed: 1) It would be helpful if it was clarified which sections of OC.5 apply to System Restoration, we don't think OC5.5 applies but if that is the case then the title of that section needs expanded to something like PROCEDURE FOR TESTING ROUTINE OPERATING CAPABILITIES 2) Similarly does OC5.6 apply and if not does a dispute resolution procedure need added to OC.5.7 3) Again, do not believe OC.5.4 applies. 4) Within OC.5.5.2 there is a section dealing with User requests for tests, but this does not appear anywhere in OC.5.7. So currently there is no method for a User to request to test their plant. 5) Within OC.5.5.3 it states "The User is responsible for carrying out the test on their	Following the legal review sessions the Grid Code text has been updated in this area.	

		Plant and retains the responsibility for the safety of personnel and their Plant during the test" there is not an equivalent section in OC.5.7. We believe that during System Restoration tests similar to Distributed Restart tests this is potential covered in a test contract which similarly seems to suggest the Generator is responsible for safety. Whilst saying that testing is the responsibly of the Generator is fine in terms of maintaining frequency and local voltage mostly limited to the Generators plant. However, during larger area tests, which may be required, once the generator is running and has done the initial local network energisation the generator then has no control over what equipment is being connected by the Network Operator and do not know or control remote voltages. We believe this needs to be fully discussed and added to the code. If cold start times become mandatory on restoration of electrical supplies to a site are there any plans to test to confirm compliance with this requirement?		
	Do you think the right requirements have been identified for Network Operators in terms of Network design and operational capability as summarised in the consultation document and annex and as detailed in the proposed legal text in CC/ECC.6.4.6.3b and OC9?	Some issues remain unclear. For instance, it's not clear how the network operator will assess the energisation and over-voltages caused by transformer energisations. Also, on a growing network with more than one generator there is a risk of potential steady state overvoltages being caused by a single generator tripping and the remaining generator not being able to hold the extremes of the network voltage down. Again, it is not clear how the Network Operator is considering or planning these issues, or what measures or actions it would take to resolve these.	Studies will be carried out when LJRPs/DRZPs are being developed to identify mitigations to energisation issues.	
	Due to comments received from some Workgroup members on Appendix 9 (technical requirements associated with	It is not clear why this has been proposed apart from moving from a transparent open governance model to a more closed one. Our	Acknowledged	

	restoration services) of the ECC draft legal text, the ESO has proposed that a separate subgroup should be established under the umbrella of GC0156 to develop a set of technical requirements associated with restoration services for inclusion in the Relevant Electrical Standards which would include appropriate experts from across the industry. Do you believe this is an appropriate way forward if not why?	view is that any changes should use appropriate codes that are governed through all parties' licences collectively.		
	Are you aware that Anchor Plants may be expected to carry out a deadline line charge test and remote synchronisation test as described in OC5.7.2.2(h) / OC5.7.2.3(d)? If so, do you have a view on this test?	The only way that anyone can confirm that anchor generator can energise the network is by testing, so this needs to be done. The problem is how is this going to be arranged and what is the extent of the network to be energised?. If you look at the distributed restart test reports it is quite clear the generator can energise the immediate local network, but the problems then occurred whilst the Network Operator then subsequently energised further lines and transformers (particularly transformers). Now a generator could pass very localised tests then during a real event suddenly find themselves energising conditions they have not been tested against, but it is difficult to see how large area test can be done, needs further consideration. In terms of remote synchronisation tests again these needs done, however there is a risk to the generator if Network Operator's equipment is faulty and there is a mal-synchronisation. The prime need for this test is for check the Network Operator has the facilities to know the frequency and voltage at the remote synchronisation location and can issue instructions to the generator to adjust frequency and voltage as they will only know the local frequency and voltage.	Potential Anchor generators provide studies to demonstrate their capability during the tender process. In addition, for successful Anchor plants, witnessed tests are carried out to demonstrate Anchor generator's capability. Acknowledged	
	The distributed restart legal text has been drafted on the basis that: i) there will be a connection agreement with the DNO that	Yes, there is the potential for confusion between parties and inconsistency. Also, the way it is being drafted it is not entirely clear what parts of the	We think this issue has been addressed in the legal review	

