Single Electricity Market

Harmonised All-Island Ancillary Services Rates and Other System Charges

Decision Paper

4 January 2010

SEM-10-001

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1. Executive Summary

Following consultation, in February 2008 the SEM Committee[1] published a High Level Decision paper[2] providing a policy framework for the all-island harmonisation of Ancillary Services (AS) and other generator payments and charges. Workshops with industry participants then followed where the Transmission System Operators (TSOs) presented for discussion the detailed harmonised arrangements and implementation alternatives. Subsequently, in September 2008, the TSOs published a consultation paper[3] containing their more detailed proposals for implementing harmonised arrangements for AS, other system charges and Generator Performance Incentives (GPIs). Following this consultation and an industry briefing session the SEM Committee published a decision paper on 30 January 2009[4].

On 8 June 2009 the TSOs published a further consultation paper[5] detailing the initial level of the proposed payments and charges. An industry briefing workshop, chaired by the TSOs and involving both Regulatory Authorities (RAs), was held on 24 June 2009 to explain the TSOs' proposals.

The RAs have considered the TSOs' proposals and reviewed the comments received to the June consultation paper. A total of eleven responses were received. Following review of these comments, the SEM Committee has now made decisions on the detailed harmonised all-island AS rates, other related system charges and generator performance incentives that will be applicable during the first period of implementation from 1 February 2010 to 30 September 2010. These decisions are set out in this paper.

The main decisions made by the SEM Committee relate to Ancillary Services Rates (Reserve, Reactive Power and Black Start), Short Notice Declarations (SND) and Trip Charges, and GPIs.

The Appendix to this document shows the detailed payments and charges approved by the SEM Committee that will apply for the harmonised AS and other system charges arrangements from 1 February 2010 to 30 September 2010. It should be noted that the original proposed implementation date was 1 October 2009. However, the SEM Committee decided[6] in August 2009 that the Go-Live of the new AS arrangements would be postponed until 1 February 2010 so as to provide opportunity and adequate time for all involved to smoothly effect the transition to the new arrangements.

While the payments and charges follow closely those proposed in the TSOs' June '09 consultation paper, in view of the responses to the consultation and following consideration with the TSOs, the SEM Committee has decided to make the following amendments (see the relevant section of this paper for more details):

- Extension, in principle, of Black Start payments to existing Northern Ireland generators. Harmonised Black Start arrangements will apply to all plant in the SEM; however the actual rates applicable will vary due to the different cost bases of the plant involved and for historical reasons,

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[1] The SEM Committee is established in Ireland and Northern Ireland by virtue of section 8A of the Electricity Regulation Act 1999 and Article 6 (1) of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 respectively. The SEM Committee is a Committee of both CER and NIAUR (together the Regulatory Authorities) that, on behalf of the Regulatory Authorities, takes any decision as to the exercise of a relevant function of CER or NIAUR in relation to an SEM matter.

[2] [SEM-08-013] 'Harmonised All-Island Ancillary Services Policy - A Decision Paper, February 2008

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

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

[5] [SEM-09-062] "Harmonised Ancillary Services & Other System Charges. Rates Consultation' Consultation, 8th June 2009

[6] [SEM-09-090] "Ancillary Services; Postponement in implementation of Harmonised Arrangements", 28th August 2009

for example because the capital and/or maintenance costs of some Black Start plant has already been recovered. The appropriate rates will be the subject of long term negotiated contracts between the TSO and generator (or PPB) as described in section 6.4.

- Modification of Trip and SND charges. Without prejudice to the future performance of plant and applicable charges, the RAs consider that the proposed Trip and SND charges could have been punitive when compared to existing charges. The approved harmonised charges therefore reduce the Trip Charge Rates and SND Charge Rate significantly from what was proposed in the consultation, and reintroduce the 100 MW threshold for calculation of trip charges as is currently being applied in Ireland. In addition to the above the short notice declaration threshold for charges has also been reduced from 12 hours to 8 hours, while a threshold of 1 MW/s (none was indicated in the TSOs' proposals) has also been approved for slow wind-down charges so that plant winding down as part of normal operations are not penalised. In relation to the SND Charge Rate, the RAs consider the consultation paper charge rate of €100/MW to be too high and have decided that €70/MW would be proportionate and reasonable for the medium term. However in order to smooth the transition to the harmonised arrangements and to allow a reasonable time for generators to improve their performance, the charge rates for SNDs will be phased in. The rate to apply from 1 February 2010 will be €20/MW. From 1 October 2010 this rate will increase to €40/MW. From 1 October 2011 it will increase to €70/MW. This allows an adjustment period of circa 20 months for generators. The impact and appropriateness of this and the other Trip and SND charges and parameters will be kept under review and consulted upon annually.
- In relation to GPIs, the RAs believe that the consultation paper charge rates are proportionate and reasonable for the medium term. However in order to smooth the transition to the harmonised arrangements and to allow a reasonable time for generators to improve their performance, the charge rates for two of the GPIs, i.e. the Minimum on Time and Maximum Starts in a 24 hour period, will be phased in. The rate to apply to both from 1 February 2010 will be €0.29/MWh as opposed to the €1.00/MWh proposed in the most recent consultation paper. From 1 October 2010 these rates will increase to €0.60/MWh. From 1 October 2011 they will increase to €1.00/MWh - the original proposal. This allows an adjustment period circa 20 months for generators. The impact and appropriateness of these and the other GPI charge rates will be kept under review and consulted upon annually.

Overall the RAs consider that the harmonised AS arrangements and other charges are an important step towards the full harmonisation of arrangements under the SEM. They provide an appropriate balance of signals about the importance of ancillary services and plant performance for the efficient operation of an otherwise relatively small system. They also provide an initial implementation of a significant framework, described in the High Level Decision paper, which can evolve in subsequent years to accommodate SEM changes that will occur in the future - for example as more renewable generation connects across the island. All future AS rates and other system charges, i.e. those from 1 October 2010 and beyond, will be subject to public consultation and RA decision separately.

2. Introduction

2.1. Background

At present a number of payments and charges are paid/levied on generators outside the main energy markets by the Transmission System Operators (TSOs), EirGrid in Ireland and SONI in Northern Ireland respectively. Most of these charges are related to Ancillary Services (AS) which are services necessary for the secure operation and restoration of the electricity system. The structure, treatment and arrangements of these charges are different in Ireland and Northern Ireland. However in all cases these costs are recovered from demand customers, through the Transmission Use of System (TUoS) charges in Ireland and the System Support Services (SSS) levy in Northern Ireland. Any AS income/rebates accruing to the TSOs in one tariff period will impact on the TUoS charges or SSS levy in the following tariff period(s).

These charges are not included in the Trading and Settlement Code (TSC) of the Single Electricity Market (SEM) and therefore it was considered necessary to define the harmonised arrangements that will be applicable in both jurisdictions under the SEM.

In September 2006 the Regulatory Authorities (RAs) approved[7] the continuation of separate commercial arrangements for AS and related charges within Ireland and Northern Ireland for the Go Live of the SEM pending a full and proper review and development of suitable harmonised all island arrangements for the longer term.

As part of this review process the TSOs published a consultation paper in August 2007[8]. This set out the high-level harmonised all-island policy options for AS and other system operations related payments and charges, for implementation post SEM Go-Live.

Following this consultation period the SEM Committee[9] issued a High Level Decision (HLD) paper on 27 February 2008[10] that confirmed the intention to have in place a set of harmonised arrangements for Ancillary Services/System Support Services (AS/SSS) across both Ireland and Northern Ireland. The HLD paper established the high level policy framework for the development of the proposed harmonised AS arrangements, and also addressed other payments and charges and generator performance incentives.

Following the publication of the high level decision paper the TSOs organised industry workshops on 29 April 2008 and 1 May 2008[11] on the detail of the possible services and invited feedback from participants. In September 2008 the TSOs published a consultation paper[12] containing their detailed proposals for implementing harmonised arrangements for AS, other generator payments (i.e. secondary fuelling in Ireland) and system charges, and Generator Performance Incentives (GPIs). This consultation paper was the subject of an industry briefing session on 1 October 2008, chaired by the TSOs and involving both RAs, to explain the proposals.

