# Other System Charges

# Methodology Statement

**Applicable from 1st February 2010**

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# 1. Introduction

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' (RA) Decision Paper SEM-001-10. This document is referred to in the Transmission Use of System Statement of Charges ("TUoS Statement of Charges") published in each jurisdiction by EirGrid and SONI and has been approved by CER and NIAUR. This document may be revised by EirGrid and SONI from time to time, subject to the approval of CER and NIAUR.

## 1.1. Background

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 considered necessary to document the harmonised arrangements that will be applicable in both jurisdictions under the SEM. These charges are referred to as Other System Charges and have been subject to consultation.

In September 2006 the RAs approved[1] the continuation of separate commercial arrangements for Ancillary Services and related charges within the Republic of Ireland (RoI) and Northern Ireland (NI) prior to SEM Go-Live and pending a longer-term review of suitable harmonised all island arrangements.

As part of this review process the TSOs published a consultation paper in August 2007[2]. This set out the high-level harmonised all-island policy options for Ancillary Services (AS) and other system operations related payments and charges, for implementation post SEM Go-Live.

Following this consultation period the SEM Committee issued a high level decision (HLD) paper on 27th February 2008[3] that confirmed the intention to have in place a set of harmonised arrangements for AS/System Support Services (SSS) across both RoI and NI. The HLD paper established the high level policy framework for the development of the proposed harmonised AS arrangements, and also addressed other system charges and generator performance incentives (GPI's).

Following the publication of the HLD the TSOs organised industry workshops on 29th April 2008 and 1st May 2008[4] and invited feedback from participants. Subsequently in September 2008 the TSOs published a consultation paper[5] containing detailed proposals for the implementation of harmonised arrangements for AS, other generator payments (i.e. secondary fuelling in Ireland) , other system charges, and GPIs. This consultation paper was the subject of an industry briefing session on 1 October 2008, chaired by the TSOs and involving both RAs,.

Following a consultation period, the SEM Committee made decisions on the future implementation of harmonised arrangements for AS, other system charges and GPIs across the island. This decision paper was published on the 30th January 2009[6].

[1] [AIP-SEM-160-06] Day 1 Decision for System Support Services in NI and Ancillary services, Short notice declarations

[2] [AIP-SEM-07-447] Proposed System Operations Services' Payments & Charges in SEM, August 2007

[3] [SEM-08-013] Harmonised All-Island Ancillary Services Policy, High Level Decision policy paper, February 2008

[4] [SEM-08-063] and [SEM-08-064] Harmonised Ancillary Services workshops April/May 2008.

[5] [SEM-08-128] Harmonised Ancillary Services, Other System Payments & System Charges, September 2008

[6] [SEM-09-003] Harmonised Ancillary Services, Other System Payments & System Charges. A Decision Paper' 30th January 2009

On 8th June 2009 the RAs published a TSO consultation paper[7] detailing the proposed payments and charges to be applied in the first period of implementation. An industry briefing workshop, chaired by the TSOs and involving both RAs, was held on 24th June 2009 to explain the proposals.

The SEM Committee published its decision paper[8] on All-Island Ancillary Services Rates and Other System Charges on 4th January 2010, setting out the rates and related parameters applicable for the initial period after 1st February 2010.

## 2. Harmonised Other System Charges Rates Framework

### 2.1. Monetary Flows

Other System Charges (Trips, Short Notice Declarations (SNDs) and GPIs) will be reviewed annually and will be included in the TUoS Statement of Charges published by each TSO in their respective jurisdictions. The Decision Paper published in January 2009 determined that the income from these charges will be used to reduce the SEM Imperfections Tariff for the following tariff period. Note that the charging period for Other System Charges will be a calendar month.

### 2.2. Payment of Charges

The GPI, SNDs and Trip charges are payable by generators party to a Transmission Use of System Agreements (TUoSA). This includes the NIE Energy Power Procurement Business (PPB) in respect of Generating Units contracted to PPB through a Generating Unit Agreement.

### 2.3. Exchange Rate

- An exchange rate will be fixed annually for each tariff year/period using market forward exchange rates.
- At the end of each tariff year/period the exchange rates will be reviewed to determine if an adjustment is required in NI and/or 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.