	binds an embedded restoration service provider to the Distribution Code and ii) a tripartite agreement that binds the embedded restoration service provider to the relevant parts of the Grid and Distribution Codes. Do you see any difficulties with this proposed contractual arrangement?	Grid Code apply to embedded Restoration Service Providers - does it all or is it only specific sections. There is also the EU Generator part again it's not clear if they are an EU generator in some of the OC5 test sections. It would be neater if the technical requirements for an embedded generator providing Restoration Services were in the Distribution code and only the OC 9 and BCs applied. It would be helpful if there was a more detailed description of how the distributed restart process will actually work.	sessions and the subsequent updates made.	
	Do you believe it is appropriate to have a mains independence minimum resilience period of 24 hours as required by the NCER or 72 hours as a general GB standard for existing black start purposes as proposed with the GC0156 solution for Grid Code parties, BM parties, VLPs and restoration service providers? Do you agree with a retrospective application of this and if not, what is your suggestion / views about this?	72 hours seems reasonable for all sites communications equipment. It also seems reasonable for all parties who wish to enter into contracts to provide Restoration Services. However, it does seem excessive to apply this to parties who are not going to get any recompense for providing this capability. In terms of retrospectively applying these requirements to existing parties who do not have these capacities we believe this could be very difficult and expensive with currently no way of refunding the costs. Staffing levels and locations have been adjusted and evolved to match current market conditions. There are now numerous unstaffed sites, organisations who sub-contract various activities to ensure efficient operation. To ensure that all sites have absolutely everyone needed to restart a deenergised site would be costly for consumers and given resource constraints probably impossible nowadays.	CMP398 is addressing funding for the 72hrs capability We have updated the legal text for this requirement as appropriate -see CC/ECC.7.11.2	
	As a stakeholder, are there any implications of the proposed future requirements which are not clear?	What are the penalties if as a general User with no Restoration Service Provider services if the start-up time submission in DRC Schedule 16 is not met in the event of a system shutdown?	Investigations will be carried out and, if found to be in breach, Ofgem will issue fines accordingly.	

		As highlighted in previous questions the need case has not been clearly demonstrated, there is no assessment of current and future capability requirements, no assessment of the capability improvement from the proposed changes and no CBA has been produced.	Cost Benefit Analysis has been carried out by Ofgem. ESRS is a License Obligation	
	Do you have any views on how the requirements should be implemented into the Grid Code bearing in mind the requirements of the ESRS are not enforceable until 31 December 2026?	If the changes only apply to commercially agreed requirements, then the requirements can be codeified and then only applied as parties get contracts. It's a lot more difficult to retrospectively apply them to all parties, one suggestion is to add all the parts into the code listing them in the general condition as only apply from 31 December 2026 but highlighting that text in say yellow or green as opposed to lots of foot notes, but that's difficult with the deletions	Acknowledged – We will updating the legal text to address the implementation issue.	
SP Energy Networks – Graeme Vincent	Do you have any other comments?	The proposals represent a step change in the way in which electricity restoration will be delivered and utilises tools and techniques which have not yet been deployed at an operational level or at scale. It is inevitable that some tweaking/changes will be required to the legal text as learning is gained through the deployment and development of Distributed Restoration Zone Plans (DZRP). We currently do not believe that the proposed Distributed Restoration Zone Control System Standard is sufficiently well developed to allow a Network Operator to be able to determine what is required and it is heavily biased towards the communications requirements rather that the requirements of the DRZC system itself	The legal text ~~are~~ is drafted to allow for flexibility and if changes are required in future, we will make the changes. The DRZC Standard has been updated and is subject to further review~~.~~	
	Do you believe that a cost benefit analysis should be undertaken by the Workgroup and if yes what factors should be considered?	The requirements arising from the new ESRS is a mandatory requirement and we believe that the costs associated with adopting (and implementing) the new standard will have previously been considered during its	Agree	

