Harmonised Other System Charges Recommendations Paper

Tariff Year

1st October 2018 to 30th September 2019

20th August, 2018

EXECUTIVE SUMMARY

EirGrid and SONI (the TSOs) published a consultation paper on 4th April 2018 for the upcoming tariff period running from the 1st October 2018 to the 30th September 2019 outlining a number of proposals. Comments on the consultation paper were received from five (5) respondents, having reviewed the responses, we are now making a number of recommendations to the RAs.

1. Retain the OSC rates approved for the 2017/2018 tariff year, only adjusting for inflation at forecast rate of 1.45% for the tariff year 2018/2019 for the following GPIs:
   - Minimum Generation,
   - Governor Droop,
   - Secondary Operating Reserve,
   - Tertiary Operating Reserve 1,
   - Tertiary Operating Reserve 2, and
   - Reactive Power.

2. Reduce the rate of the Trip and Short Notice Declaration charges to 50% of the 2017/2018 tariff rate.

3. Set the charging rate to zero for the early and late synchronization GPIs.

4. Set the charging rate to zero for the loading and de-loading rates GPIs.

5. Set the charging rate to zero for the Minimum On Time GPI.

6. Set the charging rate to zero for the Maximum Number of Starts in 24 hours GPI.

7. Increase the Primary Operating Reserve GPI rate from €0.13 to €0.52.

8. Implement the GPI for Secondary Fuel Availability declarations with a charge rate of €0.03.

No other changes are recommended for this tariff period.

ABBREVIATIONS

AGU	Aggregated Generator Unit
DETI	Department of Enterprise, Trade and Investment
DMOL	Design Minimum Operating Level
DSU	Demand Side Unit
DS3	Delivering a Secure Sustainable System
EDIL	Electronic Dispatch Instruction Logger
GPI	Generator Performance Incentive
HAS	Harmonised Ancillary Services
HICP	Harmonised Index of Consumer Prices
I-SEM	Integrated Single Electricity Market
UK	United Kingdom
OSC	Other System Charges
NI	Northern Ireland
NIE	Northern Ireland Electricity
RA	Regulatory Authority
RoCoF	Rate of Change of Frequency
RPI	Retail Prices Index
SEM	Single Electricity Market
SND	Short Notice Declaration
SONI	System Operator Northern Ireland
TSO	Transmission System Operator
TUoS	Transmission Use of System
WFPS	Wind Farm Power Station

1. INTRODUCTION

We consult on an annual basis regarding proposed changes to Other System Charges and associated rates. The purpose of this paper is to make recommendations for approval to the RAs in Ireland and Northern Ireland. They are based on a consideration of the responses received by the TSOs on this year's Harmonised Other System Charges Consultation paper[1] for the tariff year 1st October 2018 to 30th September 2019.

If the recommendations are approved by the RAs, we will publish revised Statements of Charges and Other System Charges Methodology Statement for the 2018-2019 tariff period.

We received responses from the following parties:

Party	**Abbreviation**
AES Kilroot Power Ltd and AES Ballylumford Ltd	AES
Bord Gáis Energy	BGE
ESB Generation and Wholesale Markets	ESB GWM
Energia[2]	ENE
Power NI Energy Ltd Power Procurement Business	PPB

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

[1] "Harmonised Other System Charges Consultation" 4th April, available at http://www.eirgridgroup.com/site-files/library/EirGrid/OSC-18-19-consultation-paper_final.pdf and http://www.soni.ltd.uk/media/documents/Operations/Ancillary-Services/OSC%2018%2019%20consultation%20paper_final.pdf

[2] Response from Energia was received 2 days after the consultation had closed.

2. OTHER SYSTEM CHARGES CONSULTATION RESPONSES

2.1. Trip Charge and Short Notice Declaration (SND) Charge

In the consultation paper we proposed the retention of Trips and SND charges but at a reduced rate of 50% of the 2017/2018 tariff year rate for both charges. We stated that when we have more experience of operating in I-SEM, the appropriateness of setting these charges to half of their current rate will be reviewed.

2.1.1 Respondents' Comments

Five comments were received (AES, BGE, ESB GWM, ENE and PPB) in relation to the delivery of I-SEM and its impact on the Trip Charge and SND charge.

AES welcomed the review of the OSC and the TSOs' approach in taking cognisance of the impact of I-SEM. AES questioned, due to the delay in the introduction of I-SEM, would there be any delay in the introduction of the proposed OSC changes. AES further queried if it would be suitable to adjust the 8 hour notification window to take into account balance responsible actions by market participants.

ENE commented that there was there is an inconsistency in the approach taken by the TSOs when setting charges in the paper. For some charges the TSO acknowledged the role that I-SEM will have in ensuring generators deliver their contracted position and as a result are reducing the charges to zero. For other charges such as SNDs, which will also be incentivised in I-SEM, the TSO are maintaining a charge. ENE believe there is no clear justification in the paper for these inconsistencies and logically if the TSO assumes that I-SEM will sufficiently incentivise generators for some charges then the approach for all charges associated with I-SEM should be the same.

Two respondents (PPB and BGE) welcomed the 50% reduction in the Trip and SND charge rate. However, PPB believe the rates are still much too high. PPB and ENE commented that the 50% reduction seemed arbitrary and is not backed up by any detail or supported by robust analysis on the impacts on the system.

BGE stated they were in favour of minimising double payments by generators (by virtue of the continued application of certain OSC charges, the objectives of which should be achieved through I-SEM imbalance exposure), and costs for customers, insofar as possible. BGE urged the TSOs to commit to a certain date to review what the imperfections costs are following experience in I-SEM, and whether the Trip and SND charges should be maintained or should be further reduced or removed. BGE stated that this review should occur within 12 months of I-SEM go live with the benefit of data backed analysis. An opportunity for consultation on the results of such analysis and the possibility of changes in tariffs, should be given to stakeholders at that point.

ESB GWM wished to re-highlight that Trip Charges and Short Notice Declarations are not warranted or justified in I-SEM and that participants will a have number of new exposures in the event of a unit tripping and will pay the costs incurred by the TSO to maintain system balance through the balancing market mechanism. Consequently, to maintain these charges in I-SEM they believe would amount to double charging by the TSO rather than recovery of costs incurred by the system due to these events. Also from a desk top review, they are not aware of existence of such charges in other balance responsible markets (e.g. GB). A similar view is held by ENE that the TSO should set to zero charges that will be captured in I-SEM.

ESB GWM gave further details on participant exposures in I-SEM, breaking their comments down into three sections, Balance Responsibility, Credit Cover Exposure and Difference Payments.

ESB GWM stated that the energy market is undergoing a fundamental change and at a very high level, the market is changing from an ex-post market to an ex-ante market where balance responsible participants will have strong incentives to deliver energy sold in the ex-ante timeframes. They believe that a participant that changes their availability or trips will face significant exposure in I-SEM that does not exist in SEM.

They further stated that participants in I-SEM will have to post credit cover across all the various market timeframes. One aspect of this will be credit cover required to cover the SEMOs exposure in the Balancing Market to purchase energy elsewhere when a unit sells a volume but fails to deliver it due to a trip or short notice declaration of availability. ESB GWM believe the credit cover calculation will take account of the probability of a unit tripping and therefore participants will have an incentive to reduce trip incidents to minimise the amount of credit cover they need to post.

2.1.2 TSOs' Response

The TSOs welcome the comments received in relation to the delivery of I-SEM and its impact on Trip and SND charges.

With reference to the comment from AES regarding a delay to the proposed OSC changes we can confirm that all proposed OSC changes are planned to be implemented at the start of the coming tariff year 2018/2019, on 1st October 2018. In response to the query regarding the adjustment of the 8 hour notification window for SNDs, and also the comment on the seemingly arbitrary application of the 50% reduction, we believe that until we have experience of operating in I-SEM the scale of imperfections costs is not known and therefore the retention of the charges in the current form is appropriate albeit at a reduced rate of 50%. We are cognisant of the industry feedback received to the 17/18 tariff year OSC consultation and believe the 50% reduction also takes account of this feedback. We acknowledge the request from BGE that a review of the 50% reduction should occur within 12 months of I-SEM go live. We propose to review this has part of the annual OSC consultation for the tariff year 2020/2021 when adequate data will be available.

