ofgem Making a positive difference for energy consumers

| | | | |
|---|---|---|---|
| Modification proposal: | **Connection and Use of System Code (CUSC) CMP261: 'Ensuring the TNUoS paid by Generators in GB in Charging Year 2015/16 is in compliance with the €2.5/MWh annual average limit set in EU Regulation 838/2010 Part B (3)'** | | |
| Decision: | The Authority[1] has decided to reject CMP261[2] | | |
| Target audience: | National Grid Electricity Transmission plc (NGET), Parties to the CUSC, the CUSC Panel, Large Users and other interested parties | | |
| Date of publication: | 16 November 2017 | Implementation date: | N/A |

## Background to the modification

European Commission Regulation 838/2010 ('**the Regulation**') requires annual average transmission charges paid by generators in Great Britain ('**GB**') to be within the range €0 - €2.5/MWh. CUSC Modification Proposal '**CMP261**' was raised by SSE in March 2016 to remedy an alleged breach of the upper limit of the charge range imposed by the Regulation in charging year 2015/16. Whether a breach has occurred is dependent on the interpretation of the Regulation as to the charges which were intended to be excluded from the charge range. This letter sets out our interpretation of the Regulation and decision regarding CMP261.

The total revenues that transmission network owners are allowed to recover via Transmission Network Use of System ('**TNUoS**') charges each year are set by Ofgem using the price control process. Generator TNUoS charges are levied on transmission-connected generators and embedded generators ('**EG**') larger than 100MW (collectively referred to herein as '**large generators**'). The proportion of allowed revenue recovered from generation ('**G**') and demand ('**D**') network users is determined by the '**G:D split**'. The generation proportion ('**target G revenue**') of the allowed revenue is constrained by the charge range set out in the Regulation. The remainder of the networks' allowed revenue is recovered from demand network users.

The target G revenue is set ahead of the relevant charging year taking into account the permissible charge range and based on forecasts of demand, allowed revenue, chargeable generation capacity and the £/€ exchange rate. To mitigate the risk that generator charges exceed the upper limit of the charge range due to forecast error, an error margin is also included in the calculation.[3]

Generator TNUoS charges comprise a 'wider locational' charge, a 'local' charge (together referred to as 'cost-reflective' charges), and a 'residual' charge (the 'Transmission Generation Residual' ('**TGR**')). All of these charges are levied on large generators based on their Transmission Entry Capacity ('**TEC**').[4] Wider locational charges reflect the different costs that users impose on the network according to where they are located. Local charges are bespoke charges that reflect the cost of assets ('local assets')[5] required to accommodate an individual generator's connection design and location relative to the

[1] References to the "Authority", "Ofgem", "we" and "our" are used interchangeably in this document. The Authority refers to GEMA, the Gas and Electricity Markets Authority. The Office of Gas and Electricity Markets (Ofgem) supports GEMA in its day-to-day work. This decision is made by or on behalf of GEMA.
[2] This document constitutes notice of the reasons for this decision as required by section 49A of the Electricity Act 1989.
[3] The error margin is based on historic error.
[4] The maximum contractual amount of power a generator can export to the transmission system.
[5] Those assets whose primary purpose is to facilitate the connection of a generator to the MITS.

Main Integrated Transmission System ('**MITS**'). Local charges are levied on generators who connect to the MITS via local assets.

Cost reflective charges are determined based on the CUSC charging methodology, and determined irrespective of the charge range. Where the revenue from the cost-reflective charges is less than the target G revenue, the TGR charge is then set to recover the remainder. Where total revenue from cost-reflective charges exceeds the target G revenue, the TGR is used as a downward (i.e. negative) adjustment charge to ensure that average charges stay within the charge range. Generators pay 'connection charges' in addition to TNUoS charges.[6]

European Commission Regulation 838/2010

The Regulation was made pursuant to Article 18 of Regulation 714/2009 of the European Parliament and of the Council on conditions for access to the network for cross-border exchanges in electricity ('**the Electricity Regulation**'). The Regulation is intended to ensure that, with respect to transmission charges, "*variations in charges faced by producers of electricity for access to the transmission system should not undermine the internal market. For this reason average charges for access to the network in Member States should be kept within a range which helps to ensure that the benefits of harmonisation are realised*".[7]

