Harmonised
Other System Charges
Recommendations Paper

Tariff Year

1st October 2021 to 30th September 2022

4 August, 2021

EXECUTIVE SUMMARY

EirGrid and SONI (the TSOs) published a consultation paper on 31th March 2021 concerning the Harmonised Other System Charges for the upcoming tariff period, 1st October 2021 to the 30th September 2022. Comments on the consultation paper were received from four (4) 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 2021/2022

1. Retain the OSC rates approved for the 2020/2021 tariff year, only adjusting for inflation at the forecast rate of 0.99% for the tariff year 2021/2022 for the following GPIs:

   - Minimum Generation;
   - Governor Droop;
   - Primary Operating Reserve
   - Secondary Operating Reserve;
   - Tertiary Operating Reserve 1;
   - Tertiary Operating Reserve 2;
   - Reactive Power;
   - Trip Charges and Short Notice Declarations (SND) for generators without traded market position (FPN);
   - Trip Charges and Short Notice Declarations (SND)) for generators with a traded market position (FPN); and
   - Secondary Fuel GPI.

2. Remove the RoCoF GPI.

3. No DSU SND rate for 2021/22, as a result of ongoing liaison with the Industry.

No further changes are recommended for this tariff period.

ABBREVIATIONS

AGU	Aggregated Generator Unit
BM	Balancing Market
BOA	Bid Offer Acceptance
CCP	Controllability Categorisation Policy
CRM	Capacity Remuneration Auction
DAM	Day-Ahead Market
DBC	Dispatch Balancing Costs
DMOL	Design Minimum Operating Level
DSU	Demand Side Unit
DS3	Delivering a Secure Sustainable System
EDIL	Electronic Dispatch Instruction Logger
FPN	Final Physical Notification
GPI	Generator Performance Incentive
HICP	Harmonised Index of Consumer Prices
IDM	Intra-Day Market
I-SEM	Integrated Single Electricity Market
LTS	Long-Term Schedule
MMS	Market Management System
MPI	Market Participant Interface
NI	Northern Ireland
NIE	Northern Ireland Electricity
OSC	Other System Charges
PPM	Power Park Modules
QEX	Ex-Ante Quantity
RA	Regulatory Authority
RO	Reliability Options
RoCoF	Rate of Change of Frequency
RPI	Retail Prices Index
SEM	Single Electricity Market

SEMC	Single Electricity Market Committee
SND	Short Notice Declaration
SNSP	System Non-Synchronous Penetration
SONI	System Operator Northern Ireland
SPS	Special Protection Scheme
TCG	Transmission Constraint Group
TSO	Transmission System Operator
TUoS	Transmission Use of System

1 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 2021 to 30th September 2022.

The TSOs will publish revised Statements of Charges and the Other System Charges Methodology Statement for the 2021-2022 tariff period reflecting the approved rates and arrangements.

Responses were received from the following parties:

Party	**Abbreviation**
Bord Gáis Energy	BGE
ESB Generation and Trading	ESB GT
Scottish and Southern Energy	SSE
Energia	Energia

No confidential responses were received. Copies of the responses received have been appended to this recommendations paper.

2 OTHER SYSTEM CHARGES CONSULTATION RESPONSES

2.1 Trip Charge and Short Notice Declaration (SND) Charge

This section summarises the comments received from participants in relation to the SND and Trip Charges. Please refer to Appendix A for the responses in their entirety. This section also contains the TSOs' response to the comments received.

2.1.1 Respondents' Comments

SSE stated that the 'Charges are a legacy from the old SEM and were necessary at that time, given the absence of a cash-out mechanism.'

SSE stated that previous communications mentioned that OSC were 'necessary to ensure managed shut downs and advance/timely notification of outages'. With regard to this, SSE stated that they 'would welcome justification that these charges are in fact managing these activities in a positive way, and why they are still needed in addition to an effective cash-out mechanism'.

With regard to increased rates for units without a market position, SSE 'disputed this on the grounds that the new market provides enough downside to encourage early notification, i.e. cost borne via imbalance price'. In addition, SSE noted that 'under the new SEM, having the benefit of a cash-out mechanism, we consider that imbalance price would be enough to cover the cost of trips/SNDs in many cases.'

SSE also contended 'that the QEX metric is not strictly designed for this purpose and therefore, does not always provide a true reflection of the market position of a unit, e.g. its commercial position'.

With regard to the application of OSC, SSE asserts that they 'have not seen the settlement algebra that governs this process in order to appreciate the factors that are considered.' SSE request that this information be shared.

The response from ESB GT stated that they would welcome the publication of the data in 'the interests of transparency'. ESB GT also asserts that the Trip/SND charges should be based on the value of system service provision contracted from the generator, that cannot be delivered, due to unavailability, and not production costs. This is to align with the view that it is the position in SEM that the value created by generators in constrained parts of the system should not be reflected in their bids.

ESBGT also stated that that the most equitable manner to incentivise behaviour, in relation to availability, is to impose a charge, proportional to the impact on production costs, of a unit becoming unavailable.

Energia do not agree with the proposal that increased trip or SND charges should be applied to those units, without a QEX. The basis for this is that a 'trip or SND event for a generating unit is almost always incurred due to technical issues at the unit which are unavoidable. The presence of a market position has no bearing on the likelihood of a technical fault'.

Energia stated that no evidence has been provided to demonstrate that imposing a higher tariff charge has altered the rate of trips/SNDs.

Energia also maintains that OSCs fail to take a holistic view of the market in which generating units participate. This includes considering Reliability Options under the Capacity Remuneration Mechanism (CRM)

BGE remains of the view that where trips or SNDs occur, which require energy balancing actions to be taken by the TSO, the cost of these actions to the TSO, should be entirely covered by the balancing market (BM) cost, paid by 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 also refer to the exposure of units to RO payments and that reserves are provided under DS3 System Services. BGE also requests supporting analysis as to the requirement.

