Harmonised Other System Charges Methodology Statement

Applicable from 01st October 2023

06th Nov 2023

Contents

Revision History						
Revision	**Date**	**Description**	**Originator**	**Reviewer**	**Checker**	**Approver**
R0						
R1						
R2						

ABBREVIATIONS

AS	Ancillary Services
DSU	Demand Side Unit
GPI	Generator Performance Incentives
MW	Megawatt
NI	Northern Ireland
OSC	Other System Charges
POR	Primary Operating Reserve
RAs	Regulatory Authorities
RoI	Republic of Ireland
SEM	Single Electricity Market
SND	Short Notice Declaration
SOR	Secondary Operating Reserve
TOR	Tertiary Operating Reserve
TSC	Trading and Settlement Code
TSO	Transmission System Operator
TUoS	Transmission Use of System
TUoSA	Transmission Use of System Agreements

1. Executive Summary

Other System Charges (OSC) are levied for non-compliance to provide necessary services to the system. This document sets out the harmonised arrangements for the calculation of Other System Charges by the Transmission System Operators (TSOs), EirGrid in Ireland and SONI in Northern Ireland respectively, in accordance with the Regulatory Authorities' (RAs) Decision Paper SEM-23-057 [1].

This document is referred to in the Statement of Charges published in each jurisdiction by EirGrid and SONI and has been approved by the RAs. This document may be revised by EirGrid and SONI from time to time, subject to regulatory approval.

1 SEM-23-057 - Decision Paper on OSC Tariffs 2023-24.pdf (semcommittee.com)

2. Introduction

At present a number of charges are not included in the Trading and Settlement Code (TSC) of the Single Electricity Market (SEM) and therefore it was necessary to document the harmonised arrangements applicable in both jurisdictions under the SEM. These charges are referred to as Other System Charges and have been subject to consultation.

All island arrangements for Other System Charges were harmonised in Ireland and Northern Ireland in 2010[2] and are set out each year in the Statement of Charges previously identified as Transmission use of System (TUoS) Charging Statements. All these statements are available on the EirGrid and SONI websites[3].

Proposed OSC rates and charges are reviewed annually and documented in the annual consultation paper, followed by a recommendations paper. Based on the recommendations therein, the SEM Committee make decisions on the future implementation of harmonised Other System Charges across the island. All decision papers are available on the SEM Committee website[4].

The SEM Committee published its decision paper SEM-23-057[5] for Other System Charges on 22nd August 2023, setting out the rates and related parameters applicable from the 1st of October 2023. The introduction of new charges is reflected in this methodology statement paper, therefore superseding the Other System Charges Methodology Statement that was applicable since 1St October 2018[6] .

2 https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-10-001.pdf

3 https://www.eirgridgroup.com/library/ and https://www.soni.ltd.uk/library/

4 https://www.semcommittee.com/

5 https://www.semcommittee.com/sites/semc/files/media-files/SEM-23-057%20-%20Decision%20Paper%20on%20OSC%20Tariffs%202023-24.pdf

6 https://www.eirgridgroup.com/site-files/library/EirGrid/OSC-methodology-statement-1819.pdf and https://www.soni.ltd.uk/media/documents/OSC-methodology-statement-1819.pdf

3. Harmonised Other System Charges Rates Framework

This section summarises the framework and description of charges.

3.1. Monetary Flows

Other System Charges (Trips, Short Notice Declarations (SNDs) and Generator Performance Incentives (GPIs) are reviewed annually and will be included in the Statement of Charges published by each TSO in their respective jurisdictions. The income from these charges will be used to reduce the SEM Imperfections Costs. Note that the charging period for Other System Charges will be a calendar month.

3.2. Payment of Charges

The GPI, SNDs and Trip charges Payment of Charges are payable by generators party to a Transmission Use of System Agreement (TUoSA) or Demand Side Unit System Operator Interface Agreement.

