# Harmonised Other System Charges Recommendations Paper

## Tariff Year

01st October 2023 to 30th September 2024

20th July 2023

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| Revision History | | | | | | |
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| **Revision** | **Date** | **Description** | **Originator** | **Reviewer** | **Checker** | **Approver** |
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# ABBREVIATIONS

| | |
|---|---|
| AGU | Aggregated Generator Unit |
| BM | Balancing Market |
| CPI | Consumer Price Index |
| CRU | Commission for Regulation of Utilities |
| DBC | Dispatch Balancing Costs |
| DQ | Dispatch Quantity |
| DSU | Demand Side Unit |
| DS3 | Delivering a Secure Sustainable System |
| EDIL | Electronic Dispatch Instruction Logger |
| GPI | Generator Performance Incentive |
| HICP | Harmonised Index of Consumer Prices |
| MPI | Market Participant Interface |
| MMS | Market Management System |
| OBR | Office of Budget Responsibility |
| OSC | Other System Charges |
| PPM | Power Park Modules |
| QEX | Ex-Ante Quantity |
| QFPN | Final Physical Notification Quantity |
| QM | Metered Quantity |
| OSC | Other System Charges |
| RAs | Regulatory Authorities |
| RO | Reliability Option |
| RPI | Retail Prices Index |
| RTD | Real Time Dispatch |
| SEM | Single Electricity Market |
| SEMC | Single Electricity Market Committee |
| SND | Short Notice Declaration |
| TSOs | Transmission System Operators |
| WDT | Wind Dispatch Tool |

# 1. Executive Summary

EirGrid and SONI (the TSOs) published a consultation paper on 12th May 2023 concerning the Harmonised Other System Charges for the upcoming tariff period, 1st October 2023 to 30th September 2024. Comments on the consultation paper were received from six (6) respondents. Having reviewed the responses, in this paper the TSOs propose a number of recommendations to the Regulatory Authorities (the RAs) for their consideration and approval.

**Proposed arrangements for tariff year 2023/2024**

1. Retain the OSC rates approved for the 2022/2023 tariff year, only adjusting for inflation at the forecast rate 3.2875% for the tariff year 2023/2024 for the following:
    - Minimum Generation;
    - Governor Droop;
    - Primary Operating Reserve;
    - Secondary Operating Reserve;
    - Tertiary Operating Reserve 1;
    - Tertiary Operating Reserve 2;
    - Reactive Power;
    - Secondary Fuel Availability;
    - Trip Charges;
    - Short Notice Declarations (SND) Charge Rates for Generators;
2. Introduce New Demand Side Unit (DSU) Short Notice Declarations (SND);
3. Introduce New DSU Performance Monitoring for declared availability of DSU MW Capacity;
4. If/when directed by RAs introduce New DSU Generator Performance Incentive (GPI).

No further changes are recommended for this tariff period.

# 2. Introduction

The TSOs consult on an annual basis regarding proposed changes to Other System Charges and associated rates. The purpose of this paper is to make recommendations for approval to the RAs in Ireland and Northern Ireland. They are based on a consideration of the responses received by the TSOs to this year's Harmonised Other System Charges Consultation paper for the tariff year 1st October 2023 to 30th September 2024.

The TSOs will publish revised Statements of Charges and the Other System Charges Methodology Statement for the 2023-2024 tariff period reflecting the approved rates and arrangements.

Responses were received from the following parties:

| Party | Abbreviation |
|---|---|
| | |
| Bord Gáis Energy | BGE |
| Demand Response Association of Ireland | DRAI |
| ESB Generation and Trading | ESB GT |
| Federation of Energy Response Aggregators | FERA |
| iPower Flexible Energy | iPower |
| Lumcloon Energy Limited | LEL |

No confidential responses were received.

Copies of the responses received have been appended to this recommendations paper.

Please refer to Appendix A for the responses in their entirety.

# 3. Response to existing OSC section

This section summarises comments received from Participants in relation to Trip, Short Notice Declaration and Generator Performance Incentive Charges. This section also contains the TSOs' response to the comments received.

## 3.1. Trip Charges

The TSOs proposed to retain the trip charges, at the rate approved for tariff year 2022/23, apart from adjusting for inflation.

### 3.1.1 Respondents Comments

With regards to MW Trip threshold, both FERA and iPower welcomes a proposal for the threshold to remain at 100MW and have commented that this "informs industry that there is no significant financial impact to the system, should conventional power plants lose up to 100MW of provision". They query the correlation with proposed new Short Notice Declaration (SND) for Demand Side Unit (DSU) for its loss of 4MW within 60minutes.

BGE remains of the view that where trips or SNDs occur which require energy balancing actions to be taken by the TSOs, the cost of these actions to the TSOs should be entirely covered in the Balancing Market (BM) with costs levied on the causal unit(s).

BGE believes that if the charges in question do not cover the cost to the system, then this is a market issue, which needs to be resolved through the market. BGE understands the rationale to levy on units without an Ex-Ante Quantity QEX position, but not for units that has a (QEX) position. BGE also refers to the exposure of units to Reliability Option (RO) payments, DS3 procurement and the increasing cost to customers, should be better explained.

ESB GT provided a link to Other System Charges (OSC) Trip Report for 2021/2022 and was unable to find a more up to date version for consideration.

### 3.1.2 TSOs' Response

The Trip and SND is not comparable, the treatment of these occurrences is different.

The purpose of the trip charge is to minimise the number of trips; however, when a trip is unavoidable, it incentivises a Generator to wind down a unit as slowly as possible and therefore reduce the rate of loss on the system. The purpose of the SND charge is to incentivise behaviour that enhances system security and reduce the costs of actions taken by the TSOs to mitigate SNDs. In the event of a unit making a downward declaration of its availability at short notice, a Short Notice Declaration (SND) Charge is levied on the service provider depending on the amount of notice given and the quantity of downward declaration (i.e., €/MW charge). New SND charge for DSUs is explained in more detail in section 3.2.2.

A Trip or SND can occur as a result of technical issues; the TSOs are of the opinion that regardless of the technical background to a SND/trip, the monetary outcome should be treated on a 'causer-pays' basis, and the end-consumer should not have to bear this cost. The TSOs have previously communicated that current market mechanisms do not cover all costs associated with SNDs and trips, specifically the creation of Imperfection Component Payments, in relation to short notice changes in availability. The market design does not take account of the causer of these payments, but rather ensures that the TSOs are accountable for their actions, regardless of the root-cause, which in this case is outside of their control.

The current Trip Report[1] for 2022/2023 is available on the Ancillary Service & Other system charges landing page while previous years are available in the library of both SONI and EirGrid website.

### 3.1.3 TSOs Recommendation

The TSOs recommend retaining the rate of Trip Charges, its current framework and adjusting for inflation from 2022/23 rates.

[1] https://www.eirgridgroup.com/site-files/library/EirGrid/Trip-Report-2022-23.pdf

## 3.2. SND Charges

This section summaries the comments received from Participants in relation to existing Short Notice Declarations along with a proposed new SND for DSUs.

### 3.2.1 Respondents Comments

ESB GT remains of the view that the SND notice time parameter should not maintain last year's increase from 480mins (8 hours) to 720mins (12 hours), but, if it were to do so, should have a lower SND charge rate. ESB GT also requests supporting data for this matter. While FERA and iPower noted reasons for increase in the SND notice time parameter to 720mins (12 hours) and queried if MPI (Market Participant Interface) forecast Availability values (could be used in absence of EDIL declarations. DRAI request "data interface between DSUs and the TSOs in order to automate the EDIL declaration process".

BGE noted it welcomed "any measures that level the playing field amongst technologies" in relation to SND for DSU; however, as stated in previous section in more detail, they believe it should be covered in Balancing Market (BM).

Many responses seek clarification on setting a DSU SND threshold of 4MW while FERA and iPower seek clarification as to why DSU SND threshold (4MW) is different from Generators' SND threshold (15MW) and explain treatment of Generator units under threshold.

FERA and iPower believe the 60minutes notice time is plausible, while DRAI seeks clarification on justification for this.

FERA and iPower have the view that introduction of SNDs for Demand Side Response is difficult to understand in comparison to conventional plants that don't have variable energy source.

DRAI noted Grid Code SDC1.4.3.4 and express concern that the new DSU SND proposed charge is creating two conflicting obligations.

DRAI state "The DSU Aggregator has no control over the demand load of the customer sites which are being made available for demand response" and DSU SND charge wont "incentivize behaviour that enhances system security."

### 3.2.2 TSOs' Response

Since the increase in SND Notice Time parameter in tariff year 2022/2023 from eight (8) hours to twelve (12) hours, a review of data for the same period considered in the 2022/2023 recommendations paper[2] has shown a significant reduction in instances of this occurrence from 169 to 23. The system has benefited from this reduction and incentivises unit behaviour to enhance System Security.

The TSOs uses the Real Time Dispatch (RTD) Scheduler and additional actions as required, through EDIL directly to unit to respond. However, any changes of application or proposal for data interface would require consideration under Market Management System (MMS) and SEM rules.

[2] https://www.eirgridgroup.com/site-files/library/EirGrid/OSC-2022-23-Recommendations-Paper_V1.02.pdf

The TSOs' viewpoint is that current market mechanisms do not cover all costs associated with SNDs, specifically in relation to short notice changes in availability which creates Imperfection costs.

The TSOs saw it prudent to use the minimal Demand Side Unit MW Capacity of 4MW as a starting point and took into consideration the minimal size of the DSUs. Generators have different technical characteristics, much larger notice periods and greater capacity, resulting in a different criterion needed. The TSOs have noted commentary regarding SND charges not being applicable to Generators under 15MW threshold. A review of Generator units which fall within this category concludes that the number affected is not material however this will be assessed as part of next year's consultation.