In relation to units without a QEX, BGE has requested publication of quantitative information to support any decision.

2.1.2 TSOs' Response

OSCs are utilised to counteract the costs of actions taken by the TSOs, to secure the system, after a SND or trip, in addition to incentivising unit behaviour, in the long term. The cost impacts of trips and SNDs have increased over the past six months, with forced generator outages increasing.

The Imperfection costs incurred as a result of TSO actions, taken in order to secure the system, were outlined in detail in the OSC Recommendations Paper 2020/21[1]. In that paper, the TSOs detailed how the 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 out of their control.

During recent periods when the available generation came under sustained pressure to meet demand, the poor performance of certain units (i.e. increased number of SNDs), has forced the TSOs to take longer term actions to ensure security of supply. These TSO actions are costly in terms of Imperfections Charges, with increased Premium Component payments to units which are 'Must Run' for security of supply reasons.

Availability issues in the month of January 2021 demonstrated this issue when, for example, a single station had 18 SNDs, of which 8 were greater than 100 MW. In addition, on a day of tight generation margins, the same station declared two units from fully available to 0 MWs in the space of under 30 minutes. For both cases, the SND Declaration Notice time was 0 minutes, and the SNDs were made at the early stages of start-up, leaving the TSOs with only limited options to mitigate the loss of generation. Examples such as these are not isolated events, with the same station declaring a SND to 0 MW on the day before, just prior to the TSOs having to declare an amber alert in the associated jurisdiction.

The TSOs require reliable generating capacity, not only to schedule economically, but also to secure supply. In terms of scheduling economically, there is no market mechanism for the recovery of Imperfection Charges associated with SNDs. These charges are levied on suppliers, with SND and Trip Charges being the only methods of both cost recovery and incentivising good behaviour.

The recent unreliability of units has also led to the increased cost of system constraints, with trips

[1] https://www.semcommittee.com/sites/semc/files/media-files/SEM%20-%20OSC%20Recommendations.pdf

and SNDs contributing to increased Imbalance Prices, and thus increased Discount Component (CDiscount) payments to units, which are constrained-down due to system limitations. Although the TSOs are actively working to reduce the impact of these constraints, the consumer is left exposed to increased Imperfection charges (as detailed above) if the scheduling of adequate generation is impacted by SNDs and/or trips.

With regard to the use of the QEX to determine the correct rate to be applied, the TSOs are using the Final Physical Notification (FPN) as the best method to determine balance responsibility. This decision is in line with the SEMC Energy Trading Arrangements Detailed Design Markets Decision Paper (SEM-15-065)[2]. That decision paper states that a unit's PN will be linked to its ex-ante trades at gate closure, coupled with a requirement to submit a best estimate of their FPN.

In relation to trips and SNDs resulting from technical issues, and not being behaviours that can be incentivised, 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.

A number of participants cited the existence of RO Difference Charge payments, linked with capacity market payments. As discussed in the consultation for 2020/21, these are a capacity market mechanism which are only realised during a scarcity event. They are also not linked to, or netted off, Imperfection charges to consumers, but are rather linked to capacity and difference payments to generators through the Socialisation Fund.

With regard to requests for quantitative data, the TSOs are monitoring the increase in Imperfections Charges associated with SNDs. Imperfection Charges are communicated to the industry via the Quarterly Imperfections Cost Report[3]. Actions taken by the TSOs to mitigate a potential SND in relation to a generating unit in March 2021, cost in the region of €200,000 in CPremium payments, over a period of 5 days. The TSOs were forced to take this action in the interest of security of supply. The total SND Charges for the month of March 2021 was €173,399[4]. This supports the recent trend that SND/Trip associated Imperfection Charges are significantly more than SND/Trip Charges. The TSOs also believe that Settlement data supports the contention that correct units are being charged (i.e. the unreliable units triggering Imperfections Costs are being charged proportionally more SND/Trip charges).

2.1.3 TSOs' Recommendation

The TSOs recommend retaining the rate of Trip Charges and SND Charges for generators without traded market position (FPN) to that which aligns with changes introduced for the 2020/21 tariff year, adjusting for inflation. The TSOs also recommend retaining the reduced rate of Trip Charges and Short Notice Declarations for generators with a traded market position (FPN), adjusting for inflation.

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[3] https://www.eirgridgroup.com/site-files/library/EirGrid/Quarterly-Imperfections-Cost-Report-Q2-Jan-Mar-FY2021.pdf
[4] https://www.soni.ltd.uk/media/documents/AS-OSC-Report_2020-21.pdf

2.2 Secondary Fuel

This section summarises comments received from participants in relation to the Secondary Fuel GPI. Please refer to Appendix A for the responses in their entirety. This section also contains the TSOs' response to the comments received.

2.2.1 Respondents' Comments

ESB GT stated in their response that 'secondary fuel capability is placed on a subset of generators, with no mechanism in place for the resulting incremental costs to be recovered, and thus it is, arguably, discriminatory to levy a charge on these generators. ESB GT recognised the importance of securing the system against a gas emergency event, but stated that the 'important policy goal' 'is not considered to be related, to the recovery of efficiently incurred cost, in operating the network'.

In relation to the capacity market, ESB GT outlined their opinion that gas-powered generating units are at 'a competitive disadvantage to other categories of capacity providers that do not face this obligation'.

ESB GT stated that that a 'secondary fuel service should be defined as an additional service under DS3 arrangements'. In that way 'Secondary Fuel Capability could be appropriately remunerated and providers would be able to compete for the provision of capacity on an equal basis with other categories of capacity providers'.