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

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

9 The SEM Committee is established in Ireland and Northern Ireland by virtue of section 8A of the Electricity Regulation Act 1999 and Article 6 (1) of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 respectively. The SEM Committee is a Committee of both CER and NIAUR (together the Regulatory Authorities) that, on behalf of the Regulatory Authorities, takes any decision as to the exercise of a relevant function of CER or NIAUR in relation to an SEM matter.

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

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

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

Following the consultation period, the SEM Committee made decisions on the future implementation of harmonised arrangements for ancillary services, other related system charges and GPIs across the island in the SEM. This decision paper was published on the 30th January 2009[13]. It was envisaged at that time that the new harmonised arrangements would go live on 1 October 2009.

However, the SEM Committee decided[14] in August 2009 that the Go-Live of the new AS arrangements would be postponed until 1 February 2010 so as to provide opportunity and adequate time for all involved to smoothly effect the transition to the new arrangements as follows:

- Participants will have more time to manage the transition and to put in place their own systems.
- The revised date will also allow an extended period of trialling/parallel running between participants and the TSOs.
- In Ireland participants can become familiar with changes to their AS contracts while in Northern Ireland they can understand the format of new AS contracts, which are supported by the RAs.
- Facilitation of Grid Code changes.
- Development of proposals and consultation on the future of Black Start payments for existing sites in Northern Ireland as part of the harmonised arrangements.
- Implementation of the alternative Replacement Reserve option which was widely welcomed in the Rates consultation.

On 8 June 2009 the RAs published a TSOs' consultation paper[15] detailing the proposed payments and charges to be applicable in the first period of implementation. An industry briefing workshop, chaired by the TSOs and involving both RAs, was held on 24 June 2009 to explain the TSOs' proposals.

2.2. Responses and General observations

The RAs have reviewed the comments received to this most recent consultation paper. A total of eleven responses were received, one in confidence, from the following groups:

1) Bord Gáis Energy
2) Bord na Móna Energy Ltd
3) Endesa Ireland
4) ESB International
5) ESB Power Generation
6) IWEA
7) Joint response by AES Kilroot, Coolkeragh ESB, NIE Energy (PPB) and Premier Power Ltd.
8) Synergen
9) Tynagh Energy Limited
10) Viridian Power and Energy Ltd.
11) Confidential response

Note that all responses were from generators. However in formulating the decisions set out in this paper the RAs have also given due regard to the interests of demand customers. Following consideration of the responses and issues raised during the consultation, the SEM Committee has made decisions on the detailed harmonised all-island AS rates, other system charges and generator

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

[14] [SEM-09-090] "Ancillary Services; Postponement in implementation of Harmonised Arrangements", 28th August 2009

[15] [SEM-09-062] "Harmonised Ancillary Services & Other System Charges. Rates Consultation' 8th June 2009

performance incentives that will be applicable in the SEM during the first period of implementation from 1 February 2010 to 30 September 2010, as set out in this paper.

Overall the RAs have been satisfied with the engagement in this consultation from industry participants and indeed in the general consultative process that has been followed in developing all-island AS arrangements over the last two years. This consultative process has included three consultations and several industry workshops where participants had the opportunity to express their views, seek further clarifications from the TSOs and RAs and generally engage with the development of the TSOs' proposals and RAs' decisions.

3. Scope and Structure of Paper

3.1. Scope of Paper

The main objective of this paper is to present the SEM Committee's decisions on the detailed harmonised all-island AS rates and other related system charges and generator performance incentives that will be applicable from 1 February 2010 to 30 September 2010 in the SEM. For clarity, the existing jurisdictional AS arrangements will continue until the harmonised arrangements go live from 1 February 2010.

3.2. Structure of Paper

This paper should be read in conjunction with the TSOs' June 2009 AS consultation paper (SEM-09-062) and covers the following issues:

- Harmonised Ancillary Services Rates Framework
- An overview of general comments
- Harmonised Ancillary Services Rates
- Trip and Short Notice Declaration (SND) Charges
- GPIs

For each of the above a brief summary is provided of the TSOs' proposals as set out in their consultation paper, followed by an overview of the responses from commentators. A response and commentary by the RAs is included, as appropriate, on the issues raised. This paper does not respond to comments on issues already decided in earlier decision papers unless where considered necessary for clarity. It also does not address issues raised in some of the responses which were outside the scope of the consultation document.

The responses themselves are published with this paper where they were not indicated as private/confidential.

Taking into account the views of respondents to the consultation, the decision of the SEM Committee follows. A summary of the rates approved by SEM Committee are provided in an appendices at the end of this document.

4. Harmonised Ancillary Service Rates Framework

4.1. Background

A number of requirements and constraints were taken into consideration by the TSOs in their analysis of their AS rates and other charges proposals. Amongst these some key requirements relate to the overall AS allowance, which affects the AS rates only, and the exchange rate which affects all rates and charges. The review of the consultation responses to those issues, including further clarifications on the monetary flows, are presented below.

4.2. Monetary Flows

The arrangements indicated in the TSOs' consultation briefly included:

- For AS rates (payments and charges): These will be reviewed annually and published by EirGrid & SONI in harmonised annual statements of payments & charges. AS payments will be funded from demand customers through Transmission Use of System charges in Ireland and the System Support Services levy in Northern Ireland. AS charges for the shortfall in a service provision were decided in the previous decision paper[16] essentially equal to a fixed number of days of the payments for the service involved. As decided in the January 09 decision paper, collected AS charges will be used to contribute to the funding of the AS expenditure of the following tariff period(s); hence reducing the funding requirements from general customers.
- Other Charges -Trips, Short Notice Declarations (SNDs) and Generator Performance Incentives (GPIs): These will be reviewed annually and will be included in the TUoS Statement of Charges in both jurisdictions. As decided in the January '09 decision paper, the income from these charges will be used to reduce the Imperfections Tariff for the following tariff period. This is the mechanism used to pass the cost of performance that deviates from that assumed in the calculation of the SMP onto electricity customers.

4.2.1. Respondents' Views

Several respondents requested further information about the rationale for the proposed monetary flows and for the charges in particular. Some respondents suggested including the GPI charges as part of the AS agreements. One respondent expressed concern that the offsetting of Dispatch Balancing Costs (DBC) with charges could be used to mask inefficiencies of the TSOs or would give the impression of improved system/dispatch efficiency. The majority of responses did not express concerns with the TSOs' proposals.

4.2.2. RAs' Comments

Although not explicitly mentioned in the TSOs' consultation paper, the RAs had already made a decision about the magnitude and treatment of AS charges. The level of AS charges in any given tariff period will be taken into account when determining the TUoS charges in Ireland and SSS levy in Northern Ireland in the following tariff period(s). The overall objective for the first tariff period of the new arrangements was that the net AS payments to generators should remain unchanged i.e. provide a baseline against the previous, unharmonised arrangements. Further details can be found in the above referred January '09 decision paper.

In the case of the other charges (i.e. Trips, SNDs and GPIs), the TUoS statement of charges will be used as a facilitating vehicle to impose and publish the charges annually. It is appropriate to net off these charges from the DBC. The DBC are partially incurred by generators having poor performance

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

and behaviour. They are recovered in the SEM through an imperfections tariff levied on suppliers by the Single Electricity Market Operator (SEMO), which in turn is regulated by the RAs. For the avoidance of doubt the non-AS charges reduce the imperfections tariff and not the DBC themselves. The charges are easily distinguishable from the DBC and hence there is no risk of masking system operational costs as one respondent suggested.

It should be noted that the DBC are not used to benchmark system or TSOs' performance. The TSOs' licences and both Grid Codes require the TSOs to minimise the total cost of **production** on an ongoing basis; there is no requirement for them to undertake this with reference to the ex-post market schedule which is calculated with perfect foresight. Trips and short notice declarations directly impact the magnitude of the DBC, as the market schedule will ramp down any generator who trips over the length of time necessary to start up the lowest cost compensatory plant, while in reality the TSO must start less efficient fast-acting plant at a higher cost. The difference between these costs is recovered from customers via the Imperfections Charge.