3.3. Exchange Rate

- An exchange rate will be fixed annually for each tariff year/period using market forward exchange rates based on a 5-day average rate.
- At the end of each tariff year/period the exchange rates will be reviewed to determine if an adjustment is required in Northern Ireland (NI) and/or Republic of Ireland (RoI) accordingly for the coming tariff year/period.

The setting of the exchange rate on an annual basis is a compromise between the certainty provided by a daily exchange rate used in the SEM wholesale market and an alternative long-term view consistent with the principles of capacity pot predictability and ease of calculation. This will be included as part of the regular annual review of Other System Charges.

3.4. Rates and Parameters

Each rate and parameter are set out in the relevant tariff year Statement of Charges paper under "Other System Charges."

3.5. Trips

The Trip Charge incentivises generators to minimise the number of trips and to aim for slow tripping, when a trip is unavoidable. The Trip Charge is designed to incur higher charges, the higher the MW loss. A charge applies for all full trips and/or partial trips where the reduction is greater than, or equal to, the trip threshold.

3.6. Short Notice Declarations

Short Notice Declarations (SNDs) incentivise generators or DSUs to avoid changing declarations at short notice or at least provide maximum notice. The Notice Time Weight is an empirical weighting corresponding to the relative importance of notice time and applicable reason codes are forced, outage and certain trips.

3.7. Generator Performance Incentive Charge

Generator Performance Incentive Charges (GPIs) incentivise generators to maintain the performance required of them, in the respective Grid Codes for the efficient and economic operation of the system. These arrangements intend to quantify and track generation performance, identify non-compliance with standards and help evaluate the performance gap between what is needed and what is being provided by generators, in an evolving power system.

4. Trip Charges

The purpose of the trip charge is to minimise the number of trips and, when a trip is unavoidable, to incentivise a Generator to wind down a unit as slowly as possible.

There are three categories of trips – Direct Trip, Fast Wind-down and Slow Wind-down. The three categories are defined based on the average rate of MW loss as follows:

Direct Trip	*Average Rate of MW Loss >= 15 MW/s*
Fast Wind-down	*Average Rate of MW Loss >= 3 MW/s & < 15 MW/s*
Slow Wind-down	*Average Rate of MW Loss >= 1 MW/s & < 3 MW/s*

- Each trip event is considered for all three trip categories independently.
- Each maximum MW loss is calculated for all three trip categories.
- If the maximum MW loss is greater than the Trip MW Loss Threshold the relevant formula is used to calculate the trip charges for that trip charge category.
- The final trip charge which is applied is the maximum of the three trip charges.

The trip charge formula is a function of the maximum MW loss for the trip category and two empirical values. The three formulae are as follows:

$$DT\ Charge = DT\ Charge\ \ Rate\ \ x\ \ e^{(DT\ Const\ \ x\ \ (Max\ MW\ Loss - Trip\ MW\ Loss\ Threshold))}$$

$$FWDCharge = FWD\ Charge\ \ Rate\ \ x\ \ e^{(FWDConst\ \ x\ \ (Max\ MW\ Loss - Trip\ MW\ Loss\ Threshold))}$$

$$SWDCharge = SWD\ Charge\ Rate\ \ x\ \ e^{(SWDConst\ \ x\ \ (Max\ MW\ Loss - Trip\ MW\ Loss\ Threshold))}$$

where:

(i) "DT Charge Rate" is the Direct Trip Charge Rate;

(ii) "DT Const" is the Direct trip Constant;

(iii) "Max MW Loss" is the maximum MW loss for the trip;

(iv) "Trip MW Loss Threshold" is the Trip MW Loss Threshold;

(v) "FWD Charge Rate" is the Fast Wind Down Rate of MW Loss;

(vi) "FWD Const" is the Fast Wind Down Constant;

(vii) "SWD Charge Rate" is the Slow Wind Down Charge Rate; and

(viii) "SWD Const" is the Slow Wind Down.

5. SND Charges

The purpose of the SND charge is to incentivise Generators to avoid notifying changes to availability declarations at short notice, or at least, to provide the maximum possible notice of changes.