### 2.4. Trips

Trip charges are designed to reduce the rate of loss to the system following a trip event. The application of multiple charges to trip events strengthens the incentives to generators to improve their performance. Generator trip charges are expected to be less than the system costs as a result of the outages including the costs of holding reserve.

### 2.5. Short Notice Declarations (SNDs)

SNDs relate to unscheduled variations in availability of committed plant or to the unscheduled outage of dispatched plant. The charges are intended to incentivise behaviour to enhances system security and reduce operating costs. Further details can be found in the June 2009 consultation paper[9].

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[7] [SEM-09-062] "Harmonised Ancillary Services & Other System Charges. Rates Consultation' 8th June 2009
[8] [SEM-10-001] Harmonised All-Island Ancillary Services Rates and Other System Charges
[9] [SEM-09-062] "Harmonised Ancillary Services & Other System Charges. Rates Consultation' Consultation, 8th June 2009

### 2.6. Generator Performance Incentives (GPIs)

In a relatively small power system it is very important that the system is operated in an efficient and economic manner in accordance with the performance standards required by the Grid Codes. The GPI charges are intended to incentivise performance that enhances system security and reduces operating costs. Further details can be found in the June 2009 consultation paper[10]

## 3. 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:

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

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

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

Where:

“DT Charge Rate” is the Direct Trip Charge Rate set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges;

“DT Const” is the Direct trip Constant set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges;

“Max MW Loss” is the maximum MW loss for the trip;

“Trip MW Loss Threshold” is the Trip MW Loss Threshold set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges;

“FWD Charge Rate” is the Fast Wind Down Rate of MW Loss set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges;

“FWD Const” is the Fast Wind Down Constant set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges;

[10] [SEM-09-062] “Harmonised Ancillary Services & Other System Charges. Rates Consultation’ 8th June 2009

“SWD Charge Rate” is the Slow Wind Down Charge Rate set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges; and

“SWD Const” is the Slow Wind Down Constant set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges.

## 4. 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.

The SND charge applies for downward availability declarations within the time period set by the SND Time Zero parameter. There is a minimum threshold, known as the SND Minimum Threshold, below which no charge applies. This minimum threshold provides for normal ambient changes in availability. The SND Minimum Threshold is set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” in the relevant TUoS Statement of Charges. The SND charge does not apply for declarations relating to scheduled availability changes and non-generator plant availability changes.

To discourage multiple SNDs below the minimum threshold in quick succession, re-declarations below the SND Minimum Threshold within the Time Window for Chargeable SNDs are subject to an SND charge, provided the sum of the SND reductions are above the SND Minimum Threshold. In such circumstances, the SND reduction is the summation of the smaller SND reductions and set to no notice.

The charge is calculated as follows:

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

where the Notice Time is in minutes and Notice Time Weight is a value between zero and one which is calculated as follows:

If Notice Time < SND Time Minimum

then *Notice Time Weight = 1*

If Notice Time >= SND Time Minimum but < SND Time Medium

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

If Notice Time >= 20 min but < 480 min

then

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

and where:

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

“SND Charge Rate” is the SND Charge Rate set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges;

“SND Powering” is the SND Powering Factor set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges;

“SND Time Medium” is the value for SND Time Medium set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges;

“SND Time Minimum” is the value for SND Time Minimum set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges;

“SND Time Zero” is the value for SND Time Zero set out in the table headed “Trips and Short Notice Declaration Charge Rates/Parameters” set out in the TUoS Statement of Charges.

## 5. GPI Charges

### 5.1. GPI Trading Period Based Charges

For the purposes of this section 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 TUoS Statement of Charges)

**Minimum Generation**

The Minimum Generation charge applied in respect of each Trading Period in which the Minimum Generation of the Generating Unit has been declared to be, in the case of a ROI Generating Unit, above the highest of the values specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit (“NI Uncontracted Unit”) that is not subject to a Generating Unit Agreement (“GUA”), Schedule 9 to the HASC[11] or, in the case of a NI Generating Unit (“NI Contracted Unit”) that is subject to a GUA, the relevant schedule to the GUA, by an amount calculated as follows:

$$MG\_Charge_X = TP * (DMG – CMG) * MinGen\_RATE$$

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; |
| CMG | is the Minimum Generation (expressed in MW), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Uncontracted Unit, Schedule 9 to the HASC or, in the case of a NI Contracted Unit, the relevant Schedule to the GUA; and |
| MinGen_RATE | is the Minimum Generation charge rate (expressed in €/MWh or £/MWh) specified in the table headed “Generator Performance Incentive Charge Rates/Parameters” set out in the TUoS Statement of Charges, |

provided, however, that the Generating Unit is Available. In the case of a Late Declaration the charge is doubled.

