Grid Code Modification Recommendation Form	EIRGRID

Title of Recommended Proposal:
MPID 293 DSU Maximum Down Time

MPID: 293

Date:	18 February 2022
Recommended at GCRP Meeting No.:	03/2021 (Meeting dated 02 November)
Grid Code Version:	Version 9 of the Grid Code was the current version when this modification was proposed and recommended.
Grid Code Section(s) Impacted by Recommended Proposal:	CC.7.4

The Reason for the Recommended Modification:

This modification was proposed by The Demand Response Association of Ireland, hereafter referred to as "The DRAI".

In 2007, when provision for Demand Side Units (DSUs) was added to the Grid Code, all DSUs 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 DSUs must have a Maximum Down Time of 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 DSU'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 restriction.

Currently, the Capacity Market Code allows for DSUs with any value for Maximum Down Time, but the Grid Code prevents to create units which are unable to deliver for at least 2 hours.

This requirement is inconsistent with the treatment of battery storage systems, which compete with DSUs to provide the same system services. Many battery storage systems are not capable of delivering their response for 2 hours, but no Maximum Down Time requirement prevents their participation in system services.

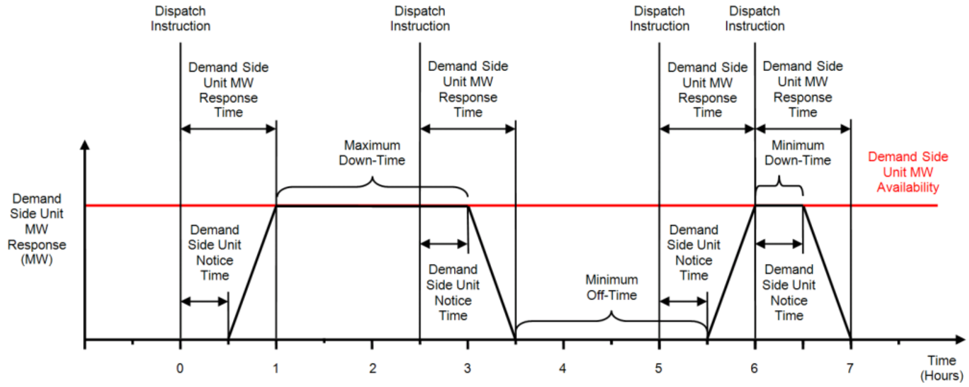
This restriction on DSUs reduces the range of customer assets that can participate, and as a result reduces competition in the relevant markets. It is a particular issue for sites that can provide a demand reduction greater than 10 MW. Such sites are not allowed to participate as part of an Aggregated Demand Side Unit but may 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 in System Services. (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 Grid Code modification would remove this restriction, so that DSUs can be created with any Maximum Down Time. Grid Code Clause CC.7.4(e) imposes the restriction. This clause is not referred elsewhere in the Grid Code. The DRAI do not propose any changes to the other requirements for DSUs in Grid Code Clause CC.7.4 are not taken into account in the Capacity Market's de-rating factor calculations.

The various DSU performance parameters illustrated in the diagram below, taken from CC.7.4:



This diagram is an example of a DSU where the Maximum Down Time is 2 hours, but this is not strictly necessary, as it is already possible to create DSUs with longer Maximum Down Times. This Grid Code modification would allow the Maximum Down Time for a DSU to be less than two hours.

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

The DRAI expect the greatest advantage will be the provision of faster services under DS3, because long Maximum Down Times are not necessary to provide these valuable services. There are many assets such as UPSs, behind-the-meter battery systems, and future EV charging systems that have the potential to provide a fast, accurate, and reliable response.

The DRAI do not expect this change will result in any existing DSUs reducing their Maximum Down Times, or any new DSUs that could maintain their response for 2 hours choosing to declare a shorter Maximum Down Time. This is because the de-rating factors for units with short Maximum Down Times provide a very strong incentive to declare the highest achievable Maximum Down Time. It is the view of the DRAI that this change will not reduce the volume of 2+ hour resources available. Its effect would allow additional demand-side resources into the market that otherwise would be unable to participate.

Note: The DRAI are proposing a similar modification to the SONI Grid Code.

History of Progression through GCRPs, Working Group and/or Consultation:

March 2021:
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 EirGrid and SONI Grid Codes. In the interests of efficiency and transparency, it was decided that the modification should be discussed at the JGCRP meeting.

At the JGCRP meeting the DRAI outlined the background, the current issues as well as the modification itself. Following the discussion, it was agreed to hold an extraordinary GCRP meeting at the end of April. This would allow EirGrid time to assess the impact of the proposed Modification.

April – September 2021:
Between April and September 2021, the TSOs carried out an assessment of the proposed Grid Code Modification. This assessment took longer than had been anticipated.