4.2.3. RAs' Decision

The RAs have considered and are comfortable with the arrangements for levying the Other Charges described in the AS Rates Consultation Paper. They follow the principles established in previous SEM Committee decisions that AS payments are ultimately socialised amongst customers and that charges, which reflect underperformance by generators and increased system costs, are used to accordingly reduce funding requirements from customers.

4.3. AS allowances

The main assumptions used in the overall AS allowance can be summarised as follows:

- There is no increase in either the Northern Ireland or Ireland total AS revenue allowances. This follows the review of the services required for the operation of the system in the 2009/10 tariff year by the TSOs and the guidelines provided by the RAs that AS costs should not be increased as a result of harmonisation if no increase in service requirements is identified.
- In the calculation of the respective AS allowances in Northern Ireland and Ireland the TSOs have taken due consideration of charges and rebates as applicable and other services to arrive at consistent allowances. More details of the assumptions made and included costs in each jurisdiction can be found in the TSOs' proposals paper.

4.3.1. Respondents' Views

Several responses expressed concerns relating to the existence and treatment of separate allowances in Northern Ireland and Ireland. Two respondents indicated that the existence of a separate AS allowance for Ireland and Northern Ireland is not consistent with delivering a harmonised AS market. One respondent indicated that the existence of separate allowances could risk creating a cross subsidy between customers in Ireland and Northern Ireland if the generators in one jurisdiction capture a bigger share of the AS market relative to the ratio of the allowance between both jurisdictions. Another commentator indicated the merit of continuing with the present arrangements until there are harmonised Grid Code obligations and that the process of setting the AS allowances needs to be made more transparent. One respondent indicated that it was not clear that with the proposed rates the AS payments added up to the existing AS allowances. One respondent disputed the assertion that with the proposed rates the size of the AS pots/allowances remain unchanged.

4.3.2. RAs' Comments

The RAs indicated in earlier consultations that current AS allowances should not be increased as a result of harmonisation if no increase in service requirements is identified by the TSO. The basis of the current AS 'pot' allowances is therefore historical but in the future, as the generation mix and system needs change, then the AS pots size may also change accordingly. This would be subject to a separate consultation, and would also be considered in the context of the other primary revenues streams for generators, i.e. the energy and capacity payments revenue mechanisms. The rates and charges in this paper refer to the tariff period from 1 February 2010 to 30 September 2010 only. The AS rates and other charges to apply following this initial tariff period will be consulted upon on an annual basis.

Many respondents showed surprise that the proposals did not include merging the two AS allowances into a single AS allowance following harmonisation of AS rates. However it was never stated in earlier consultation and decision papers that the two existing AS allowances in Ireland and Northern Ireland would be merged following harmonisation.

The RAs do not share the view of some respondents that the existence of two independently capped and managed AS allowances is contrary to the AS harmonisation principles. The AS harmonisation delivers an all-island set of rates and charges applicable to all participants in the SEM against largely harmonised definitions of Grid Code requirements. It is important to note that the objective of this workstream was harmonisation not uniformity.

The RAs consider it reasonable that some participants assumed that the harmonised AS arrangements would have resulted in a single all island AS allowance to be managed by the TSOs. However there are a number of reasons why it was decided to maintain AS allowances for each jurisdiction following harmonisation of AS rates and other charges. From a technical perspective the two jurisdictions have at present somewhat independent technical operational requirements, particularly for reserve, mainly due to limitations with their interconnection and other local issues. Historically this, together with other issues, resulted in varying generator connection requirements and agreements in each jurisdiction. However the RAs consider that although currently the Grid Codes in Ireland and Northern Ireland are not fully harmonised, the differences relating to AS are minor. Both TSOs are working to ensure future consistency in their respective Grid Codes with respect to these and other issues. Furthermore the administration of a single all-island AS allowance would require the review of related tariff arrangements in each jurisdiction with consequential impact on IT systems.

Although initially there will be separate AS allowances in each jurisdiction for the reasons stated above, it is the intention of the RAs however to transition in the future to a single all-island AS pot as is currently the case with the capacity pot under the Capacity Payment Mechanism (CPM).

Each jurisdiction is managed by its own independent TSO; however both TSOs should collaborate to operate the All Island system in the most efficient manner to meet the market needs within the technical characteristics of the plant and resources within each jurisdiction. Following removal of such technical barriers in the future, each AS allowance would correspond to the allocation of optimum all-island system AS costs between both jurisdictions with the costs being allocated to customers proportionally to demand in each jurisdiction. The RAs will monitor the performance of the TSOs through respective periodic performance reviews.

It follows from the existence of an AS allowance for each jurisdiction that the current ratio between AS allowances in Ireland and Northern Ireland could also potentially change in the future if there were significant differences in the generation mix and increased used of services from providers in one jurisdiction over the other during a tariff period. In such case the RAs acknowledge that, under the existing tariff arrangements, there is a potential market distortion risk in the future if the ratio of actual AS spend in one jurisdiction changes disproportionally to the current ratio between the AS allowances in each jurisdiction. However it is considered that this potential risk is small. The RAs would like to point out that earlier analysis[17] showed that the AS costs per unit of energy delivered in each jurisdiction were very similar and the AS allowance caps used in the calculation of the harmonised AS rates proposed by the TSOs are based on existing levels. The RAs and the TSOs will, in any case, keep monitoring annually the performance of the harmonised arrangements and will review this issue in the future if necessary. Future AS rates and other charges will in any event be reviewed and approved by the RAs annually following a TSO consultation.

4.3.3. RAs' Decision

The RAs have considered and are comfortable with the arrangements, as proposed, such that AS costs should not be increased as a result of harmonisation if no increase in service requirements is identified and also with the arrangement that separate AS allowances will exist in Northern Ireland and in Ireland in the short term. However, it is the intention of the RAs to transition in the future to a single all-island AS pot.

4.4. Exchange Rate

Closely related with the AS allowance issues above is the TSOs' proposed treatment of the exchange rate between the Euro and GBP with harmonised rates and charges. The main assumptions for the exchange rate are:

- An exchange rate will be fixed annually for each tariff year/period using the market forward exchange rates.
- At the end of each tariff year/period the exchange rates will be reviewed to determine if it is necessary to adjust the AS allowances in Northern Ireland and Ireland accordingly for the coming tariff year/period.
- The exchange rate used in the TSOs' consultation paper was set at €1=£0.85 subject to final approval by the RAs in this decision paper.

4.4.1. Summary of Responses

One respondent agreed with the TSOs' proposals on fixing the currency exchange on an annual basis, six respondents did not indicate any concerns about the exchange rate proposals and four others indicated concerns about the exchange risks that would be added to participants by fixing the exchange rates on an annual basis. Reduced exchange rate fixing periods were suggested by several commentators ranging from using monthly to daily exchange rates.

4.4.2. RAs' Comments

The setting of the exchange rate on an annual basis is a compromise between the certainty provided by daily exchange rate used in the SEM wholesale market and an alternative long term view consistent with the principles of AS income predictability and ease of calculation. Although high volatility has been apparent in the currency exchange markets recently, it has also been the result of fairly extreme economic circumstances. The RAs would also like to point out that the much larger Capacity Pot is subject to an annual exchange rate. Given that for the majority of players the size of AS revenues is

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

small relative to capacity and energy payments it is therefore considered that this financial risk is unlikely to warrant a more complicated and less predictable daily exchange rate. The use of a fixed annual exchange rate is also a balance between the sharing of risks in the currency exchange between customers and generators in Northern Ireland and the higher tariff volatility that would be associated with a more frequent adjustment in the exchange rate.

4.4.3. RAs' Decision

The RAs therefore consider that the TSOs' proposal is reasonable for the forthcoming tariff period (i.e. 1 February 2010 to 30 September 2010). However this aspect will be monitored and included as part of the regular annual review of AS rates and charges, subject to other practical implementation constraints. In any case it should be noted that the RAs do not envisage making retrospective adjustments for exchange rate variations.

