DRAI Modification to Clause CC13.1 on Maximum Down Time

SONI Grid Code Modification Consultation

Consultation Paper

21 December 2021

1. Introduction

1.1 SONI is required to consult on modifications to the SONI Grid Code. The process is set out in the Grid Code constitution, General Conditions section of the Code and in our TSO licence. This is a multi-stage process, whereby the proposer presents to the Grid Code Review Panel, then SONI undertake a wider consultation, and finally submit a report to the Utility Regulator, who will make a decision and direct the modification[s] that are to be made [if any].

1.2 DRAI presented the modification for discussion at the Joint Grid Code Review Panel [JGCRP] on 19th July and on 2nd November 2021 via teleconference/video conference. Following the feedback from the panel at the 02nd November meeting, SONI is obligated to consult more widely on this modification.

1.3 We are now presenting this proposed modification for wider consultation with all affected parties.

1.4 The proposed amended texts of the Grid Code, with both clean and redlined versions of each relevant section showing all the changes made to the existing version of the Grid Code, will be published on SONI's website. This consultation paper sets out a high-level summary of the proposed changes to the Grid Code seeks comments from relevant parties on any aspect of the proposed amendments.

1.5 Section 2 of this paper provides background information. Section 3 provides a high-level overview of the proposed Grid Code modification and Section 4 provides the TSO analysis and opinion. Section 5 outlines the next steps.

1.6 The deadline for submission of comments is close of business on **08th February 2022.** We will submit a copy of all responses to the Utility Regulator alongside our report on this consultation. If you require your response to remain confidential you should clearly state this on the coversheet of the response. We intend to publish all non-confidential responses. Please note that, in any event, all responses will be shared with the Regulatory Authorities.

2. Background and overview

2.1 This section gives the background of presentation of the modification to the Panel members.

2.2 The proposed Grid Code Modification was first presented to the JGCRP members as a discussion item at the March 2021 meeting. It should be noted that while the proposed Grid Code Modification is not a modification to an area of common governance (i.e. SDC1 and SDC2), the DRAI is proposing the same modification to both the SONI and EirGrid Grid Codes. In the interests of efficiency and transparency, it was decided that the modification should be discussed at the JGCRP meeting.

2.3 In September 2021, the TSO presented the results of their assessment of the proposed modification and stated that as TSO, they were not able to support the modification in the short term but did propose an alternative Grid Code modification.

2.4 The TSOs presented several options to the DRAI:

- Presentation of the proposal at the next JGCRP: The DRAI to present the proposal at the next JGCRP and to progress the proposal in line with the SONI and EirGrid GCRP procedures;
- A revised or alternate proposal: The TSO proposed working with the DRAI and all their members to identify an amended or alternative proposal;
- The inclusion of the proposal in Demand Side Management, as part of the Shaping Our Electricity Roadmap: To include the proposal as part of the wider and longer-term Demand Side Management works;

2.5 The DRAI stated they wished to proceed with first option, a presentation of the modification proposal at the next JGCRP meeting.

2.6 At the November 2021 JGCRP meeting, the proposer presented the modification on behalf of DRAI, outlining the reasons for the modification and its impact. There was significant discussion, as detailed in the JGCRP meeting minutes. Key points of the discussion include:

- EirGrid DSU Operator Member noted that this modification will be of benefit to competition whereby allowing more DSUs to participate in system services;
- EirGrid DSU Operator Member also noted that the current DSUs have already committed to providing a certain de-rated capacity for the next four years;
- SONI DSU Operator Member and Chairperson of Federation of Energy Response Aggregators (FERA) and a SONI GCRP member, stated that FERA are fully supportive the proposal;
- EirGrid Observers stated the TSO cannot support the proposal at this time for reasons as described in Section 4 below.
- Chairperson for the SONI Grid Code, re-iterated that the views of the EirGrid Observers mirrors the view of the SONI control room operators.

2.7 The November SONI GCRP meeting took place immediately after the JGCRP meeting. The proposed Grid Code Modification was discussed further, as detailed in the SONI GCRP meeting minutes. The Panel agreed that this modification would progress to consultation stage.