There are two categories of SND – Generator and Demand Side Unit (DSU)

- Each SND event applies for downward availability declarations within the time period set by the SND Time Zero or DSU SND Time Zero, multiple SNDs below the minimum threshold in quick succession, or re-declarations below the SND Minimum Threshold within the Time Window.
- There is a minimum threshold, known as the SND Minimum Threshold or DSU SND Threshold, below which no charge applies.
- The SND charge does not apply for declarations relating to scheduled availability changes and non-generator plant availability changes.

5.1 SND for Conventional Generator Units

The Generator Unit charge shall be calculated as follows:

$$SND\ Charge = MW\ \ Reduction\ \ x\ \ SND\ Charge\ \ Rate\ \ x\ \ Notice\ Time\ Weight$$

where:

(i) "MW Reduction" is the reduction in Availability (expressed in MW) notified to the TSO;

(ii) "SND Charge Rate" is the SND Charge Rate;

(iii) Notice Time Weight is determined in following criteria:

a. For Notice Time < SND Time Minimum, then Notice Time Weight = 1

b. For Notice Time >= SND Time Minimum but < SND Time Medium then:

$$Notice\,Time\,Weight = \left(\frac{Notice\,Time}{SND\,Time\,Minimum}\right)^{SND\ Powering}$$

c. For Notice Time >= SND Time Medium < SND Time Zero then:

$$Notice\,Time\,Weight = \left(1 - \left(\frac{Notice\,Time - SND\,Time\,Medium}{SND\,Time\,Zero - SND\,Time\,Medium}\right)\right) x \left(\frac{Notice\,Time}{SND\,Time\,Minimum}\right)^{SND\ Powering}$$

(iv) "SND Powering" is the SND Powering Factor;

(v) "SND Time Medium" is the value for SND Time Medium;

(vi) "SND Time Minimum" is the value for SND Time Minimum; and

(vii) "SND Time Zero" is the value for SND Time.

5.2 SND for Demand Side Units

The Demand Side Unit charge shall be calculated as follows:

$$DSU\ SND\ Charge = MW\ \ Reduction\ \ x\ \ SND\ Charge\ \ Rate\ \ x\ \ Notice\ Time\ Weight$$

where:

(i) “MW Reduction” is the reduction in Availability (expressed in MW) notified to the TSO;

(ii) “SND Charge Rate” is the SND Charge Rate;

(iii) Notice Time Weight is determined in following criteria:

a. For Notice Time < SND Time Minimum, then Notice Time Weight = 1

b. For Notice Time >= SND Time Minimum but < SND Time Medium then

$$Notice\ Time\ Weight = \left(\frac{Notice\ Time}{SND\ Time\ Minimum}\right)^{SND\ Powering}$$

c. For Notice Time >= SND Time Medium < DSU SND Time Zero

$$Notice\ Time\ Weight = \left(1 - \left(\frac{Notice\ Time - SND\ Time\ Medium}{Time\ Window\ for\ chargable\ SND - S \quad Time\ Medium}\right)\right)\ x\ \left(\frac{Notice\ Time}{SND\ Time\ Minimum}\right)^{SND\ Powering}$$

(iv) “SND Powering” is the SND Powering Factor;

(v) “SND Time Medium” is the value for SND Time Medium;

(vi) “SND Time Minimum” is the value for SND Time Minimum;

(vii) “DSU SND Time Zero” is the value for SND Time.

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6. GPI Charges

Where GPI Trading Period based charges occur in relation to a relevant parameter, a “Late Declaration” is a notification of impairment to a parameter which is provided later than the Late Declaration Notice Time. (Late Declaration Notice Time is specified in the table headed “Generator Performance Incentive Charge Rates/Parameters” set out in the relevant Statement of Charges).

A number of GPI Charges have become set to zero over the previous years. They have been included in Appendix A as a reference point.