With reference to the comment from the two respondents on double charging the TSOs believe this not to be the case. We believe, until we have evidence from market experience that the main objectives of Other System Charges continue to have validity for the tariff year 18/19: SNDs incentivise timely notification of availability changes and Trip Charges incentivise slow wind-downs rather than trips.

As we stated in the consultation paper, we do agree that I-SEM will introduce additional incentives to some of the behaviours that are covered by OSC; however it may not cover all OSC incentives.

2.1.3 TSOs' Recommendations

We recommend that Trips and SND charges are retained but at a reduced rate of 50% of the 2017/2018 rate for tariff year 2018/2019.

2.2. Generator Performance Incentive Charge

In the consultation paper we stated that as with the existing GPI arrangements under SEM, we consider that GPIs will remain separate to I-SEM, and as a consequence not require modification for I-SEM. The exceptions to this are the GPIs for early and late synchronization and loading and de-loading rates. Under I-SEM, participants will be balance responsible and may incur imbalance charges should they not deliver their market positions. The TSOs proposed to set these charges (early and late synchronization and loading and de-loading rates) to zero for the tariff year 2018/2019.

We also stated that following a review of the charges applied over the last two tariff years (2015/2016 and 2016/2017) it had been noted that no charges have been applied for the Minimum On Time and the Maximum Number of Starts in 24 hours GPIs. Based on the high level of industry compliance with respect to these two areas of the Grid Code, the TSOs proposed to set these charges to zero for the tariff year 2018/2019.

We believe the GPIs for Minimum Generation, Governor Droop, Operating Reserve and Reactive Power still have merit in incentivising compliance to the Grid Code standards and therefore we proposed to retain the charge rates approved for the 2017/2018 tariff year with the inclusion of the assumed inflation rate.

2.2.1. Respondents' Comments

Two respondents (BGE and PPB) welcomed the TSOs proposal to set the early and late synchronization and loading and de-loading GPI charge rates to zero. PPB also agreed with the proposal to set the Minimum On Time and the Maximum Number of Starts in 24 hours GPI charge rates to zero.

PPB stated they disagreed with the TSOs' position that certain GPIs are unaffected by I-SEM and hence should be retained. They further stated that based on the rationale for removing the other GPIs i.e. that the I-SEM will provide adequate incentives, the same approach can be used with other services where there is already an incentive in another market. The proposal is to retain the Minimum Generation GPI but PPB believe performance in this area is already addressed in the DS3 market as any increase in Minimum Generation will result in a reduction in DS3 payments. PPB consider this is enough of an incentive and does not require a second incentive through a GPI. Similarly, a re-declaration of Governor Droop will be likely to reduce the provision of Reserve and so will impact the Reserve Performance Scalar which will subsequently result in a reduction in DS3 payments.

2.2.2 TSOs' Response

We believe, until we have evidence from market experience that the main objective of GPIs, to incentivise Grid Code compliance, continues to have validity for the tariff year 18/19. Indeed, if a unit complies with its Grid Code requirements, no charges will be levied. The requirement to achieve Grid Code compliance will not change as a result of the introduction of I-SEM.

With reference to the comment from PPB regarding the Minimum Generation and Governor Droop GPIs, again we would like to highlight that if a unit complies with its Grid Code requirements no charges will be levied.

2.2.3 TSOs' Recommendations

The TSOs recommend setting the GPI charge rates to zero for early and late synchronization, loading and de-loading, Minimum On Time and the Maximum Number of Starts in 24 hours for the tariff year 2018/2019.

For all other GPIs (Minimum Generation, Governor Droop, Secondary Operating Reserve, Tertiary Operating Reserve 1, Tertiary Operating Reserve 2 and Reactive Power), the TSOs recommend retaining the charge rates approved for the 2017/2018 tariff year with the inclusion of the assumed inflation rate.

2.3. RoCoF GPI

In the consultation paper we stated although there has been significant progress, the RoCoF implementation project is not yet complete and that a review of the appropriateness of the tariff may be merited following closure of the RoCoF project. However, until such time we would continue to apply the current rate.

2.3.1. Respondents' Comments

One response was received from ESB GWM. They acknowledged that the GPIs for RoCoF non-compliance were introduced by the TSOs in line with the RAs RoCoF Decision papers and acknowledged that significant progress had been made towards the implementation of the revised RoCoF standard by different parts of the electricity industry. However, ESB GWM stated, they continue to be of the view that the level of the GPI applied to generators for RoCoF non-compliance to the specified RoCoF project timelines to be disproportionate given the cost borne by the generators as part of the RoCoF project.

ESB GWM further stated that the RoCoF project has a number of elements that must be substantially completed in advance of the operational RoCoF being increased. They believe, given that other elements remain outstanding, the RoCoF GPI as currently levied on generators is not reflective of a cost being incurred by the system solely due the generators non-compliance to the required project timelines.

2.3.2. TSOs' Response

The TSOs welcome the comments received in relation to the RoCoF GPI and have shared them with the Regulatory Authorities. The RoCoF project has been implemented in line with the RAs' decision papers[3] published in 2014 and until such time as a review is carried out we will continue to apply the current rate.

2.4. Operating Reserve GPI

In the consultation paper we presented a proposed increase to the POR GPI rate in order to provide a greater incentive to comply with Grid Code POR requirements. The TSOs proposed to increase the POR GPI rate from €0.13 to €0.52 for the tariff year 2018/2019.

2.4.1. Respondents' Comments

Five comments were received (AES, BGE, ENE, ESB GWM and PPB) in relation to the POR GPI rate increase proposal.

AES stated they believe the POR GPI calculation should be based on the declaration of POR values below those contracted within the DS3 Agreements as those are the values the TSOs have contracted to be provided. AES commented the additional reason the DS3 contracted values are used is because there are no 'Grid Code values' of operational reserve.

PPB commented that the proposal to increase the POR GPI rate by a factor of 4 is made without any analysis to justify the proposed increase in the rate. Increasing this rate could also be counterproductive causing units to be reticent to declare down for short periods. PPB further stated that it is an important principle that there should be no "double charging" and that where no other incentives exist then any GPI penalties and charges must be justified and proportionate to the costs they impose and any derivation of costs must be based on robust analysis and evidence rather than conjecture.

ENE and ESB GWM believe the magnitude of the increase to the POR GPI rate is unjustified and substantially disproportionate. BGE, ENE and ESB GWM have requested further clarification from the TSO on their calculations supporting the 400% increase in rate.

[3] https://www.uregni.gov.uk/sites/uregni.gov.uk/files/media-files/Decision_Paper_on_the_Rate_of_Change_of_Frequency_Grid_Code_Modification.pdf and https://www.cru.ie/wp-content/uploads/2014/07/CER14081-ROCOF-Decision-Paper-FINAL-FOR-PUBLICATION.pdf

2.4.2. TSOs' Response

We welcome the comments received from the five respondents.

The calculation below gives an example of applying the GPI trading period charge[4] to a 400MW unit that has a Grid Code POR requirement of 14MW but declares 10MW of POR capability.

Current rate = €0.13

POR_Charge_X = TP * (POR – DPOR) * POR_RATE
= 0.5 * (14 – 10) * 0.13
= €0.26

Proposed rate = € 0.52

POR_Charge_X = TP * (POR – DPOR) * POR_RATE
= 0.5 * (14 – 10) * 0.52
= €1.04

Annually, if the unit failed to comply with its Grid Code requirement, the proposed charge would total €18,220.80 compared to €4,555.20. We believe this greater incentive is required to send the signal to industry of their obligation to comply with Grid Code and once more we would like to highlight that if a unit complies with its Grid Code requirements no charges will be levied.

As stated in the consultation paper, the increase in the POR GPI rate has been developed in conjunction with the TSOs' Innovation Team which is responsible for DS3 System Services.

In response to the comment from AES regarding the use of DS3 declared POR values, we would like to reiterate what was in last year's recommendations paper. We stated that prior to the introduction of OSC in 2010, the consultation paper, SEM-08-128 and the subsequent decision paper SEM-10-001 stated that the charges for generator unit underperformance would be distinct from, and additional to, any charges made for the non-delivery of AS (now provided through DS3 System Services contracts). They papers further stated that charges for the non-delivery of AS arise from the failure to fulfil an AS contract; charges for generator unit underperformance would arise from a failure to meet the terms of the Connection Agreement and its requirement to meet the Grid Code requirements.