BGE stated that they do not support the Secondary Fuel GPI. BGE outlined that they believe that the secondary fuel obligation is not appropriately designed. BGE has requested that the TSOs wait until the outcome of the Clarification and Call for Evidence Paper (CRU/21/036) by the CRU on the "Secondary fuel obligations on licensed generation capacity in the Republic of Ireland[5]".

2.2.2 TSOs' Response

In the OSC Consultation for 2020/21, the TSOs outlined the necessity of compliance with the secondary fuel requirements of Grid Code in Ireland and the Northern Ireland Fuel Security Code[6] and in particular the importance of this for a small island synchronous system.

The capacity market is outside the scope of this consultation.

In terms of the timing of the CRU 'Clarification and Call for Evidence on Secondary fuel obligations on licensed generation capacity in the Republic of Ireland', and the continuation of Secondary Fuel GPIs in the interim, the TSOs will implement any RA decision as and when applicable.

[5] https://www.cru.ie/wp-content/uploads/2021/03/CRU21036-Secondary-fuel-obligations-on-licened-generation-capacity.pdf

[6] https://www.economy-ni.gov.uk/sites/default/files/publications/deti/FSC%20%20PUBLISHED%20VERSION%20OCTOBER%202015.pdf

2.3 New Other System Charges

This section summarises the comments received from participants in relation to new OSCs. Please refer to Appendix A for the responses in their entirety. The section also contains the TSOs' response to the comments received.

2.3.1 Respondents' Comments

In relation to possible DSU GPIs and Charges, BGE believes that 'the application of charges' is laudable. BGE welcomed an update from the TSOs in relation to the monitoring review and engagement with the DSUs, in addition to detail on any forward plan regarding DSUs.

BGE also commented on concerns in relation to non-application of OSCs to Power Park Modules (PPM) and solar units. BGE noted that, in particular, PPMs are an established technology that are not penalised in the same manner as large conventional generators. BGE stated in their response that PPMs 'should be treated in the same way as conventional generation in the application of these Other System Charges'. BGE requested an update from the TSOs in relation to their plans for PPMs and OSCs.

2.3.2 TSOs' Response

The TSOs have engaged with the DSU industry with regard to issues involving accuracy of DSU availability submissions to the Market Systems, since the end of the OSC Consultation process in 2020/21. These inaccuracies can impact the TSOs' ability to efficiently and effectively operate the power system, especially during periods of tight electrical supply.

Since the 2020/21 OSC consultation, the TSOs have presented the findings, of comparative analysis of market availability versus EDIL (i.e. dispatch) availability, to the DSU industry. There is ongoing engagement between the TSOs and the DSU industry in terms of performance monitoring and feedback to individual DSUs, so that specific issues that can be improved over time. The TSOs recommend that additional time is allowed for the TSOs to work on these issues with the DSU Industry, before any potential GPIs or charges are imposed.

PPMs are not dispatched in the same manner as conventional power plants, which use a centralized dispatch tool (i.e. EDIL). PPMs are dispatched using the Wind Dispatch Tool (WDT) which is a component application of the Energy Management System (EMS). The WDT has the capability to identify units, that have failed to achieve their Dispatch Instruction, and these occurrences are followed up by the Performance Monitoring teams, in both TSOs, through controllability and categorisation of windfarms[7], if not resolved in real time.

The 2020/21 OSC Consultation commented on voltage control issues in areas of the network with a high penetration of PPMs. These issues are in relation to low wind scenarios when PPMs are at 0 MW, and hence are not obliged under the Grid Codes to provide reactive power support. The TSOs continue to proactively develop operational and longer-term solutions to these problems.

2.3.3 TSOs' Recommendation

The TSOs are recommending continued engagement with the DSU industry for 2021/22, with a view to appraising the need for GPIs in future OSC Consultations.

[7] http://www.eirgridgroup.com/site-files/library/EirGrid/Controllability-Status-Update-August-2020.pdf

The TSOs are not recommending a GPI for Power Park Modules for 2021/22. The TSOs will continue to monitor the reactive power Grid Code compliance of PPMs, and may propose a GPI, if appropriate, in the OSC Consultation for future years

2.4 Inflation Rate

This section summarises comments received from participants in relation to inflation rate proposed for OSC 2021/22. Please refer to Appendix A for the responses in their entirety. The section also contains the TSO response to the comments received.

2.4.1 Respondents' Comments

BGE commented on the requirement for the SEMC to 'take account of the evolving economic situation during the pandemic and the updated information relation to COVID-19'.

SSE has requested 'clarity on what cost of provision is causing the need for inflation indexing.' SSE has requested 'that for consistency, these charges could be indexed in the same way as the imperfections pot'.

2.4.2 TSOs' Response

The TSOs have calculated the Inflation Rate using the approved methodology and as per the most up-to-date information from the Central Band Ireland (March 2021) and Office of Budgetary Responsibility UK (Q1 2021).

2.4.3 TSOs' Recommendation

The TSOs recommend the forecast blended inflation rate of 0.994%, as per the OSC Consultation, is used. The following sections define the rates used for the Other System Charges (OSC) and the proposed rates for the 2021/2022 period.

3 RECOMMENDED RATES

3.1 Inflation Rates

With respect to the blended inflation rate, the TSOs are aligning to the methodology approved by the RAs in applying a blended rate.
The TSOs, therefore, propose the following methodology to be applied:

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

According to the latest Office of Budgetary Responsibility report[8] (Mar 2021) the current CPI year on year inflation forecasts in the UK for the 2021/22 tariff year equates to c.+1.725% while the latest Central Bank report[9] (Q1 2021) forecasts HICP in Ireland for the same period at c.+0.5625%.