6.1 Minimum Generation

The Minimum Generation charge applies in respect of each Trading Period in which the Minimum Generation of the Generating Unit has declared and contracted to provide in accordance with the highest of the values specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator. The declared value must be greater than contracted value for this charge to apply.

The charge amount shall be calculated as follows:

$$MG\_ChargeX = TP * (DMG - CMG) * MinGen\_RATE$$

where:

MG_ChargeX	is the charge for Minimum Generation underperformance in the Trading Period X (expressed in € or £);
TP	is a 0.5-hour Trading Period (expressed in h);
DMG	is the Declared Minimum Generation (expressed in MW) which must be greater than CMG for this charge to apply; where the Minimum Generation of the Generating Unit is less than the Grid Code value, the Contracted Minimum Generation value is used;
CMG	is the Contracted Minimum Generation (expressed in MW), as specified in the Grid Code or the relevant Grid Code Derogation or set out in a side letter between the TSO and the Generator; and
MinGen_RATE	is the Minimum Generation charge rate (expressed in €/MWh or £/MWh).

provided, however, that the Generating Unit is Available.

In the case of a Late Declaration where the Generating Unit gives less than the Late Declaration Notice then the charge is doubled. If the Generator makes a subsequent improved declaration, albeit one which is still not Grid Code compliant, without giving the required Late Declaration Notice Time the charge will continue to be applied but will not be doubled for that time period.

6.2 Governor Droop

The Governor Droop charge shall be applied in respect of each Trading Period in which the Governor Droop of the Generating Unit has been declared and contracted to provide in accordance with the highest of the values specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator. The declared value must be greater than contracted value for this charge to apply.

The charge amount shall be calculated as follows:

$$GD\_ChargeX = TP * APuh * ((DGD – CGD) / DGD) * GD\_RATE$$

where:

GD_Charge_X	is the charge for Governor Droop underperformance in the Trading Period x (expressed in € or £);
TP	is a 0.5-hour Trading Period (expressed in h);
AP_{uh}	is the Time Weighted Average Availability of Generator Unit u in Trading Period h (expressed in MW) and calculated by the application of the following formula: $AP_{uh} = \sum_{Av=1,N} \{(A_{V1} \times T_1)/30\}$ Where: $\sum_{Av=1,N}$ is the summation for the N values of Availability during the Trading Period and where Av=1 denotes the first value of Availability during the Trading Period; T_1 is the period (expressed in minutes) for which the value of Availability was equal to A_{v1} during the Trading Period;
DGD	is the Declared Governor Droop (expressed in %) which must be greater than CGD for this charge to apply;
CGD	is the Contracted Governor Droop (expressed in %), as specified in the Grid Code or the relevant Grid Code Derogation or set out in a side letter, between the TSO and the Generator; and
GD_RATE	is the Governor Droop charge rate (expressed in €/MWh or £/MWh).

provided, however, that the Generating Unit is Available.

In the case of a Late Declaration where the Generating Unit gives less than the Late Declaration Notice Time, then the charge is doubled. If the Generator makes a subsequent improved declaration, although one which is still not Grid Code compliant, without giving the required Late Declaration Notice Time the charge will continue to be applied but will not be doubled for that time period.

6.3 Reactive Power

The Generator Performance Incentive Reactive Power charge shall be applied in respect of each Trading Period in which the Reactive Power of the Generating Unit has been declared and contracted to provide in accordance, with values specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator. The declared value must be less than contracted value for this charge to apply.