		development. The solutions developed through this modification have not (as yet) had any alternative solutions suggested and therefore it would be difficult to establish an appropriate counterfactual position. We acknowledge that costs will be incurred during the implementation, however, we expect the ESO to structure any procurement and Tender Assessment process in order to secure an appropriate level of capability to meet the ESRS requirements (both regionally and nationally) in the most cost-efficient manner taking into consideration not only the costs of the Restoration Service Providers but also of the Network Operators and Transmission Owners (if appropriate).	 The tender process is structured to meet network requirements in a cost-effective manner.	
	Do you think that the proposals are sufficient and cost effective to ensure that NGESO can meet its ESRS licence obligations?	It is still unclear how these proposals will actually be brought together in such a way as to ensure that the requirements of the ESRS are met and that this will be achieved in a sufficient and cost-effective manner. The lack of a clear and credible plan of how the demand in the various regions is to be met (80% within 24hours) and how these regions (or power islands) are then grown and then synchronised together to ensure that 100% of transmission level demand is restored gives rise to our concerns.	Our detailed analysis is confidential for national security reasons.	
	Do you agree that all the costs associated with TO/DNO implementation of ESRS should be recovered through their respective price controls? If not, what funding mechanism do you favour?	The cost recovery mechanism employed is via reopeners and allows for efficient expenditure to be recovered, it is therefore important to ensure that any of the obligations being placed on the TOs or DNOs are sufficiently well defined to avoid inefficient solutions being developed and the risk that these may not be funded. It is also important that the price controls recognise not only the capital expenditure elements but also the ongoing operational expenditure which arise from the obligations being placed upon these parties.	Ofgem has confirmed Reopeners for ESRS and would welcome funding discussions directly.	

	The ESRS restoration target is expressed in terms of transmission demand rather than total demand (see Glossary and Definitions). Do you understand the implications of this, and are you happy with those implications?	Whilst we as industry parties recognise the subtleties of this definition, we believe that those who are less involved may not fully understand the significant differences and the implications which arise. For example, it is important to understand that transmission demand does not cover all demand associated with customers and therefore not all customers may be restored within the 5 day period which may be envisaged from the text of the ESRS.	Acknowledged – We believe the Code Drafting has been updated to reflect this issue.	
	Do you see any barriers for Network Operators and Users to deliver the changes proposed to implement the ESRS by December 2026?	There is still a great deal of uncertainty around many of the new proposals which have not been deployed before and therefore there is the possibility of significant learning to be achieved across both Network Operators and Users during the transition from trials to business as usual. Some areas where we see potential issues are • Uncertainty around establishment of DZRPs and the number required to meet the ESRS requirements. • Lack of detail from NGESO on the overall plan to achieve ESRS • Distribution Restoration Zone Control Systems (DRZCS) – the specification has only just been published as part of this consultation and does not fully address all aspects of the control system. • Other Code modifications to ensure that ESRS can be achieved are still outstanding e.g. STC	Acknowledged	
	Do you believe there are further changes to the network i.e., NETS and/or Distribution Network required to implement ESRS obligations?	As previously mentioned, these proposals introduce new concepts such as the DRZP and new technologies such as the DRZCS. As these have not yet been proven within an operational environment there is still the high possibility that changes will be required. It should also be noted that the formation of a DZRP will be site and plant specific, so the exact details of what is required, including communications requirements between all parties within the	Acknowledged	

		DRZP, will only become clear once the associated restoration plan is developed in detail.		
	Do you think the right requirements have been identified for Network Operators in terms of Network design and operational capability as summarised in the consultation document and annex and as detailed in the proposed legal text in CC/ECC.6.4.6.3b and OC9?	We do not believe that there is sufficient clarity to allow network operators to fully understand the implications to their network in terms of design or operational capability. We note that the references to CC/ECC.6.4.6.3b are not valid and it should refer to CC.6.4.5.2 and ECC.6.4.6.2, however, our comments above still apply.	The DCode is being updated with clear requirements. The references in CC/ECC.6.4.6.3b are being corrected in the latest version of the legal drafting.	
	Due to comments received from some Workgroup members on Appendix 9 (technical requirements associated with restoration services) of the ECC draft legal text, the ESO has proposed that a separate subgroup should be established under the umbrella of GC0156 to develop a set of technical requirements associated with restoration services for inclusion in the Relevant Electrical Standards which would include appropriate experts from across the industry. Do you believe this is an appropriate way forward if not why?	We note that Appendix 9 has been removed from the draft legal text but believe it would be more appropriate for the required technical standards to be documented in one location rather than detailed within individual contracts as this should aid transparency and consistency in application. It would also ensure that a common set of terms, definitions and parameters are applied across GB	Acknowledged	
	Are you aware that Anchor Plants may be expected to carry out a deadline line charge test and remote synchronisation test as described in OC5.7.2.2(h) / OC5.7.2.3(d)? If so, do you have a view on this test?	Yes, we are aware of the requirement written into the draft legal text for this but as noted during the workgroup we are not convinced that potential anchor plants may fully understand what is fully involved in undertaking a deadline charge test nor what the implications are for network operators to undertake these on a routine basis (the number of tests required will vary depending on the number of anchor plants within a particular region) without putting customers at risk of interruption.	Acknowledged. The issue of customer disconnection during a test has been highlighted at workgroup meetings.	
	The distributed restart legal text has been drafted on the basis that ESO will lead on the procurement of restoration services. Do you think this should move to DNO led in future? If yes, please explain why	The ESO currently retains the licence obligation and the funding for ESRS related activities so it is only right that it retains the responsibility for procuring and funding the appropriate level of services so that it can satisfy its obligation and do this in the most cost-efficient manner taking into account the availability of resources across GB. It	Acknowledged	