Article 2 of the Regulation provides that charges applied by network operators for access to the transmission system shall be in accordance with guidelines set out in Part B of the Annex. For GB, the applicable range is €0 - €2.50/MWh. Paragraph 2 in part B of the Annex to the Regulation contains three exclusions to the calculation of annual average transmission charges:

1) *Charges paid by producers for physical assets required for connection to the system or the upgrade of the connection (referred to herein as the 'connection exclusion');*

2) *Charges paid by producers related to ancillary services;*

3) *Specific system loss charges paid by producers.*

CMP261 alleges that the upper limit of the charge range was exceeded in charging year 2015/16 resulting in a total overcharge to generators of £119.5 million. CMP261 proposes that a rebate of this amount should be paid to generators either based on the TEC they held in charging year 2015/16, or via future tariffs.[8]

To determine whether a breach of the Regulation has occurred we considered the interpretation of paragraph 2(1) in Part B of the Annex to the Regulation (the '**connection exclusion'**) in the context of the GB system. The two interpretations before the Authority are:

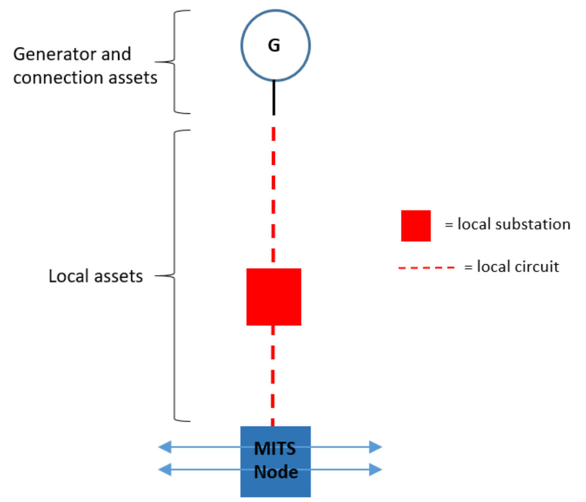
- '**narrow interpretation**' - only those charges classed in the Connection and Use of System Code ('**CUSC**') as "connection charges" are within the connection exclusion.

[6] As outlined in section 14 of the CUSC.
[7] Recital 10 of the Regulation.
[8] The proposal considers whether revenue related to cancellation charges paid in charging year 2015/16 should be included in the rebate amount. If included, the rebate would be equivalent to £119.5 million. If excluded, the rebate would amount to £101.5 million.

- '**broad interpretation**' - connection charges and most, if not all, "local charges" are within the connection exclusion (see 'the nature of the underlying asset funded by the charge' below for details).

Figure 1 shows an example of assets that constitute local assets required in order to connect a generator to the MITS[9] and are funded by local charges.

**Figure 1: Local assets required to connect a generator to the MITS**




On the basis of the facts before us, if the narrow interpretation is correct then we consider that the upper limit of the charge range has been exceeded and a breach of the Regulation has occurred in charging year 2015/16. Conversely, if the broad interpretation is correct, then the average transmission charge did not exceed the upper limit in charging year 2015/16 and hence a breach of the Regulation has not occurred.

We have previously set out our view that the Regulation is ambiguous with respect to the connection exclusion and that both the narrow and the broad interpretation constitute a reasonable interpretation.

On 8 October 2014, the Authority made a decision on CUSC modification CMP224.[10] The workgroup considering CMP224 developed four proposals, which varied in their approach to the interpretation of the Regulation. In reaching our decision, we consulted on, among other issues, the legal interpretation of the charges that fall within the connection exclusion. In the consultation document, we said that, on balance, our preliminary view was that the narrow[11] interpretation was more persuasive. The majority of responses to the consultation favoured the narrow interpretation. In our CMP224 decision we noted that, because the Regulation is ambiguous, there was a real risk that future charges based on the broad interpretation could be successfully challenged by generators, which would increase regulatory risk. By contrast, the risk of successful challenge did not arise in relation to options using the narrow interpretation because they would be compliant with the Regulation regardless of which interpretation is correct.

In reaching our CMP224 decision, we assessed the two alternative legal interpretations against the CUSC charging objectives of Standard Condition C5 of National Grid's

[9] Meaning a MITS substation, defined as a Grid Supply Point connection with two or more transmission circuits connecting at the substation; or, more than four transmission circuits connecting at the substation.
[10] CMP224: Cap on the total TNUoS target revenue to be recovered from Generation Users.
[11] Referred to as "strict" interpretation in CMP224 documents.