The charge amount shall be calculated as follows:

$$RP\_ChargeX = TP * ((RPLD - DRPLD) + (RPLG - DRPLG)) * RP\_RATE$$

where:

RP_Charge_X	is the charge for Reactive Power underperformance in the Trading Period x (expressed in € or £);
TP	is a 0.5-hour Trading Period (expressed in h);
RPLD	is the Reactive Power (Leading) (also referred to as Consumption) (expressed in MVAr), as specified in the Grid Code or the relevant Grid Code Derogation or set out in a side letter between the TSO and the Generator and the Operating Parameters of the unit;
DRPLD	is the Declared Reactive Power (Leading) (also referred to as Consumption) (expressed in MVAr) which must be less than RPLD for the Reactive Power (Leading) aspect of the charge to apply;
RPLG	is the Reactive Power (Lagging) (also referred to as Production) (expressed in MVAr), as specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator and the Operating Parameters of the unit;
DRPLG	is the Declared Reactive Power (Lagging) (also referred to as Production) (expressed in MVAr) which must be less than RPLG for the Reactive Power (Lagging) aspect of the charge to apply; and
RP_RATE	is the Reactive Power charge rate (expressed in €/MVArh or £/MVArh).

provided, however, that the Generating Unit is Available.

In the case of a Late Declaration where the Generating Unit gives less than the Late Declaration Notice Time then the charge is doubled. If the Generator makes a subsequent improved declaration, although one which is still not Grid Code compliant, without giving the required Late Declaration Notice Time the charge will continue to be applied but will not be doubled for that time period.

6.4 Operating Reserve

The Generator Performance Incentive Operating Reserve charges shall be applied in respect of each Trading Period in which the Operating Reserve of the Generating Unit has been declared and contracted to provide in accordance with values specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator, provided, however, that the Generating Unit is Available and the declared value must be less than contracted value for this charge to apply. In the case of a Late Declaration where the Generating Unit gives less than the Late Declaration Notice Time then the charge is doubled. If there is a subsequent improved declaration, although one which is still not Grid Code compliant, without giving the required Late Declaration Notice Time the charge will continue to be applied but not doubled for that time period. The amount shall be calculated as follows:

$$POR\_ChargeX = TP * (POR - DPOR) * POR\_RATE$$

$$SOR\_ChargeX = TP * (SOR - DSOR) * SOR\_RATE$$

$$TOR1\_ChargeX = TP * (TOR1 - DTOR1) * TOR1\_RATE$$

$$TOR2\_ChargeX = TP * (TOR2 - DTOR2) * TOR2\_RATE$$

where:

TP	is a 0.5-hour Trading Period (expressed in h);
POR_Charge_x	is the charge for Primary Operating Reserve underperformance in the Trading Period x (expressed in € or £);
POR	is the Primary Operating Reserve (expressed in MW);
DPOR	is the Declared Primary Operating Reserve (expressed in MW) which must be less than POR for the charge to apply;
POR_RATE	is the Primary Operating Reserve charge rate (expressed in €/MWh or £/MWh);
SOR_Charge_x	is the charge for Secondary Operating Reserve underperformance in the Trading Period x (expressed in € or £);
SOR	is the Secondary Operating Reserve (expressed in MW);
DSOR	is the Declared Secondary Operating Reserve (expressed in MW) which must be less than SOR for the charge to apply;
SOR_RATE	is the Secondary Operating Reserve charge rate (expressed in €/MWh or £/MWh);
$TOR1\_Charge_x$	is the charge for Tertiary Operating Reserve 1 underperformance in the Trading Period x (expressed in € or £);
TOR1	is the Tertiary Operating Reserve 1 (expressed in MW);
DTOR1	is the Declared Tertiary Operating Reserve 1 (expressed in MW) which must be less than TOR1 for the charge to apply;
TOR1_RATE	is the Tertiary Operating Reserve 1 charge rate (expressed in €/MWh or £/MWh);
$TOR2\_Charge_x$	is the charge for Tertiary Operating Reserve 2 underperformance in the Trading Period x (expressed in € or £);
TOR2	is the Tertiary Operating Reserve 2 (expressed in MW);
DTOR2	is the Declared Tertiary Operating Reserve 2 (expressed in MW) which must be less than TOR2 for the charge to apply; and
TOR2_RATE	is the Tertiary Operating Reserve 2 charge rate (expressed in €/MWh or £/MWh).