		may be appropriate in time that some of the procurement activities move to the DNO, but it will still be important that a GB system wide approach is maintained to ensure that sufficient resources are procured on a geographic basis so that the ESRS can be met.		
	Do you believe it is appropriate to have a mains independence minimum resilience period of 24 hours as required by the NCER or 72 hours as a general GB standard for existing black start purposes as proposed with the GC0156 solution for Grid Code parties, BM parties, VLPs and restoration service providers? Do you agree with a retrospective application of this and if not, what is your suggestion / views about this?	Yes/No is not an appropriate response to this question. In order for GB to maximise the opportunity to achieve the timescales established in the ESRS we believe that 72 hours would be a more appropriate requirement. How this is applied to customers who have no physical assets and become Restoration Service Providers is worthy of further consideration.	Acknowledged. The issue of Aggregators is an issue raised as part of the workgroup but we also expect it to be discussed as part of Grid Code modification GC0148.	
	As a stakeholder, are there any implications of the proposed future requirements which are not clear?	It is still not clear how these individual solutions will be brought together to achieve the requirements of the ESRS and the some of the concepts are new and untried and it is therefore difficult to not say ‘yes’ to this. We have previously highlighted our concerns in relation to the DRZC system standard which we believe does not fully cover the requirements needed to provide the DNO with a functional specification which can be used to develop a DRZC system.	The DRZC Standard is being updated to reflect the functional specifications. We will work with our internal colleagues and external stakeholders on the workgroup to develop this specification further.	
SSE Generation – Garth Graham	Do you support the proposed implementation approach?	Whilst in principle the change to the legal text can be introduced within ten working days, this does not reflect the practical time that will be required in order for obligated parties to transition to meet the new (GC0156 proposed) obligations. As we set out to BEIS and Ofgem[1] in the spring and summer of 2021, there are eight significant	The implementation date is being discussed with our legal team. The issue has also been discussed as part of the workgroup and post legal review sessions and future iterations of the code will address the implementation issue so it is clear what the obligations are and when they apply.	

		phases of work that will be required to be successfully undertaken before obligated parties will be in a position to implement any new obligations introduced by ESRS (as now set out here in GC0156). We summarised those eight significant phases in our recent CMP398 proposal 2: (i) design an on-site solution to that Grid Code approved obligation. (ii) (ii) identify costed solutions. (iii) seek and obtain the necessary planning permission(s) and associated other permits etc.; (iv) procure. (v) construct. (vi) (vi) commission; and (vii) (vii) train the necessary staff (as well as possibly recruit more staff). The 'missing' phase3 (that we identified in spring/summer 2021) came between (iii) and (iv) above which was namely to contract with the ESO as a Restoration Service Provider. The principle of this 'missing' phase is securing the necessary funding in order to be able to proceed from 'concept' (i-iii) to 'completion' (iv-vii) and remains relevant here – hence why we have raised CMP398 to seek to ensure there is a funding route in place for all GC0156 obligated parties. At that time (spring/summer 2021) we placed great emphasises on the point that obligated parties could only commence the first of the eight phases of significant work (in order to implement the requisite changes) once the Authority had approved the Code changes – it was for this reason that we advocated those code changes being raised, with alacrity, in the summer / early	As of late 2021, no legal text had been developed for Ofgem to approve. We had to engage with industry to develop the requirements to facilitate implementing ESRS	