Transmission Licence, and concluded that setting ex-ante charges to comply with the narrow interpretation better met objectives (a), (c) and (d) when compared to the broad interpretation. However, it was not necessary for the purposes of that decision for us to reach a concluded view on which interpretation is correct, and we did not do so.

## The modification proposal

CMP261 was raised by SSE ('**the proposer**') on 8 March 2016 to propose an ex-post reconciliation of the TNUoS charges paid by GB generators in charging year 2015/16, in order to remedy an alleged breach of the Regulation. The proposer requested that the modification proposal be treated as urgent. The Authority did not grant urgency on the grounds that any rebate to generators would necessarily take place after the end of the 2015/16 charging year and therefore, we did not consider that failure to deal with the issue urgently would have a significant commercial impact on parties, consumers or other stakeholders.

We received the original Final Modification Report ('**FMR**') on 30 November 2016. We issued a send-back letter to the CUSC Panel on 22 February 2017, setting out our decision to direct that the CMP261 FMR be revised and resubmitted. The send-back letter identified two specific issues that needed to be addressed by the workgroup, namely:

- The legal text included in the FMR was not consistent with the options discussed in the FMR.
- If there had been a breach, it was not clear that the options submitted to us remedied it, i.e. that they reimburse the right users the right amount of the alleged overcharge.

Following the send-back letter, the workgroup revised the FMR and resubmitted it to Ofgem for decision on 23 June 2017.

<u>CMP261 options</u>

The CMP261 workgroup developed four proposals: the original proposal and three Workgroup Alternative CUSC Modifications ('**WACMs**') – WACM1, WACM2, and WACM3 (Table 1). The four proposals vary based on:

- the mechanism via which the rebate is paid to generators;
- the mechanism via which the rebate is recovered from demand;
- the timing of the rebate to generators and recovery from demand;
- the inclusion of revenue in respect of cancellation charges;[12] and
- the inclusion of interest paid on the rebate amount.

**Table 1: Summary of CMP261 Options**

| Proposal | Generation Adjustment Mechanism | Demand Adjustment Mechanism | Supplier Charge Year | Cancellation Charge Treatment** | Interest on credit/debit |
|---|---|---|---|---|---|
| Original | Rebate (£1.66/kW), one-off lump sum, paid "ASAP" in 2017/18. | 12 monthly debit invoices | 2018/19 | Included in calculation of rebate | Not applicable |

[12] Generators pay cancellation charges where they terminate their agreement ahead of connection to the transmission network, or fail to give the required notice of closure. Cancellation charges are applied based on the methodology set out in section 15 of the CUSC, User Commitment Methodology. The cancellation charge revenue to be potentially factored in to the generator rebate is approximately £18.3 million.

| | | | | | |
|---|---|---|---|---|---|
| WACM1 | Rebate (£1.66kW), one-off lump sum, paid "ASAP" in 2017/18. | 12 monthly debit invoices | 2019/20 | Included in calculation of rebate | Not applicable |
| WACM2 | Rebate (£1.45/kW), one-off lump sum, paid "ASAP" in 2017/18. | 12 monthly debit invoices | 2018/19 | Excluded in calculation of rebate | Interest on rebate paid at base rate +2% |
| WACM3* | TGR at tariff setting for 2019/20 | Demand residual set for 2019/20 | 2019/20 | Included in calculation of rebate | Not applicable |

All dates above are based on a CMP261 decision in charging year 2017/18, and refer to the relevant charging year (i.e. financial year).
* Where the generator rebate is paid for and recovered via tariffs it will be paid to generators based on their TEC held in the charging year in which the rebate is paid (i.e. not in 2015/16).
** If cancellation charge revenue is excluded from the rebate, the total rebate amount would be approximately £101.5 million (compared to £119.5 million if included).

CUSC Panel voting

The CUSC Panel voted on CMP261 by reference to the applicable CUSC objectives at a Special CUSC Panel meeting on 20 June 2017. The Panel agreed by majority that the original proposal, WACM1 and WACM2 were all better than the Baseline.

**Our decision**

We have considered the issues raised by the modification proposal and both the original FMR dated 30 November 2016 and the revised FMR dated 23 June 2017. We have considered and taken into account the responses to the industry consultations on the modification proposal, which are attached to the original FMR and the revised FMR.

For the reasons set out below, we do not consider there has been a breach of the upper limit on average annual transmission charges in the Regulation in charging year 2015/16. Accordingly, we conclude that the implementation of the modification proposal will not better facilitate the achievement of the applicable objectives of the CUSC, and would not be consistent with our principal objective of exercising our functions in a way that protects the interests of existing and future consumers.