**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 to be above the highest of the values, in the case of a ROI Generating Unit, specified by the TSO within the standard set in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit (“NI Uncontracted Unit”) that is not

[11] Note: the content of Schedule 9 is still under discussion

subject to a Generating Unit Agreement ("GUA"), Schedule 9 to the HASC[12] or, in the case of a NI Generating Unit ("NI Contracted Unit") that is subject to a GUA, the relevant schedule to the GUA, by an amount calculated as follows:

$$GD\_Charge_X = TP * AP_{uh} * ((DGD - CGD) / DGD) * GD\_RATE$$

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:<br>$AP_{uh} = \sum_{\mathbf{Av=1,N}} \{(A_{V1} \times T_1)/TP\}$<br>Where:<br>$\sum_{\mathbf{Av=1,N}}$ 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;<br>$T_1$ 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 Governor Droop (expressed in %), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Uncontracted Unit, Schedule 9 to the HASC or, in the case of a NI Contracted Unit, the relevant Schedule to the GUA; and |
| GD_RATE | is the Governor Droop charge rate (expressed in €/MWh or £/MWh) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges, |

provided, however, that the Generating Unit is Available. In the case of a Late Declaration the charge is doubled.

**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 be, in the case of a ROI Generating Unit, below the lower of the values specified in the

[12] Note: the content of Schedule 9 is still under discussion

Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit ("NI Uncontracted Unit") that is not subject to a Generating Unit Agreement ("GUA"), Schedule 9 to the HASC[13] or, in the case of a NI Generating Unit ("NI Contracted Unit") that is subject to a GUA, the relevant schedule to the GUA, by an amount as follows:

$MxS\_Charge_X =$ TP * DMG * MxS_RATE

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) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges, |

provided, however, that the declared Maximum Number of Starts per 24 hour Period is below the required value, the Generating Unit is Available. In the case of a Late Declaration, the charge is doubled.

**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, in the case of a ROI Generating Unit, above the higher of the values specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit ("NI Uncontracted Unit") that is not subject to a Generating Unit Agreement ("GUA"), Schedule 9 to the HASC[14] or, in the case of a NI Generating Unit ("NI Contracted Unit") that is subject to a GUA, the relevant schedule to the GUA, by an amount calculated as follows:

$MoT\_Charge_X =$ TP * DMG * MoT_RATE

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; |

[13] Note: the content of Schedule 9 is still under discussion

[14] Note: the content of Schedule 9 is still under discussion

MoT_RATE is the Minimum on Time charge rate (expressed in €/MWh or £/MWh) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges,

provided, however, that the Minimum on Time is above the required value, the Generating Unit is Available. In the case of a Late Declaration, the charge is doubled.

**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 to be, in the case of a ROI Generating Unit, below the lower of the values specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit, the values derived from the Reactive Power Characteristic Curve set out in Schedule 9 to the HASC[15] by an amount calculated as follows:

$$RP\_Charge_X = TP * ( (RPLD – DRPLD) + (RPLG – DRPLG) ) * RP\_RATE$$

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), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit, the Reactive Power (Leading) deliverable at the Full Load of the Generating Unit in accordance with the Reactive Power Characteristic Curve set out in Schedule 9 to the HASC 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), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit, the Reactive Power (Lagging) deliverable at the Full Load of the Generating Unit in accordance with the Reactive Power Characteristic Curve set out in Schedule 9 of the HASC 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;

RP_RATE is the Reactive Power charge rate (expressed in €/MVArh or £/MVArh) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges,

[15] Note: the content of Schedule 9 is still under discussion

provided, however, that the Generating Unit is Available. In the case of a Late Declaration of either DRPLD or DRPLG, the charge is doubled.