Source		**2021**	**2022**	**Tariff Year Methodology**	**2021/2022 Tariff Year**	**Blended Rate Methodology**	**Blended rate**
OBR March 2021	CPI	1.5%	1.8%	(0.015*25% + 0.018*75%)	1.725%	1.725*25%	0.43125
Central Bank Q1 2021	HICP	0.6%	0.8%	(0.006*25% + 0.008*75%)	0.75%	0.75*75%	0.5625
Blended Rate							**0.99375%**

Table 3.0: Proposed Inflation Rate Increase

On this basis, and recognising the relative balance between Ireland and Northern Ireland, the forecast blended rate for the forthcoming 2021/22 period is 0.99375% as shown in Table 3.0.

3.2 Trip Charges

The proposed Trip Constants for the 2021/22 tariff year are shown in Table 3.1. There are no changes proposed.

	2018-2019	**2019-2020**	**2020-2021**	**2021-2022**
Direct Trip Rate of MW Loss	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
Slow Wind Down Rate of MW Loss	1 MW/s	1 MW/s	1 MW/s	1 MW/s
Direct Trip Constant	0.01	0.01	0.01	0.01
Fast Wind Down Constant	0.009	0.009	0.009	0.009
Slow Wind Down Constant	0.008	0.008	0.008	0.008
Trip MW Loss Threshold	100 MW	100 MW	100 MW	100 MW

Table 3.1 Proposed Trip Constants

Table 3.2 contains the Trip Charge proposals for units with a FPN while Table 3.3 contains the Trip Charge proposals for units without a FPN.

[8] https://obr.uk/download/economic-and-fiscal-outlook-march-2021/
[9] https://www.centralbank.ie/docs/default-source/publications/quarterly-bulletins/qb-archive/2021/quarterly-bulletin-q1-2021.pdf?sfvrsn=5

Charge	2018-2019	2019-2020	2020-2021	2021-2022
Direct Trip Charge Rate	€2,161	€2,190	€2,227	**€2,249**
Fast Wind Down Charge Rate	€1,621	€1,642	€1,670	**€1,687**
Slow Wind Down Charge Rate	€1,081	€1,095	€1,114	**€1,125**

Table 3.2: Proposed Trip Rates For Units With a FPN[10]

Charge	2018-2019	2019-2020	2020-2021	2021-2022
Direct Trip Charge Rate	€2,161	€2,190	€4,454	**€4,498**
Fast Wind Down Charge Rate	€1,621	€1,642	€3,340	**€3,373**
Slow Wind Down Charge Rate	€1,081	€1,095	€2,228	**€2,250**

Table 3.3: Proposed Trip Rates For Units Without a FPN[11]

3.3 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 TSO to schedule and dispatch in an economic manner and also to manage Transmission Constraint Groups which are essential to the secure operation of the transmission system.

Table 3.4 shows the proposed SND Constants for 2021-22.

SND Constants	2018-2019	2019-2020	2020-2021	2021-22
SND Time Minimum	5 min	5 min	5 min	**5 min**
SND Time Medium	20 min	20 min	20 min	**20 min**
SND Time Zero	480 min	480 min	480 min	**480 min**
SND Powering Factor (Notice time weighting curve)	-0.3	-0.3	-0.3	**-0.3**
SND Threshold	15 MW	15 MW	15 MW	**15 MW**
Time Window for Chargeable SNDs	60 min	60 min	60 min	**60 min**

Table 3.4: Proposed SND Constants

Table 3.5 shows the proposed SND Charge Rate for Generating Units with a FPN

SND Charge Rate	2018-2019	2019-2020	2020-2021	2021-2022
SND Charge Rate	€38 / MW	€38 / MW	€39 / MW	€39 / MW

Table 3.5: Proposed SND Charge Rate for units with a FPN

Table 3.6 shows the proposed SND Charge Rate for Generating Units without a FPN

SND Charge Rate	2018-2019	2019-2020	2020-2021	2021-2022
SND Charge Rate	N/A	N/A	€77 / MW	€78 / MW

Table 3.6: Proposed SND Charge Rates for units without a FPN

[10] The 2019/20, 2020/21 & 2021/22 Proposed Trip Rates For Units With a FPN have been changed (marginally reduced) from those in consultation paper to reflect approved 2019/20 and 2020/21 rates

[11] The 2020/21 & 2021/22 Proposed Trip Rates For Units Without a FPN have been changed (marginally increased) from those in consultation paper to reflect application of inflation for every year since 2017/2018

3.4 GPI Charges

The proposed GPI Constants and GPI Declaration Based Charges for the 2021/2022 tariff year are outlined in Table 3.7 and Table 3.8 respectively. The TSOs are proposing to make no changes, apart from adjusting for inflation.

GPI Constants	2018-2019	2019-2020	2020-2021	2021-2022
Late Declaration Notice Time	480 min	480 min	480 min	480 min
Loading Rate Factor 1	60 min	60 min	60 min	60 min
Loading Rate Factor 2	24	24	24	24
Loading Rate Tolerance	110%	110%	110%	110%
De-Loading Rate Factor 1	60 min	60 min	60 min	60 min
De-Loading Rate Factor 2	24	24	24	24
De-Loading Rate Tolerance	110%	110%	110%	110%
Early Synchronous Tolerance	15 min	15 min	15 min	15 min
Early Synchronous Factor	60 min	60 min	60 min	60 min
Late Synchronous Tolerance	5 min	5 min	5 min	5 min
Late Synchronous Factor	55 min	55 min	55 min	55 min
Secondary Fuel Availability Factor	0.9	0.9	0.9	0.9