**Reasons for our decision**

The proposal seeks to remedy an alleged breach of the upper limit of the charge range set by the Regulation in charging year 2015/16. The issue of whether or not the upper limit has been exceeded turns on the correct interpretation of the Regulation, specifically the connection exclusion at paragraph 2(1) of Part B of the Annex. The proposal is premised on an interpretation whereby only charges that are categorised as "connection charges" under the CUSC fall within the connection exclusion.

Having considered the material before the Authority, including in particular the legal advice provided by Addleshaw Goddard LLP to the workgroup, we do not agree with the interpretation of the Regulation which forms the basis for this proposal and all of the options before us. Below we set out detailed reasons for our view.

The CMP224 decision

An initial point concerns the significance of the Authority's decision on CMP224. In response to the CMP261 workgroup consultation, one workgroup member submitted that the scope of the connection exclusion under the Regulation is not defined with precision and that, therefore, it is left to the National Regulatory Authorities in each Member State to make a policy decision on what charges are excluded. The workgroup member argued that the Authority made such a policy decision in relation to CMP224 and that, as a matter of law, it is not now open to the Authority to make a fresh determination on the issue because to do so would be contrary to public law principles.

As mentioned above, in our decision on CMP224 we clearly stated that the Regulation is ambiguous and that both the narrow and the broad interpretation constitute a reasonable interpretation. Our decision on CMP224 did not express any concluded view on the correct interpretation of the Regulation. Rather, as explained above, we took a pragmatic approach to favour options based on the narrow interpretation on grounds of legal risk.

Accordingly, we do not accept the suggestion that the Authority has previously made a binding determination on the scope of the connection exclusion, or that it is not open to the Authority at this stage to conclude that the broad interpretation is correct. In reaching such a conclusion, the Authority is not committing an abuse of process, or re-opening a decision so as to provide for a different regulatory treatment retrospectively. Further, even if the Authority had previously expressed a concluded view in favour of the narrow interpretation (which it did not), in any event there can be no legitimate expectation that the Authority would maintain an incorrect view of the law.

<u>Interpretation of the Regulation</u>

As noted above, this is the first time the Authority has had to make a determination on the correct approach to compliance with the Regulation, and in particular to reach a concluded view on the correct interpretation of the connection exclusion.

We set out below the legislative history and our arguments in support of the broad interpretation of the connection exclusion, namely:

- **Nature of the underlying asset:** most, if not all, local assets, like connection assets, provide a physical link to the transmission system and, but for these assets, the generator would not be able to connect to the transmission system. Accordingly, charges for these local assets would fall within the connection exclusion;
- **Nature of the charge:** we do not consider that charges have to be "one-off" in nature to be excluded from the Regulation.
- **Reason for GB's higher cap:** evidence suggests that GB (along with Northern Ireland and Ireland) was granted the highest upper limit compared to other Member States in order to maintain its system of locational charges and not in order to reflect the inclusion of a wider range of charges (i.e. local charges).

*The legislative history*

In summary, the process leading to the making of the Regulation involved the following main stages:

(1) The Commission carried out initial work in 2003, including the formation of the European Regulators' Group for Electricity and Gas ("**ERGEG**").

(2) On 2 May 2005, ERGEG consulted on draft guidelines on harmonisation of Use of System charges for generators and published a draft explanatory note ("**ERGEG Consultation**"). As to the connection exclusion, the draft explanatory note stated: "Generators and consumers may also be required to pay a one-off charge for their initial connection to the grid, usually called a "connection charge" … These charges are not, however, considered to be part of the G charge for the purpose of these Guidelines". As to the higher cap for certain countries, it stated: "Within the Nordel,

UK and Irish systems, interconnected by DC submarine cables to UTCE, the main continental system, different ranges for the 'national average G' may be applied."

(3) On 18 July 2005, ERGEG published a final version of its guidelines and explanatory note, which retained the passages quoted above. ERGEG also published an evaluation of comments received from consultees. In response to comments from some consultees regarding the higher cap for the UK, ERGEG stated that "[t]he figure corresponds to the expected situation in the UK and Ireland (average charge for generators), and allows for currency risk and present efforts to create an All-Island electricity market for the Republic of Ireland and Northern Ireland Markets".