6.5 Secondary Fuel Availability

The Secondary Fuel Availability charge shall be applied in respect of each Trading Period in which the Generating Unit has been declared to be unavailable for Secondary Fuel.

The charge amount shall be calculated as follows:

where: ***SF_ChargeX = TP * DSFC * APuh * SFA_F * SecFuel_RATE***

SF_ChargeX	is the charge for secondary fuel underperformance in the Trading Period X (expressed in € or £);
TP	is a 0.5-hour Trading Period (expressed in h);
DSFC	is the Declared Secondary Fuel Capability of the generating unit to be available to generate on its secondary fuel, start on their secondary fuel or change fuel on load. If the generating unit cannot perform either of these capabilities, then a charge is levied on the unit. This is a Yes (0) or No (1) condition in the calculation;
Apuh	is the Time Weighted Average Availability of Generator Unit u in Trading Period h (expressed in MW) and calculated by the application of the following formula: Apuh = ∑Av=1,N {(AV1 x T1)/30} Where: ∑Av=1,N is the summation for the N values of Availability during the Trading Period and where Av=1 denotes the first value of Availability during the Trading Period; T1 is the period (expressed in minutes) for which the value of Availability was equal to Av1 during the Trading Period;
SFA_F	is the Secondary Fuel Availability Factor (dimensionless); and
SecFuel_RATE	is the secondary fuel charge rate (expressed in €/MWh or £/MWh).

6.6 DSU Metering Shortfall

Following a direction from the RAs to commence implementation of this GPI, the DSU Metering Shortfall charge shall be applied to each Trading Period in which the Demand Side Unit (DSU) is outside the shortfall limit between Dispatch Quantity (QD) and Meter Quantity (QM).

The charge amount shall be calculated as follows:

DSU GPI_ChargeX = TP * MW Shortfall * DSU GPI_RATE

where:

DSU GPI_ChargeX	is the charge for DSU underperformance in the Trading Period X (expressed in € or £);
TP	is a 0.5-hour Trading Period (expressed in h); and
MW Shortfall	is the variation between Dispatch Quantity and Metering Quantity outside of the shortfall tolerance threshold (expressed in MW);
DSU GPI_Rate	is the DSU GPI charge rate (expressed in €/MWh or £/MWh).

7. Appendix A

The following event-based GPIs will remain at zero as in previous years, noting that a previous charge component was applied, as specified in relevant Statement of Charges.

7.1 Loading Rate

The Loading Rate charge shall be applied in respect of each loading of the Generating Unit to its declared Minimum Generation following synchronisation in which the Actual Loading Rate of the Generating Unit is below the lower of the values specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator. The charge amount shall be calculated as follows:

$$LR\_Charge_Y = ((LR – ALR) / LR) * A * LR\_RATE * ((MGLT – ASyncT) / LR\_F1) * LR\_F2$$

where:

LR_Charge_Y	is the charge for Loading Rate underperformance for loading event Y from synchronisation of the Generator Unit (expressed in € or £);
LR	is the Loading Rate (expressed in MW/h), as specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator;
ALR	is the Actual Loading Rate calculated as follows: $ALR = [DMG / (MGLT - ASyncT)] * ALR\_Tol$ DMG: is the unit's Declared Minimum Generation (expressed in MW); where the Minimum Generation of the Generating Unit is less than the Grid Code value, the Contracted Minimum Generation value is used. MGLT: is the Minimum Generation Load Time which is that time at which the Declared Minimum Generation is reached. Note that tolerances MG_LR_F1 and MG_LR_F2 are applied to the Declared Minimum Generation for the MGLT calculation. In this instance the MGLT is the time at which the unit output rises above max [min((((100 - MG_LR_F1)/100)*DMinGen), (DMinGen - MG_LR_F2)),0] (expressed in min); ASyncT: is the Actual Synchronisation Time (expressed in min); ALR_Tol: is the Actual Loading Rate Tolerance (expressed as %);
A	is the Availability of the Generating Unit (expressed in MW) prevailing at Dispatched Load Time;
LR_RATE	is the Loading Rate charge rate (expressed in €/MW or £/MW);
LR_F1	is the Loading Rate Factor 1 (expressed in minutes);
LR_F2	is the Loading Rate Factor 2 (dimensionless);
MG_LR_F1	is the Minimum Generation Tolerance Factor (%); and
MG_LR_F2	is the Minimum Generation Tolerance Factor (MW).