The Grid code requirements at section SDC1.4.1.1[3] details availability notice "by not later than Gate Closure 1 each day". Proving updated availability submission, no later than Gate Closure 2 will ensure the real time dispatch schedulers has accurate data to avoid loss of MW from the grid at short notice. Analysis from previous years showed that when DSUs were called upon, and the duration was over 60mins, DSU were not redeclaring with significant notice. Therefore, an incentive was derived for DSUs to redeclare with at least 60minute notice to avoid shortfall on the system.

The SND charge for DSUs doesn't consider Demand Side Response (in response to signal).
The SND charge for DSUs is only triggered in the event a DSU submits:

1. Downward availability declaration within a 60min window that ≥ 4MW threshold
   or
2. Multiple SND within 60mins window that ≥ 4MW threshold

Both Conventional plants and DSUs have different technical capabilities, however accuracy and timely submission of availability declarations is a necessity for both.

Grid code requirements section SDC1.4.3.4[3] outlines requirements for when a DSU Operator is submitting availability it doesn't submit levels or values (i.e., its profile) that are unobtainable.
The new DSU SND charge requires a DSU Operator to submit redeclare availability profile by gate closure 2 (60mins).

The Demand Side Unit Operator is responsible for ensuring the declared availability is accurate and ensuring Individual Demand Sites (IDS)s within the DSU units are capable of responding to Dispatch Instructions in line with their declared availability, as per Grid Code requirements.

### 3.2.3 TSOs' Recommendation

The TSOs recommend:

1. Retaining the rate of existing rate of SND Charges, its current framework and adjusting for inflation from 2022/23 rates and
2. Introduction of new SND Charge for DSUs.

[3] https://www.soni.ltd.uk/media/documents/SONI-Grid-Code-June-2023.pdf and https://www.eirgridgroup.com/site-files/library/EirGrid/GridCode.pdf

## 3.3. Generator Performance Incentive Charge

This section summaries the comments received from Industry in relation to existing Generator Performance Incentive with proposed performance monitoring for DSUs and, if directed, a new GPI for DSUs.

### 3.3.1 Respondents Comments

BGE noted they support retention of Operating Reserve, Reactive Power and potential introduction of new DSU GPI. iPower acknowledges exemption for DSU from Min gen and Operating reserve and welcomes proposal for these rates.

BGE remains of the view that Secondary Fuel GPI is not "appropriately designed or applied today", stating that it's adding penalty to existing financial and operational burdens incurred by dual fuel plants. BGE is of the belief that positive reward should be instated and charge should be removed or shared. BGE acknowledges the short-term benefit of running on secondary fuel and reference two CRU papers of different proposals suggested to current practice. BGE questions the sample size of data (6 months) stated in the Consultation paper and attribution of last year's increase in Secondary Fuel rate to the already notable reduction in charges being applied and lists potentially alternative reasons. BGE requested details of charge total being lower.

In relation to DSU GPI threshold, iPower, FERA and BGE seek rationale on for 70% threshold and charge rate, while iPower and FERA seeking clarification of how the rate be charged (trading period or MWh). BGE would welcome a reduction in threshold in subsequent tariff years to further incentivise improvements and incentive to declare availability/penalty for underperformance.

FERA and iPower acknowledge the linkage between the DSU GPI and DSU energy payment decision in SEM-22-090 and state comments from RA that "no metering usable at the current time for energy payment settlement and that the DQ would be used" and "the effectiveness of using the DQ would need to be assessed."

FERA and iPower believe GPI should be "levied on those generators which fail to comply with specific standards in the Grid Code" and request section to be identified.

FERA and iPower note the SCADA signals "are to three decimal places, but the EDIL system can only handle whole values and "that the declared availability value has to be rounded up to whole values, which would then be dispatched as whole values. They provided the below table as an example in attempt to match against target.

| Actual MW availability | EDIL MW value | % delivered |
|---|---|---|
| 0.654 | 1 | 65.400% |
| 2.654 | 3 | 88.467% |
| 5.654 | 6 | 94.233% |
| | | |
| 2.1 | 3 | 70.000% |

DRAI notes their support in principle for new DSU GPI and acknowledges underperformance process already in place along with quoting SEM-22-090 "*additional measures, such as a GPI, may be put into place to enhance performance*", but express its "pre-emptive to introduce such a charge".

DRAI requests clarification the circumstance for which a charge may be introduced and on what basis.

### 3.3.2 TSOs' Response

In previous OSC recommendation papers the TSOs outlined the necessity of compliance with the secondary fuel requirements of the Grid Code in Ireland and the Northern Ireland Fuel Security Code. While the TSOs note a reduction in Units/Total Charges for the first six months since 50% rate increase was implemented and respondents' feedback on additional factors maybe at play, additional data is required. Please see last year's report[4] and this year's report for additional total charges detail[5].

The threshold of 70% is already used in existing reporting performance monitoring in place. When the DSUs are called upon in cases where their SCADA metering is less than 70% of Dispatch Quantity (DQ), a report is issued to the DSU with a request to provide an explanation. The TSOs took these inputs into assessment and consider the Grid Code requirement (for DSU compliance with Dispatch Instructions under sections EirGrid OC10.4.5.2[6] and SONI OC11.10.3[7]). 70% threshold is a reasonable starting point.

As per SEM-22-090[8] monthly reports will be issued to the RAs and, if during phase 1 performance monitoring, they are deemed unsatisfactory, a DSU GPI maybe introduced. The rate of €100 was established by taking into consideration historical data (day ahead/imbalance price) and forecast data (projection of fuel cost and price) to determine the potential cost of paying a DSU Energy payment while the TSOs have to take additional action to counteract its underperformance. The DSU GPI will be charged per MWh of shortfall in a given trading period.

The SEM-22-090 outlines the steps for acquisition of DSU Metering data. The SCADA metering data is accessible and used for DS3 products and for the Control room monitoring of system activity in real time. The requirement for Demand Side Unit Operator to provide SCADA Signals with precision within 1MW and response time within 15seconds is outlined in EirGrid Grid Code section CC12.6 and SONI Grid Code section CC.13.4. The requirement for DSUs to be compliant with Dispatch Instructions in relation to performance monitoring of SCADA percentage error is less than 5% or 0.5MWh, as outlined in Grid code sections EirGrid OC10.4.5.2 and SONI OC11.10.3.

A number of GPIs, outlined in section 5.3 are already applicable to conventional units that fail to comply with Grid Code and BM requirements, which penalise for over/under generation of metering quantity (QM) against QD. While QD is used as a proxy for QM, DSUs won't be subjected to over/under generation penalty and haven't been considered for an additional GPI.

The TSOs are exploring changes to the EDIL system to take into consideration the limitation of DSUs being unable to submit their data to three decimal places; however, we would expect compliance to "Good Industry Practice", as detailed in various sections of Grid Code. For example, if a DSU has declared availability of 3MW and receives a Dispatch Instruction of 1MW, but only provides 0.654MW, they will fall below the 70% threshold. Likewise, if a DSU is available for 2.1MW, they should declare availability of 2MW; whereas, if a DSU is available for 5.654MW, they should declare to 6MW, i.e., to the nearest whole number.

As per SEM-22-090 the RAs will provide information notes to keep the industry up to date on effectiveness of performance monitoring.

[4] https://www.eirgridgroup.com/site-files/library/EirGrid/AS-OSC-Report_2021-22.pdf
[5] https://www.eirgridgroup.com/site-files/library/EirGrid/AS-OSC-Report_2022-23.pdf
[6] https://www.eirgridgroup.com/site-files/library/EirGrid/GridCode.pdf
[7] https://www.soni.ltd.uk/media/documents/SONI-Grid-Code-June-2023.pdf
[8] https://www.semcommittee.com/publications/sem-22-090-dsu-energy-payments-decision-paper

### 3.3.3 TSOs' Recommendation

The TSOs recommend:

1. Retaining the existing rate of GPI Charges and adjusting for inflation.
2. The TSOs will formalise the monthly DSU GPI Performance Monitoring process and report quarterly to the RAs.
3. If directed by the RAs, the TSOs will introduce the new DSU GPI.

# 4. Response to New OSC section

## 4.1. Power Park Modules

This section summaries the comments received from Industry in relation to Power Park Modules and TSOs' response.

### 4.1.1 Respondents Comments

BGE requested applying OSCs to PPMs as soon as possible to incentivise compliance with Grid Code, as current absence unfairly penalises larger conventional generators. This would help with increasing risk to system stability, cost of maintain system security and levelling the playing field.

BGE seek update on continued performance monitoring, their compliance with the Grid Code and a plan for the introduction of GPI.

FERA and iPower noted that dispatchable wind should be treated in a similar fashion and purpose PPMs should have similar shortfall tolerance for metering against dispatch, just like DSUs.

### 4.1.2. TSOs Response

PPMs are not dispatched in the same manner as conventional power plants; they are dispatched using the Wind Dispatch Tool (WDT). The WDT has the capability to identify units, that have failed to achieve their Dispatch Instruction. These occurrences are followed up by the performance monitoring teams, in both TSOs, through the controllability and categorisation policy. If these issues are not resolved, the PPM may be re-categorised and face risk of being dispatched down.

PPMs are subject to Uninstructed Imbalance Charges in BM if outside tolerance limit for over/under generation that takes into consideration QM against DQ. That isn't applicable to DSUs.

### 4.1.3 TSOs Recommendation

The TSOs are not recommending a GPI for Power Park Modules for 2023/24. The TSOs will continue to monitor the reactive power Grid Code compliance of PPMs.

## 4.2. Demand Side Units (DSUs)

This section summaries the comments received from Industry in relation to DSU availability declarations with the focus on the accuracy of availability data in scheduling systems (i.e., MPI Forecast Availability) versus dispatch systems (i.e., EDIL availability) and the corresponding TSOs' response.