On 8 September 2021, TSO stated that they cannot support the proposal due to operational concerns and ongoing security of supply concerns. The TSO proposed three options to DRAI via email:

1. Presentation of the proposal at the next GCRP:
   The DRAI to present the proposal at the next GCRP and to progress the proposal in line with the GCRP procedures.
2. A revised or alternate proposal:
   The TSO proposed working with the DRAI and all their members to identify an amended or alternative proposal.
3. 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.

On 27 September 2021, the TSO and the DRAI met to discuss the TSO's assessment of the modification proposal, including the three options stated above. During the meeting, the TSO communicated the outcome of their internal assessment of the proposed modification and stated that as TSO, they were not in a position to support the modification in the short term but did propose an alternative Grid Code modification – see below.

The DRAI expressed concern about how the proposal has been assessed within EirGrid, and whether references to "lower availability" of DSUs were consistent with an understanding of de-rated capacity and its operation in the capacity market. The DRAI re-iterated that the proposal seeks to provide services from additional types of providers and not to diminish that from already-contracted parties. The DRAI also raised that in their view there is an issue of discriminatory treatment of DSUs when compared to battery storage, which does not have a 2hour requirement in the Grid Code.

The DRAI noted in conversation that Options 2 and 3 were effectively the same and EirGrid outlines that both would follow similar timeline. The DRAI stated they wished to proceed with Option 1 – presentation of the modification proposal at the next GCRP meeting. It was agreed that the modification would be presented at the November JGCRP meeting with the panel decision regarding the recommendation of the modification being taken at the GCRP meeting.

At the November 2021 JGCRP meeting, Paul Troughton (Enel X) presented the proposed 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:

- Paul Troughton (Enel X) noted that this modification will be of benefit to competition whereby allowing more DSUs to participate in system services;
- Paul Troughton (Enel X) also noted that the current DSUs have already committed to providing a certain de-rated capacity for the next four years;

- Brian Mongan, of Federation of Energy Response Aggregators (FERA) and a SONI GCRP member, stated that FERA are fully supportive the proposal;
- John Carnwath and Martin Kerin, EirGrid Observers, stated that EirGrid cannot support the proposal at this time for reasons as described in "Summary Note of any Objections to the Recommended Change from GCRP Members or Consultation Responses" section below;
- Marie-Therese Campbell, Chairperson for the SONI Grid Code, re-iterated that the views of the EirGrid Observers mirrors the view of the SONI control room operators.

The November GCRP meeting took place immediately after the JGCRP meeting. The proposed Grid Code modification was discussed further, as detailed in the meeting minutes. Following a request from Miriam Ryan, GCRP Chairperson, for members to offer their recommendation or non-recommendation, a number of participants provided comment. Four members stated their position and details on their position are provided below and the remaining members did not provide comment. The comments not supportive of the modification were from the TSO.

1. John Carnwath (TSO Observer), representing the TSO, the TSO is not in favour of recommending this proposal - "Summary Note of any Objections to the Recommended Change from GCRP Members or Consultation Responses" section below for further details;
2. Oliver Caherty (CCGT Generators) is in favour of recommending this proposal.
3. Seamus King (Demand Side Units) is in favour of recommending this proposal.
4. Mark Coleman (Non-Synchronous Renewable Generators) is in favour of recommending this proposal. At the same time, he acknowledges the knock-on impact on the TSOs, but the Regulator will have the final call on the recommendation.
   He also suggested that the modification be approved but not retrospectively applied, and it will only apply to new demand side units. Miriam Ryan (Chairperson) noted that the European Codes explicitly state that they are not retrospectively applied. However, the requirements in the Grid Code are retrospectively applied and this is stated in the code.

Following the completion of these discussions, it was agreed to proceed with the issue of recommendation paper to the Regulator, which will note that the TSO cannot support the proposal at this time.

Summary Note of any Objections to the Recommended Change from GCRP Members or Consultation Responses:

EirGrid, as TSO, is responsible for the safe and secure operation of the Transmission System. With this in mind, EirGrid carried out a detailed assessment of the proposal and determined that while there is some merit in the proposal, EirGrid cannot support the proposal at this time. The reasons for this are as follows:

<u>Security of supply:</u>
Both EirGrid and SONI are facing a number of operational challenges this winter and for the next number of winters, and the proposal would create a number of additional challenges which would exacerbate this. 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 metric including frequency, voltage, congestion, scheduling among others; and
- 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.

In addition to the operational challenges listed above, EirGrid has committed to enabling the implementation of impactful changes to meet the overall climate ambitions which would not be possible to do in a way which considers each issue in an ad-hoc manner.