2.4.3. TSOs' Recommendations

We recommend increasing the POR GPI rate from €0.13 to €0.52 for the tariff year 2018/2019.

[4] A further breakdown of the POR GPI calculation can be found in the OSC Methodology Statement on the TSOs websites, http://www.soni.ltd.uk/ and http://www.eirgridgroup.com/ .

2.5. New Other System Charges

2.5.1. Secondary Fuel Availability GPI

In the consultation paper we proposed a new GPI relating to a generating unit's declared secondary fuel capability. We believe the methodology as set out in previous consultations is required to incentivise compliance and remains essentially unchanged. In the methodology proposed we have included a factor which takes into account the fact that a generating unit during a secondary fuel test is obligated to provide a MW value of no less than 90% of its declared availability.

The TSOs proposed a secondary fuel charge rate, SecFuel_Rate, of €0.03 and a secondary fuel availability factor, SFA_F, of 0.9.

2.5.1.1 Respondents' Comments

Five comments were received (AES, BGE, ENE, ESB GWM and PPB) in relation to a Secondary Fuel GPI.

AES stated that they understood the concern of the TSOs that Ireland and Northern Ireland are heavily dependent on gas as a fuel and believed this is partly as result of the TSOs signals and Capacity procurement policy. They suggested that such actions by the TSOs should not result in the fuel risks being placed on the generators and that should the TSOs want to alleviate such perceived risks then they should instigate an investment policy to attract fuel diversity.

In addition to this AES would like to ensure that this Fuel Switching charge is limited to address the identified concern of gas dependant fuel, and to that end it should not be applied to any other type of fuel utilised by a generator. The terms used within the consultation document are not suitable for all stations and should not be applied as such.

AES stated they strongly opposed the introduction of the Secondary Fuel Availability GPI, especially on non-gas fired plant. AES also queried the definition of 'Time Weighted Average Availability' and if the summation for the N values of 'Availability' refer to 'Secondary Fuel Availability' instead. In addition, AES stated the reference to 'Availability' is somewhat confusing.

BGE commented that, in principle, they supported the application of a GPI relating to a generating unit's declared secondary fuel capability where those units are required to operate on secondary fuel. BGE noted that no decision on the CRU's 2015 Review of Fuel Stock Obligations for Electricity Generators (CER/15/213) (the 2015 Consultation) has been issued to date.

BGE noted that ultimately, this GPI seeks to achieve security of supply for the benefit of all electricity consumers. In this respect, they reiterated their concerns made in response to the 2015 Consultation regarding recovery of the cost of investment in dual-fuel operated units, as well as secondary fuel related operational and maintenance costs. BGE believes that recognition of the security of supply benefits being provided on foot of this secondary fuel obligation should materialise in the form of an ancillary service tariff.

BGE welcomed confirmation that the Secondary Fuel Availability GPI is not intended to apply to units that are on outage. They understood from the proposed formula that once a unit declares itself as being unavailable, the GPI will not apply.

ENE noted that the proposed secondary fuel charge is based on 90% of the availability of the primary fuel. Further stating that this should be based on the minimum of 90% of the availability of the primary fuel or the derogated secondary availability requirement and that any changes to the secondary fuel obligation must respect existing derogations for generators. ENE suggested that generators can be unavailable on secondary fuel for 5% of the year before charges are applied.

ESB GWM commented they do not believe that a secondary fuel GPI is appropriate as the secondary fuel requirement is an obligation on a specific group of generators as opposed to all participants and there is no remuneration to provide this service. However, they stated, if a mechanism is to be implemented on certain units to incentivise compliance with this aspect of the Grid Code as this provision represents a significant value to the system's security there should also be a remuneration mechanism, such as an additional secondary fuel related DS3 System Service, available to generators who provide this service. ESB GWM consider that the introduction of a secondary fuel GPI should not be implemented until a related secondary fuel system service has been developed.

PPB believe the introduction of this charge is unnecessary and discriminatory. This introduction of a charge for non-availability on secondary fuel when there is not a corresponding payment for the provision of this service is unfair. If there is no payment for the provision there should be no subsequent penalty. They further commented that such a charge would also be discriminatory since it would not apply equally across all units but would instead only be directed against those units that can provide the service. These units are providing security and flexibility to the system and yet under the proposal the only thing they receive is a penalty, while other units with no secondary fuel have no exposure. This does not engender equal and fair treatment of all technologies and provider types.

PPB stated that the consultation paper makes reference to the NI Fuel Security Code (NIFSC) being revised in 2015, however, they believe the NIFSC is not relevant as it only applies to a Fuel Security Event that has been notified by DETI under Article 37 of the 1992 Order and that it has no bearing on day to day operation of the system.

In relation to Fuel Switching Agreements, PPB commented that they are still not in place and hence similarly provide no justification to introduce a Secondary Fuel availability GPI. If introduced, the proposal would also impose a second penalty on the generator who is already exposed to costs under the NI Fuel Switching Agreement (FSA) for failure during fuel switching events, which includes fuel switching tests required by SONI. Such failure can also lead to termination of the FSA. Further, there is no cost to the system if a unit is available on its primary fuel and there is no requirement to switch fuel. Secondary Fuel has been available for many years and has rarely been required. Therefore to apply penalties is totally unacceptable particularly when conditions on the system are normal and there is no risk or potential requirement of a fuel switch.

Finally PPB noted note there is an error in the proposed formula suggested for this charge. TP is defined in hours (as 0.5) whereas T1 is defined in minutes. These two must be defined on the same units (i.e. hours or minutes) to achieve a coherent average over the trading period.

2.5.1.2 TSOs' Response

We welcome the comments received from the five respondents.

Regarding the comment from AES that should the TSOs want to alleviate such perceived risks (dependency on gas) then they should instigate an investment policy to attract fuel diversity. It should be noted that neither TSO is responsible for fuel security: in Ireland CRU is responsible and in Northern Ireland DETI is responsible for fuel security. Therefore, it would be outside the remit of the TSOs to investigate investment policy to attract fuel diversity. It is the TSOs' opinion that this is a matter for CRU and DETI in the relevant jurisdiction. The TSOs are seeking to introduce an incentive to improve secondary fuel availability, because we are of the opinion that lack of availability would impact on transmission system security, in the event of a gas shortage.

With regard to AES' comment that the secondary fuel availability GPI would only be charged to generators dependent on gas. The TSOs can confirm that it is proposed that the secondary fuel availability GPI would only be charged to gas fired plant, that are required to declare availability on a secondary fuel.

In response to the query from AES regarding the definition of 'Availability' in the proposed GPI calculation. The GPI is calculated based on a generating unit's primary fuel availability not their secondary fuel availability as it only applies when secondary fuel is unavailable.

In response to BGE's comment regarding no decision being issued to date on the CRU's 2015 Review of Fuel Stock Obligations for Electricity Generators (CER/15/213), the CRU have given the following statement. The CRU published a consultation on secondary fuel stocks in late 2015. No decision has been published to date as the CRU continues to reviews the performance of generators with regard to their current requirements. The CRU is actively engaging with EirGrid on the matter.

The TSOs would like to clarify to ENE and BGE that the GPI calculation is based on 90% of the availability of the primary fuel and that the GPI would not apply when the generating unit is declared unavailable. The application of the GPI would take into account existing derogations as is normal practice for all GPIs.

The TSOs have confirmed the error in the formula that PPB highlighted regarding the inconsistency of units. The incorrect methodology to calculate AP_{uh} was:

AP_{uh} is the Time Weighted Average Availability of Generator Unit u in Trading Period h (expressed in MW) and calculated by the application of the following formula:

$$AP_{uh} = \sum_{Av=1,N} \{(A_{V1} \times T_1)/TP\}$$

Where:

$\sum_{Av=1,N}$ is the summation for the N values of Availability during the Trading Period and where Av=1 denotes the first value of Availability during the Trading Period;

T_1 is the period (expressed in minutes) for which the value of Availability was equal to Av1 during the Trading Period.