In view of current forward exchange rates, the RAs consider that the TSOs' proposals to fix the exchange rates for payments and charges to €1 per £ 0.85 GBP as reasonable for the implementation of the first period of harmonised AS rates and charges.

5. General Overview

This section reviews comments in the general consultation responses or issues that apply to several of the rates and charges (which are discussed in detail in later sections).

5.1. Respondents' Views

Many respondents indicated that they consider the balance of rates and charges as overly punitive and that they may be better off by not entering an AS agreement. One response indicated that harmonisation should leave generators in the same commercial position compared to the existing arrangements. Two respondents suggested that generators should be at most neutral to charges so that charges are never allowed to exceed the payments. Four responses considered that the TSOs' proposal would result in reductions in their revenue. Another response indicated that the TSOs do not seem to have estimated the income that will be obtained from charges. A couple of responses indicated that that bidding practice may be changed as a result of these new arrangements and become less flexible.

Some respondent indicate that the complexity of the proposed arrangements is contrary to the RAs' guideline for AS providers to be able to reasonably predict their annual income from providing AS and the financial implications of failing to fulfil their contracts. Many respondents requested further details from the TSOs' model and several challenged that payments to generators will be maintained at existing levels with the proposed rates.

Several responses expressed concerns about the lack of monitoring equipment at certain locations for the calculation of applicable payments and charges.

One respondent requested confirmation that the contracted characteristics in the SSSA which, in some cases are not aligned fully with certain definitions of the Go Live amended Northern Ireland Grid Code but accepted in operation since Go Live, would be considered as a 'de-facto' derogated characteristics.

Many respondents expressed concerns about the challenging timeline and that changes to participant systems have not been taken into account. Others expressed concerned about being forced to enter into a contract negotiation during the peak holiday period.

5.2. RAs' Comments

Some responses indicate confusion about the various rates and charges with many parties openly trying to establish a net position against all payments and charges. It is important that payments and charges for AS are not "netted" off the Other Charges including GPI charges, Trips and SNDs These latter "non-AS" charges are not driven by AS requirements and, although some charges relate to AS capabilities as per the Grid Code, it is incorrect to bundle them as part of the harmonised AS payments and charges. The other harmonised charges (Trips, SNDs and generator performance incentives) relate to the increase in system costs to customers resulting from the generators performance against a service standard as discussed in earlier consultations.

It follows from the above that generators will not avoid non-AS charges by not entering into an AS agreement. The RAs consider that the relatively modest charges associated with AS (Reserve, Reactive Power and Black Start) are proportionate and hence it would be unlikely that generators will be better off by not entering into an AS agreement offering as many services as possible to the TSO hence waiving the opportunity to receive AS payments. Generators are unlikely to be neutral to all the harmonised charges covered in this consultation as only the relatively modest AS charges have a corresponding revenue stream. Also it is important to note that although a generator can prevent AS charges by declaring itself unavailable for a particular service, it will still be liable to GPI charges, trips and SNDs. The RAs do not expect any generator to reduce its flexibility as a result of these harmonised arrangements.

It is unavoidable that as a result of harmonisation there will be some generators who fare better than others. There will be specific plants whose AS income will change in the new arrangement because of their SEM running arrangement or because of limitations on their plant to provide certain specific types of AS. In the case of Northern Ireland plant, the harmonised AS rates and charges will introduce an increased level of uncertainty over the very simple arrangements applicable at the moment.

However, having considered the comments from commentators and in view of the adjustments that will be required by certain participants during the first period of implementation of the harmonised arrangements and also the annual review that will be undertaken, the RAs, following further consultation with the TSOs, have decided to reduce the Trip/SND charges and two GPIs from those presented in the consultation paper. Further details are provided in the Trips/SND charges and GPI section and the Appendix at the end of this document.

The RAs do not share the view of some respondents that the proposed arrangements are complex. Trips and SNDs are largely based on existing arrangements in Ireland and GPI charges are based on existing arrangements in Northern Ireland. The TSOs also considered the implementation issues in previous and extensive public consultations. They planned and costed an implementation programme to meet the desired implementation date of 1 February 2010. It should be possible for any generator to develop an approximate model for their own use with the details provided to date about the harmonised arrangements. The TSOs also offered assistance on these issues to any interested party. On the availability of monitoring equipment for payments and charges it should be noted that AS Reactive Power has no charges in practice as it is only based on availability. GPIs are either based on declarations or SCADA and this is consistent in Northern Ireland and Ireland. SNDs are based on declaration and this is consistent in both jurisdictions. Only Reserve and trips have varying monitoring equipment with event recorders being connected to settlement systems in Northern Ireland but only SCADA output information being available at certain sites in Ireland. In order to take these differences in the monitoring equipment into account when calculating applicable charges, the TSOs will apply a tolerance to compensate for differing monitoring equipment at all sites. The Reserve tolerance will be the greater of 10% of the expected Reserve provision or 1 MW when a charge is applicable.

On the issue of the validity of the SSSA, as raised in one of the comments, the generator characteristics are taken from the Generator Unit Agreements (GUAs) which are referenced in the Northern Ireland Grid Code and therefore state the Generator obligations.

Finally on the issue of the timeline, it is considered that market participants have had - and have - sufficient time to adapt to the new all-island AS arrangements. Although the TSOs' proposed schedules of rates and payments was not published until June 2009 the majority of those arrangements for payments and charges were similar to those published as illustrative examples in the September '08 consultation which preceded the RAs' decision paper in January 2009. Furthermore, EirGrid and SONI have been working with market participants to help ensure that the AS arrangements are implemented to plan from 1 February 2010. For information, they have already published on their websites[18] the proposed all-island AS contracts which will facilitate these arrangements from a

[18] EirGrid Harmonised Ancillary Service Contract (Draft) and SONI Harmonised Ancillary Services Contract (un-contracted plant) (Draft) available on EirGrid's website:
http://www.eirgrid.com/operations/ancillaryservices/ancillaryservices-all-islandharmonisation/#d.en.809

contractual/legal perspective, and have indicated that they are happy to discuss these with market participants.

5.2.1. RAs' Decision

The RAs consider that the payments and charges which apply to the "AS only" services of Black Start, Reactive Power and reserve are proportionate and not overly punitive.

In response to comments from AS service providers and, following consultation with the two TSOs, the RAs have decided to put in place transition arrangements which will provide for the initial application of less onerous rates for some trip/SND rates and some GPI rates as detailed in Sections 7 and 8 respectively.

Overall the RAs consider that the harmonised AS arrangements and other charges are an important step towards the full harmonisation of arrangements under the SEM. They provide an appropriate balance of signals about the importance of ancillary services and plant performance for the efficient operation of an otherwise relatively small system. They also provide an initial implementation of a significant framework, described in the High Level Decision paper, which can evolve in subsequent years to accommodate SEM changes that will occur in the future - for example as more renewable generation connects across the island. All future AS rates and other system charges, i.e. those from 1 October 2010 and beyond, will be subject to public consultation and RA decision separately.

6. Harmonised Ancillary Services Rates

6.1. Outline of Decision

This decision paper sets out, in Appendix A, the all-island harmonised AS rates to be applied from 1 February 2010 to 30 September 2010 for Reserve (Primary, Secondary, Tertiary and Replacement), Reactive Power and Black Start. Additional details can be found in the June '09 consultation paper[19].

6.2. Reserve

In order to manage the transmission systems, the TSOs must be able to contend with unexpected losses of generation capacity or increases in demand. In order to accommodate unexpected increases in demand or shortfalls in generation output a prudent level of operating margin is maintained by the TSOs, where the operating margin is the amount of Reserve available (provided by additional generation or demand reduction measures) above that required to meet the forecast demand. The provision of Reserve is a mandatory service for generators under the Ireland and Northern Ireland Grid Codes.

6.2.1. Respondents' Views

Several responses questioned the rationale for the split between the different types of Reserve, particularly the higher weighting of the "faster" Primary and Secondary Reserve categories over the "slower" Tertiary and Replacement Reserve. Some indicated that they would face a reduced Reserve payment as a result. Other commentators highlighted the need for more tertiary Reserve in a system with increased wind penetration given the relatively slow changes in output from all wind generators connected to the system due to their diverse nature. One commentator suggested equal weighting to all categories.