(4) On 9 December 2008, the Commission published a consultation document on the inter-Transmission System Operator compensation mechanism and on harmonisation of transmission tarification, which, amongst other things, sought views on the ERGEG draft guidelines. This document did not comment directly on the connection exclusion. As to the higher cap for certain Member States, it stated that "[i]t would be possible to increase the acceptable range to 2.5 €/MWh and remove the exceptions", or alternatively "to narrow the range so that it approaches zero", but that the latter course "[c]ould inhibit the extent to which Member States can provide locational signals at national level without adopting very significant negative charges for some zones".

(5) The Commission then produced a draft Regulation and accompanying Impact Assessment. The draft Regulation maintained the ERGEG ranges and the exclusion for physical assets required for connection was drafted in substantially the same terms as those in the final Regulation. The Impact Assessment contained a detailed analysis of what tariff harmonisation was intended to achieve. Annex F discussed the concept of "shallow" or "deep" connection charges but did not indicate what should be covered by the connection exclusion.

(6) The Regulation was made on 23 September 2010.

*The nature of the underlying asset funded by the charge*

We consider that "connection charges", as defined by the CUSC, clearly fall within the scope of the connection exclusion in the Regulation. In addition, we take the view that, properly construed, the connection exclusion also covers most, if not all, local charges that pay for local assets required to connect the generator to the MITS. This is on the basis that the latter also amount to "charges paid by producers for physical assets required for connection to the system" within the meaning of the Regulation.

We do not consider that the domestic demarcation (i.e. as defined in the CUSC) between "connection charges" and "TNUoS charges" can in itself be determinative of the meaning of the connection exclusion in the Regulation, not least since this is a harmonising EU law measure which needs to be interpreted and applied consistently across all Member States. In this regard, we note that the proposer specifically recognises[13] that the connection exclusion is not defined by reference to specific charges within the GB regulatory framework, and that an autonomous EU law meaning has to be applied. It is also of some note that in the Republic of Ireland, which has the same charge range as GB, comparable assets (to local assets) are paid for via connection charges and those charges are excluded for the purposes of calculating the annual average transmission charges under the Regulation.

[13] At §54 of their CMP261 workgroup consultation response.

In order to apply the connection exclusion, we therefore consider that it is necessary to look at the nature of the underlying assets funded by local charges, not merely at the nominal classification of the charge within our domestic GB charging structure.

Local charges are a category of charges created in 2008, which have a specific meaning within the CUSC and recover costs in respect of the "local assets" that link a generator (and its connection assets) to the MITS. We consider local assets built between a generator and the pre-existing transmission system, including (to take a particularly clear example) offshore generation-only spurs, are physical assets required for connection to the system (see Figure 1).

Put simply, such local assets provide the physical link from the generator (and its connection assets) to the transmission system and, but for these local assets, the generator would not be able to connect to the transmission system.

We are therefore satisfied that local charges in respect of (at very least) offshore generation-only spurs fall within the connection exclusion. On the basis that local charges in respect of these assets fall within the connection exclusion, we are satisfied that there was no breach of the upper limit of the charge range in the charging year 2015/16.

*Nature of the charge*

The proposer argues that the ERGEG consultation supports the view that the drafters of the Regulation only intended to include assets paid for by "one-off" charges for initial connection to the grid in the connection exclusion.

The Authority notes that references to "one-off charges" for "initial connection to the grid" do not appear in the Regulation itself. Therefore, the Authority is of the view that when applying the connection exclusion, the manner in which the charge is paid (e.g. annually as part of TNUoS local charge, rather than "one-off" or "initial") is not determinative and one must instead focus on the nature of the assets in question. This accords with ERGEG's point that the relevant charges are "usually" (but, implicitly, not always) called a "connection charge".

Furthermore, we consider that a detailed comparison of the structure of the current "connection" and "local TNUoS" charges in the GB system demonstrates that they are all, in substance, very similar to each other, since:

- Local charges and connection charges are derived from the capital cost of assets required for connection to the system, rather than being "use of system" charges in the ordinary meaning of the term.
- The capital costs in respect of connection charges and local charges can be annuitized over the lifetime of the assets (40 and 50 years for connection and onshore local charges, 20 years for offshore local charges). As such, connection charges are not required to be paid upfront in full.
- Local charges and connection charges include O&M costs, other overheads, and rates of return/margin and as such, neither local charges nor connection charges are strictly "one-off".
- In both cases, if the assets continue to be used after the depreciation periods, the generator will not pay for the original capital cost again.