Table 3.7: Proposed GPI Constants

	2018-2019	2019-2020	2020-2021	2021-2022
GPI Declaration Based Rates	**€ / MWh**	**€ / MWh**	**€ / MWh**	**€ / MWh**
Minimum Generation	1.29	1.31	1.33	1.34
Max Starts in 24 hour period	0	0	0	0
Minimum On time	0	0	0	0
Reactive Power Leading	0.32	0.32	0.32	0.32
Reactive Power Lagging	0.32	0.32	0.32	0.32
Governor Droop	0.32	0.32	0.32	0.32
Primary Operating Reserve	0.52	0.53	0.54	0.55
Secondary Operating Reserve	0.13	0.13	0.13	0.13
Tertiary Operating Reserve 1	0.13	0.13	0.13	0.13
Tertiary Operating Reserve 2	0.13	0.13	0.13	0.13
Secondary Fuel Availability	0.03	0.03	0.03	0.03

Table 3.8: Proposed GPI Declaration Based Charge Rates

The Event Based GPIs will remain at zero (i.e. Loading Rate, De-Loading Rate, Early Synchronisation and Late Synchronisation).

4 APPENDIX A

This section contains all the responses received.

Energy for generations

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ESB Generaton and Trading Response:

Other System Services Consultation 2021-22

28th April 2021

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General Comments

ESB Generation and Trading (ESB GT) welcomes the opportunity to respond to the consultation on the Harmonised Other System Charges for the tariff period 2021/22. ESB GT continues to believe that the compliance of the Other Systme Charges framework with the requirement of Article 18 of the Electricity Regulation (EU 2019/943) should be reviewed. Under Article 18 network charges are required to be cost reflective, non-discriminatory and not include unrelated costs supporting unrelated policy objectives.

In ESB GT's view it is not clear that some of the current GPIs are sustainable particularly the Secondary Fuel GPI. While the security of supply in the case of a gas supply interruption is an important consideration it is not the case that there are direct costs incurred in operating the system where one or more generators' secondary fuel capability is unavailable.

It is also the case that the requirements under the Grid Code for secondary fuel capability are placed on a subset of generators with no mechanism in place for the resulting incremental costs to be recovered, in this context it is arguably discriminatory to levy a charge on these generators when their secondary fuel capability is unavailable. As noted, security of supply in the case of a gas supply interruption is an important policy goal but it is not considered to be related to the recovery of efficiently incurred cost in operating the network.

A recent publication of the 2020 fuel mix showed that the renewable generation had increased to 43.4% and also the reliance on gas generation increased to 49.6% these values show that the system is increasing dependent on the availability of gas when renewable resources are not available. As such the value of secondary fuel capability to maintaining security of supply in the case of a gas supply interruption is increasing.

It remains ESB GTs view that the current arrangements for the provision of secondary fuel in the context of a competitivecapacity auction are distortive and contrary to the long-term interests of end users. Under the current arrangements' generators, both new and existing, required under the Grid Code to provide secondary fuelcapability are placed at a competitive disadvantage to other categories of capacity providers that do not face this obligation. Where this results in those generators being displaced by the other categories of capacity providers the policy of maintaining secondary fuel capability is undermined and where the generators clear the auction at a price reflective of maintaining secondary fuel capability the other categories of capacity that also clear in the auction extract rent from the end users through the capacity market for a service they do not provide.

ESB GT notes in the TSOs OSC Recommendations for 20_21[1] the TSOs state their believe that the impact of the secondary fuel GPI on the capacity market is outside the scope for the OSC consultation. ESB GT

[1] Harmonised Other System Charges Recommendations Paper 2020-21

does not agree that were the implementation or retention of a measure is being proposed within a consultation that its potential to have distortive impacts on the wider market can set aside as out of scope.

To develop a positive incentive to ensure secondary fuel capability is available, a secondary fuel service should be defined as an additional service under revised DS3 arrangements that is under development. In this way the provision of Secondary Fuel Capability could be appropriately renumerated and providers would be able to compete for the provision of capacity on an equal basis with other categories of capacity providers. In the absence of these reforms being developed ESB GT believes that the current secondary fuel GPI should be suspended.

In relation to Trip and SND charges ESB GT notes the TSOs view the that the most equitable manner to incentivise behaviour in relation to availability is to impose a charge proportional to impact on production costs of a unit becoming unavailable. In the consultation there is reference to a review of Trip Charge and SND settlement data for the period 2020/21, and also to significant increases in imperfection costs and issues with the TSOs' ability to secure the system as the basis to retain the higher level of charges for unit without an ex-ante market position. ESB GT would welcome the publication of the data underlining this view in the interests of transperancy.

It remains ESB GT contention that the impact on production costs should not be the basis of these charges but rather any charge should be based on value of system service provision contracted from the generator that can not be delivered due to unavailability. For example is could the case that the unavailability of a generator that was scheduled run in a constrained part of the system results in a sigficant increase in production costs but it has long been policy in SEM, implemented through the bidding controls, that the value created by generators in constrained parts of the system should not be reflected in their bids and instead these bids be limited to short run manginal costs. In this way the value created by the generator being located in the constrained part of the system is captured for the end user, it follows that when the generator becomes unavailable the absence of this value or increased production costs should be faced by the end user rather then charged against the generator.