The corrected methodology for AP_{uh} is:

AP_{uh} is the Time Weighted Average Availability of Generator Unit u in Trading Period h (expressed in MW) and calculated by the application of the following formula:

$AP_{uh} = \sum_{Av=1,N} \{(A_{V1} \times T_1)/30\}$

Where:

$\sum_{Av=1,N}$ is the summation for the N values of Availability during the Trading Period and where Av=1 denotes the first value of Availability during the Trading Period;

T_1 is the period (expressed in minutes) for which the value of Availability was equal to Av1 during the Trading Period.

With regard to PPB's comment that the consultation paper makes reference to the NI Fuel Security Code (NIFSC) being revised in 2015, however, they believe the NIFSC is not relevant as it only applies to a Fuel Security Event that has been notified by DETI under Article 37 of the 1992 Order and that it has no bearing on day to day operation of the system. The TSOs are of the opinion that Fuel Switching Agreement directs how to pay following an actual gas shortage event and it follows that this is also the appropriate mechanism to recover costs for testing. This is why the NI TSO is actively engaging with the generators to close out Fuel Switching Agreements.

With regard to PPB's comment that Fuel Switching Agreements are still not in place and hence similarly provide no justification to introduce a Secondary Fuel availability GPI. The TSO in Northern Ireland has had significant engagement, with the generators involved and the Utility Regulator, with the aim to achieve agreement of the Fuel Switching Agreements. Although not all Fuel Switching Agreements have been signed yet we do not believe this should hold up the introduction of an incentive to improve performance in this area and thereby provide greater system security.

There have been a number of comments on whether there should be remuneration for secondary fuel capability. The TSOs are of the opinion that this is a matter for the Regulatory Authorities.

2.5.1.3. TSOs' Recommendations

The TSOs recommend introducing the GPI as proposed in the consultation paper with the amendment to the Time Weighted Average Availability parameter detailed in section 2.5.1.2. The GPI will be effective from the start of the next tariff year, 1st October 2018.

The TSOs recommend a secondary fuel charge rate, SecFuel_Rate, of €0.03 and a secondary fuel availability factor, SFA_F, of 0.9.

2.5.2. Wind Farms and Demand Side Units

In the consultation paper we stated that there have been significant strides by windfarms over the last couple of years in terms of achieving Grid Code compliance through the issuing of Operational Certificates. We have continued to observe that the majority of new windfarms connected to the system are compliant with their Grid Code requirements. For those wind farms that are not compliant a number of temporary derogations have been granted to allow time to investigate and implement remedial works.

We stated that we continue to monitor and develop the performance of Demand Side Units (DSUs).

It was noted in the consultation paper that the Enhanced Performance Monitoring System Phase 1 will be in operation in the coming tariff year, 2018/2019, and will be used as a tool to performance monitor all types of generation for Grid Code compliance.

2.5.2.1 Respondents' Comments

Three comments were received (BGE, ENE and PPB) in relation to the introduction of OSC for wind farms and DSUs.

PPB believe all technologies should be treated the same and so GPIs should be equally applied to all technologies.

BGE agrees that continued collaboration between the TSOs and wind farms should identify the necessary procedures to ensure Grid Code compliance, before applicable GPIs commence. BGE would welcome an indicative timeline as to when this assessment will complete as ultimately grid code compliance is critical for universal security of supply.

ENE believe that DSUs are being left out of the stringent requirements being placed on conventional generators and that a wait and see approach is being adopted in relation to I-SEM and balancing. They further stated that this is in stark contrast to the duplication of charges that conventional generators will be subject to in terms of OSC and the balancing market.

2.5.2.2 TSOs' Response

As discussed in the consultation paper, a significant proportion of the connected wind farms are now achieving Grid Code compliance/Operational Readiness Confirmation from the Wind Farm Controllability Categorisation Policy and we believe this has been effective in accomplishing this.

Currently GPIs are only levied on conventional generating units and we believe it is appropriate to apply GPIs for all generating units, including DSUs and wind farms in the future. Based on the 2020 renewable policy targets in Ireland and Northern Ireland wind farms may at times be the major energy source on the all island power system. We therefore need to ensure that there is adequate performance from all plant.

Any new GPIs will be consulted with industry on the actual design of the charge. The Regulatory Authorities would then have a final decision on whether the proposed GPI is implemented and the date from which the GPI should become effective. The GPI would be benchmarked against the Grid Code requirement or the derogated requirement if a derogation has been approved by the Regulatory Authorities.

3. ADDITIONAL COMMENTS

PPB commented that as discussed at the time of the introduction of the Harmonised Ancillary Services arrangements they still believe the Transmission Use of System (TUoS) Agreement is not the correct agreement to contain GPIs. For example, disputes in relation to RoCoF GPIs could end up being referred to the Utility Regulator as a licence breach. Interconnector owners have also argued that GPIs should not be applicable to them as they do not sign up to a TUoS agreement. PPB further stated that as new technologies come on board, they must be treated in the same manner as other participants and so must receive GPIs and so there needs to be a mechanism for charging these even if there is no requirement for them to sign up to a TUoS Agreement.

3.1 TSOs' Response

Regarding PPB's comment on the TUoS agreement not being the correct agreement to contain GPIs, the RAs Decision Paper SEM-10-001[5] published on 4th January 2010 provided a policy framework for the all-island harmonisation of Ancillary Services (HAS) and Other System Charges (OSC). The TSOs understand that the RAs are not minded to reopen the framework at this stage.

5 https://www.semcommittee.com/publication/sem-10-001-harmonised-all-island-ancillary-services-rates-and-other-system-charges

4. PROPOSED RATES

In the Harmonised Ancillary Services Rates and Other System Charges Decision paper for 2011-2012, the SEM Committee was satisfied that the exchange rate methodology be aligned to that utilised in the SEM. We will use the same methodology for 2018-2019 using the last five working days of July.

In the consultation paper, we detailed the following methodology to be applied going forward:

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

At the time of publication of the consultation paper according to the Office of Budgetary Responsibility report[6] (Nov 2017) the current RPI inflation was forecast in the UK for the 2018/19 tariff year at 2.925% while the Central Bank report[7] (Q1 2018) forecast HICP in Ireland for the same period at 0.85%.

Source		**2018**	**2019**	**Tariff Year Methodology**	**2018/2019 Tariff Year**	**Blended Rate Methodology**	**Blended rate**
OBR Nov 2017	RPI	3.3%	2.8%	(.033*25% + .028*75%)	2.925%	2.925*25%	0.73125
Central Bank Q1 2018	HICP	0.7%	0.9%	(.007*25% + .009*75%)	0.85%	0.85*75%	0.6375
Blended Rate							**1.369%**

Table 4.0: Proposed Inflation Rate Increase as published in the consultation paper

On this basis, and recognising the relative balance between Ireland and Northern Ireland, the forecast blended rate published in the consultation paper for the forthcoming 2018/19 period was 1.369% as shown in Table 4.0.

At the time of publishing this recommendations paper the latest available Office of Budgetary Responsibility report[8] (Mar 2018) the current RPI inflation forecasts in the UK for the 2018/19 tariff year is 3.175% while the Central Bank report[9] (Q2 2018) forecasts HICP in Ireland for the same period at 0.875%.

[6] http://obr.uk/efo/economic-fiscal-outlook-november-2017/
[7] https://www.centralbank.ie/publication/quarterly-bulletins/quarterly-bulletin-q1-2018
[8] http://obr.uk/efo/economic-fiscal-outlook-march-2018/
[9] https://www.centralbank.ie/publication/quarterly-bulletins/quarterly-bulletin-2-2018

Source		2018	2019	Tariff Year Methodology	2018/2019 Tariff Year	Blended Rate Methodology	Blended rate
OBR Mar 2018	RPI	3.7%	3.0%	(.037*25% + .030*75%)	3.175%	3.175*25%	0.79375
Central Bank Q2 2018	HICP	0.8%	0.9%	(.008*25% + .009*75%)	0.875%	0.875*75%	0.65625
Blended Rate							**1.45%**

Table 4.1: Recommended Inflation Rate Increase using the latest available forecast values

On this basis, and recognising the relative balance between Ireland and Northern Ireland, the forecast blended rate for the forthcoming 2018/19 period is 1.45% as shown in Table 4.1.