2.8 The UR noted there may be a licence condition conflict and would investigate this. Following the completion of these discussions, it was agreed to proceed with a consultation paper, which will note that the TSO cannot support the proposal at this time.

2.9 The final SONI GCRP meeting was held on 14th December 2021. The Chairperson stated the modification process is progressing to consultation.

3. High-level overview of proposed modification

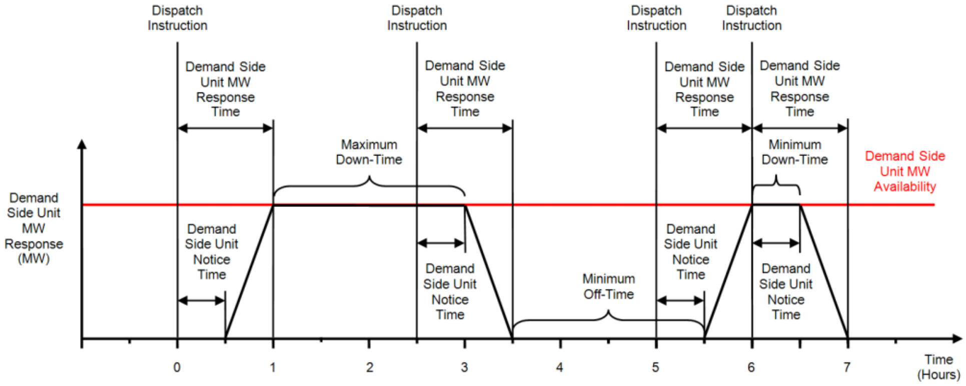
3.1 This section details the DRAI proposed modification.

Modification Proposal Justification:	When provision for Demand Side Units (DSUs) was first added to the Grid Code, all Demand Side Units were eligible to be paid the same for their availability through the Capacity Payment Mechanism, regardless of their performance characteristics. It was therefore necessary for the Grid Code to establish a minimum set of performance characteristics so that all capacity provided by Demand Side Units was of similar value. One of these requirements was that all Demand Side Units must have a Maximum Down Time no less than 2 hours. The SEM Committee's decision SEM-18-030, in June 2018, has changed this. Now, as is the case for other run-hour limited units (such as energy storage), each Demand Side Unit's Maximum Down Time affects its de-rating factor in the Capacity Market. To give an example from the Final Auction Information Pack for the 2023-24 T-4 auction, a 20 MW DSU with a Maximum Down Time of 6 hours would have a de-rating factor of 0.894, whereas if its Maximum Down Time was 10 minutes, the de-rating factor would be 0.081. Now that the capacity payments received by any DSU consider its Maximum Down Time, there is no longer any need for the Grid Code to impose a minimum. In fact, it is illogical for it to do so: at the moment, the Capacity Market Code allows for DSUs with any value for Maximum Down Time, but the Grid Code makes it impossible to create units which are unable to deliver for at least 2 hours. This requirement is also inconsistent with the treatment of battery storage systems, which compete with DSUs to provide the same system services: many are not able to deliver for 2 hours, but no Maximum Down Time requirement prevents their participation. This restriction reduces the range of customer assets that can participate in DSUs, and so needlessly reduces competition in the relevant markets. It is an issue for sites which can provide a demand reduction greater than 10 MW – and so are not allowed to participate as part of an Aggregated Demand Site – and want to provide System Services, such as Fast Frequency Response. For example, data centres often have uninterruptible power supply (UPS) systems with capacity of more than 10 MW. Modern UPSs can provide a high-quality Fast Frequency Response, much like any other battery, and need only be able to keep up their response for less than a minute to deliver this service reliably. However, under the current Grid Code, for such a facility to register as a DSU, it

would first have to demonstrate that it can maintain its response for at least 2 hours – something that a UPS would typically be incapable of doing. Hence such resources are currently prevented from participating. (Note that a dedicated battery with the same specifications would be allowed to participate, because the Grid Code only imposes a Maximum Down Time requirement on DSUs.)