		autumn of 2021 and treated as urgent (with a final Authority decision in late 2021 / early 2022) in order to allow obligated parties the maximum possible time to complete the eight phases of significant work ahead of December 2026. It is therefore of deep regret to us that circa 18 months will have been lost (from late 2021 / early 2022 to summer/autumn 2023) before the Authority decision on the Code change is forthcoming. This, in turn, will delay by circa 18 months the commencement of phase (i) (of the eight phases) which is needed to practical implement GC0156. The proposed implementation approach for GC0156 does not currently reflect the need for a transition phase; from when GC0156 is approved and 'implemented' ten working days later into the Grid Code; in order to allow for obligated parties to successfully complete the practical implementation (if that is now possible for December 2026) on the plant and apparatus.	Acknowledged As noted above, the drafting will be updated to reflect the implementation of the mod so it is clear what the obligations are and when they apply.	
	Do you believe that a cost benefit analysis should be undertaken by the Workgroup and if yes what factors should be considered?	Yes. We note the ESO's comments in the recent CMP398 workgroup meeting that a CBA was, in their view, required in order to understand what the cost implications, that arise from GC0156, are likely to be. At the very least the factors that the GC0156 CBA should consider are the following: (i) design an on-site solution to that Grid Code approved obligation. (ii) identify costed solutions. (iii) seek and obtain the necessary planning permission(s) and associated other permits etc. (iv) procure. (v) construct. (vi) commission.	Cost Benefit Analysis has been carried out by Ofgem.	

		(vii) train the necessary staff (as well as possibly recruit more staff); and the ongoing OPEX4 to maintain the obligated requirements. These costs, including the associated CAPEX , should form part of the GC0156 CBA as the costs only arise, for obligated parties, from GC0156 (and not, for example, from CMP398).		
	Do you believe that parties obligated by GC0156 should have a cost recovery mechanism in place?	The table at the bottom of page 6 / top of page 7 of the consultation document lists all the parties that will, to a greater or lesser extent, be obligated according to the proposed GC0156 legal text. It is an important principle of the GB regulatory framework; and in particular the Licencing regime as governed by Statute; that parties who face such obligations; and especially where that is to be applied, retrospectively, to existing plant; have the ability to recover those costs and not be placed at a commercial disadvantage. Furthermore, we are also mindful of the UK Government policy, when introducing the new 'Electricity System Restoration Standard' 6 (ESRS) in April 2021, which stated that: "All parties have been supportive of the establishment of a new Electricity System Restoration Standard, so long as it is implemented in a way which does not commercially disadvantage individual parties." "In the interim, Ofgem would put in place processes to monitor the implementation of the new Standard to ensure that the ESO remains on track with meeting this provision as part of its licence obligations and that any new services will not commercially disadvantage individual parties." [emphasis added]	We established a GC0156 Subgroup (Markets and Funding Mechanism) to review current processes and proposed processes to ensure that all parties have a funding mechanism where applicable. As specified in the subgroup report, it was recommended to raise a CUSC Mod to facilitate a funding mechanism for parties where it is deemed appropriate and does not already exist.	

		Of all the parties listed in the aforementioned table, all except non-contracted CUSC parties have such a funding route available to them (or have the option not to incur the obligation by, for example, not entering into a contract to do so). It was to address this inequitable exception that we raised CMP398 to ensure (like all other GC0156 obligated parties) that non-contracted CUSC parties have such a funding route available to them.	Noted – As part of the legal review sessions we have sought to clarify the obligations on Top Up Restoration Contractors and CUSC Parties. CC/ECC.7.11.2 has also been updated to refer to the derogation process.	
	The ESRS restoration target is expressed in terms of transmission demand rather than total demand (see Glossary and Definitions). Do you understand the implications of this, and are you happy with those implications?	Whilst we understand the implications of this proposed definition, we are very concerned about the implications that arise from it. Thus, whilst answering positive in the first part of the question we'd answer no to the second part. As we noted during the Workgroup deliberations on this matter, the effect of basing the restoration percentage upon the total demand on the transmission system alone and not the overall whole system7 will be that at certain times of the year (when demand on the distribution system, such as with low importing GSPs or net exporting GSPs for example, supresses 'total demand' if measured only as transmission demand) that a significant volume of overall demand on the GB whole system will not be taken into account when looking at the 24 hour target restoration quantum at the time of a total or partial shutdown. By way of illustration, it was pointed out to the Workgroup by a number of DNO representatives that it is increasingly common that there are periods of time in a year (and these are growing both in frequency and duration) where a DNO's total demand, as measured at the transmission system, is at or very near to zero MW.	Acknowledged – We believe this issue has been addressed through the legal review sessions and in particular the updates that have been made in OC9 and OC1.7.	