### 4.2.1 Respondents Comments

BGE welcomed this approach and advised maintaining a level of engagement to increase improvements as a whole and to incentivise remainder DSUs to improve.

FERA, iPower and DRAI note that its members have engaged successfully. They are providing more relevant forecast data and updated data via EDIL.

### 4.2.2. TSOs' Response

The TSOs have ongoing engagement with the DSU industry and reiterate the importance of accuracy of DSU availability submissions, as these can impact on the TSOs' ability to efficiently and effectively operate the power system, especially during periods of tight generation margins.

### 4.2.3 TSOs' Recommendation

The TSOs are recommending continued engagement with the DSU industry. They intend to only issue reports to DSUs and RAs where variances were identified.

## 4.3. Emerging Non-Thermal Technologies

This section summaries comments received from Industry and the corresponding TSOs' response.

### 4.3.1 Respondents Comments

BGE voiced concerns regarding the term, criteria and its application to battery storage and solar generation. They requested to establish a process for exiting classification from being considered an emerging technologies category and an approach to introduce them to OSC in a stage bases, to promote competitiveness.

FERA and iPower state comment from 4.1 is applicable here.

LEI "observe how the technologies impact the grid and understand the full range of service they can provide".

### 4.3.2. TSOs' Response

The TSOs welcome the comments received and will take these into consideration in future.

### 4.3.3 TSOs' Recommendation

The TSOs are not recommending an Emerging Non-Thermal Technologies Charge for 2023/24.

## 4.4. Security of Supply

This section summaries the comments received from Industry in relation to declared Availability is less than a unit's Registered Capacity (or DSU MW Capacity) and TSOs' response.

### 4.4.1 Respondents' Comments

BGE noted the importance of improving DSU declared Availability. They have proposed to consider introducing a charge as we move to net-zero system. They have concerns around DSU low availability and request clarification regarding whether the quarterly reports will become publicly available.

FERA and iPower believe "a severe lack of understanding regarding the technology of "Demand Side Response" and request insight into why "a demand should remain at a static level" or "certain forms of generation and technologies cannot perform at their maximum at all times".

FERA and iPower noted "no payment for Registered Capacity" under Grid Code and therefore consider no basis for a charge to be applied, albeit in future years, should a participant declare is capability down, in line with Grid Code rules. DRAI reference Capacity Market Code section: I.1.2.1(b) to which it states, "participant must *dedicate and use its reasonable endeavours to make available the Awarded Capacity*, which is de-rated" and catered for through Balancing Market Non-Performance Difference Charges while no obligation stands in relation to DSU's Registered Capacity (Operational Certificate value).

FERA and iPower state the connection type may impact on the ability of Individual Demand Site(s) (IDS) to be aggregated to DSU which impacts availability of the unit.

DRAI believes, if it was to be introduced in future to avoid discriminating against DSU, it should be applied to all technologies.

### 4.4.2. TSOs' Response

The TSOs have published monthly availability reports on the EirGrid[9] and SONI[10] websites since 2022 outlining Unit by Unit average monthly availability for Conventional units and Demand Side Units. Therefore, additional quarterly reports will be issued to DSUs and RAs only.

The TSOs will gain additional insight of DSU availability issues through issuing quarterly reports and request DSUs to provide explanation of variations.

The TSOs welcome comments received noting the reference to Grid Code, Capacity Market and Balancing Market and will reflect when considering its approach in future tariff years.

Regardless of connection type, the Demand Side Unit Operator is responsible for ensuring the declared availability is accurate and ensuring Individual Demand Sites (IDS)s within DSU units are capable of responding to Dispatch Instructions in line with their declared availability, as per Grid Code requirements. The TSOs would like to reiterate the importance of data accuracy from DSUs, as inaccuracies can impact the TSOs ability to efficiently and effectively operate the power system, especially during periods of tight generation margins.

TSOs welcome comments received and as noted in the consultation paper, a workshop with the industry will be scheduled early next year to discuss.

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[9] https://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Monthly-Availability-Report-April-2023.pdf
[10] https://www.soni.ltd.uk/media/documents/SONI-Monthly-Availability-Report-Mar23.pdf

### 4.4.3 TSOs' Recommendation

The TSOs are recommending an introduction of a performance monitoring report for 2023/24.

## 4.5. Proposed Rates

This section summarises comments received from participants in relation to the inflation rate proposed and the corresponding TSOs' response.

### 4.5.1 Respondents' Comments

FERA/iPower welcomes application of an inflation rate to reflect increase in costs and notes it should be applied to System Services tariffs and other charges/payments under control of EirGrid/SONI.

### 4.5.2. TSOs' Response

TSOs note the comments received and the following section details the proposal for 2023/2024.

# 5. Recommended Rates

With respect to the applicable inflation rate, the TSOs are aligning their methodology to that approved by the RAs with respect to a blended rate.

The TSOs, therefore, propose the following methodology to be applied:

- 75% from Central Bank HICP forecast using the latest available quarterly report adjusted for the relevant tariff timeframe;
- 25% from Office of Budgetary Responsibility CPI forecast using the latest available quarterly report adjusted for the relevant tariff timeframe.

According to the latest Office of Budgetary Responsibility report[11] (Mar 2023) the current CPI year on year inflation forecasts in the UK for the 2023/24 tariff year equates to c.+2.20% while the latest Central Bank report[12] (QB2 2023) forecasts HICP in Ireland for the same period at c.+3.65%.

| **Source** | | **2023** | **2024** | **Tariff Year Methodology** | **2023/2024 Tariff Year** | **Blended Rate Methodology** | **Blended rate** |
|---|---|---|---|---|---|---|---|
| OBR March 2023 | CPI | 6.1% | 0.9% | (0.061*25% + 0.009*75%) | 2.20% | 2.20*25% | 0.55 |
| Central Bank March 2023 | HICP | 5.0% | 3.2% | (0.05*25% + 0.032*75%) | 3.65% | 3.65*75% | 2.7375 |
| | | | | | | **Blended Rate** | **3.2875** |

**Table 1 Proposed Inflation Rate Increase**

On this basis and recognising the relative balance between Ireland and Northern Ireland, the forecast blended rate for the forthcoming 2023/24 period is 3.2875%, as shown in Table 1.

[11] https://obr.uk/docs/dlm_uploads/OBR-EFO-March-2023_Web_Accessible.pdf
[12] https://www.centralbank.ie/docs/default-source/publications/quarterly-bulletins/qb-archive/2023/quarterly-bulletin-q1-2023.pdf?sfvrsn=541f991d_5

## 5.1 Trip Charges

The proposed Trip Constants for the 2023/24 tariff year are shown in Table 5.1, which bears no proposed changes. Tables 5.2 & 5.3 have been adjusted by the blended rate of inflation, as defined above.

| | 2019-2020 | 2020-2021 | 2021-2022 | 2022-2023 | 2023-2024 |
|---|---|---|---|---|---|
| Direct Trip Rate of MW Loss | 15 MW/s | 15 MW/s | 15 MW/s | 15 MW/s | 15 MW/s |
| Fast Wind Down Rate of MW Loss | 3 MW/s | 3 MW/s | 3 MW/s | 3 MW/s | 3 MW/s |
| Slow Wind Down Rate of MW Loss | 1 MW/s | 1 MW/s | 1 MW/s | 1 MW/s | 1 MW/s |
| Direct Trip Constant | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Fast Wind Down Constant | 0.009 | 0.009 | 0.009 | 0.009 | 0.009 |
| Slow Wind Down Constant | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 |
| Trip MW Loss Threshold | 100 MW | 100 MW | 100 MW | 100 MW | 100 MW |

**Table 5.1 Proposed Trip Constants**

Based on the reasoning in Section 3.1, Table 5.2 contains the Trip Charge proposals for units with a QFPN, while Table 5.3 contains the Trip Charge proposals for units without a QFPN.

| Charge | 2019-2020 | 2020-2021 | 2021-2022 | 2022-2023 | 2023-2024 |
|---|---|---|---|---|---|
| Direct Trip Charge Rate | €2,190 | €2,227 | €2,249 | €2,339 | **€2,416** |
| Fast Wind Down Charge Rate | €1,642 | €1,670 | €1,687 | €1,756 | **€1,813** |
| Slow Wind Down Charge Rate | €1,095 | €1,114 | €1,125 | €1,170 | **€1,209** |

**Table 5.2 Proposed Trip Rates for Units With a QFPN**

| Charge | 2019-2020 | 2020-2021 | 2021-2022 | 2022-2023 | 2023-2024 |
|---|---|---|---|---|---|
| Direct Trip Charge Rate | €2,190 | €4,454 | €4,498 | €4,678 | **€4,832** |
| Fast Wind Down Charge Rate | €1,647 | €3,340 | €3,373 | €3,508 | **€3,624** |
| Slow Wind Down Charge Rate | €1,095 | €2,228 | €2,250 | €2,340 | **€2,417** |

**Table 5.3 Proposed Trip Rates For Units Without a QFPN**

## 5.2 Short Notice Declarations

A SND can have the same impact on scheduling and dispatch as that of trips. These short notice outages can have a significant effect on the ability of the TSOs to schedule and dispatch in an economic manner and to manage Transmission Constraint Groups which are essential to the secure operation of the transmission system. There are no proposed changes for Generator units Constants, while DSU constants have been added (see table 5.4). The DSU SND Threshold is set to 4MW, in line with minimal DSU MW Capacity, and DSU SND Time Zero to 60mins. Table 5.4 shows the proposed SND Constants for 2023-24. Table 5.5 & 5.6 rates have increased by the rate of inflation from previous year.