The proposed modification removes this restriction, so that DSUs can be created with any Maximum Down Time. It is only clause CC13.1(e) that imposes the restriction, and nothing else in the Grid Code or other codes seems to depend on it. The requirements on the other performance parameters in CC13.1 are left unchanged, because they are not considered in the Capacity Market's de-rating factor calculations.

The various DSU performance parameters illustrated in the diagram below, taken from CC13.1:



It may be worth clarifying that this diagram is only an example of a DSU where the Maximum Down Time just happens to be 2 hours, but this is not strictly necessary, as it is already possible to create DSUs with longer Maximum Down Times.

Making this change will allow a wider range of customer assets to participate in DSUs – either individually or as part of an aggregation. Maximising the potential of such demand-side assets will benefit all customers by bringing more supply and greater competition into all markets – for capacity, system services, and (once it is opened to DSU participation) energy.

We expect the greatest benefit to come in the faster services under DS3, because long Maximum Down Times are not necessary to provide these valuable services, and there are many assets – UPSs, behind-the-meter battery systems, and future EV charging systems – that have the potential to provide a fast, accurate, and reliable response.

We do not expect this change to lead to existing DSUs reducing their Maximum Down Times, or to new DSUs that could maintain their response for 2 hours choosing to declare a shorter Maximum Down Time. This is because the much more severe de-rating factors for units with short Maximum Down Time provide a very strong incentive to declare the highest achievable Maximum Down Time. Hence, we do not believe that this change would in any way reduce the volume of 2+ hour resources available: its only effect would be to allow additional demand-side resources into the market that otherwise would not be able to participate.

Red-line Version of Impacted Grid Code Section(s) - show proposed changes to text:
Deleted text in ~~strike-through red font~~ and new text highlighted in blue font CC13.1 Each Demand Side Unit shall, as a minimum, have the following capabilities: ... (e) ~~**Maximum Down- Time** not less than 2 hours;~~ [Not used] ...
Green-line Version of Impacted Grid Code Section(s) - show proposed final text:
CC13.1 Each Demand Side Unit shall, as a minimum, have the following capabilities: (e) [Not used]

Defined Terms (Bold):	We are not proposing any changes to definitions.
Implication of Not Implementing the Modification:	1. Needless limitation of the range and volume of resources allowed to provide System Services, particularly Fast Frequency Response. 2. Continuation of Illogical situation where the Capacity Market Code explicitly makes provision for DSUs with Maximum Down Times of less than 2 hours, but the Grid Code prevents their creation. 3. Continuation of inconsistent treatment of batteries and DSUs, whereby the same asset with the same capabilities can participate as a front-of-meter dedicated resource, but not as part of a DSU.

4. TSO Analysis and Opinion

4.1 This section sets out a summary of the TSO position to the modification proposed.

4.2 SONI as TSO is responsible for the safe secure operation of the Transmission system Given the operational challenges SONI are facing over the winter period and beyond SONI cannot support this modification at this time for the following reasons;

4.3 **Security of supply:** The proposal would create several additional challenges which would exacerbate the already difficult winter with tight margins. These challenges include:

- System security concerns;
- The risk of potential impacts of capacity changes on system security in periods of low capacity margins;
- Operational Complexity in dispatching;
- Risks to system metrics including frequency, voltage, congestion, scheduling
- The need to take a holistic approach to coordinating, prioritising, combining and sequencing of major changes to policies, processes and systems through the "Shaping Our Electricity Future (SOEF)" programme.

4.4 The past five years have seen a decline in the Capacity Margins on an all-island basis. These lower Capacity Margins present a security of supply risk, particularly during times of low wind generation.

4.5 Based on operational experience and analysis, there are some concerns regarding the real-time availability of DSUs for use in meeting capacity shortfalls and balancing in terms of dispatch, and that this availability could reduce under this proposal.

4.6 It is acknowledged that the total MW amount of availability from DSUs who avail of a lower Maximum Down Time requirement could increase for the shorter timeframes associated with the shorter duration reserve products, the availability of which is the focus of this proposal, and therefore the levels of reserve provision would increase. However, based on the concerns outlined here, the TSOs see a risk in that the additional capacity would be available over a shorter period of time which may mean that the overall level of response over an extended period of time, in the timeframes considered for capacity and system balancing, could be reduced.