Accordingly, there is no reasonable justification for treating most, if not all, local charges differently from charges that are labelled as connection charges in the context of the connection exclusion.

*The higher cap for GB*

ERGEG's evaluation of consultation responses identifies that the reason that GB was given a more generous upper limit than most other Member States (with the exception of Northern Ireland, and the Republic of Ireland) as "corresponding to the expected situation in the UK and Ireland". From this, the proposer concludes that this must have been based on GB's charging arrangements at the time, i.e. the fact that GB had a shallow connection boundary,[14] and that the connection exclusion was only intended to cover the narrow category of "connection charges" in the GB system at that time (i.e. in 2005). In other words, that GB needed to have a higher cap because it had higher charges for assets that are constrained by the charge range.

We disagree with this assessment for two reasons. Firstly, we consider that the higher upper limit allocated to GB was, at least in part, intended to allow GB to continue with its system of "wider locational" charges without significant negative charges. Both the Commission's consultation and Impact Assessment for the Regulation discuss the risk of significant negative transmission charges (i.e. paying generators to use the transmission system) if the charge range was too narrow, with specific reference to difficulties in implementation of an effective system of locational charges.[15]

Our position that GB was given a higher upper limit due to our system of locational charges is further supported by the fact that: (i) wider charge ranges do not correlate with connection boundaries (i.e. some jurisdictions with shallow connections boundaries have narrow charge ranges, €0-0.5/MWh); and (ii) wider charge ranges generally do correlate with locational charges (i.e. jurisdictions with a system of locational charges were granted an upper limit of at least €1.2/MWh).[16]

Therefore, the evidence suggests that GB was granted a higher upper limit to maintain our system of locational charging without significant negative charges, which refutes the argument that a higher limit was granted to reflect the inclusion of assets funded by local charges in the charge range.

Secondly, we also consider that it is unlikely that the Commission intended that the charging arrangements in GB (or any other Member State for that matter) that existed in 2005 would be frozen in time and not be allowed to evolve as the system demands change. As exemplified below, it is a matter of fact that GB's charging structures have changed significantly since 2004. In summary:

- Prior to 2004, GB had a "deeper" connection boundary, whereby the majority, if not all, of what we now classify as local assets, were classed as connection assets for charging purposes.

- From 2004 to early 2008, GB had a "shallow" connection boundary but no local TNUoS charges. There was a single TNUoS charge that recovered the cost of all infrastructure assets, including those now defined as local infrastructure assets. However, there was no link between the local assets a generator used, and its wider TNUoS charge.

[14] A shallow connection boundary means only costs which are exclusively associated with the new connection are charged as 'connection charges'. 'Shallowish' or deeper connection charging regimes mean connection charges also reflect some or all costs associated with additional upgrades to the network.
[15] Commission consultation pg. 24. Regulation IA, pg 25: http://ec.europa.eu/smart-regulation/impact/ia_carried_out/docs/ia_2010/sec_2010_1075_en.pdf
[16] The only exception is Denmark, which has an upper charge limit of €1.2/MWh but does not have a system of locational charges.

- Finally, in 2008, the Authority approved the introduction of local TNUoS charges which split infrastructure assets into "local" and "wider" infrastructure. The intention was to enable TNUoS charges to reflect more accurately local transmission infrastructure cost resulting from an individual generator's choice of the design and location of its connection to the network.

Accordingly, prior to 2008/9 there was no distinct category of local charges in respect of which the connection exclusion in the Regulation could be applied. The issue of whether the exclusion extends to such charges did not arise at the time when ERGEG was considering the matter. Furthermore, at that time, offshore network links were not yet in existence and it was thought they would be built and owned by generators themselves, rather than become part of the transmission network and charged for via local charges.[17] On that basis, it was understandable that no mention was made of excluding elements of TNUoS for local assets at the time of the ERGEG negotiations: these were not the subject of specific charges, so there was nothing to exclude. We therefore do not consider that ERGEG's comments should bear the weight placed on them by the proposer.

**Assessment against the applicable CUSC charging objectives**

Standard Licence Condition C10(7)(a) of National Grid's Transmission Licence requires the Authority to make its approval decision on the basis of whether the modification "would, as compared with the then existing provisions of the CUSC and any alternative modifications set out in such report, better facilitate achieving the applicable CUSC objectives".