7.2 De-Loading Rate

The De-Loading Rate charge shall be applied in respect of each de-loading from the declared Minimum Generation of the Generating Unit following a De-Synchronisation Instruction in which the De-Loading Rate of the Generating Unit is below the lower of the values specified in the Grid Code or the relevant Grid Code Derogation or, as set out in a side letter between the TSO and the Generator. The charge amount shall be calculated as follows:

$$DLR\_Charge_Y = ((DLR – ADLR)/DLR) * A * DLR\_RATE * ((DSyncT – MGDLT) / DLR\_F1) * DLR\_F2$$

where:

DLR_Charge_Y	is the charge for De-Loading Rate underperformance for de-loading event Y following a De-Synchronisation Instruction of the Generator Unit (expressed in € or £);
DLR	is the De-Loading Rate (expressed in MW/min), as specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator;
ADLR	is the Actual De-Loading Rate calculated as follows: $ADLR = [DMG / (DsyncT – MGDLT)] * ADLR\_Tol$ DMG: is the Declared Minimum Generation at the time of the De-Synchronisation Instruction (expressed in MW); where the Minimum Generation of the Generating Unit is less than the Grid Code value, the Contracted Minimum Generation value is used. MGDLT: is the time at which the unit reduces its output below the Declared Minimum Generation. Note that the tolerances MG_DLR_F1 and MG_DLR_F2 are applied to the Declared Minimum Generation for the MGDLT calculation. In this instance the MGDLT is the time at which the output drops below max [min((((100 – MG_DLR_F1)/100)*DminGen), (DminGen – MG_DLR_F2)),0] (expressed in min); DsyncT: is the De-Synchronisation Time (expressed in min) which is the time at which the Generator Unit actually de-synchronised; ADLR_Tol: is the Actual Loading Rate Tolerance (expressed as a percentage);
A	is the Availability of the Generating Unit (expressed in MW) prevailing at the De-Synchronisation Load Time;
DLR_RATE	is the De-Loading Rate charge rate (expressed in €/MW or £/MW);
DLR_F1	is the De-Loading Rate Factor 1 (expressed in minutes);
DLR_F2	is the De-Loading Rate Factor 2 (dimensionless);
MG_DLR_F1	is the Minimum Generation Tolerance Factor (%); and
MG_DLR_F2	is the Minimum Generation Tolerance Factor (MW).

7.3 Late Synchronisation

Save where Late Synchronisation is specifically requested by the TSO and agreed by the Generator, on each occasion upon which the Generating Unit synchronises to the Transmission System more than 5 minutes after the time that was instructed for synchronisation by a valid Despatch Instruction, the Generator shall pay to the TSO. The charge shall be calculated as follows:

For synchronisation within 60 minutes after the instructed synchronisation time:

$$LS\_ChargeY = \{(LS - LS\_Tol) / LS\_F\} * A * LS\_RATE$$

For synchronisation at or greater than 60 minutes after the instructed synchronisation time:

$$LS\_ChargeY = A * LS\_RATE$$

where:

LS_ChargeY	is the charge for the Late Synchronisation underperformance for synchronisation event Y following a Synchronisation Instruction of the Generating Unit (expressed in € or £);
LS	is the number of minutes after the Despatched Synchronising Time that the Generating Unit was synchronising to the Transmission System;
A	is the Availability of the Generating Unit (expressed in MW) prevailing at the Dispatched Load Time;
LS_RATE	is the Late Synchronisation charge rate (expressed in €/MW or £/MW);
LS_Tol	is the Late Synchronisation Tolerance (expressed in min); and
LS_F	is the Late Synchronisation Factor (expressed in min).