On the TSOs' proposals to split the replacement reserve in two categories, one for when a unit is already synchronised and the other for when the unit is desynchronised but has the capability to provide capacity within the replacement reserve timescale, the majority of commentators were supportive. Only one respondent was not supportive although it would seem from the comments that they misunderstood the proposal.

6.2.2. RAs' Comments

Compared to the existing AS rates in Ireland the TSOs' proposals have reduced payments to the slower reserves and increased the rates for primary and secondary reserve as many responses have indicated. Although it is correct that a higher penetration of wind generation will generally increase the requirements for tertiary reserve in the medium to long run, the allocation of rates amongst reserve categories proposed by the TSOs is based on the requirements for the 2009/2010 tariff year only. It is the TSOs' responsibility to ensure the operation of the system and they consider that the AS signals are consistent with the system requirements. Depending on system developments these rates may change in subsequent tariff periods and the TSOs may propose alternative allocations as indicated in the High Level Design decision paper of February 2008 [20].

6.2.3. RAs' Decision

The RAs consider that the proposal by the TSOs for harmonised rates for Reserve is reasonable and meets the requirements of the RAs, as highlighted in the February '08 HLD decision paper. This

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[19] [SEM-09-062] "Harmonised Ancillary Services & Other System Charges. Rates Consultation' Consultation, 8th June 2009

[20] [SEM-08-013] 'Harmonised All-Island Ancillary Services Policy - A Decision Paper, February 2008

included the option for the TSOs to suggest new or modified services if considered of benefit to the efficient operation of the system. Accordingly, the harmonised rates for Reserve to apply from 1 February 2010 to 30 September 2010 are set out in Appendix A.

6.3. Reactive Power

Reactive Power is the result of the cyclical energy exchange between the electric and magnetic fields of the plant and equipment connected to the network. Reactive Power is essential in controlling voltages across the network and maintaining an adequate voltage profile is required for the stability of the power system. Generators and certain network equipment are the main sources of Reactive Power. Generally, Reactive Power must be provided close to the location where it is required. The provision of Reactive Power is a mandatory service for generators under the Ireland and Northern Ireland Grid Codes.

6.3.1. Summary of Respondents' Views

Several respondents indicated concerns about the reduction in payments to generators that would result from the proposed rates - and in particular for generators in Ireland from payments for availability and utilisation under the existing arrangements to only availability under the harmonised rate. Some comments indicated that the payment for availability only when synchronised would result in a reduction of payments to mid and low merit plants. One respondent suggested that a payment for availability as considered in the current scheme in Ireland should also be extended to the harmonised arrangements.

6.3.2. RAs' Comments

The RAs consider that the TSOs' proposal, as decided in the January 2009 decision paper (SEM-09-003) to pay only for availability (and not utilisation) is reasonable. For generators the actual cost of providing Reactive Power for a committed unit is very small as the excitation system involved is required for the generation of electricity. Additional costs arise from marginal increases in losses in the exciter and stator of the alternator and from small and difficult-to-quantify increases in maintenance and plant life costs.

Although many responses have also pointed to the reduction in availability payment, many respondents did not take into consideration in their analysis that Reactive Power payments are doubled if the generator's Automatic Voltage Regulator is active, as indicated in the Jan '09 decision paper. Accordingly, total Reactive Power payments will be higher than previously estimated by some commentators. Also, as indicated in the TSOs' consultation paper, the split of 70:30 which is being applied between Reserve and Reactive Power is similar to the existing 60:40 split in Ireland. When compared with existing payments, providers should, on average, see a slight increase in Reserve payments and a slight reduction in Reactive payments.

RAs' Decision

The RAs consider that the proposal by the TSOs for the harmonised rates for Reactive Power is reasonable and meets the requirements of the RAs, as highlighted in the February '08 HLD decision paper and is consistent with the January 2009 decision paper on implementation arrangements. Accordingly, the Reactive Power rates to apply from 1 February 2010 to 30 September 2010 are set out in Appendix A.

6.4. Black Start

Black Start units are generators capable of being started and synchronized without the support of the power grid. Black Start service is required because the TSOs need to be able to re-establish system operations after an extensive failure of the system. This entails isolated power stations being started individually and gradually being reconnected to each other in order to re-establish an interconnected system.

The selection of Black Start generators is, to a degree, location dependent given that Black Start generators must be electrically close to other generators in order to re-build the system following a black out. The Black Start units must also have sufficient capacity and ramping capability to be able to provide the restart power required by the other units. Each TSO will determine how many units within its control area must have Black Start capability, in which locations they are needed and how to use them in the event of a blackout.

6.4.1. Summary of Respondents' Views

Six respondents considered that the design intention of creating a harmonised framework is not met as the TSOs' proposed methodology fails to pay for Black Start to existing (though not new) Northern Ireland generators while continuing to pay to generators in Ireland. Some respondents considered that, under the proposals, existing Northern Ireland generators appear to be at a disadvantage because they could be penalised for failing Black Start tests but do not receive any harmonised Black Start service payment. Several respondents pointed out that in the January '09 decision paper, the RAs stated that "The RAs consider that the proposed [Black Start] arrangements should apply to all plants in both Northern Ireland and Ireland".

6.4.2. RAs' Comments

The justification for the apparently different treatment of existing Black Start units in Northern Ireland was stated in the January '09 decision paper. The paper stated that, because the plant is still under contract to PPB, any Black Start income that PPB would receive would not be paid to the generators but simply be cycled back to customers via a reduction in the PSO levy. The following explains why this decision is consistent with a harmonised policy.

In Ireland, Black Start is provided by ESB PG plants exclusively. These black start plants consist of hydro sites, Turlough Hill pump storage and Aghada OCGTs. The Black Start capabilities in Ireland are considered by the TSO to be adequate and EirGrid continues to review its requirements. In Northern Ireland the Black Start service is provided at all three Black Start sites (Coolkeeragh, Kilroot and Ballylumford). The Black Start capabilities in Northern Ireland are considered by the TSO to be adequate.

The harmonised policy and design for Black Start has been developed during the consultation process. Payment for the Black Start service is harmonised. Under harmonised arrangements, all Black Start service providers are paid for the same four cost elements – capital, maintenance, TSO-initiated testing and usage costs. Accordingly, Black Start is typically compensated by the System Operator paying, on an annuitised basis, the capital costs for construction of the Black Start facility plus maintenance costs. Typically, utilisation, including any testing, is not paid for under contract if the Black Start facility can recover this via the wholesale market. For the Black Start service a combination of a tendered approach with regulatory approved rates for existing generators and negotiated contracts for new generators was proposed.

Therefore the RAs concur with the TSOs' and respondents' views and have decided that, due to the nature of the service, Black Start facilities should be procured under negotiated long-term contracts with the TSOs. Black Start contracts will cover capital and maintenance costs and also testing and usage to the extent that the latter two are not recoverable in the energy market. Under the new harmonised arrangements charges will be applicable in the case of underperformance. New contracts with Black Start providers will be established either following a tender process or via a direct award (for example when a new plant connects to the system). In this latter case the TSOs will ensure that the detailed arrangements for approaching a candidate provider, which will be the subject of a subsequent review, are transparent and non-discriminatory. For the same reason it is considered appropriate to review Black Start contracts on a "needs basis", instigated by the TSOs' request for additional Black Start plants.

The RAs have therefore decided that all existing Black Start plants should be paid a site-specific hourly rate for Black Start service with charges for underperformance. This hourly rate will cover fixed costs, maintenance costs to the extent that these costs have not already been capitalised and paid for. As with the other AS rates, Black Start rates under new contracts will be the subject of RA approval.. Existing rates in Ireland as shown in Appendix A are consistent with these above principles and accordingly are approved. All Black Start plant will be subject to testing by the TSOs.

The process outlined above will be applied from go-live of the harmonised AS arrangements from 1 February 2010.

6.4.3. RAs' Decision

The RAs consider that the proposal by the TSOs for the harmonised rates for Black Start is reasonable and meets the requirements of the RAs, as highlighted in the February '08 HLD decision paper and is consistent with the January 2009 decision paper on implementation arrangements. Accordingly, the Black Start rates and charge parameters and rates to apply from 1 February 2010 to 30 September 2010 are set out in Appendix A.