The recommended rates are displayed with 2 decimal places in Euro and have been calculated using the latest available forecast values giving a forecasted blended rate of 1.45%. The TSOs would like to clarify that 4 decimal places from the current tariff year rates are used in the calculation of the inflationary increase.

4.1 Trip Charges

The following tables recommend the Trip Charges and Constants for the 2018-2019 tariff year. As seen in Table 4.2 and Table 4.3. We recommend to reduce the rate to 50% of the 2017/2018 tariff year rate for all three trip types; direct, fast wind down and slow wind down.

	2017-2018	2018-2019
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	1 MW/s
Direct Trip Constant	0.01	0.01
Fast Wind Down Constant	0.009	0.009
Slow Wind Down Constant	0.008	0.008
Trip MW Loss Threshold	100 MW	100 MW

Table 4.2: Recommended Trip Constants

Charge	2017-2018	2018-2019
Direct Trip Charge Rate	€4,322	€2,161
Fast Wind Down Charge Rate	€3,242	€1,621
Slow Wind Down Charge Rate	€2,161	€1,081

Table 4.3: Recommended Trip Rates

4.2 Short Notice Declaration (SND) Charges

The following tables recommend the SND Charges and Constants for the 2018-2019 tariff year. As seen in Table 4.4 and 4.5. We recommend reducing the rate to 50% of the 2017/2018 tariff year rate.

SND Constants	2017-2018	2018-2019
SND Time Minimum	5 min	5 min
SND Time Medium	20 min	20 min
SND Time Zero	480 min	480 min
SND Powering Factor (Notice time weighting curve)	-0.3	-0.3
SND Threshold	15 MW	15 MW
Time Window for Chargeable SNDs	60 min	60 min

Table 4.4: Recommended SND Constants

SND Charge Rate	2017-2018	2018-2019
SND Charge Rate	€76 / MW	€38 / MW

Table 4.5: Recommended SND Charge Rate

4.3 GPI Charges

The recommended GPI Constants, GPI Declaration Based Charges and GPI Event Based Charges for the 2018-2019 tariff year are outlined in Table 4.6, Table 4.7 and Table 4.8 respectively. We recommend making changes to the rates for 2018-2019 as detailed in sections 2.2 and 2.4.

GPI Constants	2017-2018	2018-2019
Late Declaration Notice Time	480 min	480 min
Loading Rate Factor 1	60 min	60 min
Loading Rate Factor 2	24	24
Loading Rate Tolerance	110%	110%
De-Loading Rate Factor 1	60 min	60 min
De-Loading Rate Factor 2	24	24
De-Loading Rate Tolerance	110%	110%
Early Synchronous Tolerance	15 min	15 min
Early Synchronous Factor	60 min	60 min
Late Synchronous Tolerance	5 min	5 min
Late Synchronous Factor	55 min	55 min
Secondary Fuel Availability Factor	N/A	0.9

Table 4.6: Recommended GPI Constants

	2017-2018	2018-2019
GPI Declaration Based Rates	**€ / MWh**	**€ / MWh**
Minimum Generation	1.28	1.29
Max Starts in 24 hour period	1.08	0.00
Minimum On time	1.08	0.00
Reactive Power Leading	0.31	0.32
Reactive Power Lagging	0.31	0.32
Governor Droop	0.31	0.32
Primary Operating Reserve	0.13	0.52
Secondary Operating Reserve	0.13	0.13
Tertiary Operating Reserve 1	0.13	0.13
Tertiary Operating Reserve 2	0.13	0.13
Secondary Fuel Availability	N/A	0.03

Table 4.7: Recommended GPI Declaration Based Charge Rates

	2017-2018	2018-2019
GPI Event Based Rates	**€ / MWh**	**€ / MWh**
Loading Rate	0.64	0.00
De-Loading Rate	0.64	0.00
Early Synchronisation	2.86	0.00
Late Synchronisation	28.60	0.00

Table 4.8: Recommended GPI Event Based Charge Rates

4.4 Respondents’ Comments

No comments on the proposed rates section were received.

4.5 TSOs’ Recommendation

A blended inflation rate of 1.45% is recommended to be implemented.

5. NEXT STEPS

Once the RAs have considered these recommendations and made their final decision, the TSOs will then publish a revised TUoS Statement of Charges for the 2018-2019 tariff period.

Response to Consultation on

Harmonised Other System Charges

On behalf of

AES Kilroot Power Ltd and AES Ballylumford Ltd

2nd May 2018

Prepared by AES Commercial Department,

Kilroot Power Station, Larne Road,

Carrickfergus, BT38 7LX

1. Introduction

AES Kilroot Power Ltd (“AES Kilroot”) and AES Ballylumford Limited (“AES Ballylumford”), (collectively “AES”), welcome the opportunity to comment on the consultation paper relating to Harmonised Other System Charges.

AES is a global energy company with assets in the all island market, consisting of CCGT plant, coal and gas fired conventional units, additional distillate fired peaking gas turbine plant and new technology Battery Energy Storage Array (BESA). AES is a non-vertically integrated independent generator which owns and operates Kilroot and Ballylumford power stations in Northern Ireland with a combination of merchant and contracted base load, mid merit and peaking plant. AES also operates Energy Storage via its battery array located at Kilroot. The responses to this consultation reflect our current position and portfolio of assets operating in the All Island Market (SEM) and the electricity grids, as well as development plans for new generation and storage assets.

2. Comments

2.1 AES welcomes the review of the Other System Charges and the approach of the TSOs to take cognisance of the impact of the new energy market (I-SEM).

Since the introduction of I-SEM has been delayed to the 1st October 2018, then AES would ask if the proposed OSC changes shall be introduced as expected or delayed until I-SEM experience has been obtained.

2.2 The TSOs have proposed to adjust the SND charges as generators in I-SEM will be expected to be ‘balance responsible’. Given that SNDs are based on the notice given, shorter than eight hours, AES would suggest that balance responsible actions could be seen as alleviating any imperfection charges that may arise and should therefore be taken into account when applying SNDs. Would it be suitable to adjust the 8 hour notification curve to allow for balance responsible actions?

2.3 AES are concerned that TSOs have witnessed units declaring down their POR values to reduce the impact on their performance scalars. However, the consultation document refers to these units declaring below “their required Grid Code POR capability”. AES propose that this is an incorrect approach regarding the calculation of the Operational Reserve GPIs. The calculation should be based on the declaration of POR values below those contracted within the DS3 Agreements as those are the values the TSOs have contracted to be provided. The additional reason the DS3 contracted values are used is because there are no ‘Grid Code values’ of operational reserve.

AES remain concerned that the TSOs continue to refer to Grid Code values regarding Operational Reserve. We acknowledge the values within the DS3

Agreements, and the expectation of the TSOs that such values should be provided by those units. A reduction of provision of the values specified in the DS3 Agreements could result in imperfection charges and as such could be seen as attracting a GPI charge as well as a reduction in DS3 payments.

2.4 AES note the proposal to introduce a Secondary Fuel GPI. It should be pointed out that the form of the Fuel Switching Agreement approved by the Utility Regulators in Northern Ireland has been shown to be inappropriate for 2 of the 3 major power station players. This has meant that different forms have had to be produced and one is still to be drafted, even 2 years later. It is incorrect to state that the remaining two agreements are anticipated to be signed in the near future.

We understand the concern of the TSOs that Ireland and Northern Ireland are heavily dependent on gas as a fuel. This is partly as result of the TSOs signals and Capacity procurement policy. It is suggested that such actions by the TSOs should not result in the fuel risks being placed on the generators. Should the TSOs want to alleviate such perceived risks then they should instigate an investment policy to attract fuel diversity.

In addition to this we would like to ensure that this Fuel Switching charge is limited to address the identified concern of gas dependant fuel, and to that end it should not be applied to any other type of fuel utilised by a generator. The terms used within the consultation document are not suitable for all stations and should not be applied as such.

AES strongly opposes the introduction of the Secondary Fuel Availability GPI, especially on non-gas fired plant.

2.5 NB – in the definition of ‘Time Weighted Average Availability’ should the summation for the N values of ‘Availability’ refer to ‘Secondary Fuel Availability’ instead? The reference to ‘Availability’ is somewhat confusing.