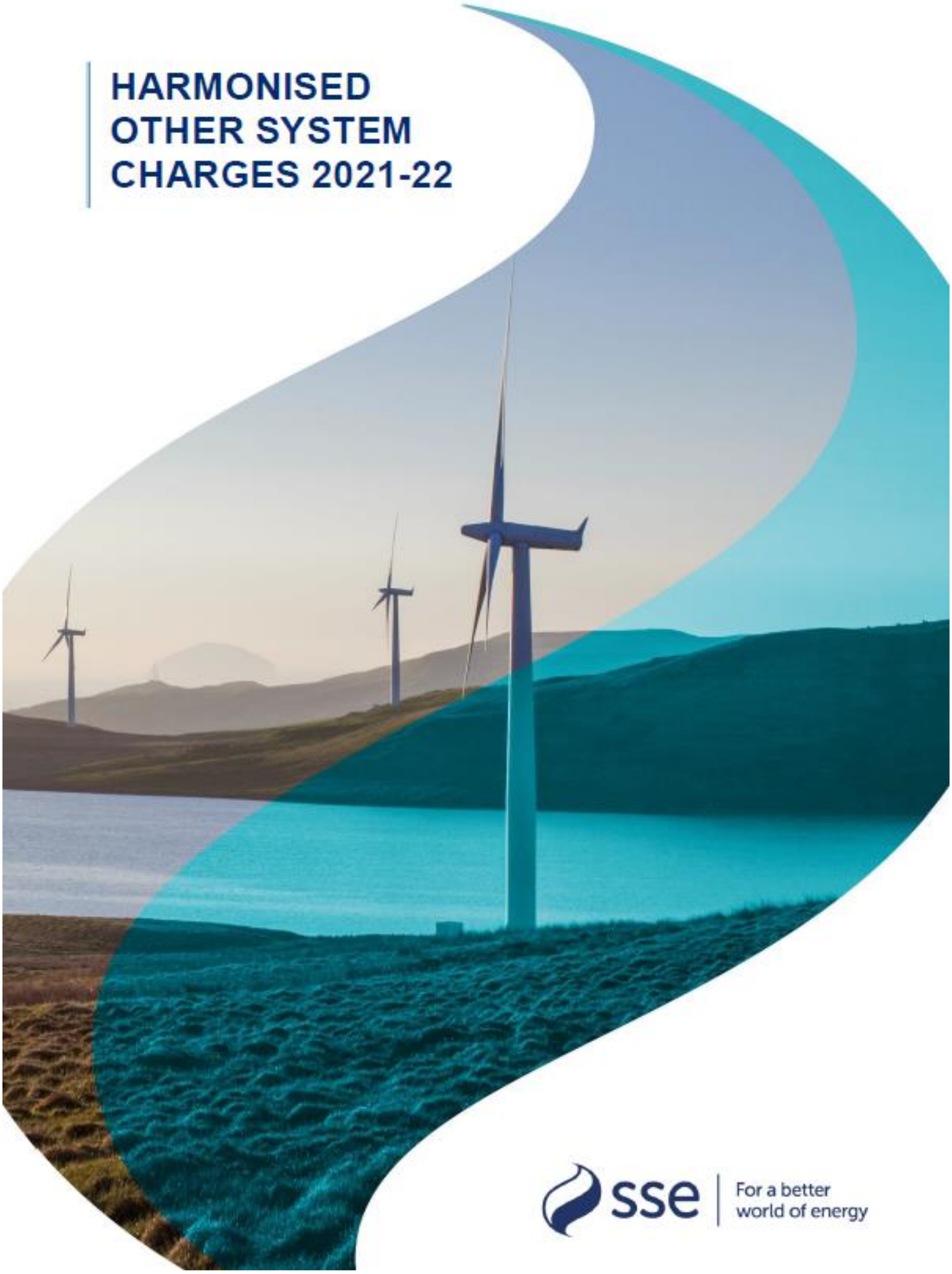
In the context of the future arrangement of system services ESB GT would welcome engagement with the TSO on the development of an appropriately balanced incentive to encourage service providers to forecast as accurately as practicable their service availability and deliver their contracted service levels.

If you have any questions in relation to any of the points raised in this response, please do not hesitiate to contract me to discuss further.

Yours sincerely,

William Carr

Regulation, ESB Generation and Trading


HARMONISED
OTHER SYSTEM
CHARGES 2021-22
sse
For a better
world of energy

INTRODUCTION

SSE welcomes the opportunity to comment on the *"Harmonised Other System Charges Consultation"* (OSC). For the avoidance of doubt, this is a non-confidential response and therefore we are comfortable that it can be published by EirGrid. In addition, please be advised that we have shared this response with the Regulatory Authorities, for their consideration.

As a large generation provider in the market, Other System Charges have an impact of our generation fleet. Given the progress to the new SEM with multiple trade windows, it is important to consider the context of the stagnant GPIs and other charges, to ensure they continue to be relevant for determining of behaviour. Therefore, as in previous years we have provided comments.

As previously stated, we maintain our view that these charges are a legacy from the old SEM and necessary at that time, given the absence of a cash-out mechanism. However, now that a cash-out mechanism is in place within the new SEM, it is not clear what these charges are designed to achieve. There is mention that these charges are still necessary to ensure managed shut downs and advance/timely notification of outages. We would welcome justification that these charges are in fact managing these activities in a positive way, and why they are still needed in addition to an effective cash-out mechanism. We will be posing this question to the RAs for their view.

SSE RESPONSE

We note that the TSO proposes that for the forthcoming tariff year there will be no material change from previous years. We have provided general comments about the structure of the OSCs (as updated for the last tariff cycle), notwithstanding our comment above that this is a legacy arrangement whose continued purpose in the new market has still not been fully justified.

QEX position-rationale

The TSOs have determined (for tariff year 2020-21), that the definition of having a traded position is understood to be related to having or not having a QEX position. In our previous response we disputed this on the grounds that the new market provides enough downside to encourage early notification, i.e. cost borne via imbalance price.

Now that this change is active, we wanted to provide comments regarding the use of a QEX position as the only measure to confirm that a unit has a traded position. As per previous correspondence with the TSO, they have explained the following regarding the use of a QEX position:

In the determination of the Trip Charge rate to be applied, the TSOs are proposing to use the QEX position over a number of trading periods, immediately after the trip, for which the gate closure time will have expired

We consider that the QEX metric is not strictly designed for this purpose and therefore, does not always provide a true reflection of the market position of a unit, e.g. its commercial position. We would encourage a better or more diverse approach to determining whether a unit has or has not entered a traded position in the market.