7. Trip and Short Notice Declaration Charges

Short Notice Declarations (SND) and Trip charges are made for the variation in availability of committed plant or unscheduled outage of dispatched plant. The charges are intended to incentivise behaviour that enhances system security and reduces operating costs. Further details can be found in the June ‘09 consultation paper[21]. The final parameters and rates for the period 1 February 2010 to 30 September 2010 are presented in Appendix B of this document.

7.1. Summary of Respondents’ Views

Many comments related to both the SND/Trip charges and the GPI charges (which are covered in Section 8 of this document) and, in some cases, it was difficult to discern whether some of the statements applied to SND/Trip charges, GPI charges or charges in general. Although a majority of respondents agreed with the objectives of the SND and Trip charges, several respondents considered the SND and Trip charges as too punitive with two respondents indicating that charges increase by a factor of 10 compared with existing charges in Ireland. Most respondents in Northern Ireland considered the charges disproportionate and unjustifiable and considered that the charges do not bear any relationship to the costs incurred. Two commentators considered that there was insufficient information on the charging rates methodology, the income that would be obtained and the dispatch balancing costs.

One response commented that the SND charges are increasing by orders of magnitude over existing arrangements in Ireland, in particular for smaller plants, based on analysis using the proposed empirical charging profiles. The current rate is €12/MW. The SND Charge rate proposed in the June ’09 consultation was €100/MW. This empirical value was derived from the rebalancing between Trips and SNDs. However the TSOs have clarified that this rebalancing is based on a higher capacity unit – the reference used was a 400MW unit.

One commentator criticised the increase in the applicable timescale for SNDs from 4h to 12h and the difficulty of certain types of plant anticipating their availability on this timescale due to ambient or fuel quality changes. One commentator suggested reducing this timescale to 6h. On this issue another commentator noted the 10 MW dead-band to account for temperature changes but suggested increasing this band to 15 MW during de-icing events in CCGT plants.

Several commentators claimed that the combination of Trip and SND will be the biggest factor in reducing net income for generators. Several responses disagreed that multiple charges should be applicable for a single incident. A number of responses suggested that the model currently used in Northern Ireland, where only the larger of the two charges is imposed, be employed. One noted that the charges for a trip appear to have increased by almost 50% for some plant.

Two commentators suggested that generator trips are unavoidable and that therefore it would be appropriate to incorporate a threshold for the number of trips before the charges would be applicable. Another commentator also suggested that it should be established that the generator was responsible for the trip before being penalised.

One respondent suggested that the same SND charge should not apply to a unit on load as an off load unit as the cost to the system is not the same. The respondent also suggested that the SND charge needs to take account of the Uninstructed Imbalance (UI) charge that may also be incurred. It was also noted that there appears little incentive to give greater than 12 hours notice.

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

One commentator also pointed out that it seemed unfair to apply penalties to service providers who are not required to offer such services under the relevant Grid Code in reference to the different types of trips with Northern Ireland generators. Another response put forward the merit of introducing a slow wind down threshold above which charges are applicable to incentivise very slow wind down by the generators.

7.2. RAs' Comments and Decisions

At a high level, the RAs consider that the proposed Trip and SND charges, based on existing arrangements in Ireland, would incentivise appropriate generator behaviour for trips and declarations. The RAs consider that the separate charges for trip events incentivise different aspects of performance and thus strengthen the incentives on generators to improve their performance when compared to the existing arrangements. Although some commentators considered this arrangement as too punitive, generator trip charges are expected to be less than the system costs caused by the outages plus the costs of holding reserve for such eventualities, the costs of which are ultimately borne by customers.

However acknowledging the comments received and without prejudice regarding future performance of plant and applicable charges, the SEM Committee considers that the proposed Trip and SND charges could have been overly onerous when compared to existing charges. The RAs have consulted with the TSOs and the SEM Committee has decided to make the following changes to the arrangements presented in the TSOs' consultation paper, which, overall, result in a reduction of charges to all generators, especially to small and medium sized plant. Further details of the final parameters and rates to be applied are published in Appendix B at the end of this document. The changes along with justifications are explained below.

- The RAs concur with the observation that the combination of proposed Trip and SND rates increase disproportionately the charges for small and medium plant compared to current arrangements in Ireland. However, while recognizing that larger plants may cause larger system costs per MW lost, the RAs are also of the view that current charges for small/medium plant are too low, do not reflect system costs adequately and do not provide a sufficiently strong performance signal to the generators. With these issues in mind the RAs, in conjunction with the TSOs, have reviewed the rates in the June '09 consultation paper. The approved harmonised charges reduce the trip charge rates and SND charges for all applicable plant compared to the rates proposed in the June '09 consultation paper. They also reintroduce the 100 MW threshold for calculation of trip charges, as is currently being applied in Ireland.
- It is considered that the 12 hour (720 minutes) window for SND charges which was proposed in the earlier consultation paper is too long and that an 8 hour (480 minutes) window will be sufficient which is a balance between the current 12 hour window in Northern Ireland and the 4 hour window currently being applied in Ireland.
- The RAs also agree with one of the comments that the introduction of a threshold for slow wind down charges will incentivise generators to avoid charges by winding down very slowly which will be of benefit to the system operation costs. A threshold of 1 MW/s (none was indicated in the TSOs proposals) has also been approved for slow wind-down charges so that plant winding down as part of normal operations is not charged.
- It is considered that the proposed dead-band of 10 MW for SND provides enough margin to allow for changes in ambient temperature which may impact the performance of some plant. However to take into account the reduction in output resulting from the use of de-icing equipment in CCGT plant, it is considered appropriate to increase this tolerance by a further 5 MW to 15 MW.

- In relation to the SND Charge Rate, the RAs consider the consultation paper charge rates to be too high and have decided that €70/MW would be proportionate and reasonable for the medium term. However in order to smooth the transition to the harmonised arrangements and to allow a reasonable time for generators to improve their performance, the charge rates for SNDs will be phased in. The rate to apply from 1 February 2010 will be €20/MW. From 1 October 2010 this rate will increase to €40/MW. From 1 October 2011 it will increase to €70/MW. This allows an adjustment period of circa 20 months for generators. The impact and appropriateness of this and the other Trip and SND charges and parameters will be kept under review and consulted upon annually.

The table below summarises the changes made with respect to the proposals in the June '09 Consultation Paper.

7.3. RAs' Decision on Trip and SND Rates

In consideration of the above the Trip and SND rates to apply from 1 February 2010 to 30 September 2010 are set out in Table 1 below and in Appendix B.

Table 1: Summary of SEM Committee decisions on Trips and SND rates to apply from 1 February 2010 until 30 September 2010 and comparison with the proposals in the June '09 consultation paper.

Trips	**June '09 Consultation proposals**	**SEM Committee decision[22]**
Direct Trip Rate of MW Loss	15 MW/s	15 MW/s
Fast Wind Down Rate of MW Loss	3 MW/s	3 MW/s
Slow Wind Down Rate of MW Loss		1 MW/s
Direct Trip Charge Rate	€ 5,000	€ 4,000
Fast Wind Down Charge Rate	€ 4,000	€ 3,000
Slow Wind Down Charge Rate	€ 3,000	€ 2,000
Direct Trip Constant	0.007	0.01
Fast Wind Down Constant	0.006	0.009
Slow Wind Down Constant	0.005	0.008
Trip MW Loss Threshold	0 MW	100 MW
SNDs		
SND Time Minimum	5 min	5 min
SND Time Medium	20 min	20 min
SND Time Zero	720 min	480 min
SND Powering Factor (Notice time weighting curve)	-0.3	-0.3
SND Charge Rate	€ 100 /MW	€ 20 /MW
SND Threshold	10 MW	15 MW

[22] The purpose of the table, as denominated in €, is primarily to provide comparison between the final rates and the proposed rates. For details of the sterling/GBP rates refer to the Appendix.