On the basis of the legal interpretation set out above, we do not accept that there has been a breach of the Regulation, hence GB generators have not been overcharged and there is no defect to remedy in the CUSC. It follows that the premise on which CMP261 is based is incorrect and that the alleged need for a modification to the CUSC is not present. Our assessment of the impacts of the proposed modification on the relevant CUSC charging objectives also supports the Authority's decision to reject this modification. In particular, we consider that this modification would not better facilitate the CUSC charging objectives.

***(a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;***

The proposer argues that the alleged breach of the Regulation could have had a negative impact on competition in the context of cross-border trade where interconnectors could have financially benefited due to increased flows in the 2015/16 charging year. As such, the proposer argues that reconciliation is required to remedy these competition impacts. To do this, CMP261 would redistribute costs from generators to suppliers and pay an ex-post rebate to generators, determined on the basis of their TEC held in 2015/16.

We do not consider a breach of the Regulation has occurred, and since charges have not exceeded the permissible range, we do not consider adverse impacts on the competitive position of GB generators within the internal market have arisen. Further, even if a breach had occurred and demonstrably impacted the ability of GB generators to compete in the internal market, paying an ex post rebate to retrospectively adjust charges in a previous year would not directly remedy GB generators' competitive position in 2015/16.

[17] http://webarchive.nationalarchives.gov.uk/+/http:/www.berr.gov.uk/files/file38705.pdf

Since we do not consider there has been a breach of the Regulation, a generator rebate would constitute a windfall gain to transmission-connected generators (who held transmission capacity in 2015/16). This would have a negative impact on competition since it would not be paid to other types of generation (such as smaller EG) or demand-side response. Hence, a one-off rebate to larger generators in relation to past transmission charges would be likely to confer a material benefit to those receiving the rebate.[18] As such, CMP261 is less likely than existing arrangements to better facilitate objective (a).

***(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the System Operator – Transmission Owner Code) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);***

The proposer argues that CMP261 will improve cost reflectivity since it better reflects how charges should have been set in 2015/16, assuming a breach of the Regulation occurred in that charging year. Since we do not consider there has been a breach of the Regulation, charges paid by generators in charging year 2015/16 already reasonably reflect the costs incurred by transmission licensees. Accepting CMP261 and paying a rebate to generators would reduce the cost-reflectivity of charges by re-distributing already accurate costs incurred in an earlier charging year. Therefore, accepting CMP261 would not better facilitate objective (b).

***(c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;***

We consider CMP261 is neutral against objective (c). No observations on this objective were made in the revised FMR.

***(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc. License under Standard Condition C10, paragraph 1;***

On the basis of the legal interpretation set out above, this proposal does not better facilitate objective (d). The Authority has a duty to ensure compliance with the Regulation, as a result of both EU law (Article 19 of the Electricity Regulation) and domestic law provisions under section 25(1) of the Electricity Act 1989 (regarding contravention of any "relevant condition or requirement"). We believe that rejection of this proposal is consistent with our duty to comply with EU law.

***(e) Promoting efficiency in the implementation and administration of the system charging methodology.***

The current charging methodology to ensure compliance with the Regulation does not include a reconciliation process. Paying any rebate (to generators or suppliers) would be an additional and non-standard process. Where there has not been a breach of the Regulation, there is no legal basis on which a rebate is warranted and paying one would therefore not be consistent with efficient implementation or administration of the CUSC.

[18] E.g. payment of a rebate could potentially distort efficient entry/exit decisions.

Therefore, we consider that the modification proposal would not better facilitate objective (e).

**Assessment against the Authority's principal objective and statutory duties**

In making a decision on this modification proposal, we have to act in accordance with our principal objective and statutory duties. Our view is that approving this modification would not be consistent with the Authority's principal objective to protect the interests of existing and future consumers as compared to the status quo.

In reaching our decision, we have considered the likely implications the generator rebate would have for GB electricity consumers. The proposed rebate would be a short-term adjustment to generator charges, the savings from which are unlikely to be significantly passed through to consumers and therefore, unlikely to lead to lower GB wholesale prices. Although we would expect ongoing transmission charges on generators to be largely passed through to customers (through wholesale and other prices) in the long-run, cost pass-through theory suggests that short-term fixed costs or rebates are not likely to be factored into firms' pricing decisions.