| SND Constants | 2019-2020 | 2020-2021 | 2021-22 | 2022-23 | 2023-2024 |
|---|---|---|---|---|---|
| SND Time Minimum | 5 min | 5 min | 5 min | 5 min | **5 min** |
| SND Time Medium | 20 min | 20 min | 20 min | 20 min | **20 min** |
| SND Time Zero | 480 min | 480 min | 480 min | 720 min | **720 min** |
| DSU SND Time Zero | N/A | N/A | N/A | N/A | **60 min** |
| SND Powering Factor (Notice time weighting curve) | -0.3 | -0.3 | -0.3 | -0.3 | **-0.3** |
| SND Threshold | 15 MW | 15 MW | 15 MW | 15 MW | **15 MW** |
| DSU SND Threshold | N/A | N/A | N/A | N/A | **4 MW** |
| Time Window for Chargeable SNDs | 60 min | 60 min | 60 min | 60 min | **60 min** |

**Table 5.4 Proposed SND Constants**

Table 5.5 shows the proposed SND Charge Rate for Generating Units with a QFPN.

| SND Charge Rate | 2019-2020 | 2020-2021 | 2021-22 | 2022-2023 | 2023-2024 |
|---|---|---|---|---|---|
| SND Charge Rate | €38 / MW | €39 / MW | €39 / MW | €41 / MW | **€42 / MW** |

**Table 5.5 Proposed SND Charge Rate for units with a QFPN**

Table 5.6 shows the proposed SND Charge Rate for Generating Units without a QFPN.

| SND Charge Rate | 2019-2020 | 2020-2021 | 2021-22 | 2022-2023 | 2022-2023 |
|---|---|---|---|---|---|
| SND Charge Rate | N/A | €77 / MW | €78 / MW | €81 / MW | **€84 / MW** |

**Table 5.6 Proposed SND Charge Rates for units without a QFPN**

## 5.3 GPI Charges

There are no proposed changes for Generator GPI Constant, while DSU constant has been added (see table 5.7) and with the direction from RAs may be implemented at a future date. The DSU MW Shortfall tolerance limit is at 70%, so anytime SCADA is under this threshold from its DQ will receive a charge. Table 5.8 lists Generator rates that have increased by the rate of inflation and new DSU GPI rate added for the 2023/2024 tariff year.

The Event Based GPIs will remain at zero (i.e., Loading Rate, De-Loading Rate, Early Synchronisation, Late Synchronisation, Max Starts in 24-hour period and Minimum On time).

The proposed GPI Constants and GPI Declaration Based Charges for the 2023/2024 tariff year are outlined in Table 5.7and Table 5.8, respectively.

| **GPI Constants** | **2019-2020** | **2020-2021** | **2021-22** | **2022-2023** | **2023-2024** |
|---|---|---|---|---|---|
| Late Declaration Notice Time | 480 min | 480 min | 480 min | 480 min | **480 min** |
| Loading Rate Factor 1 | 60 min | 60 min | 60 min | 60 min | **60 min** |
| Loading Rate Factor 2 | 24 | 24 | 24 | 24 | **24** |
| Loading Rate Tolerance | 110% | 110% | 110% | 110% | **110%** |
| De-Loading Rate Factor 1 | 60 min | 60 min | 60 min | 60 min | **60 min** |
| De-Loading Rate Factor 2 | 24 | 24 | 24 | 24 | **24** |
| De-Loading Rate Tolerance | 110% | 110% | 110% | 110% | **110%** |
| Early Synchronous Tolerance | 15 min | 15 min | 15 min | 15 min | **15 min** |
| Early Synchronous Factor | 60 min | 60 min | 60 min | 60 min | **60 min** |
| Late Synchronous Tolerance | 5 min | 5 min | 5 min | 5 min | **5 min** |
| Late Synchronous Factor | 55 min | 55 min | 55 min | 55 min | **55 min** |
| Secondary Fuel Availability Factor | 0.9 | 0.9 | 0.9 | 0.9 | **0.9** |
| DSU MW Shortfall Tolerance | N/A | N/A | N/A | N/A | **70%** |

**Table 5.7 Proposed GPI Constants**

| | **2019-2020** | **2020-2021** | **2021-22** | **2022-2023** | **2023-2024** |
|---|---|---|---|---|---|
| **GPI Declaration Based Rates** | **€ / MWh** | **€ / MWh** | **€ / MWh** | **€ / MWh** | **€ / MWh** |
| Minimum Generation | 1.31 | 1.33 | 1.34 | 1.39 | **1.44** |
| Reactive Power Leading | 0.32 | 0.32 | 0.32 | 0.33 | **0.34** |
| Reactive Power Lagging | 0.32 | 0.32 | 0.32 | 0.33 | **0.34** |
| Governor Droop | 0.32 | 0.32 | 0.32 | 0.33 | **0.34** |
| Primary Operating Reserve | 0.53 | 0.54 | 0.55 | 0.57 | **0.59** |
| Secondary Operating Reserve | 0.13 | 0.13 | 0.13 | 0.14 | **0.15** |
| Tertiary Operating Reserve 1 | 0.13 | 0.13 | 0.13 | 0.14 | **0.15** |
| Tertiary Operating Reserve 2 | 0.13 | 0.13 | 0.13 | 0.14 | **0.15** |
| Secondary Fuel Availability | 0.03 | 0.03 | 0.03 | 0.05 | **0.05** |
| DSU Metering Shortfall | N/A | N/A | N/A | N/A | **100** |

**Table 5.8 Proposed GPI Declaration Based Charge Rates**

# 6. Appendix A

## 6.1 Bord Gáis Energy Response:

Bord Gáis Energy

EirGrid Plc.
The Oval
160 Shelbourne Road
Ballsbridge
Dublin 4
D04 FW28

tariffs@eirgrid.com

28 June 2023

**RE: Harmonised Other System Charges Consultation Paper for Tariff Year 1 October 2023 – 30 September 2024 (the "Consultation")**

Dear Tariffs team,

Bord Gáis Energy (BGE) welcomes the opportunity to respond to the consultation on Harmonised Other System Charges (OSC) for Tariff Year 2023/24. We are concerned that the proposed OSCs will continue to effectively double charge units via Trip and Short Notice Declaration (**SND**) charges alongside Balancing Market (**BM**) commercial penalties. The TSO has not set out robust rationale for continuing to apply these charges. It is our view that these charges are ineffective at incentivising better generator performance and that generator behaviour is in fact driven by market circumstances, the level of TSO engagement with industry and, in some instances, running hours.

BGE is particularly concerned that the TSO propose to continue to apply the Generator Performance Incentive charge (**GPI**) for the Secondary Fuel Obligation (**SFO**). The SFO GPI does not incentivise operational change to increase fuel security. Instead, it just increases the financial and operational penalty burden being carried by these SFO units. We believe that all units in the SEM have an equal obligation to help maintain security of supply and therefore, the SFO burden should be borne equally across all units.

We welcome the TSO's proposals relating to DSUs as these will incentivise better DSU performance and help level the playing field between DSUs and other standard technologies in the SEM. However, the TSO must do more to decrease the market distortion and imperfections cost created by the current approach, which are ultimately passed on to the consumer.

It is crucial as we move towards a net-zero system that the TSO takes measures to (i) ensure a fair and competitive market to level the playing field across technologies, and (ii) incentivise better performance and compliance across all units. Our response outlines some measures we ask of the TSO to achieve this, such as:

- Removing Trip and SND charges for units with a day-ahead (**QEX**) position as these should be covered by BM costs paid by the causal unit(s).
- Removing the SFO GPI and instead create an optional bidding market for all grid-connected generation units to provide security of supply generation services to the grid.
- Introducing a GPI charge for Power Park Modules (**PPMs**) once the process of using existing PPM grid code capabilities to manage voltage control is fully understood and deployed by the TSO.
- Taking a measured approach to the application of OSCs to emerging market technologies and define "Emerging Technology".
- Implementing the proposals outlined in the consultation that level the playing field between DSUs and other standard technologies in the SEM and incentivise more accurate DSU declared Availability.

We have outlined these measures in greater detail in our response below.

1. **EXISTING OSC**

Page **1** of 5

### 1.1 Trip and Short Notice Declaration Charges

BGE remains of the view that where trips or SNDs occur which always require energy balancing actions to be taken by the TSO, the cost of these actions to the TSO should be entirely covered by the BM cost paid by the causal unit(s). The BM charges paid by units causing BM actions to be taken should be sufficient to cover the relevant trip. If the BM charges in question do not cover the cost to the system, we believe that this is a market issue which needs to be resolved through the market as opposed to through system charges such as Trip and SND. We request supporting analysis from the TSOs on why they believe that this extra Trip and SND money is required to cover market-driven energy imbalances. If there are increased costs to customers, this needs to be better explained.

Reserves are already provided under DS3 procurement and between these, imbalance costs and the risk of Reliability Option (RO) payments where applicable, there should be no need for Trip or SND charges. These charges act as an unnecessary and unavoidable penalty on responsible units in the event of an unplanned loss of production event. The focus of the TSOs should be to protect the consumer from any additional costs triggered by trips or SNDs. Inefficiencies in the market that can result in increased costs to the TSOs should not be subsidised by "direct incentive" (Trip or SND) charges on responsible units.

#### *Units with a QEX position*

BGE does not believe that units with a QEX position should be subject to trip or SND charges. Units with a QEX position at the time of a trip or SND are already fully commercially self-incentivised to remain operative as:

- they likely face significant imbalance charges, and the imbalance charges payable contribute towards minimising costs for consumers; and
- they also likely face exposure to RO payments in the event of an unplanned outage.

#### *Units without a QEX position*

BGE understands the rationale to levy costs on units without a QEX position to ensure that they are balance responsible and to mitigate Direct Balancing Costs (DBCs), but we ask for further quantitative information to support the decision as to the appropriate charge levels for such units. From a consumer perspective, the quantum of impact these units are having on DBCs is of particular importance and should in our view be published to ensure that overall, the consumer is receiving best value for money and that appropriate charges are being applied.