8. Generator Performance Incentives

In a relatively small power system, such as the all-island SEM, it is very important for the efficient and economic operation of the system to ensure that the generators maintain the performance required in the Grid Codes. Otherwise the safety, security and efficiency of the system could be compromised and/or costs could be imposed on other (compliant) users of the system, for example through higher constraint costs, which is neither efficient nor, arguably, fair. Consequently, and with the support of the RAs as highlighted in the January decision paper, the TSOs have proposed GPIs for key areas of generator performance. Further details can be found in the June '09 consultation paper[23]. Final arrangements are presented in the Appendix section of this document.

8.1. Summary of Respondents' Views

Generally there was not much support for these charges from generators. In addition many commentators confused these charges with the AS payments and charges indicated earlier. One respondent indicated that the proposed GPI charges are considered to be too complex. Another respondent asked for further details on the input and rationale for the calculation of the GPI charges. One response considered that the doubling of the GPI charges for late declarations should be removed. Another respondent considered that the GPI charges will incentivise generators to seek derogations.

8.2. RAs' Comments

The SEM Committee supports the TSOs' proposals on generator performance incentives as these are considered important for efficient and economic operation of the transmission system, especially a small one. As discussed earlier the RAs consider that the background and rationale for the GPI have been covered at length during previous consultations and hence it does not share the view from some respondents that insufficient details have been provided

In relation to the rates, the RAs believe that the consultation paper charge rates are proportionate and reasonable for the medium term. However in order to smooth the transition to the harmonised arrangements and to allow a reasonable time for generators to improve their performance, the charge rates for two of the GPIs, i.e. the Minimum on Time and Maximum Starts in a 24 hour period, will be phased in. The rate to apply to both from 1 February 2010 will be €0.29/MWh as opposed to the €1.00/MWh proposed in the most recent consultation paper. From 1 October 2010 these rates will increase to €0.60/MWh. From 1 October 2011 they will increase to €1.00/MWh - the original proposal. This allows an adjustment period of circa 20 months for generators. The impact and appropriateness of these and the other GPI charge rates will be kept under review and consulted upon annually.

Despite some comments to the contrary in some of the consultation responses, the RAs consider that the proposed arrangements are significantly simpler than the current SSSA arrangements in Northern Ireland upon which the TSOs proposals are mainly based. They are a subset of the charges currently applied in Northern Ireland.

On the issue of the doubling of the GPI charges for late declarations, this is based on current arrangements with the SSSA in Northern Ireland. No clear benefits or justification for the reduction of this signal have been indicated and hence the RAs do not consider it necessary to remove this feature for the forthcoming tariff period (although this would be monitored and may be subject of a future review).

[23] [SEM-09-062] "Harmonised Ancillary Services & Other System Charges. Rates Consultation' Consultation, 8th June 2009

8.3. RAs' Decision

The RAs consider the TSOs' proposals as reasonable and in line with the principles of the RAs' February 2008 High Level Design paper (and subsequent decisions during the harmonisation process), with changes to just two GPIs as discussed above. The GPI rates to apply from 1 February 2010 to 30 September 2010 are set out in Appendix C.

Appendix A Ancillary Services Parameters and Rates

Appendix A consolidates the decisions on parameters and rates relevant to the payment and charge calculations for the three Ancillary Services of Reserve, Reactive Power and Black Start.

A.1 Ancillary Services Parameters & Rates Applicable from 1 February 2010 to 30 September 2010

Ancillary Services Parameters & Rates		
Payment Parameters & Rates	**Payment Rates**	
Primary Operating Reserve	€ 2.22 /MWh	£ 1.88 / MWh
Secondary Operating Reserve	€ 2.13 /MWh	£ 1.81 / MWh
Tertiary Operating Reserve 1	€ 1.76 /MWh	£ 1.50 / MWh
Tertiary Operating Reserve 2	€ 0.88 /MWh	£ 0.75 / MWh
Replacement Reserve (Synchronised)	€ 0.20 / MWh	£ 0.17 / MWh
Replacement Reserve (De-Synchronised)	€ 0.51 / MWh	£ 0.44 / MWh
Reactive Power Capability (Lagging)	€ 0.13 /Mvarh	£ 0.11 /Mvarh
Reactive Power Capability (Leading)	€ 0.13 /Mvarh	£ 0.11 /Mvarh
Automatic Voltage Regulator ON Factor	2	2
Black Start (Aghada)	€ 64.71 /h	NA
Black Start (Ardnacrusha)	€ 22.84 /h	NA
Black Start (Erne)	€ 22.04 /h	NA
Black Start (Lee)	€ 9.82 /h	NA
Black Start (Liffey)	€ 8.02 /h	NA
Black Start (Turlough Hill)	€ 81.63 /h	NA
Charge Parameters & Rates for Under Provision		
POR Charge Period	30 days	
SOR Charge Period	30 days	
TOR1 Charge Period	30 days	
Event Frequency Threshold	49.5 Hz	
Reserve MW Tolerance[24]	1 MW	
Reserve Percentage Tolerance	10 %	
Black Start Charge Period (Partial Fail)	30 days	
Black Start Charge Period (Total Fail)	90 days	

A.2 Ancillary Services Design

The Ancillary Services designs are contained in the published harmonised Ancillary Services agreement which is available on the TSOs' websites.

[24] The Reserve tolerance will be the greater of 10% of the expected Reserve provision or 1 MW when a charge is applicable.

Appendix B Rates for Trips & Short Notice Declarations

Appendix B consolidates the decisions, parameters and rates relevant to the charge calculations for both the Trip and the Short Notice Declaration charges.

B.1 Trips & SNDs Parameters & Charge Rates Applicable from 1 February 2010 to 30 September 2010

Trips		
Direct Trip Rate of MW Loss	15 MW/s	
Fast Wind Down Rate of MW Loss	3 MW/s	
Slow Wind Down Rate of MW Loss	1 MW/s	
Direct Trip Charge Rate	€ 4,000	£ 3,400
Fast Wind Down Charge Rate	€ 3,000	£ 2,550
Slow Wind Down Charge Rate	€ 2,000	£ 1,700
Direct Trip Constant	0.01	
Fast Wind Down Constant	0.009	
Slow Wind Down Constant	0.008	
Trip MW Loss Threshold	100 MW	
Short Notice Declarations		
SND Time Minimum	5 min	
SND Time Medium	20 min	
SND Time Zero	480 min	
SND Powering Factor	- 0.3	
SND Charge Rate	€ 20 /MW	£ 17 /MW
SND Minimum Threshold	15 MW	
Time Window for Chargeable SNDs	60 min	

B.2 Trips Design

The purpose of the trip charge is to minimise the number of trips and, when a trip is unavoidable, the charge should incentive a unit to trip as slowly as reasonably 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:

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

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

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

For clarity, the charge formulae which apply for the first harmonised tariff year/period are as follows:

$$Direct\ Trip\ Charge = 4000\ \ x\ \ e^{(0.01\ \ x\ \ (Max\ MW\ Loss - Trip\ MW\ Loss\ Threshold))}$$

$$Fast\ Wind\ Down\ Charge = 3000\ \ x\ \ e^{(0.009\ \ x\ \ (Max\ MW\ Loss - Trip\ MW\ Loss\ Threshold))}$$

$$Slow\ Wind\ Down\ Charge = 2000\ \ x\ \ e^{(0.008\ \ x\ \ (Max\ MW\ Loss - Trip\ MW\ Loss\ Threshold))}$$

B.3 Short Notice Declarations Design

The purpose of the Short Notice Declaration charge is to incentivise dispatchable units to avoid changing their MW availability declarations to the relevant control centre 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.

To discourage multiple SNDs below the minimum threshold in quick succession, however, 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 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

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

For clarity, the charge formulae which apply for the first harmonised tariff year/period are as follows:

If Notice Time < 5 min

then *Notice Time Weight = 1*

If Notice Time >= 5 min but < 20min

then $$Notice\ Time\ Weight = \left(\frac{NoticeTime}{5}\right)^{-0.3}$$

If Notice Time >= 20 min but < 480 min

then $$Notice\,Time\,Weight = \left(1 - \left(\frac{NoticeTime - 20\min}{480\min - 20\min}\right)\right) x \left(\frac{NoticeTime}{5}\right)^{-0.3}$$

Appendix C Rates for Generator Performance Incentives

Appendix C sets out the regulatory-approved rates to be applied for the Generator Performance Incentive charges.