		In such a situation then the 24-hour 60% restoration target, and indeed the five days 100% target could potentially be ‘met’ at the moment of total or partial shutdown by virtue of there being no (zero MW) total demand (as defined). However, in such a situation there could be many hundreds of thousands of customers without power in the concerned DNO’s area and it would be inappropriate; based on a limited (transmission system) ‘total demand’ definition; to not proceed to take active steps to restore such (distribution based) demand. Therefore, it would be appropriate to consider measuring the 60% and 100% restoration targets based upon total demand on the whole system.		
	Do you see any barriers for Network Operators and Users to deliver the changes proposed to implement the ESRS by December 2026?	As we set out in our answer to Question 2 above, there are multiple phases to be undertaken, such as: (i) design an on-site solution to that Grid Code approved obligation. (ii) identify costed solutions. (iii) seek and obtain the necessary planning permission(s) and associated other permits etc. (iv) procure. (v) construct. (vi) commission. (vii) And (train the necessary staff (as well as possibly recruit more staff). Each of the above items, on their own (as well as collectively) is a barrier to the successful deliver (by Networks and Users) of the significant effort needed to be undertaken in order to meet the December 2026.	Acknowledged	

		Furthermore, many of these barriers are out with the direct or indirect control of the obligated party. For example, in terms of phase (iii), these are in the purview of external bodies (such as local councils and environmental bodies) who may be operating to different timescale to those needed, by the GC0156 obligated parties, in order to meet the December 2026 date. Another example concerns the procurement phase (iv) where multiple GB obligated parties will, at broadly the same time, be seeking, potentially from a small pool of providers / staff, a very specialist service / capability. Accordingly, it is distinctly possible (probable?) that these barriers will impede the overall delivery, by all parties collectively, of what's needed by the December 2026 deadline (which was why, in the spring/summer of 2021, we flagged these timing / delivery concerns).		
	The Annex (pages 29 – 32) in the Future Networks subgroup report covers 2 scenarios where site supplies are lost up to 72 hours. Which of these 2 scenarios is the	☐Scenario 1 ☒Scenario 2 In our view it is very clear that in the event of a Total Shutdown that Scenario 2 will be realistic (and Scenario 1 will not be realistic). Whilst it is dependent upon the depth of the geographic (and electrical) area affected in a Partial Shutdown, it seems highly likely that Scenario 2 will also be realistic (and Scenario 1 less realistic) in a Partial Shutdown. Furthermore, (as with question 12 above8) in considering the answers from consultation respondents to this question it is important that the Workgroup takes into consideration whether the respondent is an operator (or not) of plant	Acknowledged	

		that would be affected by the Scenario 1 / Scenario 2 situations. For the avoidance of doubt, we are clearly a major GB (and non-GB) operator of generation plant that would be affected by the Scenario 1 / Scenario 2 situations.		
	What are your views on the scope of the parties being impacted by the mandatory changes proposed as part of GC0156?	We have considered the analysis of the parties set out on pages 10-12 of the consultation document. Accordingly, in terms of non-network parties, it is our understanding that the proposed GC0156 obligations will be applied to all new and existing: (a) CUSC contracted parties, including generators, storage, pump storage and interconnectors; and (b) All BM Participants, including generators, Suppliers, Virtual Lead Parties (VLPs) and Aggregators. For the avoidance of doubt, as neither Anchor or Top Up is mandatory (it being a voluntary service that a party can choose, if they wish, to participate in) those providers are not relevant in terms of this question.	Acknowledged	
	The GC0156 proposed solution 72 hrs resilience is expected to be applied retrospectively to existing CUSC parties. Do you agree with this retrospective application and if not, what is your rationale / view about this?	No, we do not agree with the proposed retrospective application to all plant irrespective of its technology type, fuel, size or age. Some of our generation plant was connected to the transmission system over 90 years ago and as the costing analysis gathered by the ESO10 (and, bizarrely, not included in the consultation) shows some of these assets (according to that ESO analysis) are the most impacted, in terms of cost, whereas the volume of associated generation is often very small. In this regard we note that the ESO's proposed approach could well be discriminatory in requiring such plant to meet the 72 hours (non-	We have updated the legal text (CC/ECC.7.11.2) for this requirement as appropriate	