**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 to be, in the case of a ROI Generating Unit, below the lower of the values specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit, Schedule 9 to the HASC, by an amount calculated as follows:

$POR\_Charge_X =$ TP * (POR – DPOR) * POR_RATE

where:

| | |
|---|---|
| $POR\_Charge_X$ | is the charge for Primary Operating Reserve underperformance in the Trading Period x (expressed in € or £); |
| TP | is a 0.5 hour Trading Period (expressed in h); |
| POR | is the Primary Operating Reserve (expressed in MW), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit, as derived in accordance with the relevant provisions of the HASC from the POR HAS Reserve Curve set out in Schedule 9 of the HASC; |
| DPOR | is the Declared Primary Operating Reserve (expressed in MW) which must be less than POR for the charge to apply; and |
| POR_RATE | is the Primary Operating Reserve charge rate (expressed in €/MWh or £/MWh) specified in the table headed “Generator Performance Incentive Charge Rates/Parameters” set out in the TUoS Statement of Charges, |

provided, however, that the Generating Unit is Available. In the case of a Late Declaration, the charge is doubled.

$SOR\_Charge_X =$ TP * (SOR – DSOR) * SOR_RATE

where:

| | |
|---|---|
| $SOR\_Charge_X$ | is the charge for Secondary Operating Reserve underperformance in the Trading Period x (expressed in € or £); |
| TP | is a 0.5 hour Trading Period (expressed in h); |
| SOR | is the Secondary Operating Reserve (expressed in MW), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit, as derived in accordance with |

| | |
|---|---|
| | the relevant provisions of the HASC from the SOR HAS Reserve Curve set out in Schedule 9 to the HASC; |
| DSOR | is the Declared Secondary Operating Reserve (expressed in MW) which must be less than SOR for the charge to apply; and |
| SOR_RATE | is the Secondary Operating Reserve charge rate (expressed in €/MWh or £/MWh) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges, |

provided, however, that the Generating Unit is Available. In the case of a Late Declaration, the charge is doubled.

$TOR1\_Charge_X =$ TP * (TOR1 – DTOR1) * TOR1_RATE

where:

| | |
|---|---|
| $TOR1\_Charge_X$ | is the charge for Tertiary Operating Reserve 1 underperformance in the Trading Period x (expressed in € or £); |
| TP | is a 0.5 hour Trading Period (expressed in h); |
| TOR1 | is the Tertiary Operating Reserve 1 (expressed in MW), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit, as derived in accordance with the relevant provisions of the HASC from the TOR1 HAS Reserve Curve set out in Schedule 9 to the HASC; |
| DTOR1 | is the Declared Tertiary Operating Reserve 1 (expressed in MW) which must be less than TOR1 for the charge to apply; and |
| TOR1_RATE | is the Tertiary Operating Reserve 1 charge rate (expressed in €/MWh or £/MWh) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges, |

provided, however, that the Generating Unit is Available. In the case of a Late Declaration, the charge is doubled.

$TOR2\_Charge_X =$ TP * (TOR2 – DTOR2) * TOR2_RATE

where:

| | |
|---|---|
| $TOR2\_Charge_X$ | is the charge for Tertiary Operating Reserve 2 underperformance in the Trading Period x (expressed in € or £); |
| TP | is a 0.5 hour Trading Period (expressed in h); |
| TOR2 | is the Tertiary Operating Reserve 2 (expressed in MW), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit, Schedule 9 to the HASC; |

| | |
|---|---|
| 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) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges, |

provided, however, that the Generating Unit is Available. In the case of a Late Declaration, the charge is doubled.

## 5.2. GPI Event-Based Charges

**Loading Rate**

The Loading Rate charge shall be applied in respect of each loading of the Generating Unit following synchronisation in which the Actual Loading Rate of the Generating Unit is, in the case of a ROI Generating Unit, below the lower of the values specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit ("NI Uncontracted Unit") that is not subject to a Generating Unit Agreement ("GUA"), Schedule 9 to the HASC[16] or, in the case of a NI Generating Unit ("NI Contracted Unit") that is subject to a GUA, the relevant schedule to the GUA, by an amount calculated as follows:

$$LR\_Charge_Y = ( (LR - ALR) / LR ) * A * LR\_RATE * ((DpLT - ASyncT) / LR\_F1) * LR\_F2$$