It is unclear how for SND the increase in notice time from 8 hours to 12 hours has resulted in improvements in the notice time provided by units. Apart from the random variation expected from one tariff year to another, BGE believes that this improvement is more likely to be (i) the result of better administration by tripped units (ii) the result of units being more aware of tight system margins through better engagement with the TSO, and (iii) increased oversight and testing of units. While the TSO notes that the notice time provided by units has improved, in our view the increase from 8 to 12 hours does not incentivise units to trip less and therefore the benefit to the system of this improvement is minimal. Generators would give as much notice as possible no matter the period of hours specified. BGE believes there is no justification for this charge, and we seek its removal for units with a QEX position.

#### *DSUs*

DSUs are an established technology, and we welcome any measures that level the playing field amongst technologies. However, we maintain that the cost of energy balancing actions resulting from SNDs should be covered by the BM cost by the causal SND unit, regardless of its technology, and should only apply to units without a QEX position. Should the TSO decide to implement an SND charge to DSUs following consultation, BGE requests more information on the TSOs' rationale for setting a threshold of 4MW for the calculation of the charge.

### 1.2 Generator Performance Incentive Charge

In general, we are supportive of the proposals in the consultation to retain the Primary Operating Reserve GPI, and Reactive Power GPI charges at a level adjusted for inflation. We also welcome the potential introduction of a new DSU GPI which would help level the playing field between DSUs and other technologies in the SEM and encourage competition in the market.

#### *Secondary Fuel GPI*

BGE does not however support the Secondary Fuel GPI. We do not believe that the SFO is appropriately designed or applied today[1]. The SFO does not incentivise a participant's contribution to fuel security but instead just increases the penalty burden being carried by these units. Units with an SFO are already penalised

- financially through increased infrastructure and increasing secondary fuel stock costs, and
- operationally by having to manage the added difficulty of operations and safety that secondary fuel running brings to a generation unit.

These penalties are additional to the fact that in our view the SFO is unfair in its application as the obligation and requirement is carried by only a small sector of the SEM generation fleet when all units in SEM should carry an equal obligation of helping to maintain security of supply. Furthermore, the SFO requirement limits the cost effectiveness of plant that is subject to the SFO. Dual fuel plant is physically more complex than single fuel plant, and requires additional infrastructure at an additional cost to participants to manage secondary fuel and fulfil its obligation.

If SFO running is to be incentivised then it should be by positive reward (whether by removing/ sharing the SFO burden, or financially) rather than by penalties applied through this charge. The risk of fuel security to electricity generation is acknowledged but it should also be recognised that secondary fuel running offers only an immediate/ short term solution (up to 5 days). The short-term mitigation by secondary fuel running in electricity generation must be seen against the potential longer-term impact from any uncertainty of primary generation fuel stocks. While units running on the SFO can play their part in the immediate to short-term, continuing to apply an SFO GPI will not drive any operational change. As set out in our response[2] to CRU's clarification and call for evidence paper[3] in 2021, BGE proposed an optional bidding market for all grid-connected generation (existing, new, and embedded) units to provide security of supply generation services to the grid.

BGE questions the appropriateness of measuring the impact of the 50% increase in the SFO charge rate in the 2022/23 tariff year on the first six months of that tariff year compared to the previous tariff year. Apart from the normal variation expected from year to year, there are likely to be a range of factors at play that would have resulted in a reduction in number of units this charge applies to, such as (i) more opportunities for generator outages to improve SFO (ii) better communication between the TSO and generators which has meant generators are more aware of security of supply concerns (iii) increased industry focus on security of supply which has meant more oversight and unit testing. We believe that it would not be prudent for the TSO to attribute GPI SFO improvements to the 50% increase in the charge rate based on data gathered over a short period and given other possible factors. For clarity on this matter, BGE request the TSO to outline how it determined the charge total to be at least 153% lower on trend?

#### *DSUs GPI*

BGE welcomes the potential introduction of a new DSU GPI that will help level the playing field between DSUs and other technologies in the SEM. However, we request that the TSO set out its rationale for (i) setting a shortfall threshold of 70% or more before applying the charge and (ii) setting the underperformance change rate at €100 for each trading period. We would expect the shortfall threshold to decrease over subsequent tariff years to further incentivise improvements in DSU

[1] The secondary fuel compensation arrangements currently in place for generators in Ireland only cover secondary fuel testing, and there are no arrangements to compensate generators for their additional costs in the event that they are instructed by EirGrid to run on secondary fuel outside of the testing process
[2] CRU202252h – dated 7th May 2021
[3] CRU/21/036 - Secondary fuel obligations on licenced generation capacity in the Republic of Ireland Clarifications and Call for Evidence

performance. It is important that the impact of the charge is monitored closely by the TSO to ensure that DSUs are incentivised to properly declare Availability. The main revenue source for DSUs is the System Services market and therefore DSUs have a strong commercial incentive to declare Availability as much as possible. We ask that the TSO is cognisant of the trade-off between the commercial incentive to declare Availability and the penalty for underperformance.

## 2. NEW OTHER SYSTEM CHARGES

### 2.1 Power Park Modules

We welcome the TSO making increased use of the existing capabilities in the system. We understand that as the process of using existing PPM grid code capabilities to manage voltage control may be new, there will be a stage of learning before performance monitoring can be implemented correctly. Thereafter, given the increasing share of wind and solar units in the market, we ask that the TSO apply OSCs to PPMs as soon as possible to incentivise these units behave in line with the grid requirements and what they are contracted to do (from a system and DS3 perspective in particular). This is important as wind PPMs are particularly well established in the market and therefore, the current absence of OSCs to PPMs unfairly penalises larger conventional generators who are effectively left carrying the cost.

We would expect to see a GPI charge for these units this year so that wind and solar units are treated in the same way as conventional generation in the application of OSCs. This would (i) capture the increasing risk and impact of these sources to system stability and the potential increase in costs to maintain system security, and (ii) level playing field in the application of GPI charges across standard generation types in the SEM which we believe now includes wind and solar considering that wind at least is becoming more akin to a baseload unit. The share of established wind PPMs in generation levels should be matched by a reflective application of GPIs as otherwise larger conventional generators are being inequitably penalised.

BGE requests an update from the TSOs on the continued monitoring of PPM performance and their compliance with the Grid Code. We also request the TSO to provide a concrete plan on how it plans to introduce, as soon as possible, GPI for PPMs given the risks and potential increase in costs to maintain system security that the increasing capacity of PPMs brings to the system.

### 2.2 Demand Side Units (DSU)

BGE welcomes the increased engagement between the TSO and the DSU industry on concerns pertaining to DSU Availability declarations and notes the improved consistency of DSU Availability declarations. While we agree with the TSO's proposal to only produce reports for units that have a variation, it is important that the TSO maintains this level of engagement with the DSU over the 2023/24 tariff year. Continued engagement at this level would ensure that (i) the recent improvements seen are maintained going forward and (ii) the remaining units with variation are incentivised to improve their declared Availability.

### 2.3 Emerging Non-Thermal Technologies

BGE believes that measured application of the charges to emerging market technologies is laudable such that these units are not unfairly burdened. To not apply these charges would undermine the growth of new technology and competition in the market. Short-duration battery storage and solar generation however are now established and with a view to levelling the playing field amongst technologies, we request insights on the trigger point as to when and at what charge level these technologies will be incorporated into the OSC tariff structure.

BGE note the TSO's view that it is too early to propose charges for emerging non-thermal technologies which have not yet been embedded into normal operations. However, given the substantial increase and the further increases expected in short-duration battery storage and solar generation, continuing to not apply charges to these technologies will increasingly undermine competition in the market. We ask the TSO to consider establishing an alternative approach whereby, for example, a project using emerging technology would

i. not initially be subject to OSCs in the early stages of the project,

ii. thereafter be subject to gradual or interim OSCs for a year, and
iii. finally, be treated as a standard technology in the SEM with regards to the application of OSCs once the project has reached a certain age or the technology is no longer considered "emerging".

This approach would allow emerging technologies an advantage during the early stages of the project while ensuring that future OSC costs are built into the relevant project's initial investment case. We believe that this fully transparent approach is laudable such that it would not undermine the growth of emerging technologies and increases the competitiveness of emerging technologies relative to the current approach.

For transparency and in the interests of informing participants' views on the scope of decisions pertaining to emerging technology, we ask the TSO to define its understanding "Emerging Technology" which we expect would not include short-duration battery storage or solar generation.

### 2.4 Security of Supply

We welcome the TSO's proposal to introduce quarterly performance monitoring reports for DSUs and to continue to engage with DSUs to improve the accuracy of their declared Availability in consideration of introducing a charge for declared Availability. It is concerning that the TSOs' review of 2022 data shows that DSU declared Availability remains in the low percentile of its DSU MW Capacity given that DSUs are now an established technology and will become increasingly important as we move towards a net-zero system. It is critical that DSUs are held to the same account as other standard technology in the SEM with regards to their performance. We welcome the proposed workshop in 2024 to provide an update on the performance monitoring progress. We ask the TSO to confirm whether the DSU quarterly performance monitoring reports (similar to the EirGrid Monthly Availability Report[4]) will be made publicly available to keep the industry abreast of DSU performance over the course of the next tariff year?

I hope the above comments and queries are clear and helpful. Please do not hesitate to contact me should you wish to discuss any aspect of the above.