C.1 GPI Charge Rates Applicable from 1 February 2010 to 30 September 2010

Generator Performance Incentive Charge Parameters & Rates		
Half Hour Trading Period Charges		
Minimum Generation	€ 1.18 /MWh	£ 1.00 /MWh
Max Starts in 24 hour period	€ 0.29 /MWh	£ 0.25 /MWh
Minimum on Time	€ 0.29 /MWh	£ 0.25 /MWh
Reactive Power Leading	€ 0.29 /Mvarh	£ 0.25 /Mvarh
Reactive Power Lagging	€ 0.29 /Mvarh	£ 0.25 /Mvarh
Governor Droop	€ 0.29 /MWh	£ 0.25 /MWh
Primary Operating Reserve	€ 0.12 /MWh	£ 0.10 /MWh
Secondary Operating Reserve	€ 0.12 /MWh	£ 0.10 /MWh
Tertiary Operating Reserve 1	€ 0.12 /MWh	£ 0.10 /MWh
Tertiary Operating Reserve 2	€ 0.12 /MWh	£ 0.10 /MWh
Event Based Charges		
Loading Rate	€ 0.59 /MWh	£ 0.50 /MWh
Loading Rate Factor 1	60 min	
Loading Rate Factor 2	24	
Loading Rate Tolerance	110%	
De-Loading Rate	€ 0.59 /MWh	£ 0.50 /MWh
De-Loading Rate Factor 1	60 min	
De-Loading Rate Factor 2	24	
Loading Rate Tolerance	110%	
Early Synchronisation	€ 2.65 /MW	£ 2.25 /MW
Early Synchronisation Tolerance	15 min	
Early Synchronisation Factor	60 min	
Late Synchronisation	€ 26.47 /MW	£ 22.50 /MW
Late Synchronisation Tolerance	5 min	
Late Synchronisation Factor	55 min	

C.2 GPI Trading Period Based Charges

Minimum Generation

The Minimum Generation charge shall be applied in respect of each Trading Period in which the Minimum Generation of the Generator Unit has been declared to be above the highest of the value specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, by an amount calculated as follows:

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

where:

MG_Charge_X	*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] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.*
MinGen_RATE	*is the Minimum Generation charge rate [expressed in €/MWh or £/MWh].*

provided, however, that the Generator 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 Generator Unit has been declared to be above the highest of the value specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, 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 Availability Profile of Generator Unit u in Trading Period h [expressed in MW].*
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 %] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.*
GD_RATE	*is the Governor Droop charge rate [expressed in €/MWh or £/MWh].*

provided, however, that the Generator Unit is Available and that 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 Generator Unit has been declared to be below the lower of the value based on Grid Code parameters or the relevant Grid Code Derogation or as specified in ASA Schedule, by an amount as follows:

$MxS\_Charge_X = \quad TP * DMG * MxS\_RATE$

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].*

provided, however, that the declared Maximum Number of Starts per 24 hour Period is below the required value, the Generator Unit is Available and that 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 Generator Unit has been declared to be above the higher of the value specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, 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.*
MoT_RATE	*is the Minimum on Time charge rate [expressed in €/MWh or £/MWh].*

provided, however, that the Minimum on Time is above the required value, the Generator Unit is Available and that 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 Generator Unit has been declared to be below the lower of the value specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, by an amount calculated as follows:

$$RP\_Charge_X = TP * ((RPC – DRPC) + (RPP – DRPP)) * RP\_RATE$$

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].*
RPC	*is the Reactive Power Consumption [expressed in MVAr] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.*
DRPC	*is the Declared Reactive Power Consumption [expressed in MVAr] which must be less than RPC for the Reactive Power Consumption aspect of the charge to apply.*
RPP	*is the Reactive Power Production [expressed in MVAr] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.*
DRPP	*is the Declared Reactive Power Production [expressed in MVAr] which must be less than RPP for the Reactive Power Consumption aspect of the charge to apply.*
RP_RATE	*is the Reactive Power charge rate [expressed in €/MVArh or £/MVArh].*

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration of either DRPC or DRPP, 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 Generator Unit has been declared to be below the lower of the values specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, 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] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.*

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].*

provided, however, that the Generator Unit is Available and that 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] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.*

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].*

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

$$\mathrm{TOR1\_Charge}_X = \mathrm{TP} * (\mathrm{TOR1} - \mathrm{DTOR1}) * \mathrm{TOR1\_RATE}$$

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] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.*

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].*

provided, however, that the Generator Unit is Available and that 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] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.*
DTOR2 is	*the Declared Tertiary Operating Reserve 2 [expressed in MW] which must be less than TOR2 for the charge to apply.*
TOR2_RATE	*is the Tertiary Operating Reserve 2 charge rate [expressed in €/MWh or £/MWh].*

provided, however, that the Generator Unit is Available and that in the case of a Late Declaration, the charge is doubled.

C.3 GPI Event-Based Charges

Note that the four parameters below of “DpLT”, “ASyncT”, “DLT”, “DSyncT” were incorrectly stated in the Harmonised Ancillary Services & Other System Charges Rates Consultation (SEM-09-062) as being “[expressed in h]” where it should have been stated as being “[expressed in min]”. For avoidance of confusion, the worked examples in the consultation paper were correct.

Loading Rate

The Loading Rate charge shall be applied in respect of each loading of the Generator Unit following synchronisation in which the Actual Loading Rate of the Generator Unit is below the lower of the values specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, 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] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule 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 which is a percentage.*

A	*is the Availability of the Generator Unit [expressed in MW] prevailing at the Dispatched Load Time.*
LR_RATE	*is the Loading Rate charge rate [expressed in €/MW or £/MW].*
LR_F1	*is the Loading Rate Factor 1 which is expressed in minutes.*
LR_F2	*is the Loading Rate Factor 2 which is dimensionless.*

De-Loading Rate

The De-Loading Rate charge shall be applied in respect of each de-loading of the Generator Unit following a De-Synchronisation Instruction in which the De-Loading Rate of the Generator Unit is below the lower of the values specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule, 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] as specified in the Grid Code, in the relevant Grid Code Derogation or in ASA Schedule.*
ADLR	*is the Actual De-Loading Rate calculated as follows:*

ADLR = [DLMW / (DSyncT - DLT)] * ADLR_Tol

where

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 time.*
ADLR_Tol	*is the Actual Loading Rate Tolerance which is a percentage.*

A	is the Availability of the Generator 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 which is expressed in minutes.*
DLR_F2 is	*the De-Loading Rate Factor 2 which is dimensionless.*

Late Synchronisation

Save where Late Synchronisation is specifically requested by the TSO and agreed by the Generator Unit, 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 Unit 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 Generator 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 Generator 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].*
LS_F	*is the Late Synchronisation Factor [expressed in min].*

Early Synchronisation

Save where early synchronisation is specifically requested by the TSO and agreed by the Generator Unit, 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 Generator 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.*
ES_RATE	*is the Early Synchronisation charge rate [expressed in €/MW or £/MW].*

Appendix D Glossary of Terms

AS	Ancillary Services
CCGT	Combined Cycle Gas Turbine
CER	Commission for Energy Regulation
DBC	Dispatch Balancing Costs
ESB PG	ESB Power Generation
GPI	Generator Performance Incentives
IWEA	Irish Wind Energy Association
NIE	Northern Ireland Electricity
NIAUR	Northern Ireland Authority for Utility Regulation
POR	Primary Operating Reserve
PPB	Power Procurement Business
PSO	Public Service Obligation
RAs	Regulatory Authorities
RoI	Republic of Ireland
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
SND	Short Notice Declaration
SOR	Secondary Operating Reserve
SoS	Security of Supply
SSSA	System Support Services Agreement
TOR	Tertiary Operating Reserve
TSC	Trading and Settlement Code
TSO	Transmission System Operator