BORD GÁIS ENERGY RESPONSE

Harmonised Other System Charges Consultation

Tariff Year 01 October 2018 to 30 September 2019

2nd May 2018

1. Introduction

BGE welcomes the opportunity to respond to the TSOs' consultation on the Harmonised Other System Charges (**OSC**) for the Tariff Year 1st October 2018 – 30th September 2019 (**the Consultation**).

2. Review of Existing OSC

2.1 Trip charges and Short Notice Declaration (SND) charges

BGE welcomes the TSOs' review of market and grid related charges and costs and their continued applicability in the context of the new I-SEM arrangements, which BGE has advocated for in previous charge related consultations.

We strongly support the approach of seeking to achieve a balance between: a) ensuring that generators are not subject to double-penalties (by virtue of the continued application of certain OSC charges, the objectives of which should be achieved through I-SEM imbalance exposure); and, b) minimising the risk that consumers are exposed to unnecessary costs in I-SEM, such as imperfections costs. We also recognise the TSOs' concern that even when a unit is balance responsible in the market, there could still be imperfections costs which in the absence of TRIP and SND have to be passed to the end consumer.

In this context, we welcome the reduction of both Trip and SND charges to 50% of the 2017-2018 tariff year rates. We also note the recent testing tariffs decision which sees the removal of the output drops/ tripping cost component of testing Tariff A, as well as the complete removal of testing Tariff B. Together with the reduction of the Trip and SND charges, these new testing tariffs significantly reduce the extent to which units faced potential double-penalties in the new market arrangements. This is a welcome development.

BGE is in favour of minimising double-payments by generators, and costs for consumers, insofar as possible. With experience of I-SEM it should become more apparent as to what level of imperfection costs materialize and the reasons therefor. We therefore urge the TSOs to commit to a certain date to review what these cost levels are, and whether the TRIP and SND charges should be maintained or should be further reduced or removed. BGE submits that this review should occur within 12 months of I-SEM go live with the benefit of data backed analysis. An opportunity for consultation on the results of such analysis and the possibility of changes in tariffs, should be given to stakeholders at that point.

2.2 Generator Performance Incentive charges – GPIs

BGE welcomes the proposed setting to zero of GPIs for early and late synchronization; loading and de-loading charges. The introduction of balance responsibility in I-SEM effectively negates the need for their application. Should the TSOs act on their provision to re-open and increase such GPI charges in future, any such increase should only be made on the basis of transparent, data backed analysis that clearly links increasing imperfections costs with a lack of compliance with synchronisation and (de)loading obligations.

2.3 Operating Reserve GPI

In principle, and in line with the spirit of the Grid Code, BGE supports the need for units to declare their capability to the TSOs for the purposes of Primary Operating Reserve (**POR**). If units are not doing so, a deficit in POR can drive the need for utilizing additional units in the market, to the detriment of imperfection costs and ultimately consumers.

We request however further insight into how the TSOs determined a four-fold increase in the current rate (from €0.13 to €0.52) is a suitable value to apply such that it will incentivise appropriate behaviour in future?

3. New Other System Charges (OSC)

3.1 Secondary Fuel Availability GPI

In principle, BGE supports the application of a GPI relating to a generating unit's declared secondary fuel capability where those units are required to operate on secondary fuel. The importance of this security of supply measure is underscored by the uncertainty surrounding BREXIT negotiation outcomes and ability to rely on GB for gas supplies as a non-EU member state, as well as depleting indigenous gas supplies.

Our main views with regard to the Secondary Fuel Availability GPI can be summarised as follows:

i. We note that no decision on the CRU's 2015 Review of Fuel Stock Obligations for Electricity Generators (CER/15/213) (**the 2015 Consultation**) has issued to date. BGE maintains its stance, in support of the CRU's view, that there is little rationale to increase the level of on-site fuel stocks for baseload and mid-merit gas fired generation units at this time. Moreover, the implementation of this GPI is sufficient to incentivise maintaining secondary fuel stocks at current levels without further considering the need to increase such levels. An increase in such levels, in tandem with application of this GPI, would only add additional costs to participants who are already incurring considerable expenditure in preparing for I-SEM;

ii. Ultimately, this GPI seeks to achieve security of supply for the benefit of all electricity consumers. In this respect we reiterate our concerns made in response to the 2015 Consultation regarding recovery of the cost of investment in dual-fuel operated units, as well as secondary fuel related operational and maintenance costs. BGE believes that recognition of the security of supply benefits being provided on foot of this secondary fuel obligation should materialise in the form of an ancillary service tariff. The tariff should be paid to obligated units, and paid for by all electricity stakeholders. Levying the costs on generation units (and indirectly gas consumers) only, is considered inequitable. Alternatively, akin to the approach taken in overseas markets, central management of fuel stocks could occur, the cost of which would be recovered through a TUoS charge; and

iii. BGE understands, but would welcome confirmation, that the Secondary Fuel Availability GPI is not intended to apply to units that are on outage? It is our understanding from the proposed formula that once a unit declares itself as being unavailable, the GPI will not apply.

3.2 Wind Farms and Demand Side Units

BGE agrees that continued collaboration between the TSOs and wind farms should identify the necessary procedures to ensure Grid Code compliance, before applicable GPIs commence. We would welcome an indicative timeline as to when this assessment will complete as ultimately grid code compliance is critical for universal security of supply. Ideally derogations should only be accepted as a last resort. BGE believes that an appropriate timeline for review would be within 12 months of I-SEM go-live, akin to that for the review of Trip and SND charges.

4. Conclusion

In conclusion, BGE welcomes the review of market and grid related charges adopted by the TSOs in the context of the introduction of I-SEM balancing arrangements. The proposed 50% reduction in Trip and SND charges; zero charges for synchronisation and (de)loading; as well as the recent decision on testing tariffs should minimize the risk of double-penalties for generators and minimize costs for consumers.

We believe that a review of whether the TRIP and SND charges should be reduced further or removed, and whether GPIs for wind and DSUs should apply should occur within 1 year of I-SEM go-live. We also seek further insight as to the calculations behind the suggested increase in the POR rate in order to understand key calculation inputs.

Finally, before a final decision is made on this Consultation and on the CRU's 2015 Review of Fuel Stock Obligations for Electricity Generators, we urge consideration of our main points outlined in section 3.1 above including: that the application of the secondary fuel GPI negates the need to also consider an increase in the levels of secondary fuel holdings; that this GPI is a security of supply measure and the costs of complying with the secondary fuel obligation should be reimbursed by the key beneficiaries (being all electricity stakeholders) through an ancillary service payment, and; that the GPI should not apply when an obligated unit is not compliant with the secondary fuel availability obligation due to it being on outage (i.e. having declared its unavailability).

Generation & Wholesale Markets

ESB GWM Response:

Harmonised Other System Charges Consultation (SEM-18-015)

Tariff Year 01 Oct 2018 to 30 Sept 2019

2nd May 2018

Contents

ESB Energy for generations

1. INTRODUCTION

ESB Generation and Wholesale Markets (GWM) welcomes the opportunity to respond to the TSOs Consultation on the Harmonised Other System Charges for the tariff year 1st October 2018 to 30th September 2019.

Please note that the sections of our response are aligned with the sections and subsections detailed in the consultation paper.

2. TRIP AND SHORT NOTICE DECLARATION CHARGES

ESB GWM are encouraged to see proposed charges by the TSO to reduce the levy imposed on generators who trip and/or submit short notice declarations of availability by reducing the charge rate by 50% of the 2017/18 tariff year, however ESB GWM wish to re-highlight that Trip Charges and Short Notice Declarations are not warranted or justified in I-SEM structure as market participants will a have number of new exposures in I-SEM in the event of a unit tripping and will pay the costs incurred by the TSO to maintain system balance through the balancing market mechanism. Consequently, to maintain these charges in I-SEM we believe would amount to double charging by the TSO rather than recovery of costs incurred by the system due to these events. Also from a desk top review, we are not aware of the existence of such charges in other balance responsible markets for example in GB.