Yours sincerely,

**Niamh Trant**
**Regulatory Affairs – Commercial**
**Bord Gáis Energy**
*{By email}*

[4] EirGrid-Monthly-Availability-Report-April-2023.pdf (eirgridgroup.com)

## 6.2 DRAI Response:

DRAI

27th June 2023

**Harmonised Other System Charges Consultation Response**

I am writing on behalf of the Demand Response Association of Ireland (DRAI), the trade association representing Demand Side Unit (DSU) providers in the all-island Single Electricity Market (SEM). By aggregating the otherwise passive electrical loads of individual consumers into substantial load portfolios, our members create predictable, reliable, and controllable assets, which provide a valuable source of Demand Side Flexibility (DSF) that can be actively used by system operators to meet the needs of the power system.

Today, the DRAI represents approximately 700 MW of demand and embedded generation response across hundreds of industrial and commercial customer sites throughout the island of Ireland. These sites are managed by our members each of whom actively participate in the capacity, DS3, and energy markets.

DRAI members are committed to shaping the future of power system flexibility through advancing DSF on the island of Ireland. As Ireland strives to achieve its renewable generation targets for 2030 and beyond, our promise as an industry-led organisation is to champion the development of innovative DSF solutions that are designed to address the system-wide requirement for flexibility.

The DRAI expresses a single voice on policy and regulatory matters of common interest to its members, and we welcome the opportunity to provide feedback on the Harmonised Other System Charges consultation.

On behalf of the DRAI I hope that you find our response helpful and constructive.

*Martina Assereto*

Martina Assereto
Deputy Chair, DRAI

## SUMMARY OF DRAI RESPONSE TO THE CONSULTATION

In relation to the specific proposals in the consultation, the DRAI notes the following:

- Short Notice Declaration (SND) Charge should not be applied to DSUs
- Generator Performance Incentive (GPI) Charge should not be introduced for DSUs
- Security of Supply OSCs should not be introduced for DSUs

## RESPONSE TO SPECIFIC CONSULTATION SECTIONS

The following section outlines our specific response to the consultation.

### *3.1 Trip Charges*

The DRAI has no comment on this topic.

### *3.2 SND Charges*

*The TSOs are proposing to introduce a SND charge to DSUs. In the event of a DSU unit making a downward declaration of its availability at short notice less than 60mins, a Short Notice Declaration (SND) Charge is levied on the service provider depending on the amount of notice given, while applying a threshold of 4MW and the quantity of downward declaration (i.e., €/MW charge). The charge is intended to incentivise behaviour that enhances system security and reduce the costs of actions taken by the TSOs to mitigate SNDs.*

Firstly, the DRAI is unclear on whether this proposal applies to:

- last minute downward changes of more than 4 MW in a DSU's EDIL declared availability after a dispatch instruction is received, or
- the situation where a unit's EDIL declared availability in dispatch system is more than 4 MW lower than the availability data submitted to scheduling system (MPI forecast availability).

We therefore request more clarity on what the 4 MW threshold is applied to. Moreover, we would appreciate a justification for the 60 minutes specifically.

Secondly, DSU Aggregators will declare availabilities that reflect the actual technical capabilities of the site(s) within the unit. Following Grid Code SDC1.4.3.4:

*Each Demand Side Unit Operator shall, subject to the exceptions in SDC1.4.3.5 and SDC1.4.3.5A, use reasonable endeavours to ensure that it does not at any time declare the Demand Side Unit MW Availability and the Demand Side Unit characteristics of its Demand Side Unit at levels or values different from those that the Demand Side Unit could achieve at the relevant time. The TSO can reject declarations to the extent that they do not meet these requirements.*

The proposed SND Charge could penalise DSUs for complying with SDC1.4.3.4 and declaring actual availability of the site(s) at the relevant time. We would like more clarity on the two conflicting signals.

The DSU Aggregator has no control over the demand load of the customer sites which are being made available for demand response. Therefore, levying charges for short notice declarations will not incentivize behaviour that enhances system security.

In addition, we would like to reiterate our request for data interface between DSUs and the TSO in order to automate the EDIL declaration process, to the benefit of both DSUs and TSO.

To conclude, the DRAI notes SND Charges should not be applied to Demand Side Units.

### *3.3. GPI Charge*

The DRAI has no comment on this topic.

#### *3.3.1. GPI Secondary Fuel*

The DRAI has no comment on this topic.

#### *3.3.2. GPI Minimum Generation and GPI Operating Reserve*

The DRAI has no comment on this topic.

#### *3.3.3. New DSU GPI*

*As per decision paper SEM-22-0902, once DSU energy payments has been implemented in Balancing Market, DSU dispatched quantity (QD) will be used as a proxy for metered quantity (QM), the effectiveness of this will be assessed and reported on quarterly. Through the continuous monitoring process if it is deemed additional measures are required the below charge will be applied.*

*The TSOs issue Dispatch Instructions to the DSU, and this is currently compared to SCADA Metering data. If the shortfall between these is greater than 70%, an underperformance change rate will apply for each trading period at a rate of €100.*

In principle, the DRAI is not opposed to a charge for underperformance as specified. Monitoring processes are already in place to deal with underperformance during a dispatch event and DSUs continue engaging with the TSO on those occasions.

However, it does seem rather pre-emptive to introduce such a charge. SEM-22-090 states that following a SEMC assessment of Phase 1 and following the publication of an Information Note with the outcome of the QD monitoring, should the review be deemed unsatisfactory, "*additional measures, such as a GPI, may be put into place to enhance performance*". The DRAI would appreciate greater clarity regarding the circumstances it is envisaged such a charge might be introduced and on what basis.

### *4.1 Power Park Modules*

The DRAI has no comment on this topic.

### *4.2. Demand Side Units*

As mentioned in the Consultation paper, there has been a noteworthy improvement in the consistency of availability declarations (EDIL vs MPI Forecast) and we will continue to engage with the TSO to further reduce variations in declarations between the two systems.

<u>The DRAI agrees with the TSO that a charge should not be introduced on this matter.</u>

### *4.3. Emerging Non-Thermal Technologies*

The DRAI has no comment on this topic.

### *4.4 Security of Supply*

*The TSOs are proposing to introduce quarterly performance monitoring reports for DSUs and to engage with the DSUs, to reduce variations in declared Availability and DSU MW Capacity for the tariff year 2023/24 and potentially to include reports as part of section 4.2. In early 2024 a workshop will be held to provide update on performance monitoring progress. The TSOs are not proposing to introduce OSCs for the tariff year 2023/24.*

The DRAI points to Capacity Market Code section I.1.2.1(b), in which a participant must *dedicate and use its reasonable endeavours to make available the Awarded Capacity*, which is de-rated, and to the fact that market mechanisms are already in place to penalize Demand Side Units in the event of availability below the unit's capacity obligation (Non Performance Difference Charges). There is no obligation regarding a DSU's Registered Capacity (Operational Certificate value). If a charge penalizing market participants for availability below their Registered Capacity were to be introduced in the future, it would have to be applied to all technology types to avoid discriminating against DSUs.

<u>Therefore, the DRAI agrees with the TSO that a charge should not be introduced on this matter.</u>

### *5.1 Trip Charges*

The DRAI has no comment on this topic.

### *5.2. Short Notice Declarations*

As mentioned in section 3.2, <u>the DRAI notes SND Charges should not be applied to Demand Side Units.</u>

The DRAI would also appreciate greater clarity on the items mentioned in section 3.2

### *5.3 GPI Charges*

The DRAI has no comment on this topic.

## 6.3 ESB Generation and Trading’s Response:

Energy for generations

ESB Generation and Trading's Response to the Harmonised Other System Charges Consultation:

2023-2024 Tariff Year

28/06/2023

## 1. INTRODUCTION

ESB Generation and Trading (GT) welcomes the opportunity to respond to EirGrid and SONI's, collectively the Transmission System Operators (TSOs), Consultation Paper on the 'Harmonised Other System Charges' for the Tariff Year of 1st October 2023 to 30th September 2024.

## 2. SUMMARY

ESB GT recognises the significant work that EirGrid and SONI perform in relation to their stakeholder engagement and belief the following comments will be helpful in relation to future engagement.

Firstly, there is a lack of supporting data in the consultation paper or published on the EirGrid website that can allow a market participant to fully understand the impacts of proposed changes or previously implemented changes. For example, in our response to the 22-23 OSC consultation we stated:

"*The consultation paper proposes to increase the Short Notice Declaration (SND) Time Zero parameter from 480 mins (8 hours) to 720 mins (12 hours), however, the paper offers very little justification from the TSOs for this decision. While it is disappointing to see a proposal to increase this value, and not a removal of this charge, if this SND Time Zero parameter was to be increased, any benefit of this extended notice period should be determined and reflected in the SND charge, as the TSOs will have a much longer period in which to make decisions and optimise their redispatch costs. Hence, ESB GT believes any increase in the SND from 480 mins to 720 mins should have a lower SND charge rate associated. If the proposed value of 720 mins was to be taken forward without a decrease in the charge rate, the resultant would be an increase in the SND Charge for the same hours' notice as compared with today (applying the SND Charge Methodology).*"

Unfortunately, the trip report[1] for 22-23 does not appear to be readily available for consideration in relation to this consultation paper nor has any supporting evidence been provided to determine whether or not the actual cost incurred for rescheduling under the new 720mins is still the same when under the 480mins regime.

Finally, ESB GT wants to take the opportunity to highlight a long standing request, in December 2022, from the SEMC (Mod_02_22) on the TSOs in relation to a modification on unit under test. ESB GT trusts that EirGrid and SONI will have completed this work prior to publishing any consultation on the testing tariffs for the next year.

[1] https://www.eirgridgroup.com/site-files/library/EirGrid/Trip-Report-2021-22.pdf

## 6.4 FERA Response:

FERA Federation of Energy Response Aggregators

FERA Response to

SONI/Eirgrid Consultation –

Harmonised Other System Charges for Oct23 to Sep24

FERA's members operate in the Demand Side Response sector of the electricity industry and perform a significant role in supporting the operation of the I-SEM balancing market and facilitating the continuous introduction of renewables. They have significant experience in working with SONI and Eirgrid to provide stability and balance to the system operations. The FERA members have together a registered capacity above 160MW, which carries a significant contribution to system support and stability.