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), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Uncontracted Unit, Schedule 9 of the HASC or, in the case of a NI Contracted Unit, the relevant Schedule of the GUA, allowing for the heat state of the Generator Unit; |
| ALR | is the Actual Loading Rate calculated as follows: |

$$ALR = [ DpL / (DpLT - ASyncT) ] * ALR\_Tol$$

Where

| | |
|---|---|
| DpL | is the Dispatched Load following a Synchronisation Instruction (expressed in MW); |
| DpLT | is the Dispatched Load Time which is that time at which the Dispatched Load is reached (expressed in min); |
| ASyncT | is the Actual Synchronisation Time (expressed in min); |
| ALR_Tol | is the Actual Loading Rate Tolerance (expressed as %); |

[16] Note: the content of Schedule 9 is still under discussion

| | |
|---|---|
| A | is the Availability of the Generating Unit (expressed in MW) prevailing at the Dispatched Load Time; |
| LR_RATE | is the Loading Rate charge rate (expressed in €/MW or £/MW) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges; |
| LR_F1 | is the Loading Rate Factor 1 (expressed in minutes) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges; and |
| LR_F2 | is the Loading Rate Factor 2 (dimensionless) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges. |

**De-Loading Rate**

The De-Loading Rate charge shall be applied in respect of each de-loading of the Generating Unit following a De-Synchronisation Instruction in which the De-Loading Rate of the Generating Unit is, in the case of a ROI Generating Unit, below the lower of the values specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Generating Unit ("NI Uncontracted Unit") that is not subject to a Generating Unit Agreement ("GUA"), Schedule 9 to the HASC[17] or, in the case of a NI Generating Unit ("NI Contracted Unit") that is subject to a GUA, the relevant schedule to the GUA, by an amount calculated as follows:

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

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), in the case of a ROI Generating Unit, as specified in the Grid Code or the relevant Grid Code Derogation or, in the case of a NI Uncontracted Unit, Schedule 9 to the HASC or, in the case of a NI Contracted Unit, the relevant Schedule to the GUA; |
| ADLR | is the Actual De-Loading Rate calculated as follows: |

$$ADLR = [ DLMW / ( DSyncT - DLT ) ] * ADLR\_Tol$$

where

[17] Note: the content of Schedule 9 is still under discussion

| | |
|---|---|
| DLMW | is the MW Output at the time of the De-Synchronisation Instruction (expressed in MW); |
| DLT | is the De-Synchronisation Instruction Time which is that time at which the De-Synchronisation Instruction was issued (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) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges; |
| DLR_F1 | is the De-Loading Rate Factor 1 (expressed in minutes) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges; and |
| DLR_F2 | is the De-Loading Rate Factor 2 (dimensionless) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges. |

**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 a charge calculated as follows:

For synchronisation within 60 minutes after the instructed synchronisation time:

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

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

$$LS\_Charge_{Y} = A * LS\_RATE$$

where:

| | |
|---|---|
| $LS\_Charge_{Y}$ | 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) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges; |
| LS_Tol | is the Late Synchronisation Tolerance (expressed in min) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges; and |
| LS_F | is the Late Synchronisation Factor (expressed in min) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges. |

**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 a charge calculated as follows:

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

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) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges; |
| ES_F | is the Early Synchronisation Factor (expressed in min) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges; |

| | |
|---|---|
| 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) specified in the table headed "Generator Performance Incentive Charge Rates/Parameters" set out in the TUoS Statement of Charges. |

## Appendix A Glossary of Terms

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|---|---|
| AS | Ancillary Services |
| CER | Commission for Energy Regulation |
| GPI | Generator Performance Incentives |
| GUA | Generating Unit Agreement |
| HASC | Harmonised Ancillary Services Agreement |
| NI | Northern Ireland |
| NIAUR | Northern Ireland Authority for Utility Regulation |
| POR | Primary Operating Reserve |
| RAs | Regulatory Authorities |
| RoI | Republic of Ireland |
| SEM | Single Electricity Market |
| SEMO | Single Electricity Market Operator |
| SND | Short Notice Declaration |
| SOR | Secondary Operating Reserve |
| SSSA | System Support Services Agreement |
| TOR | Tertiary Operating Reserve |
| TSC | Trading and Settlement Code |
| TSO | Transmission System Operator |
| TUoS | Transmission use of System |