4.7 There is a risk of existing DSUs reconfiguring their units to focus on system services with shorter duration. This would reduce the current levels of DSU availability over longer periods of time. The DRAI have stated they do not believe that this would occur, as the existing DSUs already have Capacity Market obligations based on the de-rating factors applying to the existing 2-hour Maximum Down Time requirement. While SONI acknowledge that this reduces the risk, this could still occur with existing capacity based on operational experience with real-time availability of certain DSUs in comparison to their de-rated capacity and load-following de-rated capacity metrics.

4.8 It is the TSOs view, this modification would change the focus away from the characteristics required for capacity and balancing to maintain a secure system in favour of focussing on the availability of system services, at a time when capacity and balancing are of primary concern for system security.

4.9 **Future operational concerns:** There are also number of other operational issues why SONI cannot support the Grid Code Modification at this time. The priority of the CHCC [Castlereagh House Control Centre] is to have enough capacity to meet the energy demand in a secure manner. This does not just mean the MW amount of capacity in each instant, but also that the capacity can be relied upon and be consistent for the duration of the main period over which it would be required, being the evening peak.

4.10 The key operational argument against removing the “Maximum Down Time not less than 2 hours” requirement is that capacity is not just required across relatively short periods (10 min or less) but is required on a sustained basis (2 hours or more), and particularly over the evening peak, in order to maintain system security in balancing supply and demand, and in providing capacity adequacy in a secure manner. In fact, given this winter’s capacity concerns, there is a potential counter argument to enhance system security by increasing the “Maximum Down Time” beyond the current requirement of not less than 2 hours.

4.11 It is also essential to note that having higher levels of capacity over shorter lengths of time is not as secure as having capacity which can be provided consistently over the periods around peak demand.

4.12 Consistently needing to ramp down one source of capacity while ramping up another would be a very complex way of ensuring that the system remains balanced and maintaining all system operational metrics at stable and secure levels. In addition, this approach could have other knock-on implications for other units, including voltage issues and local congestion, which would be more difficult to foresee and manage than taking a consistent response over a longer period.

4.13 A User providing a consistent level of response over the whole period is much more reliable and dependable from a system security perspective, especially now when capacity margins are tight. The TSOs in their scheduling activities are carrying out forecast assessments on the actions they need to take to secure the system, in very tight periods over the evening peaks which encompasses a time of at least 2hrs where there are few options. Any assessment of the likely impacts on system balance, frequency, voltage, congestion, and other indicators of system strength at a time when the system is generally less secure, would be more accurate with less risk of introducing insecurity when a consistent provision over a 2hr period is considered rather than considering the same level of MW provision through multiple different units in different locations ramping up and down multiple times over that period.

4.14 Another consideration is the practicality of the TSO being able to issue far larger volumes of dispatch instructions in order to maintain the same level of capacity response which could be obtained via a smaller number of DSUs under the current approach. This could impact on the TSOs ability to carry out other actions required to maintain system security at times of tight margins.

4.15 IT and Market Systems considerations: The systems are not currently able to accommodate DSUs in a way that would not further complicate scheduling and dispatch operations for the control centre. Changes to the TSO’s key operational systems are still under development and will need to be assessed in the context of wider system changes.

4.16 Scheduling Systems: Further investigation of the existing scheduling systems will be required to assess if they can manage the level of granularity of the scheduling intervals in their optimization if Maximum Down Times of less than two hours were used. The Long-Term Schedule (LTS) run considers 30-minute scheduling intervals, the Real Time Commitment (RTC) run considers 15-minute scheduling intervals, and the Real Time Dispatch (RTD) run considers 5-minute scheduling intervals. As only the LTS and RTC schedules are capable of committing and de-committing plant (RTD is expressly MW instructions for system balancing), it is uncertain whether it would be feasible for units with lower maximum down times to be included in the scheduling systems. Even if possible, there is potential that the lower maximum down times may cause a conflict amongst the different scheduling tools ultimately leading to the production of insecure schedules. The relevant systems would need to be tested extensively to confirm the extent of these potential issues and their impacts before any such change in the Grid Code requirement could be considered.