Participant Exposures in I-SEM

The energy market is undergoing a fundamental change. At a very high level, the market is changing from an ex-post market to an ex-ante market where balance responsible participants will have strong incentives to deliver energy sold in the ex-ante timeframes. This is a significant change from today where the market is centrally dispatched by the system operator and the market price is determined ex-post based on perfect hindsight of events that occurred in real time.

In SEM, notwithstanding the foregone revenue to a generator in the event of a short notice change to availability or a trip, the costs borne by the TSO in re-dispatching the system due to these events is not shared by that generator. Instead it is picked up by suppliers in the Imperfections Charge and ultimately borne by the consumer. Hence, the introduction of Trip Charges and Short Notice Declarations Charges could be justified as it created an incentive on generators to minimise these events where possible or give as much notice as possible where unavoidable. Furthermore, the MSQ run is carried out ex-post on D+4 in perfect hindsight and therefore the SMP will likely not reflect the short term actions taken by the TSO.

In I-SEM this is no longer this case and a participant that changes their availability or trips will face significant exposure that did not exist in SEM.

Balance Responsibility

In I-SEM, the single largest incentive for a generator to minimise short notice declarations or trips will be through their exposure to the imbalance price in such an event (which does not exist today). Participants in I-SEM will have a strong incentive to submit physical notifications (PNs) of their intended running that are backed by ex-ante trades as any Bid Offer Acceptances (BOAs) from the TSO on PN volumes not sold ex-ante will be cashed out at the imbalance price rather than the incremental or decremental price submitted.

This means that when a unit trips or makes downward re-declaration to its availability on short notice it will have to pay the imbalance price for the volumes it did not deliver. The imbalance price for this volume will be set by the most expensive unit that the system operator had to call on short notice to meet the shortfall that was caused by the trip or downward availability declaration. This means that a) the TSO should not incur the costs of balancing in this simplistic example as its paid for by the participants that are short and b) participants have a strong incentive not to trip as they face this exposure of the difference between the imbalance price and the price at which that volume of energy had been sold for in the ex-ante market.

Furthermore, the shorter the change in availability and the greater the change will likely result in a higher imbalance price as a fast acting expensive unit will be required by the TSO to maintain the generation required to meet demand. This mitigates the needs for the notice time aspect of SNDs that currently exists where the SND penalty is proportional to the notice time given.

If the existing SND framework is allowed to operate under I-SEM a situation could arise where a generator, due to a change in availability, trades out of a D-1 market position in the intra-day market timeframe and both the generator and its intra-day counterparty submit PNs in advance of gate closure to the TSO in line with their revised expected running profile. In these circumstances the TSO may or may not have to take actions and yet a SND charge would be levied regardless. In these circumstances the SND framework will have become penal rather than an incentive mechanism.

Credit Cover Exposure

Participants in I-SEM will have to post credit cover across all the various market timeframes. One aspect of this will be credit cover required to cover the SEMOs exposure in the Balancing Market to purchase energy elsewhere when a unit sells a volume but fails to deliver it due to a trip or short notice declaration of availability. The credit cover calculation will take account of the probability of a unit tripping and therefore participants will have an incentive to reduce trip incidents to minimise the amount of credit cover they need to post.

Difference Payments

Today, participants receive a capacity payment without any risk. In I-SEM, participants that clear in the Capacity Remuneration Mechanism (CRM) auction will be faced with an exposure to the Administered Scarcity Price in I-SEM if triggered. Specifically, when the CRM reference price (blend of DAM, IDM and BM price) exceeds the strike price, participants with CRM contracts will be obligated to pay back the difference between the reference price and the strike price for volumes not sold in the ex-ante markets up to their de-rated capacity. This means that participants with CRM contracts will have an incentive to maintain full availability and any reductions in availability will therefore run a risk of incurring a difference payment should a scarcity event occur. Additionally through the CRM capacity derating mechanism the TSO has recognised that all generators have an associated forced outage rate. By continuing to levy trip charges the TSO will increase the operational costs for generators.

3. ROCOF GPI

ESB GWM acknowledges that the GPI's for RoCoF non-compliance were introduced by the TSOs in line with the RAs RoCoF Decision papers and acknowledges that significant progress has been made towards the implementation of the revised RoCoF standard by different parts of the electricity industry. However ESB GWM continues to be of the view that the level of the GPI applied to generators for RoCoF non-compliance to the specified RoCoF project timelines to be disproportionate given the cost borne by the generators as part of the RoCoF project.

Also, the RoCoF project has a number of elements that must be substantially completed in advance of the operational RoCoF being increased. Given that other elements remain outstanding the RoCoF GPI as currently levied on generators is not reflective of a cost being incurred by the system solely due the generators non-compliance to the required project timelines.

4. POR GPI

The implementation of the Interim DS3 System Services Agreement in October ‘16 through the introduction of the Performance Scalar framework created a strong incentive for system service providers to ensure that they will be assessed as having delivered their expected service quantity after a system event. As a consequence, in some cases this incentive could result in a service providers declaring below their POR Grid Code requirement to reduce the risk of failing to provide the declared POR capability following a system event. This impact has highlighting a conflict in the incentive structure faced by service providers between the POR GPI and the DS3 Performance Scalars. However ESB GWM believe that the proposed increase of 400% on the GPI rate for POR from €0.13 to €0.52 is a substantially disproportionate increase in GPI charges for non-compliance and request further clarification from the TSO on their calculations supporting this level of change.

5. SECONDARY FUEL GPI

As set out in the CER/09/001 Decision paper, specific technology types are required to hold fuel stocks, the level of fuel stocks required is dependent on the generators’ run hours (merit). Not all technology types have an obligation to provide this requirement, however the fuel stock obligation is required to provide security of supply to all electricity customers. It is ESB GWM’s view that the proposed secondary fuel GPI is not appropriate as the secondary fuel requirement is an obligation on a specific group of generators as opposed to all participants and there no remuneration to provide this service. However if a mechanism is to be implemented on certain units to incentivise compliance with this aspect of the Grid Code as this provision represents a significant value to the system’s security there should also be a remuneration mechanism, such as an additional secondary fuel related DS3 System Service, available to generators who provide this service. This is particularly in case in the context of the induction of a competitive capacity auction under I-SEM. Under the I-SEM CRM all capacity providers compete to secure RO contracts with the TSO. Where the Grid Code imposes additional costs on a subset of participants is this market, this costs will act a distortion in the outcome of the market which in time could act to undermine the availability of the required secondary fuel capability.

ESB GWM consider that the introduction of a secondary fuel GPI should not be implemented until a related secondary fuel system service has been developed.

Yours sincerely,

____

Keith Russell

Regulation, ESB G&WM

Response by Energia to the Eirgrid/SONI Consultation

Harmonised Other System Charges Consultation

2nd May 2018

1. Introduction

Energia welcomes the opportunity to respond to this EirGrid/SONI consultation on Harmonised Other System Charges. The introduction of ISEM will see generators having to be balance responsible. This will result in generators being commercially incentivised through the balancing market to deliver their contracted position. The TSOs acknowledge this shift by dropping the Generator Performance Incentive (GPI) for early and late synchronisation to zero. However, other charges such as the Short Notice Declaration (SND) are still applied despite an acknowledgement that generators will be similarly incentivised in the balancing market. This response briefly outlines our general comments before concluding.

2. General comments

There is an inconsistency in the approach taken by the TSOs when setting charges in the paper. For some charges the TSO acknowledges the role that ISEM will have in ensuring generators deliver their contracted position and as a result are reducing the charges to zero. For other charges such as SND, which will also be incentivised in ISEM, the TSO are maintaining a charge. There is no clear justification in the paper for these inconsistencies and logically if the TSO assumes that ISEM will sufficiently incentivise generators for some charges then the approach for all charges associated with ISEM should be the same.

In contrast to the proposed reduction of some charges, the TSO are proposing that the Primary Operating Reserve (POR) GPI is increased from €0.13 to €0.52 this represents a 400% increase. An increase of this magnitude should be accompanied by some justification and detail on the calculation but this information is lacking. The magnitude of the increase to the POR is unjustified. We would ask the same question of the SND charge, where similarly no detail has been provided in relation to the seemingly arbitrary 50% reduction to the charge or indeed why a charge is being applied at all given that generators will be incentivised in ISEM. The balancing market will act as a sufficient incentive for generators to maintain their contracted position and we contend that in line with their approach to GPIs that the TSO should reduce all charges that are also incentivised in ISEM are set to zero. It is worth adding that generators are further incentivised through the Capacity Remuneration Mechanism (CRM). The combined effect is that generators will be exposed to charges on three fronts OSC, Balancing and the CRM.