We understand that the assumption underpinning the retention of OSC charges is that they are still needed because there is a residual cost left to be recovered when there is a trip or SND. This is because the TSO's baseline scenario is that the imbalance price is not firm enough to cover the full cost of any actions needed to cover a trip/SND. This we consider only to be true for a subset of scenarios (i.e. those with low cash-out coupled with a need to redispatch plant onto the system). In these specific cases, it may be warranted to consider that OSC charges are necessary.

These assumptions on the OSC would also suggest an old-SEM market view on how these charges are understood, i.e. as a residual mop up of actions not covered in that previous market. However, under the new SEM, having the benefit of a cash-out mechanism, we consider that imbalance price would be enough to cover the cost of trips/SNDs in many cases. Therefore, the rationale for a single fixed charge (under the OSC framework), which is also based on a limited view of a unit's traded position (i.e. QEX), does not hold water. This would suggest that if these charges are to be retained, they need to be applied in a more sophisticated manner.

Action needed	Cash-out	
	Low	High
Unit/Units needed to cover trip	Out of Market MWP needed to cover start cost/NL of redespatched units	Some/All Cost of redespatch covered in cash-out price
No Unit needed to cover trip	Cash-out covered replacement cost of energy	Cash-out covered replacement cost of energy

QEX position-application

We note that the proposed changes from the previous tariff year, i.e. the levying of charges on the basis of with or without a QEX position, is now live. Yet, we have not seen the settlement algebra that governs this process in order to appreciate the factors that are considered. We would ask that this is shared to inform our understanding of this new process and how it has been codified.

We would consider that there are some very likely scenarios where a penalty would appear excessive, such as where a unit acts responsibly and trades out their position following a trip (in our view the unit's PN in this case should be a reasonable confirmation of a QEX position), or where a unit fails well before scheduled, e.g. 6 hours (an instance of other factors that should be considered in addition to a traded position). In the absence of the assumptions and settlements algebra around the defining of a QEX position and how this is all reconciled, we cannot be clear about how effectively the OSC are being applied.

Charges indexed against inflation

We also note as previously that charges will be indexed against inflation. We would welcome clarity on what cost of provision is causing the need for inflation indexing. We would otherwise suggest that for consistency, these charges could be indexed in the same way as the imperfections pot, i.e. to reflect the expectations of energy costs incurred. This would provide the right signal regarding the continued rationale for these charges.

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28th April 2021

RE: Harmonised Other System Charges (OSC) Consultation, Tariff Year 1 October 2021 – 30 September 2022

Dear Sir / Madam,

Bord Gáis Energy (**BGE**) welcomes the opportunity to respond to this consultation on Harmonised OSC for 2021/ 2022.

Trip and Short Notice Declaration (SND) Charges

BGE remains of the view that where trips or SNDs occur which require energy balancing actions to be taken by the TSO, the cost of these actions to the TSO should be entirely covered by the balancing market (**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, BGE believes 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. BGE requests supporting analysis from the TSOs on why they believe that this extra trip and SND money is required to cover market-driven energy imbalances.

BGE does not believe that units with a Q_{EX} position should be subject to trip or Short Notice Declaration (SND) charges. Units with a Q_{EX} position at the time of a trip or short notice declaration have substantial commercial incentive to remain fully operative as they likely face significant imbalance charges and exposure to Reliability Option (**RO**) payments in the event of an unplanned outage.[1] Reserves are already provided under DS3 provisions and between these and Imbalance Costs there should not be a need for additional charges. Balance responsible units holding a Q_{EX} when an unplanned outage event occurs should not be penalised through trip or SND charges as the imbalance charges payable by units with a Q_{EX} already contribute towards minimising costs for consumers. The application of trip or SND charges in addition to these Imbalance charges we believe is an unnecessary and unavoidable penalty on responsible units in the event of an unplanned loss of production event. The focus of the TSOs is 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 units with a Q_{EX} position which are already fully commercially self-incentivised to remain operative.

BGE understands the rationale to levy costs on units without a Q_{EX} position to ensure that they are balance responsible and to mitigate DBCs but we ask for further supporting 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

[1] Where contracts are held by the unit in the DS3 and capacity markets respectively

be published to ensure that overall, the consumer is receiving best value for money and that appropriate charges are being applied.

Inflation Rate

We urge the SEM Committee to take account of the evolving economic situation during the pandemic and the updated information related to COVID-19 when setting the inflation rate for the Other Service Charges in the 2021/22 period. It is appreciated that the analysis and detail contained in this consultation paper would have taken time to collate and capture, and a degree of forecasting would have been involved especially in the proposed rate of inflation. The economic impact of COVID-19 on businesses, utilities and the wider society is still playing out and more can be expected in the coming years including the coming tariff year.

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 (but on inflation rates please see above) and the removal the RoCoF GPI charge.

BGE does not however support the Secondary Fuel GPI. We do not believe that the secondary fuel obligation is appropriately designed or applied today. We ask the TSOs to wait until the outcome of the Clarifications and Call for Evidence paper (CRU/21/036) by the CRU on the "Secondary fuel obligations on licenced generation capacity in the Republic of Ireland" is known before confirming the decision on this GPI.

New Other System Charges (OSC)

BGE believes that measured application of the charges to emerging market technologies such as DSUs is laudable such that these units are not unfairly burdened and undermine the growth of new technology and competition in the market. We would welcome an update from the TSOs as to the result of their monitoring review and engagement the TSOs have had with the DSU industry across 2020/21 on concerns relating to DSU availability declarations over the last year. We also request detail on any forward plan as to when and at what charge level DSUs will be incorporated into the OSC tariff structure.