The following comments are in relation to the published SONI/Eirgrid consultation and clause reference numbers are used where possible.

**Introduction**

The FERA members operate the aggregation of multiple sites in the provision of Demand Response, which comes from reduction of load, self-generation, and export onto the grid. The use of multiple sites means that outage rates are much lower and 'trips' of generation do not impact the whole unit. This functionality means that dispatched demand units are more robust in delivering the required volume than an equivalent conventional unit, which would lose all its provision during a trip.

Multiple sites also mean that the aggregated demand of those sites is flexible and changes constantly and at short notice. This is the nature of the DSU and AGU technology, and it differs from other dispatchable generation.

**Comments on proposals**

Clause 3.1 FERA welcomes the TSO's comments and note that the MW trip threshold shall remain at 100MW. The TSO's comments informs industry that there is no significant financial impact to the system, should conventional power plants lose up to 100MW of provision.

Clause 3.2 Generation units throughout the island have varying abilities over time and sometimes encounter issues that impact their output volume. Sometimes these can be seen coming and sometimes they appear at short notice. It is understandable that the TSO scheduling can be impacted if such output becomes unavailable and causes rescheduling of other plant and the TSOs

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now require over 12 hours' notice (since 2022/23) to allow them to prepare alternative scheduling. It is understood that the SND is applied to the declaration changes made via EDIL and not associated to any I-SEM forecast position. FERA would ask if the forecast value would be used in assessment should there be a lack of EDIL declaration.

This clause reviews the SND parameters and states that there shall be no change to the conventional generation plant values. It is maintaining the MW threshold at 15MW, without commenting on the size of a conventional generator that may make such a declaration change. This indicates that Eirgrid/SONI believe that a declaration value change of 15MW per unit can be handled without significant impact to their scheduling. There is no comment on the number of conventional units that could make such declarations, nor the combined impact of such. FERA is therefore confused as to why Eirgrid/SONI have suggested to treat the Demand Response technology in a different manner, by suggesting a 4MW threshold. We would welcome further explanation on how that value was derived and how other dispatchable generators with registered capability of less than 15MW are to be treated.

FERA does welcome the reduced notice time of 60 minutes for Demand side units, which reflects the variability of the technology. We notice that the factoring scalars are still applicable, to incentivise more rather than less notice time and FERA welcome that.

Clause 3.3.1 No Comment

Clause 3.3.2 No Comment

Clause 3.3.3 FERA notices that this clause is specific to Demand Side Units and has been linked to the expected DSU energy payment. The Eirgrid/SONI premise appears to be that since the payment shall be as per the Dispatched Quantity (DQ) then the metering shall need to match that. The RA decision in SEM-22-090 identified that there was no metering usable at the current time for energy payment settlement and that the DQ would be used. The RAs did comment that the effectiveness of using the DQ would need to be assessed. Eirgrid/SONI are proposing to look at the SCADA data, provided by aggregators, and compare it against the dispatch quantity. It is suggested that the SCADA metering should be within 70% of the DQ, although Eirgrid/SONI have not provided any research information on the use of the 70% value.

FERA would question why SONI are proposing to introduce this new GPI for DSU since a GPI should be *'levied on those generators which fail to comply with specific standards in the **Grid Code**'*. The section of the Grid Code should be identified otherwise the GPI may have no standing.

FERA would also like to point out that the SCADA signals provided by the aggregators are to three decimal places, but the EDIL system can only handle whole values. Grid code requires participants to declare their actual capability, although since EDIL can only handle whole numbers then rounding up is the only method to comply with Grid Code. This means that the declared availability value has to be rounded up to whole values, which would then be dispatched as whole values. The calculation of percentage (%) would then depend on the actual figures used in attempting to match against the 70% target. See the following table for examples.

| Actual MW availability | EDIL MW value | % delivered |
|---|---|---|
| 0.654 | 1 | 65.400% |
| 2.654 | 3 | 88.467% |
| 5.654 | 6 | 94.233% |
| | | |
| 2.1 | 3 | 70.000% |

Whilst this new GPI is only a suggestion and the decision to implement is being left to the RAs, the reason for the incentive does not align with Grid Code and the implementation does not appears to be treating larger and smaller units in a fair and equal manner.

Clause 4.1 The assessment of any dispatchable wind, even with QFPN, should be treated in a similar fashion to other technologies. If metering from a Power Plant Module falls short of its dispatch, then should it have a similar shortfall tolerance to that proposed for DSU?

It is noted that Eirgrid/SONI were considering GPIs for Wind Farms in August 2016[1] and yet there appears to be a stronger push to implement incentives against DSU in this current paper. There should be an equity approach to technologies, under Grid Code.

Clause 4.2 FERA acknowledges that its members have engaged successfully with the TSOs and the RAs in providing more relevant forecast data via the MPI and updated data via EDIL. Given the complexity of the MPI process most of our members limit the forecast data submission to a daily basis. The nature of demand is such that it can vary without much notice and reflecting that in the forecast is problematic.

Clause 4.3 The technologies mentioned in this clause would appear to fall under Power Park Modules, and should be treated the same as those mentioned in clause 4.1. Please see our comments above.

Clause 4.4 FERA believes that the comments made in this clause show a severe lack of understanding regarding the technology of Demand Side Response. This is a somewhat worrying situation, and we believe that Eirgrid/SONI should justify why they think a demand should remain at a static level. It should also be noted that there is no payment for 'Registered Capacity' under Grid Code and therefore there is no basis for a charge to be applied, albeit in future years, should a participant declare is capability down, in line with Grid Code rules. Whilst the TSOs may think it nice

[1] https://www.eirgridgroup.com/site-files/library/EirGrid/OSC-16-17-Recommendations-Paper.pdf

to have all installed and connected generation available to them at all times, they need to understand that certain forms of generation and technologies cannot perform at their maximum at all times.

Technologies such as Solar, Wind, Battery Storage, Hydro, Pumped Storage all have limitations and are dependent on certain energy sources. Demand Side Response is not similar to conventional power plants and Eirgrid/SONI may need to better understand the technologies participating within the All-Island electricity markets and within the Grid Code jurisdictions.

Demand Side Response is mostly connection to the distribution network and NIE/ESB implement Instruction Sets, which can impact on the ability of Individual Demand Sites to be aggregated to the DSU. This impacts the availability of the unit.

**Clause 5** FERA welcomes the application of inflation as a reflection of increased costs.. We expect that the same inflationary percentage shall be applied to the System Services tariffs and other charges/payments under the control of Eirgrid/SONI.

**Clause 5.1** This clause shows the constants relating to a trip and FERAs' comments regarding clause 3.1 above are relevant. We would like to point out that since losing up to 100MW in an instant doesn't cause the TSOs much concern then why does the loss of 4MW within 60 minutes (SND for DSU) cause such concern?

**Clause 5.2** The introduction of SNDs for Demand Side Response is difficult for FERA to understand, in comparison to conventional plant that doesn't really have a variable energy source. We refer to the comment for clause 3.2 above.

**Clause 5.3** FERA believes that there should be more information provided on how Eirgrid/SONI have arrived at the value of 70% and €100/MWh. Note that clause 3.3.3 stated that the €100 rate was per trading period (30 minutes) rather than MWh and this should be clarified. We would again point out that this would impact smaller units more than larger units, should it be applied in the suggest method.

**Conclusion**

FERA would like to express some concern over Eirgrid/SONI understanding of the technologies operating under Grid Code, in both jurisdictions. The comments in some of the proposals appear to show a severe lack of knowledge of the makeup of Demand Side Response aggregators and how it interacts with the demand variations of Individual Demand Sites. There appears to be a belief that DSU can operate and perform similar to conventional plant, which is not the case. Demand Side aggregate multiple sites and the demand of those sites is flexible and changes constantly and at short notice.

Eirgrid/SONI have made comments on DSU performance yet have not made similar comments on other operators that may have variety in their source provision, such as Solar and Wind. FERA would expect the TSOs to have a more equitable approach, within the unique abilities of each technology.

FERA would ask if the forecast value, provide via the MPI, would be used in SND assessment should there be a lack of EDIL declaration.

The existing threshold of 15MW doesn't not cause the TSOs any issues so FERA is therefore confused as to why Eirgrid/SONI have suggested to treat the Demand Response technology in a different manner, by suggesting a 4MW threshold. We would welcome further explanation on how that value was derived and how other dispatchable generators with registered capability of less than 15MW are to be treated.

Regarding the proposed GPI for DSUs, FERA would ask for justification of the value of 70%. We believe that this shall impact smaller units more than larger units. We would also ask which Grid Code clauses support the GPI of 70%, since GPIs should only be used to reflect failure to comply with specific standards in the Grid Code.

## 6.5 iPower Response:

19-Jun-2023

### iPower Response to
### SONI/EirGrid Consultation:
### Harmonised Other System Charges for
### Tariff Year 01 October 2023 to 30 September 2024

iPower operates in both the Aggregated Generators and Demand Side Response sectors of the electricity industry and perform a significant role in supporting the operation of the I-SEM balancing market and facilitating the continuous introduction of renewables.

iPower currently have a registered capacity above 65MW, which carries a significant contribution to system support and stability, and have significant experience in working with SONI and EirGrid to provide stability and balance to the system operations.

The following comments are in relation to the published SONI/EirGrid consultation and clause reference numbers are used where possible.

**Introduction**

iPower operates the aggregation of multiple sites in both the provision of Demand Response, which comes from reduction of load, self-generation, and export onto the grid, and also operates an Aggregated Generators in an AGU across multiple sites. The use of multiple sites means that outage rates are much lower and 'trips' of generation do not impact the whole unit. This functionality means that dispatched Demand Units and Aggregated Generating Units are more robust in delivering the required volume than an equivalent conventional unit, which would lose all its provision during a trip.