4.17 Considering the above, SONI strongly contends that completely removing the "Maximum Down Time not less than two hours" requirement would increase operational complexity, would be detrimental to the safe operation of the grid, and would substantially add to the operational burden on Control Room staff.

4.18 Shaping Our Electricity Future (SOEF): During November 2021, SONI and EirGrid jointly launched "Shaping Our Electricity Future" which is designed to advise and guide on the optimal pathway to deliver Northern Ireland and Ireland's ultimate ambition for decarbonisation of the power system, while maintaining an affordable, secure, and reliable supply of electricity.

4.19 Demand side flexibility will be critical to enabling the transition and facilitate electrification of the heat and transport sectors while maintaining power system security.

4.20 One of the main challenges identified in SOEF is having a planned approach to scoping, designing, and implementing the changes required to enable the transition, with the appropriate programming and sequencing of different projects. This is important because the many different aspects of network, market, and operational policies, all have impacts on each other, meaning that the most efficient means of handling them would be to consider these issues together in a more holistic way.

4.21 It also means that there are multiple major change projects needed which all require the same resources from the TSOs, RAs, industry, and system vendors. The changes needed to be implemented will be on the same functions in IT systems and on the same processes. A coordinated approach is required to ensure those resources can deliver the changes which would have the greatest impact in meeting the SOEF ambitions.

4.22 Demand Side Participation Review under SOEF: As part of SOEF, SONI, EirGrid, NIEN and ESBN will be working with industry to develop a Demand Side Management (DSM) strategy, which will include the participation of demand side resources in the energy, capacity and system services markets. The key components of this strategy are to:

- Analyse the importance of Demand Side Management (DSM) on the transmission and distribution networks and the advantages it brings to the TSOs/DSOs;
- Identify the main challenges facing DSM adoption and further integration onto the network;
- Address the issue of DSU availability;
- Deliver a DSM strategy on how to address the challenges facing DSM adoption going forward, including prioritising the issues, identifying where the issues may be suited to being included in other larger pieces of system/process/policy change work, or identifying which issues will not have changes implemented over

the course of the period considered for SOEF due to other priorities and limited resources.

4.23 SONI believe that the DRAI proposal should be considered as part of this wider review, rather than a standalone Grid Code Modification. SONI would welcome the opportunity to investigate other alternatives with the aim of reaching a proposal which would be beneficial to the Demand Side Industry, as well as improving security of supply.

4.24 Conclusion: Given that the level of system changes as well as the operational impact of this proposal, SONI believes that a holistic approach should be taken and this proposal should be considered as part of the wider Demand Side Management (DSM) strategy under the "Shaping Our Electricity Future" Programme.

5. Next steps

5.1 The consultation period will run for 7 weeks to accommodate Christmas holiday period. Users are invited to send their responses to SONI via email gridcode@soni.ltd.uk by close of business on **08th February 2022**. In the interim, should any Users have any queries on this consultation they should contact the Secretary or Chairperson at gridcode@soni.ltd.uk.

5.2 Following receipt of comments in relation to this Consultation Paper and the expiration of the period for making comments, SONI will, in accordance with paragraph 2 of Condition 16 of its Licence, send to the Northern Ireland Authority for Utility Regulation (the "Authority"):

- a report on the outcome of this consultation.
- the proposed revisions to the Grid Code which SONI (having regard to the outcome of such review) reasonably thinks fit for the achievement of the objectives of the Grid Code referred to in paragraph 1(b) and (c) of Condition 16 of the SONI Licence;
- Any written representations or objections from electricity undertakings or the Republic of Ireland System Operator (including any proposals by such persons for revisions to the Grid Code not accepted by SONI during the review) arising during the consultation process and subsequently maintained.

5.3 If you require your response to remain confidential you should clearly state this on the coversheet of the response. We intend to publish all non-confidential responses. Please note that, in any event, all responses will be shared with the Regulatory Authorities.

5.4 Following the end of the consultation period and the discussions to be held with the Authority, revisions [if any] to the Grid Code will be finalised and published on the SONI website.