		communications) resilience when similar (or indeed larger) sized plant elsewhere in GB are not so obligated.		
	Are there any barriers to new entrants to provide restoration services that are not covered in the GC0156 legal drafting?	This question appears to centre around the comments at the bottom of page 12 / top of page 13 and seems to suppose that requiring parties that operate in the market to comply with the same obligations amounts to a barrier and not, in fact, a level playing field. According to the ESO it is a necessity, from December 2026 onwards, to place obligations on both new and existing electrical energy providers in order to meet the 24-hour (60%) and five-day (100%) restoration targets. Looking ahead, to December 2026 and, more importantly, beyond, it is likely that a significant, and growing, proportion of the available electrical energy will be provided by parties that are today (in 2022) considered to be 'new entrants' but who will, by that future date, not be so. There is a danger, in the medium to long term, that if these 'new entrants' (in 2022) are exempt from the GC0156 obligations that this will impede the meeting of the ESRS obligations from 2026 and that, over time this detriment will grow. Given the above, the relevant point to consider is: '*if we are to embark upon this obligation (in order to meet and maintain the ESRS in the future) is it better we do so now, when there are few parties / assets concerned, so that new assets are complaint when they come along or do we ignore them (now) until such time as they become impossible to ignore (but the cost and impact upon them of retrospectively changing is substantially more than if they had been designed*	The legal text has not been drafted to exempt new entrants from the GC0156 obligations.	

		and operated from the start of their operational life in order to meet the ESRS needs)'?		
	Do you believe there should be further assurance activities in addition to those described in the proposed legal text within OC5? If yes, please state the activity and explain why?	It is very important that the assurance activities demonstrate compliance by all parties including, especially, the ESO. It is not clear from the proposed legal text what the assurance activities; to demonstrate that the ESO itself is able to undertake what it itself is obliged to do to meet the GC0156 (and ESRS); are.	The assurance activities definitely include the ESO. In addition, the ESO has a Licence Obligation to annually provide an Assurance Framework to Ofgem.	
	Due to comments received from some Workgroup members on Appendix 9 (technical requirements associated with restoration services) of the ECC draft legal text, the ESO has proposed that a separate subgroup should be established under the umbrella of GC0156 to develop a set of technical requirements associated with restoration services for inclusion in the Relevant Electrical Standards which would include appropriate experts from across the industry. Do you believe this is an appropriate way forward if not why?	We agree that a separate group, involving appropriate experts from across the industry, should be established to develop a set of technical requirements associated with restoration services: however, in our view this single (GB) set of technical requirements should be included within the Grid Code and subject to open governance and not be included in the Relevant Electrical Standards.	Acknowledged	
	Are you aware that Anchor Plants may be expected to carry out a deadline line charge test and remote synchronisation test as described in OC5.7.2.2(h) / OC5.7.2.3(d)? If so, do you have a view on this test?	It is a necessity as we understand it for this capability to be provided by Anchor Plant if any Top-Up Provider is to perform their (subsequent) contracted service and therefore, such testing would seem to be a pre-requisite for contracted Anchor Plant.	Acknowledged	
	The distributed restart legal text has been drafted on the basis that ESO will lead on the procurement of restoration services. Do you think this should move to DNO led in future? If yes, please explain why	It is very important, from a providers' perspective, that there is a single party (a) to whom they are contracted to, and (b) from whom they take instruction(s).	Acknowledged. The general approach as codified is that any party subject to an LJRP will be under the instruction of the ESO or TO in Scotland and in the case of a DRZP will be under the	

		There is a serious concern, as we understand it, expressed at the Workgroup that a provider might be subject to multiple instructions from either the ESO or DNO which brings with it the risk of those instructions being, from the point of view of the provider, in conflict with each other (as in the provider cannot comply with both instructions – one from the ESO and one from the DNO – at the same time).	instruction of a Network Operator.	
	The distributed restart legal text has been drafted on the basis that: i) there will be a connection agreement with the DNO that binds an embedded restoration service provider to the Distribution Code and ii) a tripartite agreement that binds the embedded restoration service provider to the relevant parts of the Grid and Distribution Codes. Do you see any difficulties with this proposed contractual arrangement?	As we noted in our answer to question 23 above, it is very important, from a providers' perspective, that there is a single party (a) to whom they are contracted to, and (b) from whom they take instruction(s). There is a serious concern, as we understand it, expressed at the Workgroup that a provider might be subject to multiple instructions from either the ESO or DNO which brings with it the risk of those instructions being, from the point of view of the provider, in conflict with each other (as in the provider cannot comply with both instructions – one from the ESO and one from the DNO – at the same time)	Acknowledged – see above.	
	Do you believe it is appropriate to have a mains independence minimum resilience period of 24 hours as required by the NCER or 72 hours as a general GB standard for existing black start purposes as proposed with the GC0156 solution for Grid Code parties, BM parties, VLPs and restoration service providers? Do you agree with a retrospective application of this and if not, what is your suggestion / views about this?	As we have set out in our answer to questions 15 and 18 above, we do not believe that retrospective application (especially in the absence of any cost recovery mechanism) is appropriate as it clearly breaches UK Government policy, when introducing the new 'Electricity System Restoration Standard' 12 (ESRS) in April 2021, which stated that: *"All parties have been supportive of the establishment of a new Electricity System Restoration Standard, so long as it is implemented in a way which does not commercially disadvantage individual parties."*	CMP398 is addressing funding	