Suppliers would be required to pay the costs of any rebate via future charges. It is likely that a significant proportion of these costs would be passed through to consumers through higher retail prices. Paying a rebate to generators is thus likely to increase overall costs to consumers, without justification, in the year that the rebate is recovered from suppliers. We therefore consider consumers would likely be significantly worse off in the short-term if CMP261 was accepted.

Intent of the Regulation

In reaching our decision, we have also considered whether such charging arrangements are consistent with the intent of the Regulation; a harmonising regulation to ensure network charges for access to the transmission system do not undermine the internal market.[19] In summary, we do not consider the expected outcome of charging arrangements designed to comply with the narrow interpretation of the Regulation are consistent with its intent.

Where charges are calculated to comply with a narrow interpretation of the Regulation, a negative TGR charge is required to ensure that, on average, GB generator transmission charges remain within the range of €0 - €2.5/MWh. While still small in magnitude in the shorter-term, the negative TGR is not likely to have a significant impact on competition.[20] However, in the longer-term, forecasts show the negative TGR is expected to increase significantly (i.e. become more negative), to the extent that an increasing proportion of onshore generators will have negative TNUoS charges overall (i.e. receive TNUoS payments for holding TEC).

We consider that significant and increasing payments to large generators could distort competition both in GB, and in the internal market. Significantly increasing negative payments are likely to distort competition between large generators, and other forms of generation and demand response, including interconnected generation, smaller EG, storage and demand-side response. While it would be possible, in theory, to balance some of this distortion by giving equivalent payments to other forms of generation (for example, smaller EG) and demand respond, such a solution would directly increase costs to consumers and would not address all competition impacts (e.g. equivalent payments cannot be made to interconnected generation).

[19] Recital 10 of the Regulation.
[20] We have considered the potential impact of the negative TGR in the shorter term in our decisions on embedded benefits (CMP 264/265) and the Targeted Charging Review.

Based on current forecasts, charges set to comply with a broad interpretation of the regulation would not result in the onset of significant negative TNUoS charges to onshore generators. As such, this interpretation would likely prevent the distortion described above. Nonetheless, the TGR may still become negative under this interpretation, albeit not as significantly and not until further in the future, due to the growth in revenue recovered from wider locational charges. In this case, a negative residual, or comparable 'adjustment charge' in the event a residual charge is no longer appropriate,[21] may still need to be levied on larger generators in future to ensure generator charges remain within the charge range.

The inclusion of local charge revenue (the vast majority of which is recovered from offshore local charges) in the calculation of the average generator charge is in large part driving the TGR negative. This is important to note given that the market drivers underlying generator dispatch decisions in GB are driven by different arrangements for onshore and offshore generators.

Most GB offshore generators receive a guaranteed 'strike price' via 'Contracts for Difference' ('**CfDs**').[22] This means that offshore generators are not directly affected by wholesale prices in the same way other generators are. In general, it is onshore generators without CfDs that tend to set the wholesale price. The result of the current transmission charging arrangements means that those plant which set the wholesale price, will increasingly face negative transmission charges for using the system (i.e. be paid to use the system). This will increasingly distort the wholesale price, which has implications for GB running decisions and cross-border flows.

This scenario also means that the average transmission charge for onshore generators in GB (i.e. the charges intended to be constrained at the time the ERGEG guidelines were developed in 2005, before offshore network links existed) would fall below the lower limit of the charge range (i.e. €0/MWh), which appears at odds with the purpose of the Regulation. We note that in its 2008 consultation, the Commission supported this view when it stated that significant negative charges (i.e. paying generators to use the transmission system) could be one of the negative consequences of an inappropriate charge range.[23]

## Decision notice

In accordance with Standard Condition C10 of NGET's Transmission Licence, the Authority hereby directs that modification proposal CMP261 'Ensuring the TNUoS paid by Generators in GB in Charging Year 2015/16 is in compliance with the €2.5/MWh annual average limit set in EU Regulation 838/2010 Part B (3)' not be made.

Andrew Wright
**Senior Partner, Energy Systems**

[21] We have recently indicated through our Targeted Charging Review that we think there are good reasons which support levying all residual charges on final demand. If this approach is taken forward in the future, there would be no residual charges levied on generators.
[22] A contract held between a low carbon generator and a government-owned company that guarantees the generator the difference between the strike price and the GB wholesale market price to reduce low carbon generators' exposure to volatile wholesale prices.
[23] See pg. 25 http://ec.europa.eu/smart-regulation/impact/ia_carried_out/docs/ia_2010/sec_2010_1075_en.pdf