Capacity Margin and Availability concerns:
The past five years has seen a decline in the Capacity Margins on the all-island basis. These lower Capacity Margins present a security of supply risk, particularly during times of low wind generation.
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, in particular that this availability could reduce under this proposal.
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.
There is a risk of existing DSUs availing of this Grid Code Modification to reconfigure 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 pointed out that under capacity market design, the existing DSUs already have Capacity Market obligations based on the de-rating factors applying to the existing 2hour Maximum Down Time requirement. While EirGrid 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.
Finally, 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.

Future operational concerns:
There are also number of other operational issues why EirGrid cannot support the Grid Code Modification at this time. The priority of the National Control Centre (NCC) is to have sufficient capacity to meet the energy demand in a secure manner. This does not just mean the MW amount of capacity in a given 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.
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.
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.
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 of time.
A User providing a consistent level of response over the whole period is much more reliable and dependable from a system security perspective, especially at the moment when capacity margins are so tight. The TSOs in their scheduling activities are carrying out forecast assessments on the actions they need to take to secure the system, in particular 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.
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.

Further consideration has to be given to:

a. The IT and Market Systems:
   These systems are not currently able to handle DSUs in a way that would not further complicate scheduling and dispatch operations for the NCC. 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.
b. Scheduling systems:
   It needs to be investigated if the existing schedule systems can manage the level of granularity of the scheduling intervals in their optimization if Maximum Down Times of less than two hours was used. The Long-Term Schedule (LTS) run considers 30min scheduling intervals, the Real Time Commitment (RTC) run considers 15min scheduling intervals, and the Real Time Dispatch (RTD) run considers 5min 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.
c. The issues are further complicated by the need to monitor multiple difference Maximum Down Times which are less than scheduling period durations.

Considering all of the above, EirGrid 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.

Shaping our Electricity Future (SOEF):
During November 2021, EirGrid and SONI jointly launched "Shaping Our Electricity Future" which is designed to advise and guide on the optimal pathway to deliver Ireland and Northern Ireland's ultimate ambition for a renewables-based power system, while maintaining an affordable, secure, and reliable supply of electricity. Demand side flexibility will be critical to enabling the transition to 70% RES-E and facilitate electrification of the heat and transport sectors while maintaining power system security.
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.
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 essentially 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.

Demand Side Participation Review under SOEF:
As part of SOEF, EirGrid, SONI, ESBN and NIEN 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:

a. Analyse the importance of Demand Side Management (DSM) on the transmission and distribution networks and the advantages it brings to the TSOs/DSOs;
b. Identify the main challenges facing DSM adoption and further integration onto the network;
c. Address the issue of DSU availability;
d. 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.

EirGrid recommends that the DRAI's proposal should be considered as part of this wider review, rather than as a standalone Grid Code Modification.

Alternative proposal:

As part of EirGrid's assessment of the proposed Modification, EirGrid proposed an alternative which comprised of:

1. Retain the current DSU definition for DSUs that wish to participate in the capacity market and/or energy market, and therefore must be technically capable of being dispatched for 2 hours or more. These units will continue to be available for at least two hours. This would allow such units to continue to be of value to the system operator in balancing the system and providing capacity adequacy, for example over the daily demand peak. This would apply to any DSU with capacity greater than 10MW, and any DSU with capacity between 4MW and 10MW that wishes to be subject to Central Dispatch and participate in the Capacity Market / Balancing Market;
2. Create a new definition of a DSU (with capacities of between 4MW and 10MW) which only wishes to participate in system services, and not the capacity and/or energy markets, and therefore would not be treated as dispatchable (i.e. is not subject to Central Dispatch), but would be able to provide fast acting reserve services that would be delivered automatically, and whose Maximum Down Time requirement would be reduced from 2hrs to 20 minutes. Such a unit would be kept outside of the Balancing Market and Capacity Market, and therefore not come into system balancing or capacity adequacy considerations.

This alternative proposal was presented to the DRAI for consideration. The DRAI informed the TSOs that the alternative proposal does not meet their requirements, partly because it was complicated, but principally because it did not solve the problem for resources larger than 10 MW, and that they would like the TSOs to only consider their original proposal. EirGrid notes that this modification is not specific to DSUs with capacity of 10 MW or more. The modification would apply to all DSUs. As such, EirGrid's assessment of the proposed modification and the alternative subsequently proposed by EirGrid was not focused on DSUs of 10 MW or more.

EirGrid 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.

Outcome of any GCRP Meeting Actions Relating to the Recommended Modification:

At the November 2021 GCRP meeting, it was agreed to proceed with a recommendation paper, which will note that the TSO cannot support the proposal at this time.

Red-line Version of Impacted Grid Code Section(s) - show recommended changes to text:

Deleted text in ~~strike-through red font~~ and new text highlighted in blue font

CC.7.4 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 recommended final text:

CC.7.4 Each **Demand Side Unit** shall, as a minimum, have the following capabilities:

…

(e) *Not used*;