Outside of the stringent requirements being placed on conventional generators DSU is being left out of the proposals as a wait and see approach is adopted in relation to ISEM and balancing. This is in stark contrast to the duplication of charges that conventional generators will be subject to in terms of OSC and the balancing market.

Section 2.2

The TSO outline that the SND will be lowered by 50% as the view is that generators will be sufficiently penalised in the balancing market should they fail to meet their contracted position. The 50% reduction seems arbitrary and is not backed up by any detail. Conversely based on the same logic in terms of the generator being responsible for balancing in ISEM, the TSO are setting the GPI to zero.

Section 2.4

This section of the paper is proposing a 400% increase in the Primary Operating Reserve (POR) GPI from €0.13 to €0.52. This massive increase has not been accompanied by sufficient supporting evidence in the paper and we would question the justification of an increase of this magnitude. The proposed secondary fuel charge is based on 90% of the availability of the primary fuel. This should be based on the minimum of 90% of the availability of the primary fuel or the derogated secondary availability requirement.

Secondary fuel

Any changes to the secondary fuel obligation must respect existing derogations for generators.

In terms of the penalties relating to secondary fuel and availability they must be reflective of the difficulties that generators face in obtaining parts and labour for any issues that arise. Secondary fuel obligations are somewhat unique to the Irish market due to our reliance on imported fuel. As our nearest neighbours in the UK and the continent are not subject to the same secondary fuel obligations there is a scarcity of parts and skilled labour. This means that there can be a significant lead in time for generators to carry out repairs or maintenance. Generators cannot be penalised for wider market issues that are beyond their control and sufficient time must be afforded to generators to carry out repairs and maintenance. We suggest that generators can be unavailable on secondary fuel for 5% of the year before charges are applied.

3. Conclusion

There are inconsistencies in the approach taken by the TSO in the paper, some charges are being removed as it is deemed that sufficient incentives will exist in ISEM whilst others are being retained despite generators similarly being incentivised in ISEM. This contradictory approach is not accompanied by any supporting evidence nor is the reason for the differing approach explained. Based on the logic set out in the paper by the TSO it follows that where a generator is incentivised by ISEM or indeed the CRM, that there is no longer a need to maintain what are in effect duplicate charges.

We call for consistency in the approach taken by the TSO in applying charges. As such OSC that will be captured by ISEM should be set to zero.

Power NI Energy Limited
Power Procurement Business (PPB)

Harmonised Other System Charges Consultation

Response by Power NI Energy (PPB)

2 May 2018

Introduction

Power NI Power Procurement Business (PPB) welcomes the opportunity to respond to the consultation paper on Harmonised Other System Charges (OSC).

PPB is the counter-party to Power Purchase Agreements, which were established in 1992 as part of the restricting and privatisation of the electricity supply industry in Northern Ireland. PPB purchases both the capacity of the contracted generating units and any electricity generated by those units on terms specified in the agreements. The generating units are extremely flexible and reliable and therefore with the changes in the generation mix and typology of the system these units are likely to play a significant role in helping the System Operator manage the system. Flexibility is required to securely operate a system, which is being re-designed to accommodate ambitious renewable targets.

Existing OSC Developments

PPB agrees that the ISEM requirement for balance responsibility and the cost of imbalances will provide substantial incentives for participants to perform. We therefore welcome the proposed reduction of the Trip and SND rates; however we see no rationale for the 50% reduction and believe the proposed Trips and SND's are still much too high. Imbalance costs and potential Reliability Options payments in the ISEM provide a very significant incentive and therefore the need for any further GPI penalty is questionable. Even to the extent one is justified, we do not believe the arbitrary application of 50% of the current rates in proportionate and consider that is a charge is to be retained that it should be 5-10% of the existing charge. The TSOs have provided no analysis to support the arbitrary reduction of only 50% and if any charge is to be retained then this must be justified and supported by robust analysis on the impacts on the system, to justify the size of these penalties and the impact that Trips and SND's may have on imperfection costs.

Removal of the early and late synchronisation, loading and deloading charges is correct as the ISEM market will provide strong performance incentives for these.

We agree the requirement for the Minimum On Time and Maximum Number of Starts in 24 hours can be set to zero. This is also sensible approach based on both past performance and due to the interactions with the ISEM.

We disagree with the position, stated in section 2.2.2 of the consultation paper, that certain GPIs are unaffected by ISEM and hence should be retained. Based on the rationale for removing the other GPIs i.e. that the ISEM will provide adequate incentives, the same approach can be used with other services where there is already an incentive in another market. The proposal is to retain the Minimum Generation GPI but performance in this area is already addressed in the DS3 market as any increase in Minimum Generation will result in a reduction in DS3 payments. This is enough of an incentive and does not require a second incentive through a GPI. Similarly, a re-declaration of Governor Droop will be likely to reduce the provision of Reserve and so will impact the Reserve Performance Scalar which will subsequently result in a reduction in DS3 payments.

In line with our earlier concerns in relation to proposals made without any supporting analysis or justification, the proposal to increase the POR GPI rate by a factor of 4 is also made without any analysis to justify the proposed increase in the rate. Increasing this rate could also be counter productive causing units to be reticent to declare down for short periods. New technologies will also be declaring their POR availability and with the difficulty of proving these declarations on an hourly basis, any disincentive to redeclarations being made would be a disadvantage to the system.

It is an important principle that there should be no “double charging” and that where no other incentives exist then any GPI penalties and charges must be justified and proportionate to the costs they impose and any derivation of costs must be based on robust analysis and evidence rather than conjecture.

New Other System Charges

Secondary Fuel GPI

PPB believes the introduction of a Secondary Fuel GPI charge is unnecessary and discriminatory. This introduction of a charge for non-availability on secondary fuel when there is no corresponding payment for the provision of this service is unfair. If there is no payment for the provision there should be no subsequent penalty.

Such a charge would also be discriminatory since it would not apply equally across all units but would instead only be directed against those units that can provide the service. These units are providing security and flexibility to the system and yet under the proposal the only thing they receive is a penalty, while other units with no secondary fuel have no exposure. This does not engender equal and fair treatment of all technologies and provider types.

The consultation paper makes reference to the NI Fuel Security Code (NIFSC) being revised in 2015. However the NIFSC is not relevant as it only applies to a Fuel Security Event that has been notified by DETI under Article 37 of the 1992 Order. This has no bearing on day to day operation of the system.

In relation to Fuel Switching Agreements, they are still not in place and hence similarly provide no justification to introduce a Secondary Fuel availability GPI.

If introduced, the proposal would also impose a second penalty on the generator who is already exposed to costs under the NI Fuel Switching Agreement (FSA) for failure during fuel switching events, which includes fuel switching tests required by SONI. Such failure can also lead to termination of the FSA. Further, there is no cost to the system if a unit is available on its primary fuel and there is no requirement to switch fuel. Secondary Fuel has been available for many years and has rarely been required. Therefore to apply penalties is totally unacceptable particularly when conditions on the system are normal and there is no risk or potential requirement of a fuel switch.

Finally we also note there is an error in the proposed formula suggested for this charge. TP is defined in hours (as 0.5) whereas T1 is defined in minutes. These two must be defined on the same units (i.e. hours or minutes) to achieve a coherent average over the trading period.

Wind Farm GPIs

PPB believe all technologies should be treated the same and so GPIs should be applied equally to all technologies.

Additional Comments

As discussed at the time of the introduction of the Harmonised Ancillary Services arrangements PPB still believes that the TUoS Agreement is not the correct agreement to contain Generator Performance Incentives. For example, disputes in relation to RoCoF GPIs could end up being referred to the Utility Regulator as a Licence breach. Interconnector owners have also argued that GPIs should not be applicable to them as they do not sign up to a TUoSA. As new technologies come on board, they must be treated in the same manner as other participants and so must receive GPIs and so there needs to be a mechanism for charging these even if there is no requirement for them to sign up to a TUoSA.