Multiple sites also mean that the aggregated demand of those sites is flexible and changes constantly and at short notice. This is the nature of the DSU and AGU technology, and it differs from other dispatchable generation.

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Comments on proposals

Clause 3.1 iPower welcomes the comments that state that the MW trip threshold shall remain at 100MW. This informs industry that there is no significant financial impact to the system, should conventional power plants lose up to 100MW of provision.

Clause 3.2 Generation units throughout the island have varying abilities over time and sometimes encounter issues that impact their output volume. There are times that advance warning of issues arising is possible however there are times when issues appear at short notice.

It is understood that the TSO scheduling can be impacted if such output becomes unavailable and causes rescheduling of other plant. Since 2022/23 the TSOs now require over 12 hours' notice to allow them to prepare alternative scheduling.

It is understood that the SND is applied to the declaration changes made via EDIL and not associated to any I-SEM forecast position. iPower would ask if the forecast value would be used in assessment should there be a lack of EDIL declaration.

This clause reviews the SND parameters and states that there shall be no change to the conventional generation plant values. It is maintaining the MW threshold at 15MW, without commenting on the size of a conventional generator that may make such a declaration change. This indicates that EirGrid/SONI believe that a declaration value change of 15MW per unit can be handled without significant impact to their scheduling. There is no comment on the number of conventional units that could make such declarations, nor the combined impact of such. iPower is therefore confused as to why EirGrid/SONI are proposing to treat the Demand Response technology in a different manner, by introducing a 4MW threshold. We would welcome further explanation on how that value was derived and how other dispatchable generators with registered capability of less than 15MW are to be treated.

iPower does welcome the reduced notice time of 60 minutes for Demand side units, which reflects the variability of the technology. We notice that the factoring scalars are still applicable, to incentivise more rather than less notice time and iPower welcome that.

Clause 3.3.1 No Comment

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Clause 3.3.2 The nature of Demand Response aggregation means that Minimum Generation and Operating Reserve are not applicable to iPower Demand activities. iPower welcome the retention of GPI Minimum Generation and GPI Operating Reserve charges at the rate approved for tariff year 2023/24, apart from adjusting for inflation.

Clause 3.3.3 iPower notices that this clause is specific to Demand Side Units and has been linked to the expected DSU energy payment. The EirGrid/SONI premise appears to be that since the payment shall be as per the Dispatched Quantity (DQ) then the metering shall need to match that. The RA decision in SEM-22-090 identified that there was no metering usable at the current time for energy payment settlement and that the DQ would be used. The RAs did comment that the effectiveness of using the DQ would need to be assessed. EirGrid/SONI are proposing to look at the SCADA data, provided by aggregators, and compare it against the dispatch quantity. It is suggested that the SCADA metering should be within 70% of the DQ, although EirGrid/SONI have not provided any research information on the use of the 70% value.

iPower would question why SONI are proposing to introduce this new GPI for DSU since a GPI should be *'levied on those generators which fail to comply with specific standards in the Grid Code'*. The section of the Grid Code should be identified otherwise the GPI may have no standing.

iPower would however like to point out that the SCADA signals provided by the aggregators are to three decimal places but the EDIL system can only handle whole values. Grid code requires participants to declare their actual capability, although since EDIL can only handle whole numbers then rounding up is the only method to comply with Grid Code. This means that the declared availability value has to be rounded up to whole values, which would then be dispatched as whole values. The calculation of percentage (%) would then depend on the actual figures used in attempting to match against the 70% target. See the following table for examples.

| Actual MW availability | EDIL MW value | % delivered |
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| 2.1 | 3 | 70.000% |

Whilst this new GPI is only a suggestion and the decision to implement is being left to the RAs, the reason for the incentive does not align with Grid Code and the implementation does not appears to be treating larger and smaller units in a fair and equal manner.

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Clause 4.1 The assessment of any dispatchable wind, even with QFPN, should be treated in a similar fashion to other technologies. If metering from a Power Plant Module falls short of its dispatch then should it have a similar shortfall tolerance to that proposed for DSU?

It is noted that EirGrid/SONI were considering GPIs for Wind Farms in August 2016[1] and yet there appears to be a stronger push to implement incentives against DSU in this current paper. There should be an equity approach to technologies, under Grid Code.

Clause 4.2 iPower acknowledges there have been successful improvements in providing more relevant forecast data via the MPI and updated data via EDIL. Given the complexity of the MPI process the forecast data submission is often limited to a daily basis. The nature of demand is such that it can vary without much notice and reflecting that in the forecast is problematic.

Clause 4.3 The technologies mentioned in this clause would appear to fall under Power Park Modules, and should be treated the same as those mentioned in clause 4.1. Please see comments relating to Clause 4.1.

Clause 4.4 iPower believes that the comments made in this clause show a severe lack of understanding regarding the technology of Demand Side Response. This is a somewhat worrying situation, and we believe that EirGrid/SONI should justify why they think a demand should remain at a static level. It should also be noted that there is no payment for 'Registered Capacity' under Grid Code and therefore there is no basis for a charge to be applied, albeit in future years, should a participant declare its capability down, in line with Grid Code rules. Whilst the TSOs may think it nice to have all installed and connected generation available to them at all times, they need to understand that certain forms of generation and technologies cannot perform at their maximum at all times.

Technologies such as Solar, Wind, Battery Storage, Hydro, Pumped Storage all have limitations and are dependent on certain energy sources. Demand Side Response is not similar to conventional power plants and EirGrid/SONI may need to better understand the technologies participating within the All-Island electricity markets and within the Grid Code jurisdictions.

Demand Side Response is mostly connection to the distribution network and NIE/ESB implement Instruction Sets, which can impact on the ability of Individual Demand Sites to be aggregated to the DSU. This impacts the availability of the unit.

[1] https://www.eirgridgroup.com/site-files/library/EirGrid/OSC-16-17-Recommendations-Paper.pdf

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Clause 5 iPower welcomes the application of inflation as a reflection of increased costs.. We expect that the same inflationary percentage shall be applied to the System Services tariffs and other charges under the control of EirGrid/SONI.

Clause 5.1 This clause shows the constants relating to a trip and iPowers' comments regarding clause 3.1 above are relevant. We would like to point out that since losing up to 100MW in an instant doesn't cause the TSOs much concern then why does the loss of 4MW within 60 minutes (SND for DSU) cause such concern?

Clause 5.2 The introduction of SNDs for Demand Side Response is difficult for iPower to understand, in comparison to conventional plant that doesn't really have a variable energy source. We refer to the comment for clause 3.2 above.

Clause 5.3 iPower believes that there should be more information provided on how EirGrid/SONI have arrived at the value of 70% and €100/MWh. Note that clause 3.3.3 stated that the €100 rate was per trading period rather than MWh and this should be clarified. We would again point out that this would impact smaller units more than larger units, should it be applied in the suggested method.

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Conclusion

iPower would like to express some concern over EirGrid/SONI understanding of the technologies operating under Grid Code, in both jurisdictions. The comments in some of the proposals appear to show a severe lack of knowledge of the makeup of Demand Side Response aggregators and how it interacts with the demand variations of Individual Demand Sites. There appears to be a belief that DSU can operate and perform similar to conventional plant, which is not the case. Demand Side aggregate multiple sites and the demand of those sites is flexible and changes constantly and at short notice.

EirGrid/SONI have made comments on DSU performance yet have not made similar comments on other operators that may have variety in their source provision, such as Solar and Wind. iPower would expect the TSOs to have a more equitable approach, within the unique abilities of each technology.

iPower would ask if the forecast value, provided via the MPI, would be used in SND assessment should there be a lack of EDIL declaration.

The existing threshold of 15MW does not cause the TSOs any issues so iPower is therefore confused as to why EirGrid/SONI have proposed to treat the Demand Response technology in a different manner, by suggesting a 4MW threshold. We would welcome further explanation on how that value was derived and how other dispatchable generators with registered capability of less than 15MW are to be treated.

Regarding the proposed GPI for DSUs, iPower would ask for justification of the value of 70%. We believe that this shall impact smaller units more than larger units. We would also ask which Grid code clauses support the GPI of 70%, since GPIs should only be used to reflect failure to comply with specific standard in the Grid Code.

Yours Sincerely,

**Matt O'Kane**

**Managing Director**

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## 6.5 LEI Response:

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The Oval
160 Shelbourne Road
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Ireland

13 June 2023

Ref: Harmonised Other System Charges Consultation Paper

Submission: via online email, tariffs@eirgrid.com

To Whom it May Concern:

Lumcloon Energy Limited (LEL) would like to thank EirGrid for providing stakeholders the opportunity to comment on their recently issued *Harmonised Other System Charges Consultation Paper*. The financial mechanisms that underpin large-scale energy projects help to ensure and incentivise the security of supply to consumers. The OSC Consultation Paper provides valuable updates on forthcoming OSC charges, what will be maintained, the calculations for inflation, and the possible introduction of new tariffs. We soundly support EirGrid's position to continue excluding Battery Energy Storage Power Stations and Solar Generation from OSC charges. This provides project developers and the Regulatory Authorities additional time to observe how the technologies impact the grid and understand the full range of services they can provide.

As a specialist in project delivery for grid system services, LEL appreciates the helpful and cooperative role EirGrid has played in Ireland's deployment of projects. We continue to value EirGrid's transparent and collaborative processes with industry stakeholders via public consultations on issues such as OSCs.

We look forward to continuing our joint efforts and remain open to discussion and engagement with EirGrid in the future.

Signed: Cami Dodge-Lamm

Cami Dodge-Lamm, Policy Director, Lumcloon Energy Ltd.

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