7.4 Early Synchronisation

Save where early synchronisation is specifically requested by the TSO and agreed by the Generator, on each occasion upon which the Generating Unit synchronises to the Transmission System more than 15 minutes before the Despatched Synchronisation Time, the Generator shall pay to the TSO. The charge shall be calculated as follows:

$$ES\_ChargeY = \{ (ES - ES\_Tol) / ES\_F \} * A * ES\_RATE$$

where:

ES_Charge_Y	is the charge for the Early Synchronisation underperformance for synchronisation event Y following a Synchronisation Instruction of the Generating Unit (expressed in € or £);
ES	is the number of minutes before the Despatched Synchronising Time that the Generating Unit was synchronised to the Transmission System;
ES_Tol	is the Early Synchronisation Tolerance (expressed in min);
ES_F	is the Early Synchronisation Factor (expressed in min);
A	is the Availability of the Generator Unit (expressed in MW) prevailing at the Dispatched Load Time; and
ES_RATE	is the Early Synchronisation charge rate (expressed in €/MW or £/MW).

7.5 Maximum Number of Starts per 24-hour Period

The Maximum Number of Starts per 24-hour Period charge shall be applied in respect of each Trading Period in which the Maximum Number of Starts per 24-hour Period of the Generating Unit has been declared to greater than values specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator. The charge amount shall be calculated as follows:

$$MxS\_ChargeX = TP * DMG * MxS\_RATE * ((CMxS - DMxS) / DMxS)$$

where:

MxS_Charge$_x$	is the charge for Maximum Number of Starts per 24-hour Period underperformance in the Trading Period x (expressed in € or £);
TP	is a 0.5-hour Trading Period (expressed in h);
DMG	is the Declared Minimum Generation (expressed in MW) which must be greater than CMG for this charge to apply;
MxS_RATE	is the Maximum Number of Starts per 24-hour Period charge rate (expressed in €/MWh or £/MWh);
CMxS	is the Maximum Number of Starts per 24-hour period (expressed as a number), as specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator; and
DMxS	is the Declared Maximum Number of Starts per 24-hour period (expressed as a number) which must be less than CMxS for this charge to apply.

provided, however, that the Generating Unit is Available.

In the case of a Late Declaration where the Generating Unit gives less than the Late Declaration Notice Time then the charge is doubled. If the Generator makes a subsequent improved declaration, although one which is still not Grid Code compliant, without giving the required Late Declaration Notice Time the charge will continue to be applied but will not be doubled for that time period.

7.6 Minimum on Time

The Minimum on Time charge shall be applied in respect of each Trading Period in which the Minimum on Time of the Generating Unit has been declared to be greater than values specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator. The charge amount shall be calculated as follows:

$$MoT\_ChargeX = TP * DMG * MoT\_RATE * ((DMoT - CMoT) / CMoT)$$

where:

MoT_Charge$_X$	is the charge for Minimum on Time underperformance in the Trading Period x (expressed in € or £);
TP	is a 0.5-hour Trading Period (expressed in h);
DMG	is the Declared Minimum Generation (expressed in MW) which must be greater than CMG for this charge to apply;
MoT_RATE	is the Minimum on Time charge rate (expressed in €/MWh or £/MWh);
DMoT	is the Declared Maximum Number of Starts per 24-hour period (expressed in minutes) which must be greater than CMoT for this charge to apply; and
CMoT	is the Minimum on Time (expressed in minutes), as specified in the Grid Code or the relevant Grid Code Derogation or as set out in a side letter between the TSO and the Generator.

provided, however, that the Generating Unit is Available.

In the case of a Late Declaration where the Generating Unit gives less than the Late Declaration Notice Time then the charge is doubled. If the Generator makes a subsequent improved declaration, although one which is still not Grid Code compliant, without giving the required Late Declaration Notice Time the charge will continue to be applied but will not be doubled for that time period.