		"In the interim, Ofgem would put in place processes to monitor the implementation of the new Standard to ensure that the ESO remains on track with meeting this provision as part of its licence obligations and that any new services will not commercially disadvantage individual parties." [emphasis added]		
	As a stakeholder, are there any implications of the proposed future requirements which are not clear	Yes, for the reasons the ESO and the Workgroup noted, in terms of question 21 above: absent seeing the details of the (as yet to be developed) set of technical requirements the only logical conclusion is that the proposed future requirements are not clear at this time.	Acknowledged	
	Do you have any views on how the requirements should be implemented into the Grid Code bearing in mind the requirements of the ESRS are not enforceable until 31 December 2026?	As we set out in our response to question 2 ('implementation approach') above there is a need for a transition period (to reflect the undertaking of the eight phases of significant works listed) as well as a need to reflect what happens if it is not technically possible to retrospectively change a plant which is, in some cases, over 90 years old to meet the new requirements.	Acknowledged – As noted above we have updated the legal text to refer to a derogation process (CC/ECC.7.11.2). We also note that the Code will be updated to reflect the implementation process.	
Uniper – Sean Gauton	Do you believe that parties obligated by GC0156 should have a cost recovery mechanism in place?	All parties which have requirements applied retrospectively by GC0156 should have a mechanism in place to recover costs. This is essential for requirements which are imposed retrospectively. Post implementation of the proposed modification there should be a cutoff date after which parties seeking connection to the network must meet GC0156 requirements at their own cost.	CMP398 is addressing funding	
	The Annex (pages 29 – 32) in the Future Networks subgroup report covers 2 scenarios where site supplies are lost up to 72 hours. Which of these 2 scenarios is the most realistic? (The full details of these scenarios can be found on pages 29 – 34 of	Scenario 2 appears to be a considered description of the situation that is likely to occur following electricity system collapse. The questions posed are realistic and practical. The issues are genuine and present real barriers to achieving 72-hour resilience.	Acknowledged	

	the Future Networks subgroup report in Annex 4)			
	The GC0156 proposed solution 72 hrs. resilience is expected to be applied retrospectively to existing CUSC parties. Do you agree with this retrospective application and if not, what is your rationale / view about this?	It is clear that the ESO should take action to enable it to meet its ESRS Licence condition. To achieve this, it is logical that existing CUSC parties will be needed to act and deliver the required system restoration. The ESO has not presented any work to establish whether the new restoration standard could or could not be met without retrospective application of a mandatory resilience standard. If a resilience requirement is applied retrospectively then a cost recovery mechanism should be put in place for affected parties, as mentioned in our response to question 6.	Justification for the 72Hrs resilience requirement has since been presented to the GC0156 WG. CMP398 is addressing funding	
	As a stakeholder, are there any implications of the proposed future requirements which are not clear?	There are many implications of the proposed future requirements which are not clear. The ESO has set out a framework approach to implementation but the lack of detail, which may not emerge until specific Local Joint Restoration Plans and Distributed Restoration Zone Plans are drawn up, means that it is difficult for affected parties to fully understand what will be required. For example, if all generators are mandated to have 72-hour resilience and be capable of operating in island mode, what will be the difference between generators which are contracted to be top up restoration service providers and generators which are mandated to be available for restoration?	Restoration Service Providers have further contractual obligations to meet. We are updating the legal text to change Restoration Service Provider to Restoration Contractor. We are also updating the legal text to clarify the differences between Top Up Restoration Contractors and CUSC Parties as discussed at the legal review sessions.	