It seems unintuitive to not also already be applying appropriate charges to wind and solar not least from a level playing field perspective (considering that wind at least is becoming more akin to a baseload unit). Wind PPMs in particular are well established in the market and to continue not apply OSCs to them in effect penalises larger conventional generators who are effectively left carrying the cost. Given the evidential increasing share of wind and solar units in the market and given the importance of performance monitoring and ensuring units act in line with the grid requirements and what they are contracted to do (from a systems and DS3 perspective in particular), BGE believes that they should be treated in the same way as conventional generation in the application of these other system charges.

BGE would appreciate an update from the TSOs on the continued monitoring of Power Park Module (PPM) performance and their compliance with the Grid Code. The growing contribution of power from renewable sources onto the system does bring an increasing risk of impact of these sources to system stability and a potential increase in costs to maintain system security. We understand the operational issues with PPMs as outlined in the consultation and the proposal not to propose any GPIs for PPMs in the tariff year 2021/22. Yet we would welcome any forward plan on the introduction of a GPI for PPMs in the next/ coming tariff year(s) given the risks the increasing capacity of PPMs brings to the system.

While charges may be restricted by the size of the PPM[2], the plan should also advise on the timings and scale of trip and SND charges that may be applied to PPMs in the future.

I hope you find the above comments and suggestions helpful. If you have any queries thereon please do not hesitate to contact me.

Yours faithfully,

Ian Mullins
Regulatory Affairs – Commercial
Bord Gáis Energy

{By email}

[2] *"It should also be noted that most Power Park Modules are below the 100 MW threshold for Trip Charges."* - Harmonised Other System Charges Recommendations Paper (dated 1st July 2020) – Section 2.5.1.2 (pg18)

energia

Response by Energia to Eirgrid on Harmonised Other System Charges Consultation Paper

Tariff Year 01 October 2021 to 30 September 2022

28th April 2021

1 Introduction

Energia welcomes the opportunity to respond to the Eirgrid Consultation Paper titled "Harmonised Other System Charges Consultation Paper – Tariff Year 01 October 2021 to 30 September 2022" (the Consultation Paper). The Consultation Paper seeks to retain all of the existing Other System Charges (OSC) for tariff year 2021/22, adjusted for inflation.

Energia wish to reiterate its concerns regarding the proposal to retain the increased rate of Trip Charges and Short Notice Declarations (SND) for generators without a Day Ahead Market position (QEX) to that which aligns with 2017/18 tariff, before the introduction of the revised SEM arrangements. This differentiation in charges applied against generators depending on whether or not they have a QEX is unjustified and Energia seek to reaffirm the position outlined in our previous 2020 response to this consultation which opposed the increase of SND and Trip Charges tariff rates for generators without a QEX.

2 Proposal to Retain Trip Charges and SND rates for generators without a QEX

Both SND and Trip Charge tariff rates were reduced in advance of the new market arrangements due to these market arrangements making generators balance responsible. However, for tariff year 2020/21 the RAs approved a proposal to increase Trip Charges and SND Charges for those generators with no QEX. The Consultation Paper for tariff year 2021/22 recommends the continuation of this approach. The only rationale or justification provided for continuing with the higher charge is that during the period October 2020 to January 2021 there have been a number of SNDs / trips that have resulted in TSO taking actions that departs from the market schedule and thus increases imperfection costs with settlement data indicating that the most unreliable units driving this are those without a QEX (and therefore being charged the new increased non-QEX tariff rate). However, no further data or detailed analysis behind these comments has been provided as part of the justification for retaining the increased tariff charge for units without a QEX.

In principle, Energia do not agree with the position that increased trip or SND charges should be applied to those units without a QEX. As per our response to the 2020 consultation paper on this issue our rationale for this position is as follows:

- Primarily, a trip or SND event for a generating unit is almost always incurred due to technical issues at the unit which are unavoidable. Whether or not a generating unit has a QEX has no bearing on the likelihood of such a technical issue occurring. This was evidenced by an increase in the number of trips and SNDs in the 2018/2019 tariff year (i.e. the first year of the new market arrangements) demonstrating that despite the introduction of the balance responsible market arrangements, and accordingly the exposure to imbalance charges, the occurrence of trip and SND events increased due to the unavoidable technical issues behind these events.

- Furthermore, both last year's paper seeking to introduce the higher tariff charge and this Consultation Paper proposing to retain the higher charge have not been supported with sufficient justifying data i.e. no evidence has been provided to show that there is a correlation between units without a QEX and a change in their relative trip or SND performance.
- The Consultation Paper states that SNDs are intended to "incentivise behaviour that enhances system security." However, no evidence has been provided to demonstrate that imposing a higher tariff charge to those units without a QEX has altered the rate of trips/SNDs for those units. Therefore, Energia believe that this is an unfair penal charge against generators that does not deal with underlying objective in seeking to enhance system security.
- Finally, the Consultation Paper fails to take a holistic view of the markets in which generating units participate in. Generating units which have secured a Reliability Option (RO) under the Capacity Remuneration Mechanism (CRM) are potentially exposed to RO Difference Charge payments up to one and a half times their annual capacity income should an RO event coincide with the generating unit's trip or SND. The risk of being exposed to a RO Difference Charge payment has significant financial implications for a generating unit. Neither the potential cost or associated risk of a generator unit having to make a RO Difference Charge payment during periods of unavailability due to a trip or SND has been factored into the tariff charge structure. Consideration of this risk, which is indifferent to whether a generating unit has a QEX or not, needs to be taken into consideration.